# Future Billing Methodology

## MS14 Consultation on Billing Options for Attributing the Energy Content of Gas in the Transition to Net Zero

1st February 2022

Our vision

## Report contents

# 1 General Information

## 1.1 Why are we consulting?

There is an urgent need to decarbonise the use of natural gas which is accountable for around 40 per cent of greenhouse gas emissions via the provision of heat. As well as more efficient use of gas, this will involve moving from natural gas to greener solutions such as hydrogen and biomethane, and alternatives such as electrification.

The transition to 100 per cent hydrogen or biomethane is likely to be delivered in phases over time due to the volumes required. Blending these green gases into the existing gas grid is therefore expected to play some role in the transition to a fully decarbonised gas grid.

The energy content measured as calorific value (CV) of such gases is often lower than that of natural gas and this creates a problem for blending gases when today's metering is based on volume of gas delivered, with calorific value measured separately. Ensuring that consumers of all kinds are billed fairly for the energy they receive is an important aspect of the transition to net zero.

This consultation proposes several options to enable the fair billing of blended green gases and seeks stakeholder feedback to support a recommendation to industry in March 2022. The outputs will inform a Value-for-Money case on hydrogen blending being conducted by the department for Business, Energy and Industrial Strategy (BEIS) later in 2022.

## 1.2 Consultation Details

| | |
|---|---|
| **Issued:** | 1st February 2022 |
| **Respond by:** | 1st March 2022 |
| **Consultation reference:** | MS14 Consultation on Billing Options for Attributing the Energy Content of Gas in the Transition to Net Zero |
| **Audiences:** | All companies involved in transportation or supply of gas<br>All companies involved in the billing processes of gas<br>Companies involved in low carbon biomethane projects<br>Companies involved in low carbon hydrogen production projects.<br>Companies that are looking for development support for low carbon hydrogen or biomethane production projects.<br>Regulators and Authorities with an interest in the billing of gas |
| **Territorial extent:** | The scope of this consultation is UK-wide. |

## 1.3 How to respond

| | |
|---|---|
| **Respond online at:** | Consultation Survey (surveymonkey.co.uk) |
| **or** | |
| **Email to:** | Email victoria.mustard@xoserve.com |

## 1.4 Confidentiality and data protection

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

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

We will process your personal data in accordance with all applicable data protection laws.

# 2 Executive Summary

## 2.1 Introduction

The UK currently faces a major challenge to reduce carbon emissions to limit the impact of climate change. Nearly 40 per cent of our carbon emissions are driven from the provision of heat produced largely from the burning of natural gas. Around 85 per cent of households in the UK use natural gas as the primary means of space and water heating.

Alternatives to natural gas are therefore an important step in the transition to net zero. Green or low carbon gases such as biomethane and hydrogen are expected to have a significant role. In November 2020 the Government published its *Ten Point Plan for a Green Industrial Revolution*, which signalled policy aims to drive growth of low carbon hydrogen production to 5GW by 2030, and potential policy enabling hydrogen blending into the gas grid by 2023. This was further supported by the publication of the *UK Hydrogen Strategy* in August 2021. Biomethane continues to be supported with the *Green Gas Support Scheme.*

The current reliance on gas for heat together with the national scale and peak delivery capability of the existing gas system suggests that low carbon gases could play a key role in delivering an economically supportable transition to Net Zero alongside electrification solutions.

Whilst there is a need to fully green the gas network in the long term, such as a conversion to 100 per cent hydrogen or 100 per cent biomethane, this requires the parallel development of low carbon gas production and demand simultaneously which will be difficult to achieve. The ability to blend proportions of low carbon gases into the existing methane gas network may provide a helpful transitionary step, as it enables production to achieve scale without the need to continuously match to demand.

For hydrogen, research has established that a 20 per cent blend of hydrogen to natural gas by volume, can be achieved without any impact on the performance of domestic appliances using the blended gas and further work is progressing on commercial and industrial appliances. Biomethane is already reducing emissions from heat with around 100 plants injecting around 3 TWh per annum into the natural gas grid, and with the launch of the new *Green Gas Support Scheme*, this market is set for continued growth.

Both hydrogen and biomethane have lower energy contents than natural gas. This is currently addressed for biomethane by enrichment with propane before it is injected into the grid, undermining its green benefit. To make the transition to a low carbon gas grid, the industry needs to determine a way to manage gases that have different energy contents, without the need for enrichment while maintaining fair and equitable billing for consumers.

The concept level Future Billing Methodology (FBM) project has been exploring a range of possible billing options to maximise the delivery of green gases within the UK's gas distribution networks. Following completion of field trials, analysis of results and further work on alternative options, the sector is now seeking views from key stakeholders within the industry to help inform how billing of low carbon gases should be managed during the transition to a fully decarbonised gas network.

## 2.2 This Consultation

This consultation provides an opportunity for the gas industry and stakeholders to engage with the proposed future billing models for blends of low carbon gases and share their views. Cadent wishes to gather feedback on the findings from the concept-level gas Network Innovation Competition (NIC) project: **Future Billing Methodology**.

This is in conjunction with further work undertaken by Cadent which explored how green gases could be blended under the existing frameworks, which involves controlling the blend ratio to maintain the current Flow Weighted Average Calorific Value (FWACV) for a charging area. Cadent also wishes to gather feedback on the findings of the concept-level gas Network Innovation Allowance (NIA) Project: **Calorific Value and Gas Quality Impact Assessment of Hydrogen and Biomethane Blends.**

In this consultation paper we have set out a range of proposals of methodologies to manage green gases with varying Calorific Values (CV) for billing purposes. These are the FBM billing reform options, which focused on network analysis as a basis for zonal billing within Local Distribution Zones (LDZ), using network / CV modelling and measurement, and an alternative minimum impact option. These are ordered increasing from least change to most change and accompanied by an updated cost benefit analysis.

## 2.3 The Future Billing Options

Proposed options for consideration are set out in the table below (Options D and E are not recommended, but included here for completeness):

**Table 2-1 – Future Billing Options for consultation**

| Option | Title | Description | Opportunities | Considerations |
|---|---|---|---|---|
| **A** | **Work within existing frameworks** | Controlled blending of green gases within existing Flow Weighted Average Calorific Value (FWACV) framework. (See 6.2.1) | • No change to billing systems.<br>• No change to the Gas Calculation of Thermal Energy Regulations (GCoTER).<br>• Ability to start now | • Additional gas quality monitoring and control required to prevent Flow Weighted Average Calorific Value (FWACV) capping<br>• Limits initial blend percentages to not trigger FWACV cap<br>• Limited blend percentages likely to limit investment in blending to strategic high flow locations where the volume is significant |
| **B** | **Embedded Zone Charging** | Create new embedded charging areas around low Calorific Value (CV) gas supplies within the Local Distribution Zone (LDZ). (See 6.2.2) | • Opportunity to reduce propane enrichment for embedded biomethane supplies.<br>• Could support embedded hydrogen blending supplies | • Changes to billing systems and processes required.<br>• Changes required to Gas Calculation of Thermal Energy Regulations (GCoTER)<br>• Network modelling capability development for attribution of Calorific Value (CV) required<br>• Suitable for embedded gas supplies only<br>• Limited capacity for embedded hydrogen blending |
| **C** | **Online Calorific Value (CV) Modelling** | Calorific Value (CV) measurement at network inputs with online modelling to generate daily average CV at system node level. | • Opportunity to un-restrict the ratio of blended gas (subject to GSMR) at any location or scenario | • Changes to billing systems and processes required<br>• Changes required to Gas Calculation of Thermal Energy Regulations (GCoTER) |

| | | | | |
|---|---|---|---|---|
| | | (See 6.2.3) | • One consistent method for all gas transition scenarios | • Network modelling capability development for attribution of Calorific Value (CV) required<br>• Strategically located CV measurement required |
| D | **Zonal Calorific Value (CV) Measurement**<br><br>**NOT RECOMMENDED** | Break Local Distribution Zones (LDZs) into multiple charging areas bounded by Calorific Value (CV) measurement points.<br>(See 6.2.4)<br><br>(Up to 10,000 Calorific Value Determination Devices required). | • Limited benefit over Option B | • Changes to billing systems and processes required<br>• Changes required to Gas Calculation of Thermal Energy Regulations (GCoTER)<br>• Network modelling capability development for attribution of Calorific Value (CV) required<br>• Strategically located CV measurement required<br>• Reconfiguring of charging areas would be impractical following any network change (i.e., A new connection)<br>• High cost for CV measurement installation and maintenance.<br>• High emissions from vented gas using existing technology |
| E | **Local Calorific Value (CV) Measurement**<br><br>**NOT RECOMMENDED** | Install Calorific Value (CV) measurement points at system node level.<br>(See 6.2.5)<br><br>(Up to 44,000 Calorific Value Determination Devices required). | • Theoretically the most accurate option<br>• Potential to transmit Calorific Value (CV) data to smart meters for real time energy attribution. | • Changes to billing systems and processes required<br>• Changes required to Gas Calculation of Thermal Energy Regulations (GCoTER)<br>• Network modelling capability development for attribution of Calorific Value (CV) required<br>• Strategically located CV measurement required<br>• Reconfiguring of charging areas would be impractical following any network change (i.e., A new connection)<br>• High cost for CV measurement installation and maintenance.<br>• High emissions from vented gas using existing technology |

Further information on changes to regulations and billing systems is provided in Appendix A.

## 2.4 Cost Benefit Analysis (CBA)

The following tables have been extracted from the updated cost benefit analysis (CBA), which summarises the societal cost per tonne of carbon dioxide emissions saved by each of the proposed options.

The costs used to derive these values are limited to billing system changes only so, for example, do not include the cost of hydrogen production or network infrastructure. Further detail on make-up of the projected costs and benefits is included within section 7.

**Table 2-2 – Indicative cost per tonne of $CO_2$ abated**

| CARBON ABATED: COST PER TONNE (£) | | | | | | |
|---|---|---|---|---|---|---|
| SCENARIO | $H_2$ Blend | HIGH | CENTRAL | LOW | LOW | LOW |
| | Biomethane | HIGH | HIGH | HIGH | CENTRAL | LOW |
| FUTURE BILLING OPTION | A | 0.13 | 0.24 | 0.37 | 0.51 | 0.63 |
| | B | 4.44 | 4.58 | 4.74 | 9.01 | 16.40 |
| | C | 2.29 | 3.70 | 5.10 | 7.83 | 10.69 |
| | D | 27.93 | 27.93 | 27.93 | 59.33 | 135.44 |
| | E | 25.07 | 42.28 | 60.84 | 108.07 | 176.63 |

The gas scenarios applied in the Cost Benefit Analysis (CBA) model are shown in table 2-3 below.

**Table 2-3 - Green gas scenarios applied in the options cost benefit analysis**

| Green gas scenarios applied in CBA | High | Central | Low |
|---|---|---|---|
| Hydrogen in blend from 2035 (TWh) | 30.6 | 13.5 | 5.9 |
| Biomethane Projection for 2050 (TWh) | 125.0 | 62.5 | 31.3 |

Further detail on the basis for the above scenarios is provided in section 7.3 of this document.

## 2.5 Executive Summary Conclusion

This document proposes three viable options (A-C) to effectively manage varying CV of green gases as we transition to net zero. These are:

**Option A – work within the existing frameworks –** This option is the least change, no regrets option that can start now. Both hydrogen and biomethane blends can be delivered without enrichment under the current requirements of GCoTER by controlling the ratio of the low-CV gas with natural gas to not trigger the LDZ FWACV cap.

This results in lower percentages by volume of hydrogen (ca. 5 per cent) and biomethane (ca.30 per cent) initially where the blend is a minority proportion of the flow of gas into a charging area. This can be increased as the blend becomes a higher proportion of the gas energy flow into a charging area, as it reduces the FWACV.

If the injection of low CV gas is strategically located at high flow locations such as NTS/LDZ offtakes, the lower volumetric percentages in the initial phase would equate to significant volumes of low CV gas in absolute terms. Depending on the scale of hydrogen and biomethane deployment, this could either be the enduring solution or be implemented while work to undertake billing reform is completed.

**Option B – embedded zone charging –**This option offers a potential solution to blend from embedded supplies only, such as most existing connected biomethane plants and any future embedded hydrogen plants, without the need for enrichment.

Option B uses network modelling to create a predictable zone of influence from the embedded low CV source and allocates consumers within the zone of influence to CV measurement at low-CV input, while consumers outside of the zone of influence remain under the FWACV regime.

This option would not support blending at high volume, such as strategically located injection plants at NTS/LDZ offtakes that feed a large proportion of an LDZ.

It is worth noting that gas safety limits on blending hydrogen (hydrogen max. = $20\%_{VOL}$) may make it impractical for embedded blending sites to co-exist either locally with each other, or with upstream wide scale blending within the same Local Distribution Network.

**Option C – Online CV modelling –** This option to offers a potential solution to all blended gas scenarios and locations with unrestricted ratios (up to GSMR limits).

Option C uses strategically located CV measurement to inform online and offline network modelling to derive the CV being delivered to individual system nodes, and so to individual consumers connected to them.

This option however has not been fully tested and would require a detailed feasibility study to determine the appropriate level of inputs and software. The concept of using network modelling to determine CV has been demonstrated in FBM and is the basis for creating an embedded zone in Option B.

**Options D and E** – are discounted mainly due to the high number of CV measurement devices required for both.

Option D would require up to 10,000 CV determination devices (CVDDs) to be installed to create multiple new charging areas, which with today's technology would carry considerable costs and vent a large volume of methane into the atmosphere. Even with the advent of new technology, the practicalities of installing the volume of equipment required deem this unsupportable. In addition to this, this many charging areas would be impractical to manage because the boundaries of each zone would need to be reviewed following any change to the physical gas network.

Option E although in theory the most accurate would take this further by installing CVDDs at each system node, which would require up to 44,000 devices to be installed.

**Options in summary –** Consultees are invited to consider that Option A (work within existing frameworks) presents fewest changes and least cost, in terms of implementation at this time. This provides a distinct advantage and opportunity to begin supporting early hydrogen and biomethane blending without incurring further implementation costs. The ability to blend hydrogen at scale is most likely to vary significantly from one region to another, and the opportunity to blend biomethane without enrichment will also be dependent on the location of connection, therefore, it may also be valuable to proceed with a more detailed feasibility study on billing reform options B and/or C.

