Future Billing Methodology

Future Billing Methodology

MS15 Final Consultation Report and Recommendations on Billing Options for Attributing the Energy Content of Gas in the Transition to Net Zero

31st March 2022

Our vision

Report Contents

Contents

1 Executive Summary

1.1 Introduction

This report sets out the Future Billing Methodology (FBM) project's recommendations to Ofgem and industry on how the attribution of energy content, or calorific value (CV), for billing could be treated in the face of a changing gas mix. The objective is to provide an efficient route to decarbonise heat through the maximisation of green gases, such as hydrogen and biomethane, while maintaining fair and equitable billing for consumers.

There is heavy reliance on fossil gas for the provision of heat in the UK, so a shift to greener sources is essential to achieve our net zero ambitions. Biomethane is already playing a role, and hydrogen could be available in quantities to blend into the gas grid from 2025. These low carbon alternatives have lower energy contents than natural gas, which means more volume would be required to deliver the same heat output.

The correct allocation of CV is vital for fair consumer billing. Current regulations achieve this by limiting the lowest source CV gas to 1 megajoule per cubic metre (MJ/m^3) below the charging area's Flow Weighted Average Calorific Value (FWACV).

The Cadent-led FBM project conducted a series of field trials with specialist industry partner, DNV, that focused on how the CVs within a Local Distribution Zone (LDZ) could be managed to create new charging areas. This proof-of-concept project has shown that network modelling could be used to predict CV at a local level.

The project has also explored what could be achieved under the current billing frameworks. Hydrogen and biomethane can be blended at low ratios to natural gas to maintain a CV within 1 MJ/m^3 of the FWACV. Whilst this limits hydrogen blends to ca. $5\%_{VOL}$, and biomethane to ca. $20\%_{VOL}$, these volumes could equate to significant amounts of green gas if the injection points into the gas network are strategically located. For example, a large NTS/LDZ Offtake blending hydrogen at just $5\%_{VOL}$ could account for almost 0.5 terawatt-hours (TWh) of hydrogen, saving around 60,000 tonnes of CO_2 equivalent per year.

FBM originally explored three options: Pragmatic, Composite and Ideal. All field trial reports refer to the options using those labels. Two further options were identified and included within this consultation, at which point new option names were introduced. Table 1-1 below summarises the options, renaming and with key indicators from the final high-level cost benefit analysis (CBA) against each option.

Table 1-1 – FBM consultation options, naming, description, costs, and CBA indicators.

FBM Option	Description	Implementation Costs at 2021-22 Prices		2050 Projections – High Case		
		Initial Cost (£m)	Ongoing cost (£m/yr)	NPV (£m)	Carbon Saved (mtCO2e)	Cost per tonne saved (£)
Option A: Work Within Existing Frameworks	Least-change option developed for the FBM Project consultation - Focuses on controlled blending of green gases within calorific value (CV) limits set by the existing gas calculation of thermal energy regulations (GCoTER)	5.5	0.5	16,765.4	93.6	0.12
Option B: Embedded Zone Charging	The original ***Pragmatic*** option for embedded low-CV green gas supplies - Uses network modelling to create separate charging areas within the Local Distribution Zone around low-CV gas sources such as biomethane supplies	162.5	2.4	7,996.0	44.5	4.44
Option C: Online CV Modelling	***Modelled CV*** option - Developed following review of the three original FBM options for future billing - Would deliver a modelled CV value at meter point level for billing, based on measured actual input CVs at source. (ca. 500 extra calorific value determination devices (CVDDs) for verification)	189.2	5.4	22,566.8	125.2	2.29
Option D: Zonal CV Measurement (Not recommended)	Refers to the original ***Composite*** option - Would use network modelling to break the LDZ down into zonal charging areas in which consumers would be billed based on CV measurements in each zone (Up to 10,000 extra CVDDs)	500.6	7.0	6,774.2	40.2	25.05
Option E: Local CV Measurement (Not recommended)	Refers to the original ***Ideal*** option - Would use CV measurement installed at highly localised level throughout the LDZ for billing customers. (Up to 44,000 extra CVDDs)	909.6	16.7	15,944.6	95.8	25.07

1.2 The Consultation

An industry consultation was undertaken with a wide range of stakeholders to share learning and gain feedback to inform a set of credible recommendations. The responses demonstrate a wealth of knowledge and experience from across the industry, which has been valuable in determining project recommendations. While some of the questions delivered mixed responses, they did produce a majority consensus that Option A represents a logical first step, given its relatively small investment and speed to implement.

Recognising that Option A alone cannot go far enough across all areas of GB networks to support the scale of blending required, Option C was also endorsed by respondents. There was recognition that a dedicated, cross-industry taskforce would be required to keep costs and related implications for consumers under close review. Cadent appreciates the time taken by stakeholders across the gas industry in familiarising themselves with FBM, participating in workshops and responding to the consultation itself.

A cost benefit analysis (CBA) of the options has been undertaken with high, medium, and low hydrogen and biomethane scenarios. The high scenario has been summarised in table 1-1 above, with the other scenarios described within the main body of the report. The results indicate that Option A, *Working Within the Existing Frameworks,* has the lowest £/tonne of CO_2e abated due to the minimal investment required in system and regulatory changes. This is closely followed by Option C*, Online CV Modelling,* and then Option B, *Embedded Zone Charging*. Options D and E are more expensive due to higher capital costs of installing significant numbers of CV measurement within the network.