# 3 Consultation Purpose

## 3.1 What are we consulting on?

The UK's target of reaching net zero emissions by 2050 is an ambitious one, and to reach it will require significant changes to be made across every section of society. As we move towards a net zero future, we must think not only about what we will need to do to get there, but also about how we can make the transition as smooth as possible for businesses and consumers.

The Future Billing Methodology project has explored a range of possible billing options to maximise the delivery of low carbon gases within gas distribution networks in the UK, such as hydrogen and biomethane. Cadent is now seeking industry stakeholder views following completion of field trials, analysis of results and further work on alternative options, to help inform how billing of blended gases should be managed during the transition to fully decarbonised networks.

To date, Cadent has worked collaboratively with project partners, Det Norsk Veritas (DNV) and the gas industry to gather evidence and explore different options for billing blended low carbon gases at concept level. The aim of this consultation is to identify the most practicable and cost-effective solutions for consumers. We now need further industry stakeholder input to gather perspectives on these options and establish the next steps.

The proposed options on which Cadent is consulting are presented within section 6 of this document, and an updated cost benefit analysis for the options is summarised within section 7, which provides vital quantitative indicators for consideration. Section 4 contains background and contextual information to help better understanding of the rationale for the consultation. Further information on various aspects including gas regulations, codes and potential changes to billing and related systems are provided in Appendix A.

The final phase of the Future Billing Methodology project comprises the following elements:

- **MS14 industry consultation –** Channelled through this document.
- **MS15 final industry recommendations report –** This will take the learnings from the field trials, cost benefit analysis and consider feedback from the industry consultation to recommend a credible route to manage calorific value as the networks introduce more green gas during the transition to net-zero. Included within the report will be:
    - **Final project Cost Benefit Analysis –** will incorporate relevant information gathered through this consultation and project the Net Present Value (NPV) of each of the options considered for gas billing reform.
    - **High-level Implementation Road-Map –**will set out a conceptual process flow through development and towards implementation of the enduring Future Billing Methodology.

This consultation document should be read in conjunction with the main FBM project and related reports, which provide more detail, and can be accessed via the link:

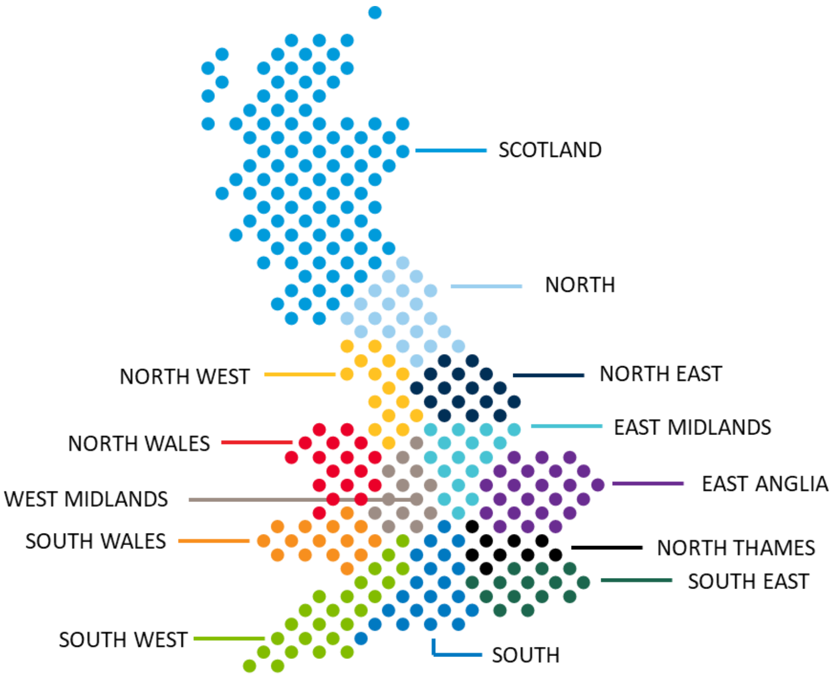
https://futurebillingmethodology.co.uk/project_updates/616/

# 4 Background and Context

## 4.1 Gas Distribution in Great Britain

Gas distribution across the geography of Great Britain currently comprises 13 Local Distribution Zones (LDZ), as shown in Fig. 4-1, below. These gas distribution networks convey gas to over 23 million consumers, such as homes, hospitals, schools, and businesses.

**Fig. 4-1 – Gas Local Distribution Zones in Great Britain**




The Local Distribution Zones (or LDZs) are owned and operated by four Gas Distribution Network (GDN) companies.

**Table 4-1 – Gas Distribution Networks (GDNs)[1] in Great Britain**

| GDN Organisation | Local Distribution Zones |
|---|---|
| Scotia Gas Networks (SGN) | Scotland, South and South East |
| Northern Gas Networks (NGN) | North, North East |
| Cadent Gas Ltd | North West, West Midlands, East Midlands, East Anglia, North Thames |
| Wales and West Utilities | North Wales, South Wales, South West |

[1] An increasing proportion of new gas connections to the gas distribution system in GB comprise networks owned and operated by Independent Gas Transporters (IGTs).

The 13 LDZs are fed primarily by the National (Gas) Transmission System (NTS), presently owned, and operated by National Grid. The NTS transports gas in bulk at high pressure from a range of gas entry terminals and storage facilities to each of the LDZs and to very large directly connected consumers, such as gas-fired power stations. Each of the LDZ networks has several input points from the NTS (NTS/LDZ offtakes) and may also have several embedded gas sources within it, such as biomethane plants.

## 4.2 Finding a Solution

The UK faces a major challenge to reduce carbon-based emissions to limit the impact of climate change. Nearly 40 per cent of our carbon emissions are driven by the provision of heat. Around 85 per cent of households in the UK use gas as the primary means of cooking and for space and water heating. Whilst some progress has been made in decarbonising electricity and transport, decarbonising heat remains problematic. Along with electrification solutions, low carbon gases are likely to play some role in the decarbonisation of heat in the future, and projects are underway by gas networks to understand what is needed to convert gas networks to 100 per cent hydrogen. A policy decision on the role of gas networks and hydrogen in domestic heating is planned by Government in 2026 as set out in the *Heat and Buildings Strategy.*

In November 2020, the Government published its *Ten Point Plan for a Green Industrial Revolution*, which signalled policy aims to drive growth of low carbon hydrogen production to 5GW by 2030, and potential policy enabling 20 per cent hydrogen blending into the gas grid by 2023. This was further supported by the publication of the *UK Hydrogen Strategy* in August 2021. Biomethane continues to be supported with the *Green Gas Support Scheme*.

The existing national gas grid has developed over many decades to provide the capability to fulfil peak heat demand safely and rapidly, with virtually 100 per cent reliability. The national reliance on gas to provide heat, together with the scale and peak delivery capability of the existing gas system suggests that the infrastructure could be used to deliver low carbon gases in the future. The fact that different gas sources can have differing energy contents is a complicating factor and impacts on the fair billing of consumers.

## 4.3 Hydrogen

Hydrogen can support the decarbonisation agenda. Low carbon hydrogen can be produced in a number of ways, including steam methane reformation with carbon capture and storage (CCS), and by electrolysis using renewable electricity from solar and wind power. Both production methods can be used in a way that keeps carbon emissions to a minimum.

The recently published *Hydrogen Strategy* signals the key role that hydrogen blending could play in supporting the development of a low carbon hydrogen economy. Hydrogen blending offers a unique opportunity because it requires no change to appliances in the homes of consumers. Therefore, hydrogen blending could be used to support early hydrogen production projects by providing a demand base to avoid the need to continuously match supply with demand.

The Department for Business Energy and Industrial Strategy (BEIS) has plans to conduct a value-for-money assessment on blending later in 2022 and will make a formal policy decision on the role of blending in late 2023. To enable a positive policy decision the safety case will be made through projects such as HyDeploy, but the technicalities of managing gases with different calorific values (CVs) for billing purposes will need to be resolved.

## 4.4 Biomethane

Biomethane is already helping to decarbonise heat with around 100 plants injecting green renewable gas into networks to date. Biogas is mainly produced by a process called anaerobic digestion, which converts feedstocks such as plant material, manure, sewage and much more, into a source of renewable gas where it can be used locally to produce heat and power or upgraded into biomethane for injection into the natural gas network to be used by consumers.

With the launch of *The Green Gas Support Scheme*, a new support mechanism running from 2021 – 2025 that subsidises production at new plants, the biomethane market is set to grow in the coming years. Biomethane is also a suitable alternative green fuel for heavy goods vehicles with a growing number of compressed natural gas refuelling stations providing biomethane for transport in the UK already. Its composition is the same as natural gas, so it can be transported and used in the same way, but it has a lower energy content than natural gas, which is currently addressed by enrichment with propane, which undermines its green benefit.

In recognition of the green benefits of biomethane, Cadent is developing a biomethane connections blending strategy, which aims to enable some future biomethane supplies to connect to the gas distribution grid in a way which that does not require pre-entry enrichment with high carbon, fossil-based propane. However, certain plants connected to parts of the network where natural gas flow is low, would still be required to enrich the biomethane before injection, and most existing sites would have to continue to do so.

Differences in the energy content of gases such as natural gas, hydrogen and biomethane sharing the same network could pose a significant barrier to enabling low carbon gases, which is explained in further detail in the following sections. The framework options presented by the Future Billing Methodology project explore different potential ways of addressing this problem.

## 4.5 Gas Energy and Charging Today

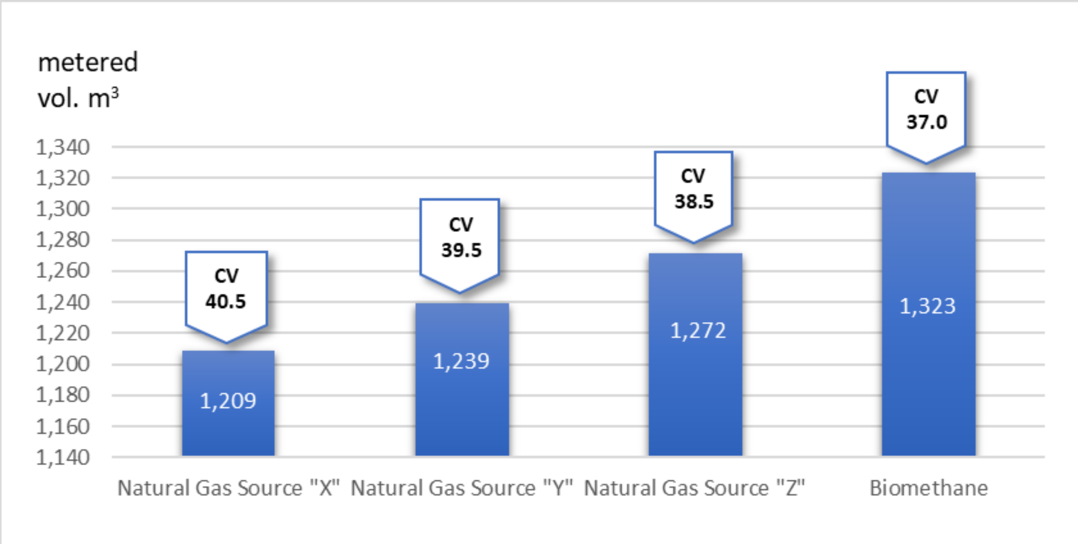
Nationally, gas is priced and sold in energy terms and expressed in kilowatt hours (kWh). Gas consumption by consumers is metered in volume by cubic metres, only at the point of use, and the energy content (Calorific Value or CV, expressed in megajoules per cubic metre $MJ/m^3$) is assigned separately as part of the billing process.

The reason for this arrangement is because, unlike electricity, the energy content of different gas sources can vary, and with today's technology, measuring the energy content of gas requires bulky and expensive gas sampling equipment which vents the sampled gas stream into the atmosphere. This measurement equipment is located at each entry point to the gas distribution network, as it would not be practical or economic to deploy such devices at scale either within the gas network or at the consumer's meter[2], based on existing technology[3]. The impact of varying energy content of gases is illustrated in Fig. 4-2, below.

[2] With the exception of Very Large Daily-Metered Customers such as power stations, which have on-site calorific value measurement equipment at the meter.

[3] Compact, non-venting technology is in development, but is yet at an early stage.

**Fig. 4-2 – Chart illustrating the impact of the calorific value of different gases / blends on metered volume required to meet a fixed 13,600 kWh energy output.**




The chart above illustrates how gases of progressively lower CV require a greater volume through the consumer's meter to meet the same fixed energy requirement. The CV of each gas (stated in megajoules per cubic metre or MJ/$m^3$) is shown above each column. At 37 MJ/$m^3$, un-enriched biomethane would require around 9.5 per cent more volume to deliver the same heat output as natural gas source "X", at 40.5 MJ/$m^3$.

## 4.6 How Energy Content Affects Consumer Bills

Under the existing gas thermal energy and billing regime, the energy content of gas used for billing consumers within each LDZ is calculated as a flow-weighted average of the energy inputs to the LDZ for each Gas Day.

This approach works well where there is little difference in energy content of the gas at each input point to the LDZ, but with the introduction of an individual low-CV gas source could disadvantage consumers receiving that gas, if billed on the overall average, as shown in the example in Table 4-2, below.

**Table 4-2 – Impact of different gas CV values on typical annual domestic consumer bills**

| **Column Ref:** | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** |
|---|---|---|---|---|---|---|---|---|---|
| **Impact of different CVs on billing** | Annual Gas Energy | CV of Gas received at meter | Metered volume | Average unit charge for gas* | Annual Gas Bill based on **B** | LDZ FWACV used for Billing | Annual Gas Bill based on **F** | Over / under-billing | Annual Bill Impact **(H/E)** |
| units | (kWh) | (MJ/$m^3$) | ($m^3$) | (p/kWh) | (£) | (MJ/$m^3$) | (£) | (£) | (%) |
| **Consumer 1** | 13,600 | 40.5 | 1,209 | 4.4853 | 610 | 39.5 | 595.00 | -15 | -2.5% |
| **Consumer 2** | 13,600 | 39.5 | 1,239 | 4.4853 | 610 | 39.5 | 610.00 | 0 | 0.0% |
| **Consumer 3** | 13,600 | 38.5 | 1,272 | 4.4853 | 610 | 39.5 | 626.00 | 16 | 2.6% |
| **Consumer 4** | 13,600 | 37.0 | 1,323 | 4.4853 | 610 | 39.5 | 651.00 | 41 | 6.7% |

** Based on 2019 Ofgem estimate that domestic households paid on average* ***£610*** *based on fixed consumption of 13,600 kWh of Gas*

The table above shows four example domestic consumers, each located near to a different entry point to a theoretical LDZ. The gas reaching consumers 1, 2 and 3 originates from different sections of the NTS. Consumer 4 is located near to an LDZ-embedded gas supply from a biomethane plant, so receiving gas at a lower calorific value of 37 MJ/$m^3$.