1.3 Recommendations

1. **Implement Option A –** Options for billing reform require further work and there is an urgent need to make policy decisions on heat, such as hydrogen blending in 2023. It is therefore recommended that gas distribution networks should immediately proceed with developing the minimal changes required to deliver Option A. This will facilitate the development and growth of hydrogen supply from industrial clusters and gain the benefits of the blending connections strategy for biomethane connections, with least investment at risk.
2. **Commence feasibility study for Option C –** Option A has limitations of scale, with current regulatory constraints capping blending rates to within ca. $5\%_{VOL}$ until hydrogen can deliver blend volumes at the majority of gas energy in the LDZ. Billing reform is needed to accelerate the benefits of biomethane and hydrogen blending for heat and Option C could deliver one consistent methodology to achieve this. It is therefore recommended that the feasibility of Option C is explored immediately in parallel to Option A.
3. **Consider Option B within development of Option C –** With regard to Option B, it is recommended that the development of this option should be explored as part of the feasibility study for Option C, to determine whether it could be delivered in a way which avoids conflicting systems changes, asset redundancy, and associated cost stranding.

NB: All information and recommendations in this report are based on the best data available at the time of writing.

Outputs from Work Packs 1 - 4 from the FBM Project can be found on the FBM Project web site: https://futurebillingmethodology.co.uk/project_updates/ and are summarised for Ofgem in the Appendix A to this main report, in fulfilment of the FBM Project SDRC 9.5.

2 Introduction

2.1 Purpose of this Report

The Future Billing Methodology Project began in April 2017, awarded funding under Ofgem's Gas Network Innovation Competition. This £5.4m project, undertaken by Cadent in partnership with DNV, originally sought to explore three options to provide a "proof-of-concept" framework for a more specific way of attributing the energy content of gas or calorific value (CV) to maintain fair billing for consumers in a diverse-CV transition to a low carbon heat future. Learning from the project has developed two further future billing options and identified that two of the original options explored cannot be recommended at this time.

This final report sets out the FBM project's recommendations to Ofgem and industry on how the attribution of CV for billing and settlement could be treated in the face of a changing gas mix. The objective is to provide an efficient route to decarbonise heat through the introduction of green gases while maintaining fair and equitable billing for consumers.

This report shares:

- Summary of project findings
- Feedback from industry consultation
- Cost benefit analysis
- High level implementation roadmap
- Final recommendations

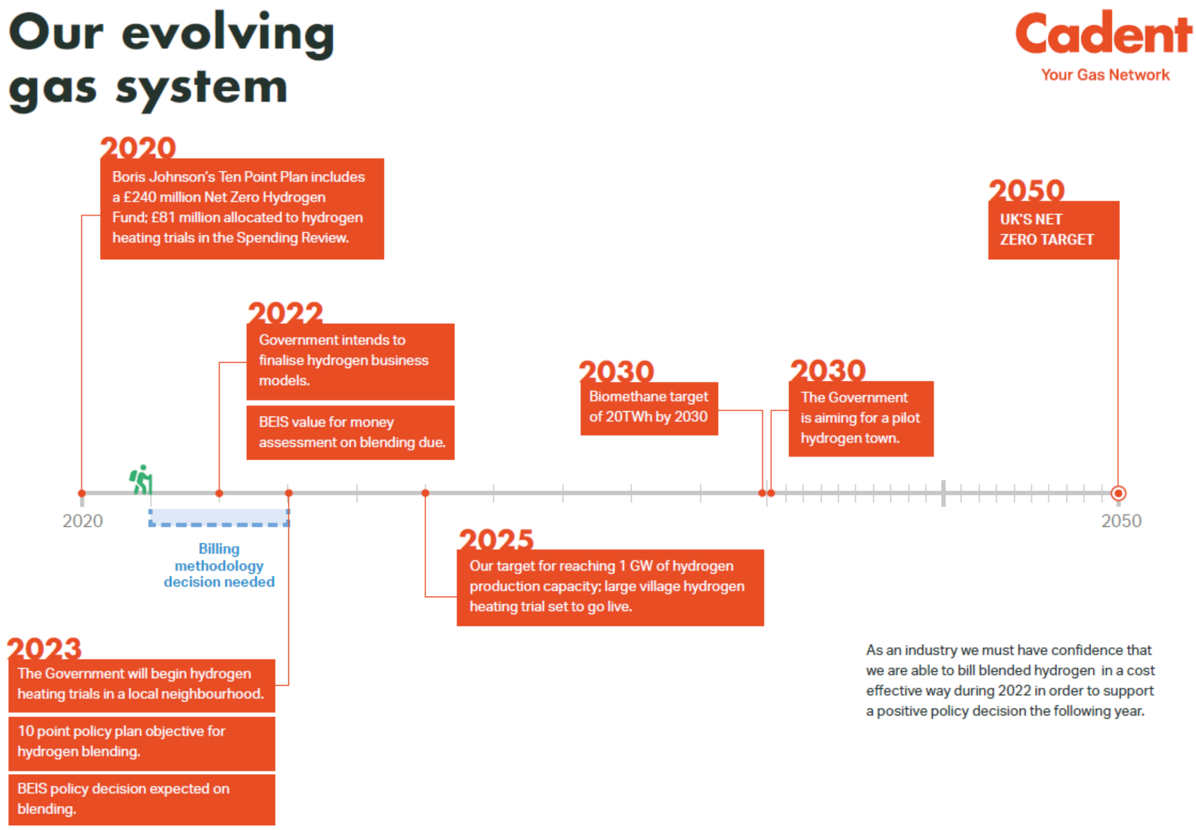
This report fulfils the second part of milestone 14, milestone 15 and Successful Delivery Reward Criteria (SDRC) 9.5 of the Project Direction, as amended*. The output of this report will also help inform a value-for-money case on hydrogen blending being conducted by the department for Business, Energy, and Industrial Strategy (BEIS) later in 2022, and a policy decision on hydrogen blending in 2023.
**See Appendixes A, B and C.*

2.2 The Role of Gas in the Energy Transition

The UK Government has legally committed to achieving net zero by 2050 and has further committed to achieving 78% of this by 2035 under the 6th Carbon Budget. Nearly 40% of the UK's emissions are produced from heat, which today is largely the result of burning natural gas, with more than 85% of homes using fossil natural gas for heating and hot water. Therefore, decarbonisation of gas is vital to reducing the UK's carbon emissions.