## 4.7 The LDZ Flow Weighted Average CV Cap

In the scenario shown in Table 3-2, the percentage variance in annual bills between consumers 1, 2 and 3 reflect the maximum level of cross-subsidy normally experienced under the existing LDZ flow-weighted average CV framework. If receiving un-enriched biomethane, consumer 4 would be further disadvantaged by being billed on the LDZ flow-weighted average CV, as shown in column F.

So, to protect consumers from being overbilled, the present Gas Calculation of Thermal Energy Regulations (GCoTER) require the average energy content of the gas (calorific value or CV) to be no more than 1 megajoule per cubic metre above the lowest-CV gas source to that LDZ.

As a result, even the smallest quantity of low-CV gas outside the CV cap tolerance can trigger significant underbilling and distortions in gas energy allocation, which affect Shipper/Supplier billing and generate NTS CV Shrinkage in respect of the unbilled energy in the LDZ.

**Table. 4-3 – Impact of triggering LDZ FWACV Cap in a medium-sized LDZ**

| | | | BIO ENRICHED WITH PROPANE | | | | PROPANE SWITCHED OFF | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **SIMPLE EXAMPLE LDZ (Gas Day)** | | | **VOLUME** | **CV** | **ENERGY** | | **VOLUME** | **CV** | **ENERGY** | |
| | | | mcm | MJ/$m^3$ | GWh | % LDZ Total | mcm | MJ/$m^3$ | GWh | % LDZ Total |
| Natural Gas Source "X" | | | 3.9 | 40.5 | 43.3 | 33.3% | 3.9 | 40.5 | 43.3 | 33.3% |
| Natural Gas Source "Y" | | | 3.9 | 39.5 | 43.3 | 33.3% | 3.9 | 39.5 | 43.3 | 33.3% |
| Natural Gas Source "Z" | | | 4.1 | 38.5 | 43.3 | 33.3% | 4.1 | 38.5 | 43.3 | 33.3% |
| | | scmh | | | | | | | | |
| Biomethane | | 600 | 0.014 | 37.0 | 0.148 | 0.1% | 0.014 | 37.0 | 0.148 | 0.1% |
| Propane | 3.5% | 21 | 0.001 | 96.0 | 0.013 | 0.0% | | | | 0.0% |
| Biomethane Total | | | 0.015 | 39.0 | 0.161 | 0.1% | 0.014 | 37.0 | 0.148 | 0.1% |
| LDZ FWACV | | | 11.9 | 39.5 | 130.2 | 100.0% | 11.9 | 39.5 | 130.1 | 100.0% |
| Lowest Source CV + 1 MJ/$m^3$ | | | | 39.5 | | | | 38.0 | | |
| LDZ FWACV USED FOR BILLING | | | 11.9 | 39.5 | 130.2 | 100.0% | 11.9 | 38.0 | 125.3 | 96.2% |
| UNBILLED ENERGY IN LDZ | | | | | 0.0 | 0.0% | | | 4.9 | 3.7% |
| SYSTEM AVERAGE PRICE GAS YEAR 2020-21 | | | | | | | | p/kWh | 2.3212 | |
| **NTS CV SHRINKAGE FOR GAS DAY VALUED AT SAP** | | | | | | | | **£m** | **0.113** | |

The example in Table 4-3 above illustrates the impact of switching off propane enrichment at a small biomethane injection site located within a medium-sized LDZ which has a flow-weighted average CV of 39.5 MJ/$m^3$ and a total daily energy throughput of 130 GWh. The inflow of just 0.148 GWh of un-enriched biomethane, at 37 MJ/$m^3$ causes the entire LDZ to be billed at 38 MJ/$m^3$, which excludes 4.9 GWh of energy from billing on the day. This is 33 times the amount of energy produced by the biomethane plant itself. The unbilled energy is transferred to the NTS CV shrinkage account, and the shrinkage cost is charged back to shippers at System Average Price (SAP). Using an average SAP price for gas year 2020-21, this would equate to around £113,000 for one gas day alone. In this example, customers receiving the pure biomethane would be over-billed by 1 MJ/$m^3$ and consumers elsewhere would be significantly under-billed because of the CV cap across the LDZ.

The example shown in Table 4-3 above clearly illustrates the disproportionate impact of the CV cap and why biomethane entry flows must be propane-enriched. If changes were made to GCoTER to remove the CV cap, consumers would suffer enduring and unacceptable levels of cross subsidy, with those consumers receiving lower-CV gas being persistently disadvantaged.

Hence the aim of the Future Billing Methodology project is to explore ways in which CV could be attributed to consumers metered gas flows more in line with the energy content of their actual physical gas supply, to keep billing fair in a diverse-CV gas supply transition.

# 5 Project Findings and Outputs Summary

The key findings from the FBM project field trials comprise three DNV reports which follow the remit set in the original NIC project direction. A separate report, assessing the potential for hydrogen and biomethane blending within the existing frameworks has been produced for Cadent by Dave Lander Consulting Limited. The findings of these reports are summarised below.

## 5.1 MS11 Report on the Smart Meter Laboratory Trial

- **Smart Meter Capability –** From the field trial, this report concluded that existing smart meters could, in principle, deliver locally derived CV data to gas smart meters and convert this to a kWh value which could then be used for direct billing purposes, and that this could potentially provide a future platform to support a phased transition to full gas energy smart metering and billing at the point of use.
- **Requirement to upgrade gas smart meters –** A significant barrier to upgrading consumer meters was identified by the trial as all metering equipment and respective power supply would need to be upgraded to have active rather than passive technology.
- **Need for Great Britain Companion Specification (GBCS) use case –** The report noted that a GBCS use case would be needed to allow retrieval of kWh data from smart meters. This would require a change to industry specifications, together with the appropriate pre-implementation testing.
- **Required changes to Data Communication Company (DCC) data capacity and billing systems –** This would also drive significantly increased DCC data traffic load and require change management to transit from the existing Xoserve settlement mechanism, together with impacts on Shipper/Supplier billing systems, with significant cost implications. The report also noted this work would fall outside the remit of gas transportation and would be driven principally by gas Shippers/Suppliers.
- **Considerations –** In the light of the above findings, the report recommended that the industry may consider whether it would be appropriate and generally advantageous to progress such changes in the future, and that such considerations should also include the implications of a future move to hydrogen transportation. If agreed, a separate industry engagement would be required to estimate the costs and timescales for implementing the necessary changes.

## 5.2 MS12 Final Report on Field Trial Progress

- **Successful deployment –** The Future Billing Methodology project field trials overcame numerous issues and successfully deployed 34 sites at suitable measurement locations. Site-by-site evaluation, taking account of cost, complexity and timing ensured a robust optimisation of the field trial site population with respect to gas zones of influence around the target embedded gas sources.

- **Effective and reliable oxygen measurement –** The installed instrumentation was suitable, and the oxygen sensor proved to be an effective and reliable instrument for successfully measuring oxygen content and hence tracking biomethane through the test networks.
- **Successful data gathering –** Except for some minor gaps in the recorded data, data was gathered and transmitted reliably from all sites which underwent successful Site Acceptance Tests (SAT). Although the Covid-19 pandemic did cause some site delays.
- **Data compatible for modelling & analysis –** The data gathered was compatible with the existing network models and so, appropriate to be fed into the development of modelling techniques for determining charging areas for the MS13 report.

## 5.3 MS13 Report on Novel Validation of Network Modelling for Embedded and Network Charging areas

- **Representative body of data –** The body of data obtained from the field trial provided a representative base for seasonal effects to be analysed. (It is worth noting that the measurement window of the FBM field trial was extended to 31st March 2021 to ensure completeness of capture of winter data across the commissioned trial sites.)
- **Strong correlation between model and measurement –** Field trial measurements of molecular oxygen levels have demonstrated how the zone of influence exerted by the biomethane supply varies under differing demand conditions. The strong correlation demonstrated between measured and modelled oxygen levels gives confidence that network modelling can accurately predict or simulate the travel and mixing of gases under varying demand conditions and, with appropriate software, could robustly attribute CV at system node[4] level.
- **Embedded charging area –** This could enable a charging area to be developed around an embedded source of gas and so remove the need for enrichment with fossil-based propane, whilst constraining billing disparities to within the range experienced under the existing LDZ flow-weighted average CV regime.
- **High-level methods for identifying charging areas –** The MS13 report developed several high-level methods for identifying charging areas for future billing purposes, with the intention of aligning with the current Gas Calculation of Thermal Energy Regulations, which requires allocation to one or more physical Calorific Value Determination Devices (CVDDs) when defining a charging area. (Further commentary is provided in section 2 within Appendix A.)
- **Factors for consideration –** Learnings from the project suggest that the charging area determination process must take a wide range of network and operational factors into account and would benefit from an appropriate level of automation to ensure timeliness and consistency of application. Further, that frequency and timing of the process is important.

## 5.4 Project Report - Calorific Value and Gas Quality Impact Assessment of Hydrogen and Biomethane Blends

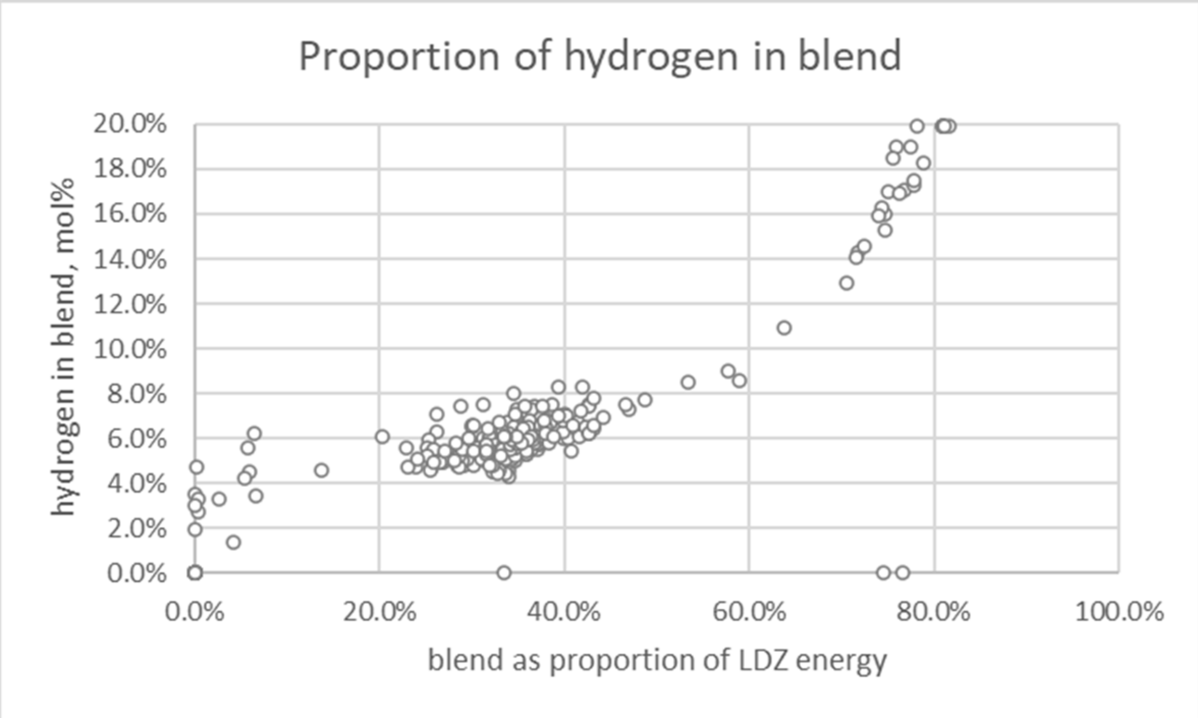
- **The no change approach -** The counterfactual to billing reform, which could avoid the need for changes to regulations, billing systems and processes or begin to decarbonise heat during their development. This approach would be to find a way to continue to work within the existing framework. Further work has been undertaken by Cadent to evaluate the potential

[4] A system node is a section of pipework, fed by specific regulators on the gas distribution system and represents the lowest level of detail at which network models could simulate gas demand from loads connected to it, and hence the travel, mixing and CV of gas.

for hydrogen and biomethane blending within the current billing methodology and regulations.

- **Separate Network Innovation Allowance (NIA) project -** During 2021 a separate NIA project, 'Calorific value and gas quality impact assessment of hydrogen and biomethane blends' was initiated by Cadent to evaluate the potential for hydrogen blending around future hydrogen supply hubs. This project identified that, where sufficient hydrogen supply exists upstream, and with the necessary Gas Safety Management Regulations (GSMR) approvals and system controls in place, blending hydrogen into the natural gas supply at strategic locations could provide a significant opportunity to begin the decarbonisation process. This would be via working within the existing GCoTER and avoiding the immediate need for changes to the existing billing regime and systems, while potentially reducing or removing the need for biomethane enrichment.
- **Initial phase: Hydrogen blend as minority of LDZ energy –** In an initial phase analysis of historical injection volumes and natural gas CV at NTS/LDZ offtakes in two of Cadent's LDZs indicated that low percentages of hydrogen could be blended with natural gas, at one or two candidate offtakes, such as a "minority energy flow" into the LDZ without triggering the FWACV cap. This could account for a significant amount of hydrogen in absolute terms and could begin to stimulate the upstream hydrogen supply market at hubs. For example, blending hydrogen at $5\%_{VOL}$ at two main offtakes in a larger LDZ could account for around 400 GWh of sustainable hydrogen per year, equating to an annual $CO_2$ abatement equivalent of 57,000 tonnes.
- **Later phase: Hydrogen blend as majority of LDZ energy –** Where hydrogen blend accounts for a "majority energy flow" into the LDZ, this would enable the percentage blend of hydrogen in natural gas to be ramped up, towards the proposed 20% vol. limit, in line with the increasing proportion of the LDZ energy supplied as hydrogen blend. This is illustrated in the chart in Fig. 5-1 below.
- **Benefit for biomethane injection -** Increasing the amount of LDZ energy supplied with a lower-CV hydrogen blend would reduce the overall charging area's FWACV, which would reduce or eliminate the need for enrichment of any biomethane injection sites embedded within the LDZ. This arrangement would be GCoTER compliant without the need for changes to billing systems.