Biomethane and hydrogen represent viable low-carbon alternatives to natural gas. With the number of biomethane plants connected to the gas grid increasing and hydrogen blending trials underway, the government is expecting to make a decision on hydrogen blending in 2023.

The ongoing hydrogen blending trials are demonstrating that a blend of up to $20\%_{VOL}$ hydrogen with natural gas can be used safely in existing domestic appliances without any changes or disruption for consumers. Blending in this way can provide an early demand base for hydrogen, enabling production to scale, thus acting as a stepping stone for 100% hydrogen applications. Blending $20\%_{VOL}$ hydrogen into the gas distribution grid would equate to taking 2.5 million cars from the roads.



2.3 Developing a Practical Way Forward

As the gas mix changes to accommodate greener gases, the energy content will vary too, and this has implications for billing. Current regulations do not allow for large variances in CV within an area, therefore this must be tightly controlled in each region to avoid generating unbilled energy.

Today, propane is added to biomethane to raise the energy content to match that of natural gas. The need to add propane to this renewable gas adds cost for producers, undermines the green benefit of biomethane and may deter investment in its production.

This paper focuses on how greener gases could be introduced to the GB gas network while maintaining fair and equitable billing for consumers. The recommendations are the result of a programme of research and subsequent consultation with stakeholders across the gas industry, facilitated by Xoserve, the gas industry's Central Data Service Provider (CDSP). Ongoing collaboration across the gas industry will be vital to reducing emissions whilst protecting consumer needs and expectations.

3 Summary of Project Findings

3.1 Future Billing Methodology

- Successful field trials monitored gas quality to understand the zone of influence from an embedded gas supply for the first time
- Network modelling closely matched the measured data, providing confidence that it could be used to predict CV
- The results proved the concept that network modelling could be applied to create new charging areas
- Following a detailed review; it was determined that changes to billing systems and Gas Calculation of Thermal Energy Regulations (GCoTER) would be required for all options other than Option A
- Options D and E are not recommended as viable options at this time, due to the high cost of installing and operating high numbers of CV determination devices (CVDDs) within the gas distribution network
- A link between measured CV data to consumer smart meters proved possible in principle in a laboratory setting, but impractical due to meter battery life and significant changes to industry codes, systems, and processes.

Relevant related documentation is as follows (see Appendix A for more detail):

- MS11 Report on the Smart Meter Laboratory Trial
- MS12 Final Report on the Field Trial Progress
- MS13 Report on Novel Validation of Network Modelling for Embedded and Network Charging areas
- MS14 Consultation on Billing Options for Attributing the Energy Content of Gas in the Transition to Net Zero

3.2 Calorific Value and Gas Quality Impact Assessment of Hydrogen and Biomethane Blends

This separate Network Innovation Allowance (NIA) funded project has explored and indicated that hydrogen and biomethane blending could take place under the existing billing framework. This limits the percentage of green gas within the blend, but could result in significant volumes if strategically located, without making changes to regulations or systems. This formed the basis for a new, minimal change option – Option A – which would minimise investment at risk.

(See Appendix D for more detail)

4 Future Billing Methodology Options

The FBM project originally explored three options: *Pragmatic, Composite* and *Ideal.* All field trial reports refer to the options using those labels. Two further options were identified and included within this consultation:

- **Online CV Modelling** - modelling is used to deliver a more granular CV value for billing purposes. CV data from system entry points is combined with live data from the Local Transmission System (LTS) to derive CV values at system node level.
- **Work Within Existing Frameworks** - where hydrogen and biomethane are blended into the natural gas supply under the current regulatory regime.

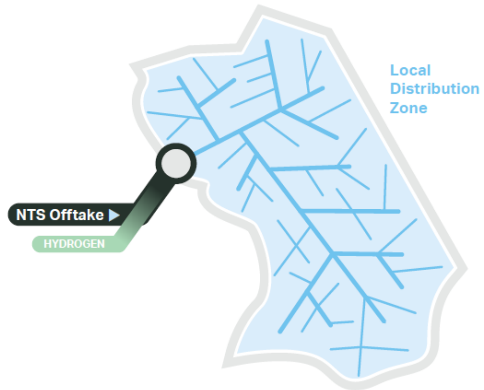
4.1 Renaming and Re-ordering of FBM Options

This is explained in table 4-1 below.