**Fig 5-1 – Percentage hydrogen blend in natural gas achievable within LDZ FWACV cap, dependent on blends proportion of total LDZ energy.**




The chart above illustrates that as the proportion of LDZ energy delivered as blend (X axis) increases, this allows for a higher volumetric percentage of hydrogen (Y axis) to be blended at the injection point, as the greater proportion of lower-CV hydrogen blend acts to decrease the flow-weighted average CV across the LDZ.

- **Biomethane blending strategy -** Cadent is developing a biomethane blending strategy, in parallel, which could enable future biomethane supplies to blend biomethane into LDZ system native gas within existing FWACV limits and so minimise or remove the requirement to add fossil-based propane pre-entry to the LDZ network. This will enable the full green benefits of this renewable-source gas.

# 6 Consultation options

## 6.1 Introduction

Any change to support the more specific attribution of gas CV to consumer metered volumes in a diverse-CV gas transitional scenario would require complex system development. It will need changes to central and client billing systems and CV data flows to support meter-point specific CV for billing (see 4 in Appendix A). As well as enabling amendments to the gas thermal energy regulations, both to allow network modelling to be used to configure sub-LDZ charging areas, and in the case of Option C below, to attribute modelled CV for billing (see section 2 in Appendix A).

However, with the necessary GS(M)R changes and system control features in place, hydrogen blending could be initiated whilst remaining within the current billing frameworks and along with biomethane blending, could start to make progress on decarbonising gas distribution networks. This could either form the definitive solution, ahead of switching networks to 100 per cent hydrogen, where feasible, or the beginning of gas decarbonisation whilst the changes that would be required to deliver billing reform to support a diverse-CV gas supply are in a transition phase.

Ultimately, 100 per cent hydrogen networks would avoid these requirements. This is because the CV of pure hydrogen is a consistent value[5]. However, it is worth noting that a transitional blended gas phase could remain for some time in network areas where hydrogen supply and storage is being scaled in increments to enable a phased roll out of network conversion to 100 per cent. This is dependent on a future policy decision on the role of hydrogen in heating.

For completeness, section 6.2 includes all the options developed within the FBM project itself, although two of these options (D and E) are not considered feasible due to cost and associated emissions.

## 6.2 Consultation Options

### 6.2.1 OPTION A – Work within existing frameworks

Option A is effectively the “do nothing” option from a billing regime viewpoint and could provide a cost-effective, no-regrets route to start and progress decarbonisation of national gas distribution networks at a small scale.

This option would involve the blending of low carbon gases, like hydrogen and biomethane, in a controlled manner to maintain compliance with the existing thermal energy regulations, as described in the two figures below.

[5] The CV of pure hydrogen is 12.1 megajoules per cubic metre (MJ/m$^3$) at 1013.25 millibars and 15 degrees Celsius.

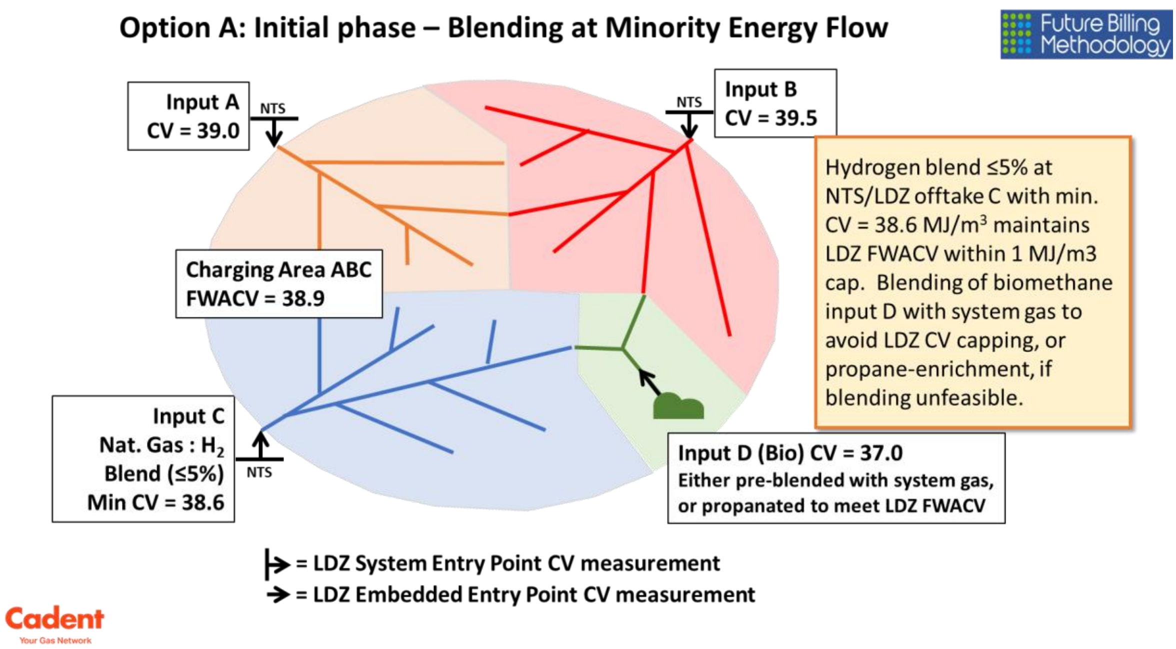



**Fig. 6-1 Schematic – Option A: Blending of green gases as minority energy flow in LDZ**

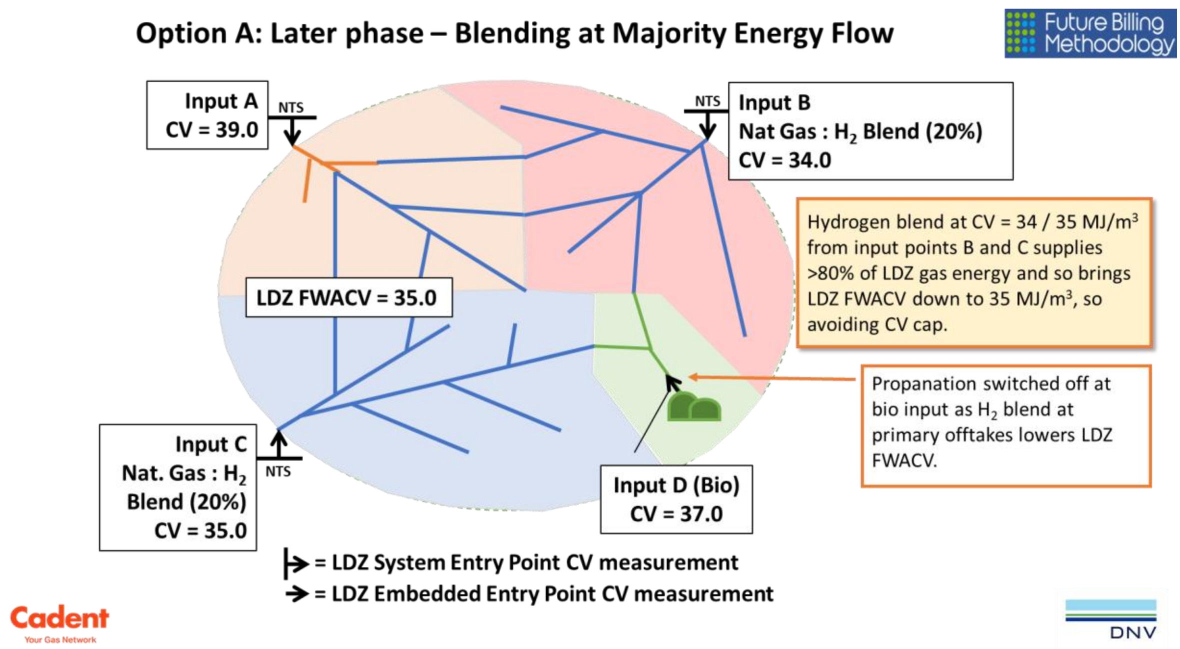



**Fig. 6-2 Schematic – Option A: Blending of green gases as majority energy flow in LDZ**

### Opportunities

- This option could begin the decarbonisation of gas distribution networks without the immediate need for changes to billing or regulations.

- It could stimulate hydrogen production by blending significant volumes at strategic locations (e.g., close to industrial clusters) while maintaining the LDZ FWACV envelope.
- Where hydrogen supply becomes sufficient, hydrogen blends up to within the 20%$_{VOL}$ limit could account for the "Majority energy flow" into the LDZ. This would automatically enable reduction or elimination of propane-enrichment of low-CV biomethane supplies, as the LDZ FWACV is lowered.

**Considerations**

- This option would require additional gas quality monitoring and control to ensure the LDZ FWACV cap is not triggered, limiting the blended percentage of hydrogen in the initial phase.

### 6.2.2 OPTION B – Embedded Zone Charging (FBM "Pragmatic" Option)

Option B would use network and CV modelling to create separate charging areas within the LDZ around embedded supplies such as biomethane plants. It would apply the CV measured at the relevant embedded gas source for billing consumers within each embedded charging area. Consumers outside the embedded charging areas would be billed on the LDZ FWACV excluding the embedded inputs.

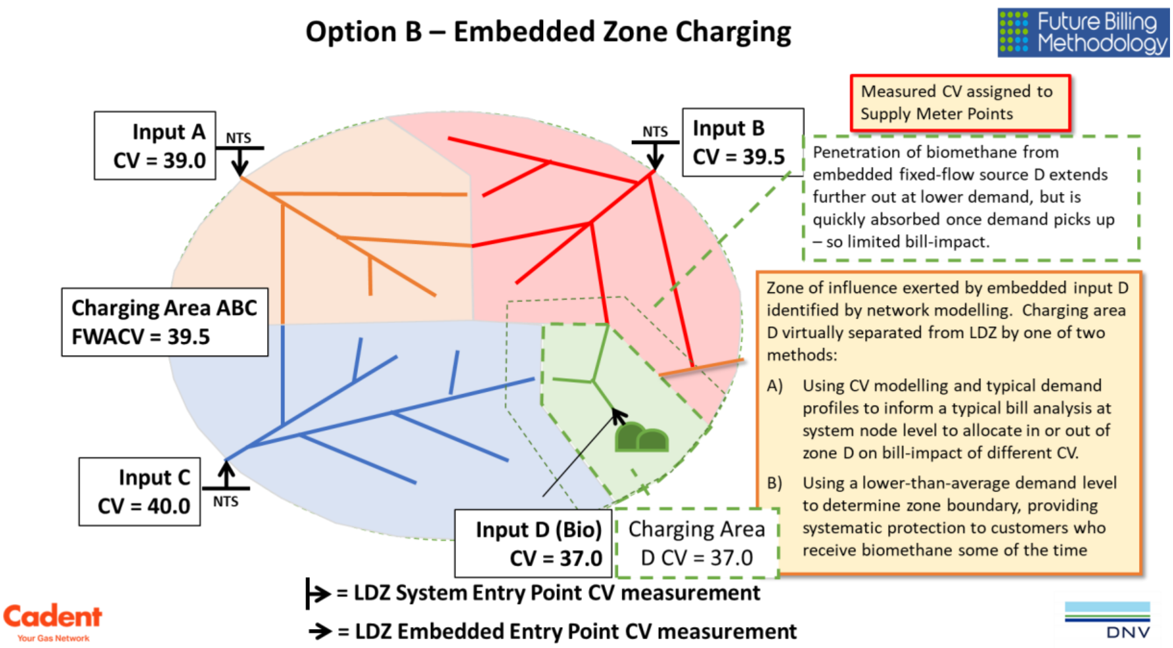



**Fig. 6-3 Schematic – Option B: Embedded Zone Charging**

**Opportunities**

- This option could enable cost-saving and carbon abatement from removal of propane-enrichment of low-CV embedded hydrogen or biomethane supplies where the network setting makes this feasible.
- Developing this option would align with the onward development of LDZ-wide network modelling for fully modelled CV for billing.

- This option could de-restrict the ratio of low-cv gas with natural gas (within GSMR limits) from embedded supplies.
- We consider this option could work for embedded low-CV supplies in LDZs alongside Option A "Work within existing frameworks".

**Considerations**

- The scope of this option is limited to specific embedded or minority flow supplies into the LDZ and could not be used to support blending upstream in the local transmission network, due to the extensive reach of blended gas across the LDZ.
- This option would require model development, set-up, and operation including some level of process automation, potentially also requiring regular reconfiguration of the embedded low-CV billing zones in a dynamic network setting.
- This approach would require a billing system change to support meter-point-specific CV and corresponding changes to central and Shipper/Supplier billing systems, processes, and data flows[6].
- This option would require amendment to GCoTER to permit and regulate the use of network modelling to create embedded charging areas within LDZs.
- Potential changes would be required to GEMINI system and Section F of Uniform Network Code (UNC) Offtake arrangements document, as the definition of charging areas would change from LDZ to a dynamic arrangement to accommodate new embedded entry connections as they arise.
- Changes would be required to UNC around CV data file formats and flows (no changes to LDZ charging methodology and LDZ could be maintained whole for quantification of unidentified gas (UIG), demand estimation, energy balancing and other purposes).

### 6.2.3 OPTION C – Online CV modelling (FBM "Fully modelled CV" Option)

An alternative approach developed as part of the preparatory work supporting the MS13 report, Option C would use CVs measured at the LDZ entry points combined with live system data to drive online network modelling of the Local Transmission System (LTS).

This would generate a continually updated set of modelled CV values at the exit points from the LTS to the lower pressure tiers over defined periods of time, for example hourly or daily. Allocation of a billing CV for consumers downstream could be achieved through either:

a) **Predictive –** undertaking upfront offline modelling of lower pressure tiers to allocate consumers to a charging area assigned to a LTS offtake for billing purposes. The billing CV would be provided by the online LTS system.
b) **Reactive –** recreating the lower pressure tiers network state after the day using the CVs from the modelling of the LTS as one of the inputs to the downstream pressure tier models. In this

[6] Except potentially for physically discrete single-fed sub-networks, which could be physically separated from the parent LDZ for CV attribution by inserting a CVDD on the in-feed pipe.

case, each network analysis model system node would become a charging area and modelled CVs would be attributed to individual meter points across the gas network.

This option also has the potential for extending online modelling to cover the lower tiers of the gas distribution system. This modelled CV approach would likely require ongoing validation from several strategically placed CV measurement devices within the network. A simple schematic describing this option is provided below.

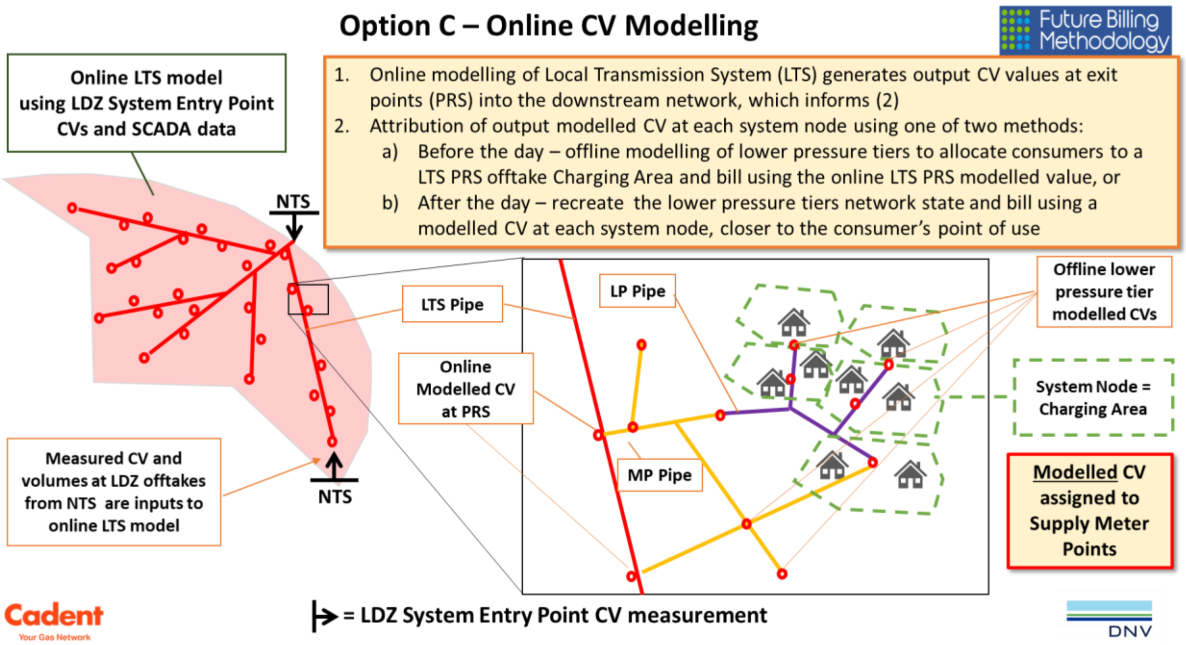



**Fig 6-4 Schematic – Option C: Online CV Modelling**

**Opportunities**

- This option could provide one consistent methodology for attributing gas CV for billing across the range of potential gas transition scenarios, including hydrogen blending both on "minority energy flow" and "majority energy flow" bases, together with biomethane.
- If proved robust, this approach could present an improved attribution of billable energy to consumers, reducing the level of cross-subsidy experienced under the existing LDZ FWACV regime.
- This option could derestrict the ratio of low-cv gas with natural gas (within GSMR limits) from both embedded supplies and strategically located supplies.

**Considerations**

- This option would involve model development, set-up, and operation including process automation, potentially requiring regular reconfiguration of the charging areas within the LDZ in a dynamic network setting.
- As with Option B, this would require a move to meter-point-specific CV and corresponding changes to central and Shipper/Supplier billing systems, processes, and data flows.
- This approach would require a detailed feasibility study and full CV modelling validation in a diverse-CV network setting, with the required derogation from regulations, together with a

level of on-going verification via strategically placed CV measurement within the LDZ network.

- This option would require amendment to GCoTER to permit/regulate the use of network modelling to create embedded charging areas within LDZs.
- Changes would be required to GEMINI system and Section F of UNC Offtake arrangements document.
- Changes would be required to UNC around CV data file formats and flows (no changes to LDZ charging methodology and LDZ could be maintained whole for quantification of unidentified gas (UIG), demand estimation, energy balancing and other purposes).

### 6.2.4 Options D and E - not recommended

The MS13 report noted that, with established technology, the additional CV measurement requirement within these options (referred to in that report as FBM Options 2 and 3) would drive very significant capital and operating costs for the installation, powering, maintenance, replacement of CV measurement devices. Also, without technological advances to avoid venting sampled gas, the levels of emissions for CV measurement at this scale would be unsupportable (see Table 6-1 below.)

**Table 6-1 Billing options: Indicative CVDD population and venting impact (current technology)**

| OPTION | DESCRIPTION | CVDD no. | Venting tCO2e |
|---|---|---|---|
| A | WORK WITHIN EXISTING FRAMEWORKS | 0 | 0 |
| B | EMBEDDED ZONE CHARGING | 0 | 0 |
| C | ONLINE CV MODELLING | 500 | 6,224 |
| D | ZONAL CV MEASUREMENT | 10,000 | 124,485 |
| E | LOCAL CV MEASUREMENT | 44,000 | 547,734 |

Whilst advances in gas analysis technology may overcome the need to vent sampled gas to the atmosphere, the installation, powering, maintenance, and data communications requirements for such a significant population of CVDDs would still prove uneconomic and impractical in the real world. As a result, neither Options D nor E are recommended for implementation, but are included here for completeness. Further commentary on this and other related factors is provided in section 12 of Appendix A.

#### OPTION D – Zonal CV Measurement (FBM Composite Option)

Option D would use a combination of network modelling, as for Option B, and the identification of single fed sections of the LDZ network to determine charging areas. These charging areas would use additional embedded CV measurement for all consumer billing. (Estimated at up to 10,000 extra Calorific Value Determination Devices (CVDDs across GB networks.)

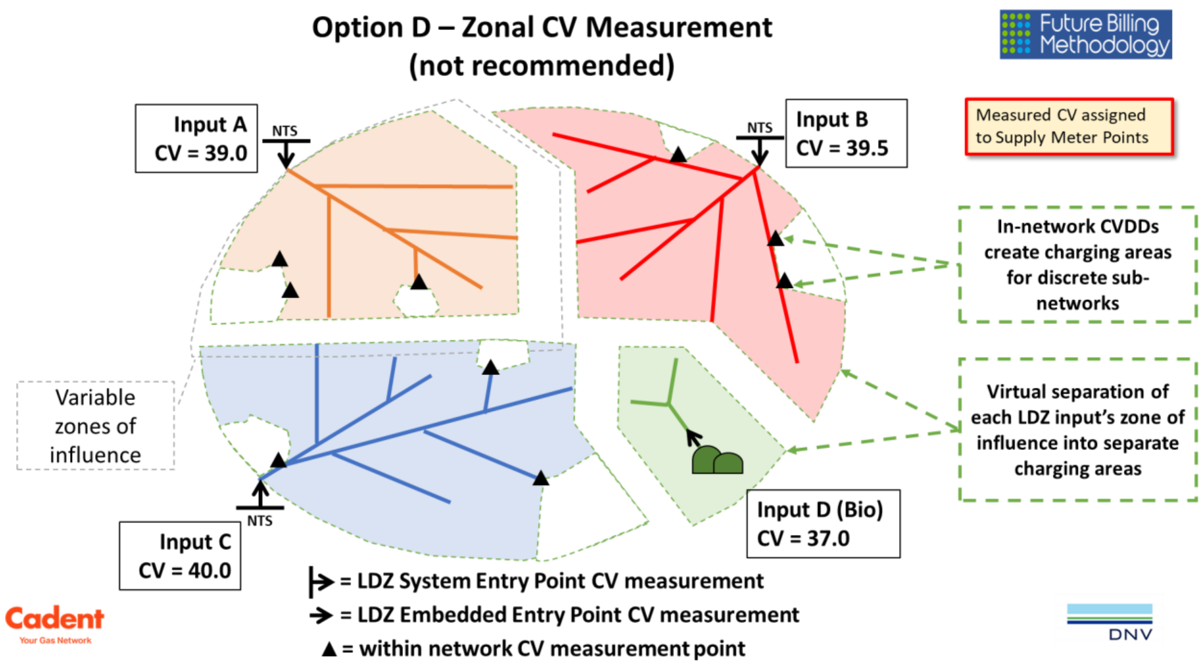



**Fig 6-5 Schematic – Option D: Zonal CV Measurement**

This embedded CV measurement-based option was originally conceived as a logical extension of Option B (FBM Option 1 Pragmatic) and is an evolutionary step towards the "ideal" local CV measurement arrangement envisaged in Option E.

However, the dynamic nature of gas networks, which has been empirically observed in the FBM field trials, demonstrated that the dependency between physical network configuration, location of CV measurement devices, and hence charging area structure to drive billing under this option would be highly complex to manage. Furthermore, the introduction of transitional gas blends such as a hydrogen blend, sharing the network with natural gas, where there could potentially be significant differences in calorific value, would effectively force a shift to highly localised CV measurement, as in Option E.

### OPTION E – Local CV Measurement (FBM "Ideal" Option)

Option E would use network modelling to determine the optimum location for CV measurement devices to be installed locally throughout the network. From these devices, CV data could be transmitted to smart meters and/or to Smart DCC, so that the consumer could ultimately be billed directly on current gas energy use, rather than metered volume at an allocated CV (see MS11 Report summary above). (Up to 44,000 extra CVDDs across GB networks.)

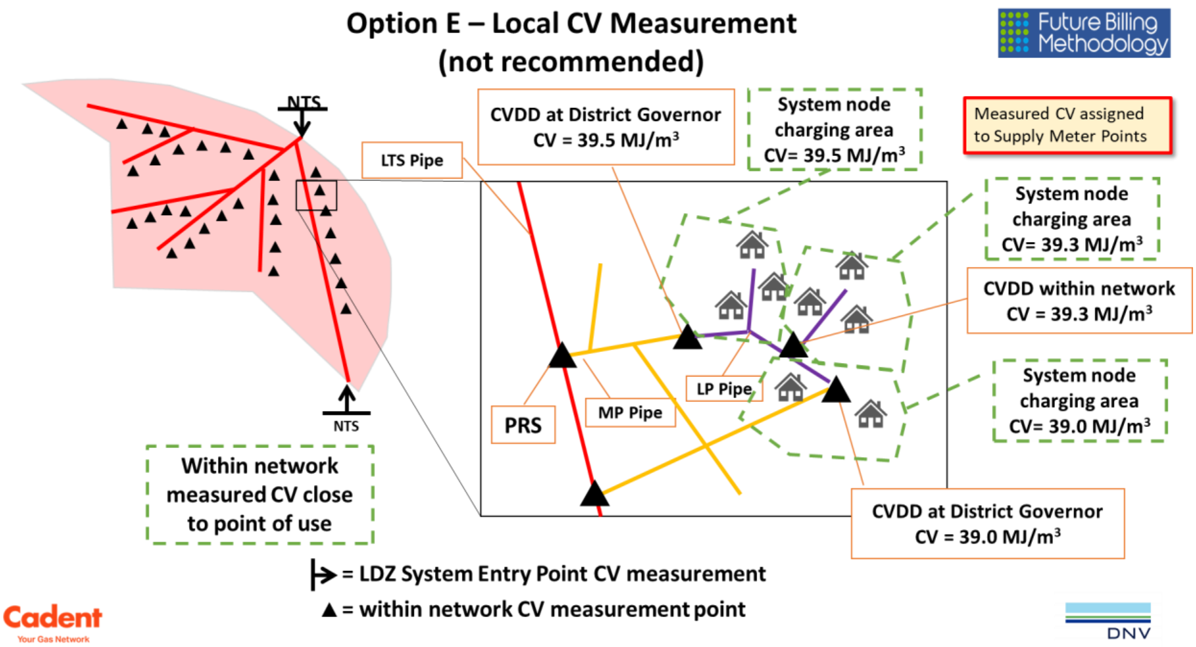



**Fig 6-6 Schematic – Option E: Local CV Measurement**

Although theoretically the most accurate option, the application of CV measurement devices at such a significant scale throughout the gas distribution network would be unsupportable in practice. Furthermore, the industry costs and complexity associated with linking locally measured CV data to smart gas meters would be very significant, as described in the MS11 technical report on the smart metering trial.

## 6.3 Consultation Options Summary

This document proposes three viable options (A-C) for consideration, that would effectively manage varying CV of green gases as we transition to net zero. These are:

**Option A – work within the existing frameworks –** This option is the least change, no regrets option that can commence now. Both hydrogen and biomethane blends can be delivered without enrichment under the current requirements of GCoTER by controlling the ratio of the low-CV gas with natural gas to not trigger the FWACV cap. This results in lower percentages by volume of hydrogen (ca. 5%) and biomethane (ca.30%) initially where the blend is a minority proportion of the flow of gas into a charging area. This can be increased as the blend becomes a higher proportion of flow of gas into a charging area due to the impact on reducing FWACV. If injection of low CV gas is strategically located at high flow locations such as NTS offtakes, the lower percentages in the initial phase would equate to significant volumes of low CV gas. Depending on the scale of hydrogen and biomethane deployment, this could either be the enduring solution or be implemented while work to undertake billing reform is completed.

**Option B – embedded zone charging –**This option offers a potential solution to blend from embedded supplies only, such as most existing connected biomethane plants and any future embedded hydrogen plants, without the need for enrichment. This option uses network modelling to create a predictable zone of influence from the embedded low CV source and allocates consumers within the zone of influence to CV measurement at low-CV input, while consumers outside of the zone of influence remain under the FWACV regime. This option will not work for blending at high volume, strategically located injection plants such as at NTS offtakes that feed a large proportion of an LDZ.

It is worth noting that gas safety limits on blending hydrogen (hydrogen max. = 20%$_{VOL}$) may make it impractical for embedded blending sites to co-exist either locally with each other, or with upstream wide scale blending within the same Local Distribution Network.

**Option C – Online CV modelling –**This option to offers a potential solution to all blended gas scenarios and locations with unrestricted ratios (up to GSMR limits). This option uses strategically located CV measurement to inform network modelling to predict the CV being delivered system nodes, and virtually individual consumers. This option however has not been fully tested and would require a detailed feasibility study to determine the appropriate level of inputs and software. The concept of using network modelling to determine CV has been demonstrated in FBM and is the basis for creating an embedded zone in Option B.

**Options D and E** – are not recommended due to the high number of CV measurement devices required for both. Option D requires up to 10,000 CV determination devices (CVDDs) to be installed to create multiple new charging areas, which with today's technology would carry considerable costs and vent large volumes of methane into the atmosphere.

Even with the advent of new technology, the practicalities of installing the amount of equipment required deem this unsupportable. In addition to this, this many charging areas would be impractical to manage because the boundaries of each zone would need to be reviewed following any change to the physical gas network. Option E although in theory the most accurate would take this further by installing CVDDs at each system node, which would require up to 44,000 devices to be installed.