Table 4-1 – Renaming of FBM Options for Consultation

FBM Option	Description
Option A: Work Within Existing Frameworks	Least-change option developed for the FBM Project consultation - Focuses on controlled blending of green gases within calorific value (CV) limits set by the existing gas calculation of thermal energy regulations (GCoTER)
Option B: Embedded Zone Charging	The original ***Pragmatic*** option for embedded low-CV green gas supplies - Uses network modelling to create separate charging areas within the Local Distribution Zone around low-CV gas sources such as biomethane supplies
Option C: Online CV Modelling	***Modelled CV*** option - Developed following review of the three original FBM options for future billing - Would deliver a modelled CV value at meter point level for billing, based on measured actual input CVs at source. (ca. 500 extra calorific value determination devices (CVDDs) for verification)
Option D: Zonal CV Measurement (not recommended)	Refers to the original ***Composite*** option - Would use network modelling to break the LDZ down into zonal charging areas in which consumers would be billed based on CV measurements in each zone (Up to 10,000 extra CVDDs)
Option E: Local CV Measurement (not recommended)	Refers to the original ***Ideal*** option - Would use CV measurement installed at highly localised level throughout the LDZ for billing customers. (Up to 44,000 extra CVDDs)

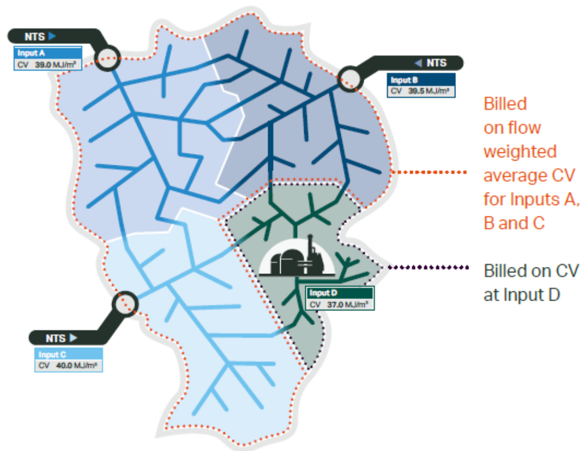
4.2 Option A: Work Within Existing Frameworks



- Low-carbon gas is blended into the natural gas LDZ network at ratios that ensure the blended gas CV remains within the regulated 1 MJ/m^3 of the FWACV
- For biomethane this means adding ca. 20%$_{VOL}$ to natural gas
- For hydrogen this means adding ca. 5%$_{VOL}$ initially, so that the CV of the blended gas is not more than 1 MJ/m^3 below the FWACV. If the hydrogen blend in proportion to the energy within an LDZ is increased, then the percentage of hydrogen within the blend can be increased due to a reduction in FWACV.
- This would reduce the target CV within a charging area, subsequently reducing the amount of enrichment required at biomethane plants.

NB: Regardless of the billing framework, where hydrogen is blended into the gas stream at or near the 20%$_{VOL}$ safe burn limit, this would prevent further hydrogen blending downstream of that point.

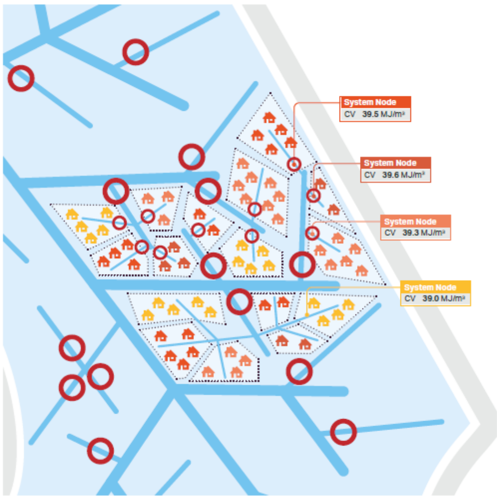
4.3 Option B: Embedded Zone Charging



- Zones are modelled around lower CV areas. For example, in locations around an embedded biomethane plant

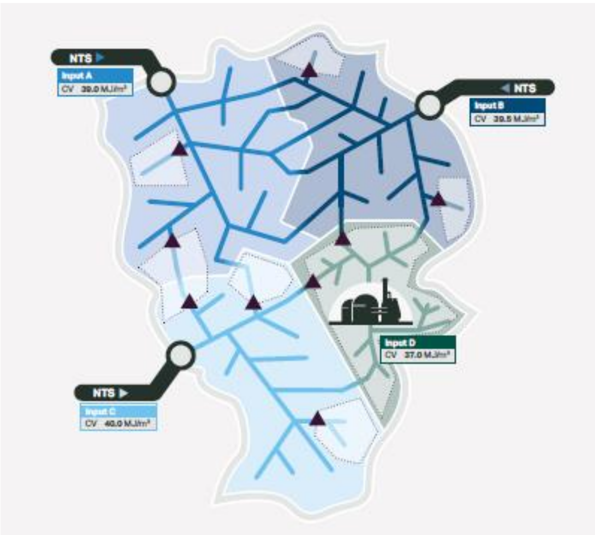
- Customers within the low CV zone are billed based on the lower CV
- Customers outside of that zone are billed on the FWACV for the rest of the LDZ
- Proof of concept demonstrated in FBM

4.4 Option C: Online CV Modelling



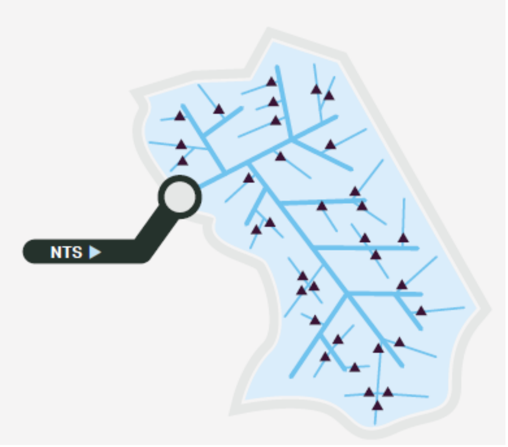
- CV is measured at all system entry points as it is now. Data is combined with live data from the LTS
- This informs modelled CV values at system node level
- Daily average CV values for each system node are attributed to the meter points attached to that node for billing purposes
- This option offers a more granular approach to gathering data. It also has the flexibility to be used for embedded supply and bulk blending at higher tiers
- This would require a detailed feasibility study to determine appropriate data inputs, model accuracy and system requirements