# 7 Options Cost Benefit Analysis (CBA)

## 7.1 Introduction

The initial cost benefit analysis which accompanied the FBM Project Stage Gate submission in 2017 has been redeveloped to incorporate a future scenario for hydrogen blending. This is based on Hydrogen UK's November 2021 report, *Hydrogen in the UK: Moving from Strategy to Delivery*, and an updated biomethane projection, based around the *Pathways to Net Zero* report also commissioning by the ENA in October 2019.

Data sources and assumptions used in the CBA are listed in Appendix B. The CBA model also incorporates an updated view of systems implementation costs for each option, together with updated factors published by BEIS for quantifying carbon abatement benefits.

## 7.2 Rationale for CBA Approach

The reasons for working to a 2050 horizon on a national basis in the CBA are as follows:

i. It is relevant to do so since a transitional gas phase could potentially endure for some time in areas of the network where 100 per cent hydrogen, electrification or alternative heat delivery vectors remain problematic.
ii. At this stage, it is uncertain which areas of the national gas distribution grid would switch to alternative heat provision as in (i) above.
iii. Billing system implementation costs include a central systems element, which cannot be meaningfully reflected in a regionalised assessment.
iv. The switch either to 100 per cent hydrogen networks, electrification or alternatives are out of scope for this assessment.
v. This approach provides a consistent basis for comparative assessment of the options.

## 7.3 Green Gas Scenarios Applied in the CBA Model

### 7.3.1 Hydrogen Scenarios

Hydrogen blending, is at an early stage of development and so, in the absence of having any detailed hydrogen blending plans mapped onto LDZ networks, three simple scenarios have been developed for the updated CBA model: high, central, and low, based around the 2030 blending capability levels indicated in Hydrogen UK's November 2021 report, *Hydrogen in the UK: Moving from Strategy to Delivery*. (The line within Table 4 in that report, labelled "blending for domestic and commercial heat".) These headline scenarios are shown in Table 7-1 below:

**Table 7-1 – Headline Hydrogen Scenarios Applied in Billing Options CBA**

| Total H2 Demand Projection for 2030 (TWh) | High | Central | Low |
|---|---|---|---|
| Blending for domestic and commercial heat | 30.6 | 13.5 | 5.9 |

In the updated CBA model used for this consultation, it is assumed that the 2030 capability levels for each scenario shown in Table 7-1 are achieved in 2035 and maintained level through to 2050. The reasoning for this simplistic approach is that the high scenario 31 TWh figure broadly aligns with our view of the maximum blending capability of national Gas Distribution Networks.

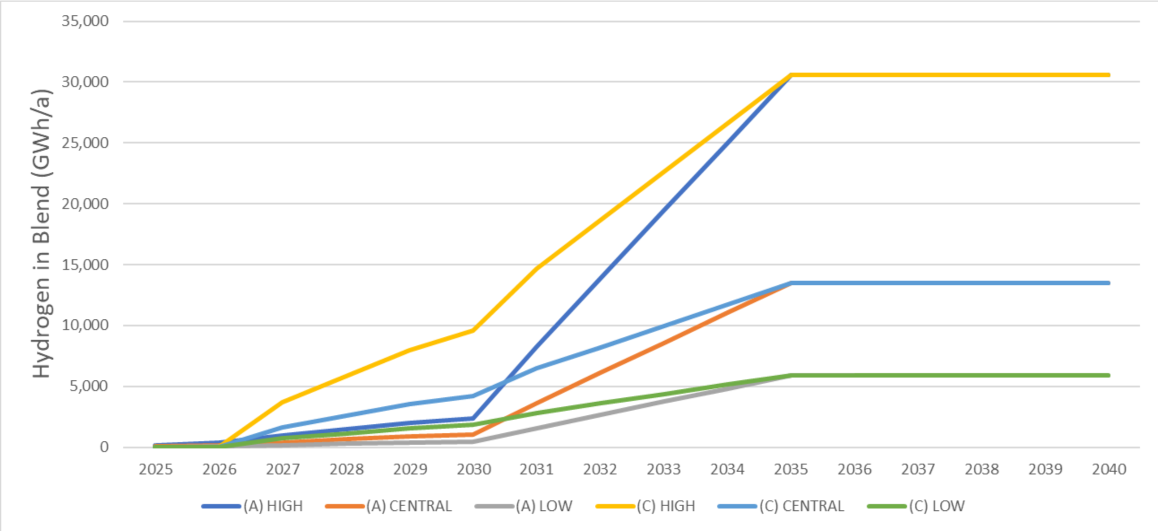
The Hydrogen UK report can be accessed via the following link: https://hydrogen-uk.org/wp-content/uploads/2021/11/Hydrogen-UK_From-Strategy-to-Delivery-Report_2021_11_23.pdf

The simplified projection in the CBA model assumes 5 blending tranches of equal scale, based on a larger-size LDZ.

**For Option A –** The first tranche comes on stream from 2025, with a preliminary blending flow in years 1 and 2, then blending hydrogen at <=5%$_{VOL}$ as a "minority energy flow", followed by a significant expansion to a "majority energy flow" phase in 2031, from which point, hydrogen is blended at 20%$_{VOL}$. Tranches 2 – 5 follow on in successive years, replicating this pattern, to achieve the headline target in 2036, as shown in the chart in Fig. 7-1 below.

**For Option C –** It is assumed that the same maximum amount of 31 Twh of hydrogen is achieved but benefits start later due to development of the required billing system. A higher amount of hydrogen is projected in the growth phase due to the implementation of the modelled CV billing framework would allow for hydrogen to be blended at $20\%_{VOL}$ even as a minority energy flow within the LDZ. See Fig 7-1 below:

**Fig. 7-1 – Hydrogen scenarios for Options A and C.**




**For Option B –** This billing option would deliver specific CV billing for embedded green gas supplies only. This is based on an assumed average plant capacity of approximately 1,000 standard cubic metres per hour of blended gas, which equates to around 5 GWh hydrogen per site, per annum. This scenario also assumes ten new connections per year, between 2026 and 2050, so reaching a total of just over 1.5 TWh/a by 2050. The central case for this scenario has been based on historical information on typical network capacity for historical biomethane plants and approximate average number of connections per annum. A high and low case have been derived simply by applying the factors 1.5 and 0.5 respectively, to the central case. Note: that hydrogen volumes under Option B are excluded from the chart in Fig. 7-1, due to scale.

Gas safety limits on blending hydrogen (hydrogen max. = $20\%_{VOL}$) may make it impractical for embedded blending sites to co-exist either locally with each other, or with upstream wide scale blending within the same Local Distribution Network.

### 7.3.2 Biomethane Scenarios

For biomethane, a set of scenarios which are based around forecasts provided in the October 2019 ENA report, *Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain*, have been applied. The 2050 projections for high, central, and low cases are set out in Table 7-2 below:

**Table 7-2 – Biomethane Scenarios Applied in Billing Options CBA**

| Biomethane Projection for 2050 (TWh) | High | Central | Low |
|---|---|---|---|
| Biomethane from Anaerobic Digestion (AD) | 57.0 | 28.5 | 14.3 |
| Bio SNG (from 2030) | 60.5 | 30.3 | 15.1 |
| Bio PtG (from 2030) | 7.5 | 3.8 | 1.9 |
| **Total** | **125.0** | **62.5** | **31.3** |

For each category line, straight-line growth has been imputed. In the case of anaerobic digestion (AD), from a present-day base of 3 TWh per annum to the corresponding case target in 2050; for Bio Synthetic Natural Gas (bio SNG) from zero in 2030 to each case target in 2050 and for Bio Power-to-Gas (Bio PtG), again from zero in 2030 to reach the case target in 2050. For Bio SNG and Bio PtG, a 50 per cent reduction to the original 2050 target presented in the *Pathways to Net Zero* report has been applied, reflecting uncertainty in these areas.

The *ENA's Pathways to Net Zero* report can be accessed via the following link: https://www.northerngasnetworks.co.uk/wp-content/uploads/2019/11/Navigant-Pathways-to-Net-Zero-2-min.pdf

For Option A (Work within existing frameworks), a set of high-level assumptions around the potential for propane savings and carbon abatement impact from Cadent's biomethane blending connections strategy has been applied (see section 5.4) as shown in table 7-3 below.

**Table 7-3: Projected percentage abatement of propane energy from biomethane blending connections.**

| **Projected % abatement of propane energy from biomethane connections blending strategy.** | **2025** | **2031** | **2035** |
|---|---|---|---|
| Target percentage of Propane Volumes mitigated by year. | 10% | 33% | 50% |

The hydrogen blending element within Option A in the CBA model contains a simplified relationship between hydrogen volumes and regional coverage to derive a projected propane abatement benefit from the reduced FWACV by blending hydrogen at $20\%_{VOL}$. The CBA model also includes an adjustment to avoid double-counting of projected benefits from the biomethane connections blending strategy and benefits from blending hydrogen at the higher rate.

We would welcome input from respondents on the green gas projections applied in this updated cost benefit analysis.

## 7.4 Implementation Costs for Billing Options

The CBA has applied a high-case estimate for capex for billing reform options B – E (inclusive) due to the systems changes which would be required to deliver and support meter point-specific gas CV for billing, settlement, etc.

Table 7-4 includes a column "within which: client systems costs" which breaks down as a memorandum item, the high-level estimates for changes to client systems cost (Shipper / Supplier) based on early work within UNC Workgroup 0251 in 2009 and have been indexed from a 2017 price base.

We would welcome input from Shippers / Suppliers on the reflectiveness of these costs since meter point-specific CV for billing would also entail daily meter point CV data for each Shipper / Supplier portfolio.

Summary results tables from the CBA model are provided overleaf.

## 7.5 Results from the Updated Billing Options Cost Benefit Analysis

Summarised results in Table 7-4 below and key indicators for the relative benefits of each of the consultation options. Based on a high case for both hydrogen and biomethane.

**Table 7-4 – Billing options CBA: Options, projected NPV at 2050 horizon and key indicators (high case biomethane and hydrogen).**

**BILLING OPTIONS CBA: SUMMARY TABLE OF OPTIONS, PROJECTED NPV AND KEY INDICATORS**

| | | |
|---|---|---|
| HYDROGEN BLEND SCENARIO: | HIGH | |
| Hydrogen within blend peak reached at 2035: | 30.6 | TWh/a |
| BIOMETHANE SCENARIO | HIGH | |
| Biomethane peak reached at 2050: | 125.0 | TWh/a |

| OPTION | DESCRIPTION | IMPLEMENTATION COSTS *(2021-22 Prices RPI = 304.4)* | | | *WITHIN WHICH: CLIENT SYSTEMS COSTS* | GO LIVE YEAR | CUMULATIVE NPV AT YEAR | | | FINAL BENEFIT : COST RATIO | BREAK-EVEN YEAR | TOTAL CARBON ABATED AT 2050 (mtCO2e) | CARBON ABATED: COST PER TONNE (£) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | CAPEX (High case) (£M) | OPEX (Set-up) (£M) | OPEX (Ongoing) (£M/a) | | | 2030 (£M) | 2040 (£M) | 2050 (£M) | | | | |
| A | WORK WITHIN EXISTING FRAMEWORKS | 2.26 | 0.65 | 0.65 | *N/A* | 2023 | 315.3 | 8,452.4 | 17,787.0 | 1384 : 1 | 2025 | 99.163 | 0.13 |
| B | EMBEDDED ZONE CHARGING | 162.20 | 0.3 | 2.4 | *33.2* | 2026 | 374.0 | 3,191.9 | 7,996.0 | 42 : 1 | 2027 | 44.511 | 4.44 |
| C | ONLINE CV MODELLING | 185.60 | 3.6 | 5.35 | *33.2* | 2027 | 1,088.2 | 11,075.4 | 22,566.8 | 80 : 1 | 2027 | 125.171 | 2.29 |
| D | ZONAL CV MEASUREMENT | 499.40 | 1.2 | 7 | *33.2* | 2030 | -360.8 | 1,909.5 | 6,050.3 | 7 : 1 | 2033 | 36.065 | 27.93 |
| E | LOCAL CV MEASUREMENT | 906.00 | 3.6 | 16.7 | *49.8* | 2035 | -529.0 | 5,391.7 | 15,944.6 | 8 : 1 | 2035 | 95.810 | 25.07 |

The performance indicators shown in the right-hand section of Table 7-4 are replicated on central and low bases for hydrogen and biomethane respectively, in Table 7-5 below.

**Table 7-5 – Billing options CBA: summary of key indicators for 2050 horizon (central and low case biomethane and hydrogen).**

| HYDROGEN SCENARIO: | | | CENTRAL | | | | | LOW | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Hydrogen within blend peak reached at 2035: | | | 13.5 | TWh/a | | | | 5.9 | TWh/a |
| **BIOMETHANE SCENARIO** | | | **CENTRAL** | | | | | **LOW** | | | |
| | | Biomethane peak reached at 2050: | | | 62.5 | TWh/a | | | | 31.3 | TWh/a |
| | **OPTION** | **PROJECTED GO-LIVE YEAR** | **FINAL BENEFIT : COST RATIO** | **BREAK-EVEN ACHIEVED IN YEAR** | **TOTAL CARBON ABATED AT 2050 (mtCO2e)** | **CARBON ABATED: COST PER TONNE (£)** | | **FINAL BENEFIT : COST RATIO** | **BREAK-EVEN ACHIEVED IN YEAR** | **TOTAL CARBON ABATED AT 2050 (mtCO2e)** | **CARBON ABATED: COST PER TONNE (£)** |
| **A** | WORK WITHIN EXISTING FRAMEWORKS | **2023** | **628 : 1** | **2025** | **44.981** | **0.29** | | **285 : 1** | **2025** | **20.383** | **0.63** |
| **B** | EMBEDDED ZONE CHARGING | **2026** | **22 : 1** | **2028** | **23.338** | **8.46** | | **11 : 1** | **2030** | **12.039** | **16.40** |
| **C** | ONLINE CV MODELLING | **2027** | **37 : 1** | **2028** | **57.827** | **4.96** | | **17 : 1** | **2029** | **26.806** | **10.69** |
| **D** | ZONAL CV MEASUREMENT | **2030** | **4 : 1** | **2036** | **16.980** | **59.33** | | **2 : 1** | **2041** | **7.438** | **135.44** |
| **E** | LOCAL CV MEASUREMENT | **2035** | **4 : 1** | **2036** | **39.559** | **60.73** | | **2 : 1** | **2040** | **13.600** | **176.63** |

## 7.6 Commentary on CBA results

A results commentary is provided in Table 7-6 below.

**Table 7-6 – Billing options CBA results commentary**

| OPTION | RESULTS COMMENTARY |
|---|---|
| **A** | This option has lowest cost per tonne of carbon abated, as it avoids system and regime changes. It can therefore be considered as the least cost / least risk option. |
| **B** | Although this option could be delivered as part of development of Option C, this has limited potential, as it would benefit only embedded biomethane and/or hydrogen supplies so its carbon benefits are smaller. |
| **C** | This option delivers a higher output than Option A, as it can support hydrogen blending up to $20\%_{VOL}$ on a "minority energy flow" basis, but its marginal benefit is limited in central and low green gas scenarios. This option would require system development and carries some additional costs for a strategic population of up to 500 CVDDs for model verification. |
| **D** | This option would not accommodate upstream hydrogen or biomethane blending, due to its complex physical linkage between network configuration, location of CV measurement and hence configuration of charging areas. This option carries significant costs for installation and societal cost from venting from 10,000 CVDDs. **This option is not recommended** |
| **E** | Projected NPV appears better than Option D as this option could handle upstream hydrogen or biomethane blending. However, this option carries significant costs for installation and societal venting from 44,000 CVDDs **This option is not recommended** |

## 7.7 CBA Results in Summary

Consultees are invited to consider that Option A (work within existing frameworks) presents fewest changes and least cost, in terms of implementation at this time, which provides a distinct advantage and opportunity to begin deploying green gases with no regrets.

This is directly in comparison to the other options appraised in terms of lowest cost per unit of carbon abated and hence minimises the level of investment at risk, although there is some uncertainty around the projections for biomethane and hydrogen and some assumptions applied in the CBA may be subject to change.

The ability to blend hydrogen at scale is most likely to vary significantly from one region to another, and the opportunity to blend biomethane without enrichment will also be dependent on location of connection, therefore, it may also be valuable to proceed with a more detailed feasibility study of Option C (Online modelled CV); our analysis suggests this is the next most effective option. The development of which may bring interim benefits from earlier, interim deployment of Option B (Embedded Zone Charging), if feasible. In that case, delivery of B would be a minor marginal cost on C since the systems development requirements for each have high commonality.

## 8. Questions for Consultation

Key questions on which Cadent is seeking views from the wider gas industry are set out in this section and are also provided in a separate editable document for population by respondents.

Respondents should identify their organisation, business activity (e.g., Shipper, Supplier, Producer, Gas Technology, Academia, etc.) and indicate which, if any of your responses you wish to remain confidential. Confidential information will be anonymised accordingly.

It would be helpful if Shippers / Suppliers could give an indication of the scale and type of their consumer base, which could aid normalisation of high-level indicative implementation costs for updating the final project CBA.

**Statement 1 – Option A: Work Within Existing Frameworks**

**Progressing this option could provide a no-regrets route to begin decarbonising the UKs gas distribution networks by enabling blending of low carbon gases without the need for changes to gas billing systems and regulations. This could be the enduring solution or while the option(s) that require billing reform and investment are developed.**

### Question 1: Do you agree with statement 1?

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Strongly Agree | | |
| Agree | | |
| Neither | | |
| Disagree | | |
| Strongly Disagree | | |

### Question 2: Would you foresee this option as an enduring solution for the transitional phase ahead of a switch either to 100 per cent hydrogen, or alternative heat delivery vectors?

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Yes | | |
| No | | |

**Statement 2 – Option C: Online CV Modelling**

**This option could enable one consistent methodology for attributing gas CV for billing across the range of potential gas transition scenarios. This would include hydrogen blending both on "minority energy flow" and "majority energy flow" bases, together with un-enriched biomethane. If proved robust, this option could present an improved attribution of billable energy to consumers, reducing the level of cross-subsidy experienced under the existing LDZ FWACV regime.**

### Question 3: Do you agree with statement 2?

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Strongly Agree | | |
| Agree | | |
| Neither | | |
| Disagree | | |
| Strongly Disagree | | |

### Question 4: Would you support progressing work on a detailed feasibility assessment to deliver Option C Online CV Modelling?

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Yes | | |
| No | | |

### Question 5: Option B: Embedded Zone Charging – Would you support exploring this billing option further as part of development work towards delivery of Option C (Online CV Modelling)?

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Strongly Agree | | |
| Agree | | |
| Neither | | |
| Disagree | | |
| Strongly Disagree | | |

### Question 6: Billing systems changes for Options B and C

**Both Options B and C would require significant changes to central and client gas billing systems to enable the attribution of gas CV at meter point specific level. If your organisation is a gas Shipper and/or Supplier, would you be able to assist this consultation by providing a high-level cost estimate for the changes to client systems to assist development of the final CBA?**

| Cost Estimate (£m 2021-22 prices) | Please provide any supporting information for your cost estimate and any other information you consider to be relevant to assist finalisation of the CBA on a GB gas distribution basis. |
|---|---|
| | |

### Question 7: Regionalised approach

**Cadent recognises that the ability to blend green gases at scale will be likely to have significant variations from one region to another. Would you consider it to be acceptable and or practicable to apply different billing options in different regions, and are there any issues you would envisage?**

| Response | (X) | Please explain the reasoning for your response in this section. |
|---|---|---|
| Yes | | |
| No | | |

### Question 8: Green gas scenarios applied in the updated cost benefit analysis

**Do you have any alternative views on the scenarios and projections set out in section 6.3 of the consultation document?**

| Please insert your comments, supporting information and references to relevant source documentation in the space below. |
|---|
| |

## Question 9: General

**Do you have any other comments or questions relating to potential options for decarbonising gas distribution networks?**

| Please insert your comments in the space below. |
| --- |
| |

# 9 Glossary of Terms

| Term | Meaning |
|---|---|
| CBA | Cost-Benefit Analysis |
| Charging area | Presently defined as an LDZ in Section F1.2.2(c) of the Offtake Arrangement Document (OAD) |
| CV | Calorific Value – expressed in mega Joules per cubic metre of gas ($MJ/m^3$) at standard temperature and pressure |
| CVDD | Calorific Value Determination Device – An Ofgem-approved device for measuring the energy content of gas. |
| DCC | (SMART) Data Communications Company |
| DNO | (Electricity) Distribution Network Owner |
| DNV | Project partner of Cadent |
| EA | The LDZ known as East Anglia |
| EM | The LDZ known as East Midlands |
| Embedded Charging Area | A contiguous group of system nodes within a Local Distribution Zone, deemed to be supplied from a specific embedded gas supply source, within which consumers are billed for gas usage based on the same calorific value for the relevant Gas Day, as determined via the use of network and CV modelling |
| ENA | Energy Networks Association |
| Enrichment | See “Propanation”. |
| EUC | End User Category – the established structure for typifying the demand characteristics of different sizes and types of Non-Daily Metered Supply Meter Points |
| FAT | Factory Acceptance Testing |
| FBM | Future Billing Methodology |
| FWACV | Flow Weighted Average Calorific Value |
| GB | Great Britain |
| GBCS | Great Britain Companion Specification – for smart meter manufacture |
| GCoTER | The Gas (Calculation of Thermal Energy) Regulations |
| GDN | Gas Distribution Network |
| GSME | Gas smart metering equipment |
| GS(M)R | Gas Safety (Management) Regulations – governs the safety of the GB gas supply |
| GWh | Gigawatt-hour – a measure of thermal energy equivalent to one million kilowatt-hours |
| IGEM | Institute of Gas Engineers and Managers |

| Term | Meaning |
| --- | --- |
| kWh | Kilowatt-hour – a measure of thermal energy equivalent to 3.6 megajoules |
| LDZ | Local Distribution Zone (gas distribution networks in GB comprise 13 LDZs) |
| LDZ FWACV | The LDZ flow-weighted average calorific value, presently applied to consumer billing. |
| LDZ FWACV Cap | A process by which the LDZ FWACV value is limited to a maximum of 1 megajoule per cubic metre above the lowest-CV gas source to the LDZ |
| LTS | The Local (gas) Transmission System – The highest-pressure tier within the LDZ, which transports gas from NTS/LDZ offtakes and local storage to the rest of the LDZ network. |
| METER POINT | Supply Meter point (As defined in Section G 1.3.1 of the UNC) |
| $MJ/m^3$ | Megajoules per cubic metre – the standard units used for expressing the energy content of gas at a temperature of 15°C and a pressure of 1013.25 millibars. |
| MPRN | Meter point Reference Number (a unique reference number for each Supply Meter point) |
| NIC | Network Innovation Competition |
| NTS | The gas National Transmission System – the national network of high-pressure gas pipelines which transports gas from primary gas terminals and storage to the 13 Local Distribution Networks in Scotland, England and Wales, and to directly connected gas power generation and very large industrial consumers. |
| Propanation | The process of enriching low-CV biomethane gas with high-CV propane (typically fossil based) to increase its calorific value to match the flow-weighted average CV for the relevant LDZ. |
| RTU | Remote Telemetry Unit |
| SAT | Site Acceptance Testing |
| SDRC | Successful Delivery Reward Criteria |
| System node | A section of pipework, fed by specific regulators on the gas distribution system which represents the lowest level of detail at which network models can simulate gas demand from loads connected to it, and hence the travel, mixing and CV of gas supplying it. |
| TWh | Terrawatt-hour – a measure of thermal energy equivalent to one billion kilowatt-hours ($1 \times 10^9$) |
| UMS | Unmetered (electricity) Supply |
| UNC | Uniform Network Code (the common contract for all system users of the GB gas grid) |

# APPENDIX A – IMPACT OF BILLING CHANGES (OPTIONS B – E) ON REGULATIONS, BILLING SYSTEMS & PROCESSES, INDUSTRY CODES, AND OTHER FACTORS

## 1. General

The gas thermal energy regulations, covered in section 1 below, have undergone a detailed assessment in relation to potential future billing options. Gas safety management regulations in section 2, are presently under review in relation to the potential widening of gas quality limits, and the future inclusion of hydrogen.

Comments elsewhere in this appendix remain initial views to be further informed by more detailed work to develop potential future implementation of any billing reform solution. More detailed work on specifying system changes and developing modifications to industry codes are outside the concept-level remit of this project and would be subject to the appropriate regulatory mechanisms for funding and approval.

## 2. Gas (Calculation of Thermal Energy) Regulations (GCoTER)

**Initial views –** The development of potential future options for gas billing under the FBM Project was based on a high-level view of the gas thermal energy regulations. This suggested that since the regulations did not define charging areas in geographical terms, network modelling could be applied to create separate charging areas within a Local Distribution Zone (LDZ), within which consumer bills would be based on the measured CV at the relevant gas sources identified, as supplying that charging area. For example, in the manner illustrated in Fig. 5-3 in the main consultation document.

**Detailed view of regulations –** The FBM Project examined these regulations in more detail and following this review, it is now clear that Part II of the existing regulations effectively mandates physical measurement of CV and volume at each connection point between charging areas. For example, every input point and output point for each charging area, with the intention of keeping the energy calculation complete for each charging area (presently defined as each LDZ).

An alternative view had suggested that the CV declaration provisions within Part III of the regulations could be used to support CV modelling. However, the detailed review for this project has confirmed that the notification and gas CV testing arrangements set out in this part of the GCoTER could not support a dynamic network setting in which CV at any given point on the network could vary, potentially on a daily basis.

**Inter-connected gas networks –** National gas distribution networks can be highly meshed in populous areas, which aids pressure control, resilience, and security of supply. In a transitionally diverse-CV gas network scenario, the travel and mixing of gases of differing CVs within the LDZ network could be complex.

Any sub-LDZ charging area could have numerous physical connection points to other charging areas. The application of measurement in the manner required by the existing GCoTER would need to be on the scale envisaged by the FBM Option 3 – "Ideal" solution, which would be uneconomic and impractical for the reasons given in the sections 4(VI) and 13 below.

**Changes required to support diverse-CV gas billing –** As a result, the review has clarified that use of network modelling to configure charging areas within an LDZ would require an amendment to the existing regulations. This would need to permit the application of a modelled CV at system node level in order to bill consumers connected to relevant system nodes. This would not invalidate any of the proposed FBM options but would enable movement away from the binary requirement to align consumer bills directly to one or other CVDD, or group of CVDDs, for billing. Therefore, if proven to be robust and sufficiently accurate this could make billing more representative of consumers actual energy usage.

## 3. Gas Safety (Management) Regulations (GSMR)

The aim of the FBM project is to provide the conceptual basis for a future billing framework for the transportation of all gases that are compliant with the Gas Safety (Management) Regulations (GSMR).

Changes presently proposed to these regulations to widen the permitted Wobbe Index range for NTS gases could potentially result in greater differences in CV between different NTS gas sources into the LDZ. This could create a steeper CV “gradient” in areas of the LDZ network linked between zones of influence exerted by separate NTS bulk supplies.

Gas transporter network analysis models have the capability to account for these differences, and the configuration of charging areas would need to accommodate such effects and minimise scope for billing variances. In this setting, the modelling of CV at system node level could provide a suitably robust attribution of gas energy content to meter points.

**Hydrogen –** Transportation of blended methane and hydrogen in ratios up to 80:20 mol. is presently facilitated by means of project-specific exemptions provided by the HSE under the GSMR. Transportation of hydrogen blends via the national gas grid on a lasting basis will require enabling changes to these regulations. These matters are the subject of separate projects, such as the HyDeploy project, and fall outside the remit of the FBM project and this specific consultation.

**Biomethane –** Is already conveyed in gas distribution networks and is subject to the specifications set out in these regulations, but with a class exemption allowing an oxygen content of up to 1 per cent mol.

## 4. Billing systems changes under Options B - E

The changes that would be required to billing systems and processes to enable diverse gas CV billing under consultation options B – E inclusive go to the core of LDZ gas energy attribution.

The management of the daily LDZ FWACV process for energy attribution to metered gas flows for LDZ-connected consumers is specified as a GDN role within the Offtake Arrangements Document (OAD).

Up to now, this role has been carried out by National Grid’s NTS business on behalf of the GDNs, but this service will be transferred back to GDNs from 1st April 2022, administered by Xoserve as Central Data Services Provider. Initial views for further consideration of any future billing options B – E are set out below:

I. The present LDZ FWACV calculations which support energy attribution for billing follow the existing gas thermal energy regulations (GCoTER) and Section F of the OAD, configuring each of the 13 LDZs as a separate charging area, to keep the quantification of energy whole for each Gas Day in each LDZ. Any low-CV gas entering the LDZ and triggering the LDZ FWACV Cap (as described in section 3.8 of the main document) generates a quantity of CV shrinkage which is transferred to the NTS CV Shrinkage account.