4.5 Option D: Zonal CV Measurement (Not recommended)



- Up to 10,000 CV Determination Devices (CVDDs) are installed across the network with meter points allocated to them using network models
- The entire LDZ is then broken down into smaller virtual charging areas for billing purposes

4.6 Option E: Local CV Measurement (Not recommended)



- An extension of Option D, this uses a far greater number of CVDDs (44,000) for more accurate billing by household
- Potential to link to smart meters as a preparatory step towards full gas energy metering at the point of use

5 Summary Review of Options

Option	Description	Impact on Billing Systems & Regulations	Possible year to implement	Benefits	Limitations
A: Work Within Existing Frameworks	Controlled & coordinated blending of green gases within LDZ FWACV limits	• No change to GCoTER • Minimal systems changes • No changes to billing • Technology Readiness Level (TRL) = 6	**2023**	• Initiates gas network decarbonisation within existing regulations • Minimal investment at risk	• Blending hydrogen limited to ca. 5% until blend volumes become majority of LDZ energy • Limited early benefit for biomethane • Favours strategic blending at high volume locations
B: Embedded Zone Charging	Network modelling used to create charging area around embedded low-CV green gas supplies	• Change to GCoTER to enable / regulate modelled charging areas • Change to meter point specific CV (Central and downstream systems) • TRL = 2/3	**2026**, if deliverable as an early, limited release of Option C	• Removes need for propane enrichment for embedded biomethane connections which can't blend into the network	• Limited to embedded supplies • Most of the functionality of Option C is needed • Requires case-by-case review of biomethane sites to determine feasibility

C: Online CV Modelling	Combines: • Online modelling of LTS • Online / offline modelling of lower tiers of LDZ system • Strategic additional CV measurement (ca. 500 CVDDs)	• Change to GCoTER to enable / regulate modelled charging areas • Change to meter point specific CV (Central and downstream systems) • TRL = 2	**2027**	• One consistent methodology to support any green gas transition scenario • Exemplars already in development / use elsewhere in Europe	• Concept not yet proven on GB gas network·
D: Zonal CV Measurement (not recommended)	Break LDZs into physical zones with CV measurement at strategic points to attribute CV for billing (Up to 10,000 extra CVDDs)	• Change to GCoTER to enable / regulate modelled charging areas • Change to meter point specific CV (Central and downstream systems) • TRL = 2	**2030** with a concerted capital programme to deliver CVDD population	• Originally conceived as a logical step-development on Option B	• Capex & Opex costs are higher than other options, due to high number of CVDDs required* • Impractical to install quantity of CVDDs* • Any change to network/ operation would change the charging zone, creating practical difficulties • Sampled gas venting issue (existing tech.)

E: Local CV Measurement (not recommended)	CV measurement installed at local level throughout LDZ network Potential for CV data transfer to smart meters (Up to 44,000 extra CVDDs)	• Change to GCoTER to enable/regulate modelled charging areas • Change to meter point specific CV (Central and downstream systems) • TRL = 2	**2035** with a concerted capital programme to deliver CVDD population	• Conceived as a logical step-development on Option D • Theoretically most accurate in all green gas transition scenarios • Delivers a measured CV	• Highest Capex & Opex costs of the options due to the high volumes of CVDDs* • Impractical to install quantity of CVDDs* • Sampled gas venting issue (existing tech.)

Note: While the installation of CVDDs can support options D and E, the project is unable to recommend these options as viable at this time, due to high installation and operating costs, plus emissions from vented sample gas from existing technology CVDDs at the numbers envisaged, and consequent levels of investment at risk.

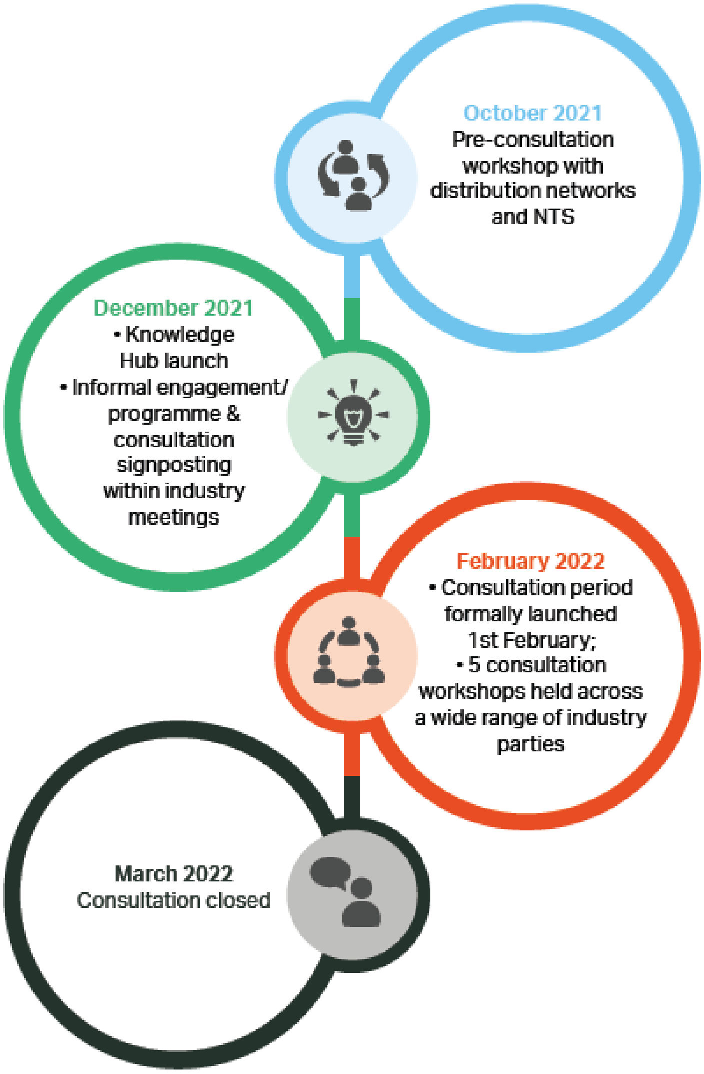
The FBM Project notes new developments in CV measurement technology, which could both avoid venting sampled gas and be much less expensive to install and maintain, but this has yet to be assessed and ratified for GCoTER purposes in a gas network setting. The Project therefore recommends that the potential of new CV measurement technology should be explored further.

6 FBM Project Consultation

6.1 Consultation Approach

The process for the final FBM consultation is shown in Fig 6-1 below.

Fig 6-1 – Final FBM Consultation Process



Comprehensive materials were developed to describe both the challenge and the consultation options in straightforward and accessible formats. The intention was to make it easy for stakeholders to engage and contribute. These documents were hosted on Xoserve's Knowledge Hub. Launched in December 2021, the Hub and FBM project details were shared widely within Xoserve's stakeholder engagement sessions.

The materials were also shared as pre-reading material within consultation workshop invitations, to allow all participants ease of access to the relevant information, with frequent reminders issued to support attendance levels. A series of consultation workshops were held during February 2022, enabling industry stakeholders to gain a better understanding of the project and to have meaningful dialogue on the proposed options.

Following the workshops, reminder emails were issued signposting the FBM consultation materials and ways to submit a response.

Consultation response methods, included:

- Anonymised online questionnaire
- Word doc version, for those that weren't comfortable using the electronic version
- Email option via Xoserve
- Polls during the workshops

Fig 6-2 – FBM Final Consultation audience and respondents

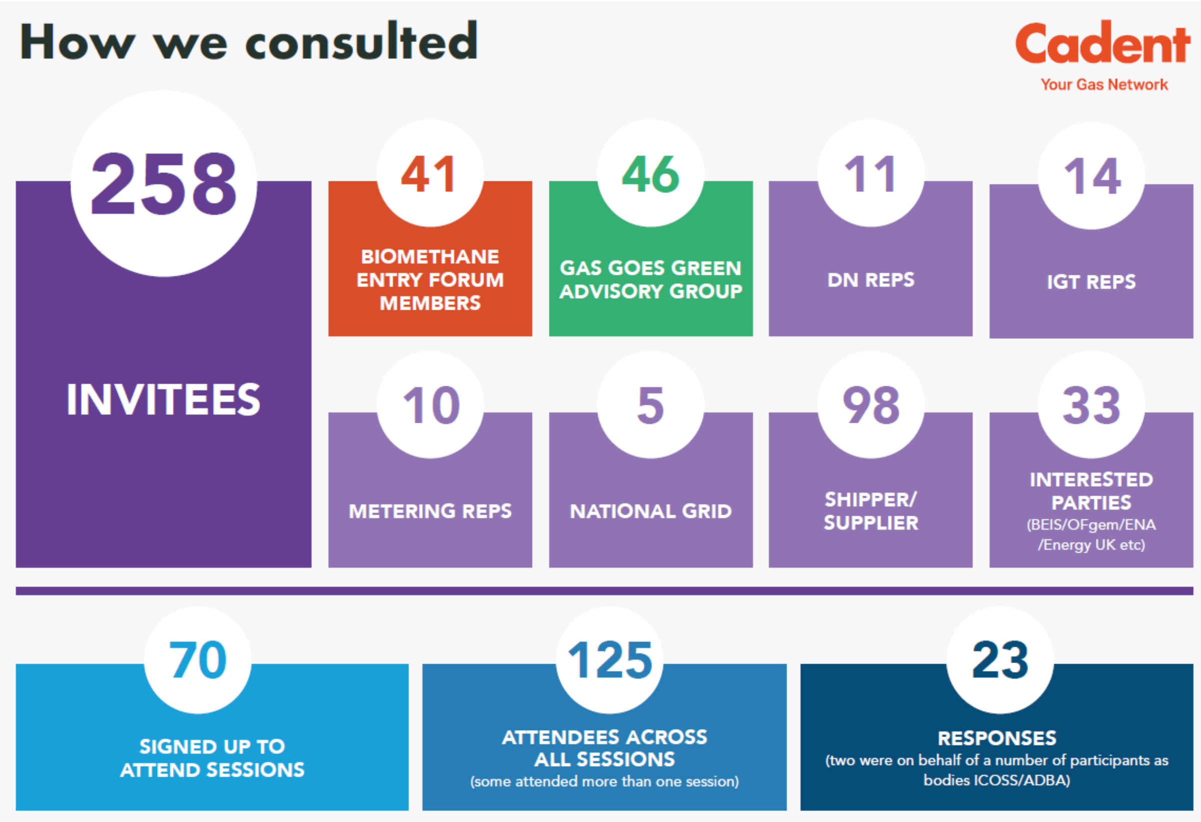
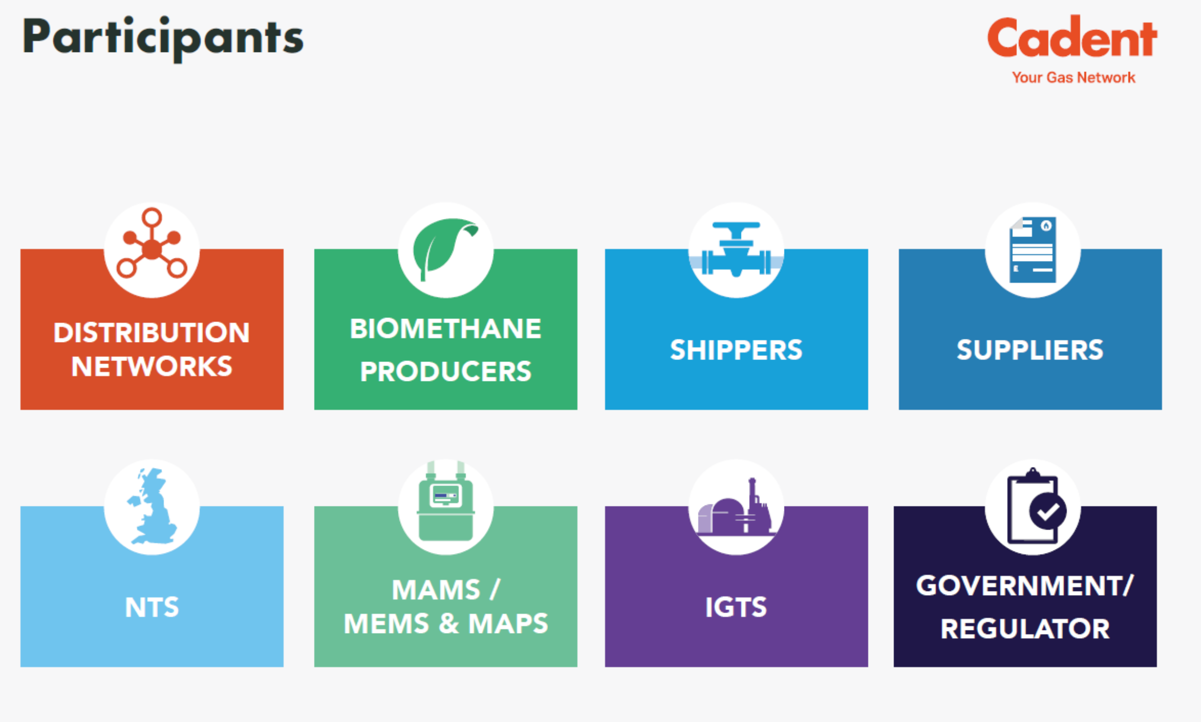