II. Creating virtual charging areas within an LDZ which are not bounded by physical volume and CV measurement, as required by the existing GCoTER, would involve removal of the LDZ FWACV Cap. Any allocation error in the configuration of embedded zones (under Option B), or the attribution of modelled CV values at system node level (as in Option C), would generate unidentified gas in the LDZ.

III. Under Option B (Embedded Zone Charging), each embedded charging area, in which groups of consumers would be billed based on the same CV value for the embedded gas source, would comprise a group of adjoining system nodes, determined by network modelling. However, the grouping of nodes within each embedded charging area could change over short timescales, due to the dynamic nature of gas flows under differing demand conditions.

IV. The LDZ energy attribution calculations for Option B would need to be adapted to work in a "nested" configuration for each LDZ, retaining FWACV calculations for the remnant LDZ and LDZ FWACV calculations (with the FWACV Cap removed) being retained for quantification of Unidentified Gas, and also "default" CV attribution to meter points in cases where they cannot be allocated to a specific FBM Charging area within the LDZ, with a correction mechanism for final resolution.

V. For Option C (Online CV Modelling) each system node would become a charging area, as the system node is the lowest level at which network modelling can differentiate gas flows and mixing, and hence average CV for each Gas Day. Modelled meter point CV would be attributed directly for billing, and the LDZ energy calculations would need to continue at top level, with the FWACV cap removed, to enable quantification of unidentified gas resulting from any modelling error. It is worth noting here that the averaging process presently applied under LDZ FWACV can itself contribute to unidentified gas (UIG).

VI. The non-recommended Options D and E would use physical CV measurement within the LDZ network, so the definition of charging areas would depend on siting of CVDDs. Under these CV measurement-intensive options, the physical charging area structure could also be impacted by changes to pipework configuration and so, could be extremely complex and administratively intensive to define.

VII. The dynamic travel and mixing of diverse-CV gases and hence variability of charging areas might suggest that Option C could provide the most capable platform for any billing reform, with the potential for development of Option B emerging as an intermediate stage in the transition to universal online modelled CV under Option C. However, the changes to energy attribution and billing systems and processes would be significant for any of the options B - E and would require a switch to daily meter point-specific CV to cope with this variability.

VIII. Moving from LDZ FWACV to meter point-specific CV would also involve changes in the derivation of the "energy factor" which drives meter point settlement calculations and AQ/SOQ updates for non-daily metered (NDM) consumers, as these are presently calculated at LDZ/EUC[7] level, using the applicable LDZ FWACV. This would result in a very significant increase in the volume of system calculations.

IX. The changes required to support any more specific billing process would need to be developed very closely alongside the necessary changes to the governing GCoTER.

## 5. Billing Process Changes – "back-end" v's "front-end" changes

The meter point-specific attribution of CV under options B - E would be achieved by linking each meter point to its relevant physical system node on the LDZ gas network, with each charging area

[7] EUC = End User Category, is an established structure for typifying the demand characteristics of different types of NDM Meter Points.

within the LDZ being defined either as the relevant system node, or as a contiguous grouping of system nodes, within which the same CV value would apply for billing.

Network modelling analysis, at an appropriate frequency and timing, to be determined by a detailed functional design assessment, would then attribute system nodes to charging areas, and so link each meter point to the appropriate CV value for billing.

These changes to the attribution of gas CV to system nodes (and thereby to meter points) would form part of the "back-end" of the billing process (from a consumer viewpoint) and would be linked into the existing billing or invoicing process via a meter point-level interface. The switch to meter point-specific CV for billing would drive changes to Gemini and UK-Link systems, as indicated above, and would also require corresponding changes to enable the daily provision of meter point-specific CV data to client systems, to underpin consistent gas energy billing downstream.

For gas distribution networks, the changes required for Option C would include significant development and integration of online and offline network models, automation of modelling processes, charging area creation, and streamlining of data feed-in processes to underpin accurate, consistent, and rapidly repeatable network modelling for CV attribution. The scale of these changes and the intensity of data processing in operation would be considerable. Delivery of Option B for embedded zones would potentially involve a significant proportion of the changes required to support Option C, hence the similarity in implementation costs.

## 6. Physically Discrete Sub-networks

It should be noted that areas of the network which are physically discrete, e.g., single-fed sub-networks at the extremities of the system, could potentially be configured as separate charging areas by having a CV measurement device installed on the feed-in pipe. However, although compliant with the existing GCoTER, the action of physically separating out these zones for billing purposes would involve changes to billing systems.

## 7. LDZ Transportation Charging Methodology and Invoicing

Under options B-E the FBM changes focus on CV attribution, and so would not impact the existing LDZ Transportation Charging Methodology. So, the existing LDZ structure would remain in place for applying the appropriate unit transportation charges.

The back-end changes for FBM (meter point link to system node and system node to charging area, at the appropriate frequency, to be determined by detailed functional design) would need to be trackable for invoice query and audit purposes, but the front-end changes would effectively appear as a switch to meter point-specific CV for deriving daily kWh values for meter point settlement and rolling AQ adjustment. The daily CV value for each MPRN would need to become an additional data item within meter point settlement invoices and a separate MPRN-CV file could be made available to Shippers/Suppliers at the same daily frequency as existing CV attribution, for billing purposes.

## 8. Consumer Billing Impact

The more-specific attribution of CV under Options B – E should in principle result in a neutral impact in total on meter point billing. Consumers receiving lower-CV gases would see an increase to metered volumes to meet the same annual kWh energy requirement, but the attribution of a lower CV to those volumes would counteract this, and vice versa. Prior to any FBM implementation, there would need to be a further set of model validation exercises and FBM charging areas could be parallel run in a test environment to fully assess billing impacts.

## 9. Uniform Network Code (UNC) - Treatment of LDZs

At this concept stage, it is believed that the provisions within the UNC relating to “LDZ” should be able to remain intact and unaffected by changes to energy attribution under Options B – E, apart from within Section S, where references to LDZ charge types would remain unchanged, but reference to the LDZ as a charging area would need to be updated to recognise the existence of multiple charging areas within each LDZ.

## 10. Offtake Arrangements Document (OAD)

The Offtake Arrangements Document is an ancillary document to the UNC, which sets out rights and obligations between gas transporters in relation to the connections between, and the planning, maintenance, and operation of, their respective systems comprising the national gas grid.

Section F of the OAD sets out provisions in relation to the determination of gas CV and minimisation of CV Shrinkage. For the application of G(CoTE)R Part II, Para 4A (calculations to determine CV values for billing), the term “charging area” is presently defined in Section F 1.2.1(c) as *“…each LDZ represents a single charging area”*.

To support an FBM implementation, this section of the OAD would require modification corresponding to the way in which charging areas would need to be configured within each LDZ. The definition of charging area would also need to accommodate reconfiguration of charging areas as the appropriate frequency, to reflect changes in the zone of influence exerted by LDZ inputs.

In the case of Option C, which would use modelled CV values for energy attribution and billing, at system node level, each system node would constitute a charging area. As previously mentioned, the LDZ FWACV calculations could be maintained in the background as a “default” arrangement and the existing LDZ structure would remain in place for the application of the LDZ Transportation Charges and all purposes other than FBM CV attribution.

## 11. Option E – SMART and Related Code Impacts

Implementation of this option is not recommended, for the reasons given in Section 5.2.6 of the main document and in section 4(VI) of this appendix. However, for completeness, it is worth noting that enabling CV data flows to consumer smart meters would have wider impacts both on regulations and industry codes. These impacts would need to be clarified and the required GBCS case developed under a wider industry review, as pointed out in section 4.1 above. This is beyond the scope of any decarbonisation initiatives presently being considered.

## 12. Significant Code Review (SCR)

For options which require billing reform (all options other than Option A), the extent of the changes required to regulations and billing systems changes suggest the development process towards implementation may be best supported within the bounds of a Significant Code Review, but this would be a matter for the regulator to determine.

## 13. Within-network CV Measurement

The options that require wide-scale installation and use of CV measurement have not been recommended due to factors described below:

**Emissions from venting –** Existing technology requires venting of the analysed gas stream to the atmosphere, and would result in unacceptable additional carbon emissions, counter to the aims of decarbonisation. Even with technological innovation to obviate venting, learning from the FBM field trial has shown that other factors remain problematic, as below.

**Powering remote equipment –** The experience of installing the FBM field trial sensors at existing gas control sites has shown that these installations are often situated in remote locations and/or embedded within private land. Powering CV measurement devices and remote telecommunications equipment in such locations can be highly problematic – Photo-voltaic arrays are vulnerable to damage and may become unreliable in sustained poor conditions. Connections to the regional power grid are expensive and gaining the appropriate legal access to land for cabling and maintenance, etc., can involve high cost and uncontrollable delays.

**Data communications –** Setting up and maintaining the required data communications networks for wide-scale network-embedded CV measurement would also be highly expensive and resource intensive.

## 14. FBM and Future Billing Validation

**GCoTER constraint on FBM validation –** The FBM field trial had to use oxygen sensors to track the presence of biomethane from the target gas input points, because propane-enrichment could not be turned off at the biomethane sites without triggering the Regulation 4A flow-weighted average CV cap which would generate significantly disproportionate CV shrinkage and associated distortion to billing as a result. For accuracy, the molecular oxygen sensors must be set at a range of 0 – 200 ppm, which equates to a maximum mix of 10% biomethane in natural gas, so effectively detecting the outer reach of the zone of influence.

**Direct CV modelling validation –** Although the modelling for the FBM field trial analysis was highly accurate in simulating the measured presence of biomethane at the test sites, the implementation of a CV modelling system for gas billing would require a direct validation of CV modelling across a the range from low-CV pure biomethane, or a hydrogen blend, to natural gas. Some form of derogation would be required to support such a trial. However, the existing GCoTER does not contain any specific provision for derogation and so may need to be amended to allow this to happen.

**Verification for CV modelling –** It is expected that any future implementation of an LDZ-wide network modelling-based method for attributing CV to meter points for billing would require some level of ongoing verification. This would take the form of a strategic placement of a small population of CV determination devices within the LDZ network. Future technological advances in CV measurement could provide a more environmentally friendly and efficient method of providing this data.

## 15. Other Factors to Consider

**Large Users –** Large industrial loads connected to the LDZ network may be sensitive to sudden changes in the CV of gas being delivered at the meter, depending upon the type of equipment or process which is consuming the gas. Further consideration needs to be given to how the impacts of changes in gas energy content could be mitigated for these consumers, which is being explored outside of this project in other programmes such as HyDeploy.

**Atypical Usage –** Certain users within a given consumer class will have atypical gas usage patterns, for example, home workers, the elderly, or care homes, which use heating throughout the day.

# APPENDIX B – BILLING OPTIONS UPDATED CBA MODEL: LIST OF ASSUPMTIONS & FACTORS APPLIED

| | | | |
|---|---|---|---|
| 1 | **Price differentials for different "green" gases and other exogenous economic drivers are excluded** | | |
| 2 | **Production and connection costs for biomethane or hydrogen are excluded (biomethane is GSMR-compliant)** | | |
| 3 | **Gas Safety Management Regulations (GSMR):** This model assumes that "green" gases will be GSMR-compliant (separate projects are in place to prove the safety case to amend GSMR for the introduction of hydrogen blends of up to 20%$_{VOL}$) | | |
| 4 | **Calorific value of gases used in this model:** | | |
| | Gas Type | CV (MJ/m$^3$) | Comment |
| | Natural gas | 39.5 | Used in assessment of abatement benefit of hydrogen blending at 20%$_{VOL}$ for biomethane. |
| | Biomethane | 37.0 | Used in quantification of propane requirement for biomethane, propane cost savings and carbon abatement from each option. |
| | Propane | 96.0 | |
| | Hydrogen | 12.1 | Used in quantification of hydrogen energy for blending and carbon abatement. |
| 5 | **Model assumption on propane enrichment of biomethane supplies** | | |
| | Model assumes that | 100% | of biomethane injection requires propane enrichment. |
| 6 | **Hydrogen and Biomethane scenarios applied in this model:** These are as set out in Section 7 of the main consultation document | | |
| 7 | **Financial values:** This CBA model applies all financial values for costs and benefits at RPI = 304.4 (2021-22 Prices) | | |
| 8 | **Options implementation costs:** These are as shown in Table 7-4 within the main consultation document. | | |
| 9 | **Propane cost savings:** Evaluation of cost savings from the abatement of propane resulting from each option is based on data from a December 2016 report commissioned by Cadent from Element Energy, Section 3.2.2 CV requirements, propanation costs and CV determination devices (page 23). This value is indicative only, as the actual costs associated with the enrichment of propane at biomethane sites is commercially sensitive information and therefore not publicly accessible. | | |
| | Estimated cost of propane provision & enrichment in this model (indexed to 2021-22 prices RPI = 304.4): | p/kWh<br>0.3631 | |
| 10 | **Carbon abatement:** Factors used for carbon abatement in this model. | | |
| | **Carbon emissions and savings:** | **(kg(CO2e)/kWh)** | **Data source:** |
| | a) Hydrogen (CV = 12.1 MJ/m3) | 0.0410000 | UK Gov't E4tech Final Report "H2 Emission Potential Literature Review" April 2019 |
| | b) Biomethane (CV = 37 MJ/m3) | 0.0003825 | Scope 1 rate from UK Government GHG Conversion Factors for Company Reporting 2021 |
| | c) LPG (CV = 96 MJ/m3) | 0.2144800 | BEIS Guidance Table 2a (March 2020) |
| | d) Natural Gas (CV = 39.5 MJ/m3) | 0.1835200 | BEIS Guidance Table 2a (March 2020) |
| | Saving: hydrogen over natural gas (d - a) | 0.1425200 | Used in model for carbon abatement quantity from deployment of sustainable-grade hydrogen to 2050 |
| | Saving: biomethane over propane (c - b) | 0.2140975 | Used in model for carbon benefit of displacing propane with biomethane |
| 11 | **Monetisation of carbon abatement:**<br>BEIS Supplementary guidance to the HM Treasury Green Book on Appraisal and Evaluation in Central Government Table 3: Carbon values and sensitivities 2020-2100 for appraisal, 2020 £/tCO2e (Central case) | | |
| 12 | **Discout rate used to generate NPV costs & benefits in this model:** | 3.5% | Standard use in regulatory CBA models. |

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