Fig 6-3 – FBM Final Consultation industry sector breakdown



6.2 Summary of Consultation Responses

A total of 23 formal responses to the consultation were received. Two were on behalf of a group of companies from the Industrial and Commercial Shippers and Suppliers Group (ICOSS) and the UK Anaerobic Digestion and Bioresources Association (ADBA), delivering combined representative views for their respective sectors. All responses have been reviewed in full and analysed by sector. Key themes are outlined below.

In addition to the formal responses, polls were conducted during the workshops to provide supplementary insight. Up to 60 responses were gathered and that data is also presented.

Option A: Working Within Existing Frameworks

Statement 1 – Progressing Option A could offer a no-regrets route to begin decarbonising the UK's 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.

Consultation Q 1 – Consultees were asked whether they agreed with the above statement.

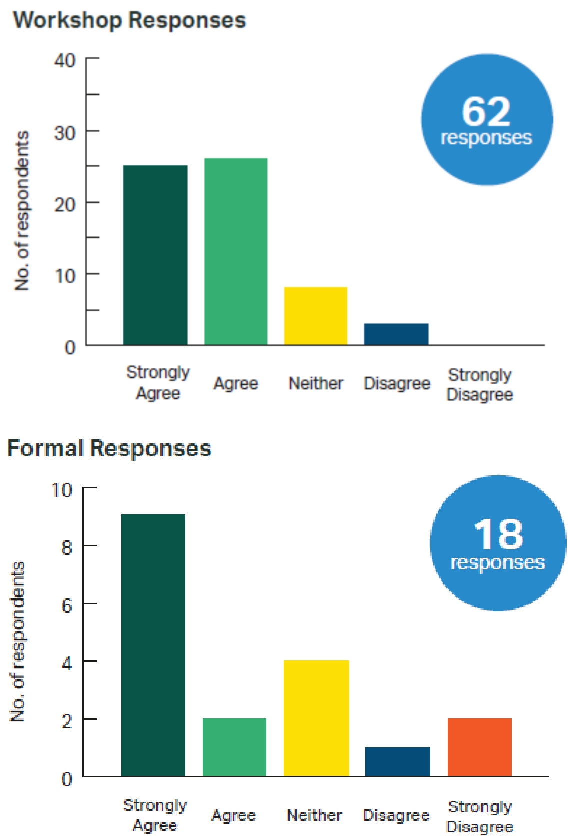
Outcome

Option A was largely endorsed from across the range of stakeholder groups as a logical first move. Chiefly owing to the minimal investment required and short implementation timescales. The ability to progress without making changes to GCoTER was considered favourable within consultation responses, as was the low financial impact to consumers versus other options.

It was noted that new control mechanisms may be required to monitor blend ratios and ensure the CV remains within tolerance.

Some biomethane producers disagreed, arguing that impacts of Option A might be considered negligible, recognising the current low levels of hydrogen availability.

Fig 6-4 – Responses to consultation question 1



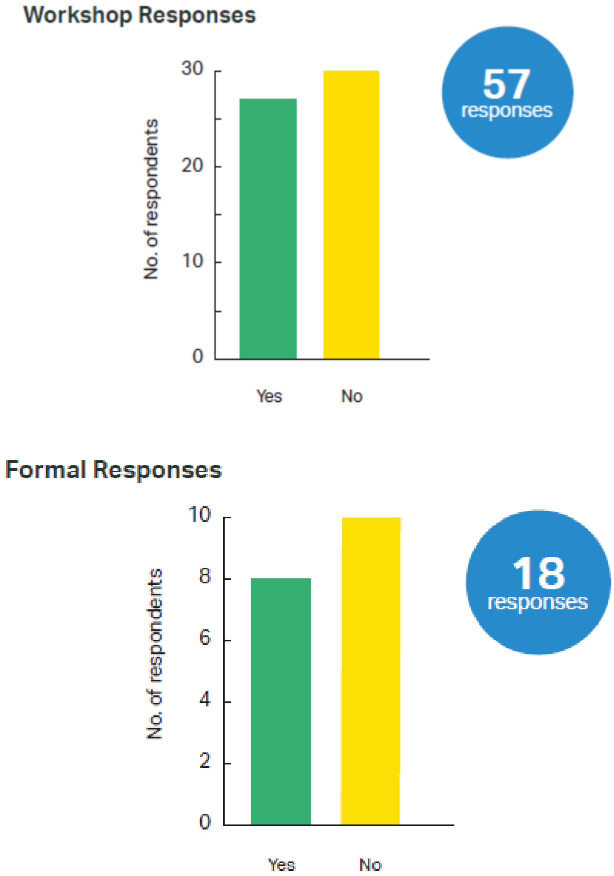
Consultation Q2 – Consultees were asked whether they would foresee Option A as an enduring solution for the transitional phase ahead of a switch either to 100% hydrogen, or alternative heat delivery vectors.

Outcome

While Option A was endorsed by most in principle, many viewed it as a stepping stone to a more sophisticated option rather than a long-term solution.

Some concerns were expressed that it could limit the opportunity to fully decarbonise and questioned whether it could represent a strong enough stimulant for the hydrogen market alone.

Fig 6-5 – Responses to consultation question 2



FBM Project View

The FBM Project agrees with the bulk of responses. Option A (Work within Existing Frameworks) can be considered a way of commencing hydrogen blending at the earliest stage. It places least investment at risk, due to its minimal implementation requirements.

The blending of hydrogen in natural gas is a vital enabler for the development of 100% hydrogen networks. This is because a blending phase can facilitate the development of hydrogen supply upstream without direct reference to fluctuating demand levels downstream.

Acknowledgement is given that there are some limitations of scale. The ability to increase hydrogen blends to $20\%_{VOL}$ under Option A would only work in LDZ networks with access to a significant supply of hydrogen at multiple input points. The project therefore also recommends rapidly commencing feasibility studies for Option C.

Cadent's biomethane connections blending strategy is included within Option A. This strategy is being developed to maximise the potential for new biomethane connections to blend into the local network wherever feasible. This will minimise dependence on propane for gas enrichment.

Option C: Online CV Modelling

Statement 2 – 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.

Consultation Q3 – Consultees were asked whether they agreed with the above statement.

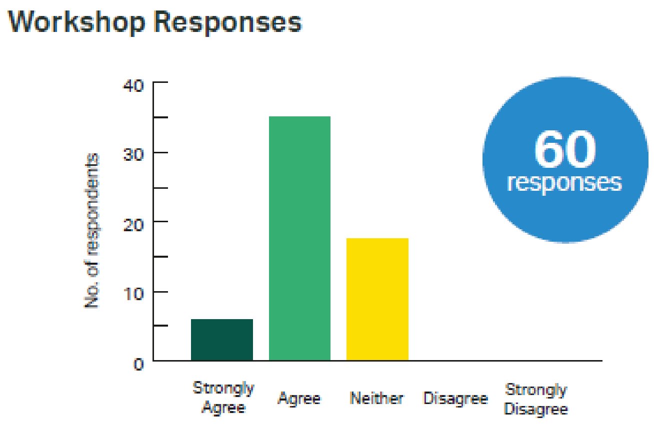
Outcome

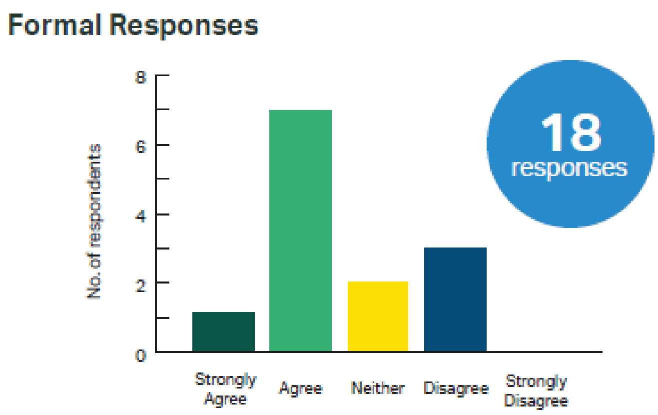
There was strong agreement with this statement within formal consultation responses and from the consultation workshop poll results. It was felt that this methodology would well support both biomethane and hydrogen, providing a consistent and enduring approach.

Some respondents cautioned that a feasibility study would be required to better understand system requirements and any limitations. However, it was felt that in principle Option C would provide a deeper level of granularity, supporting fair customer billing.

It was acknowledged that similar methods are being explored in other countries, which should result in less operational risk.

Fig 6-6 – Responses to consultation question 3



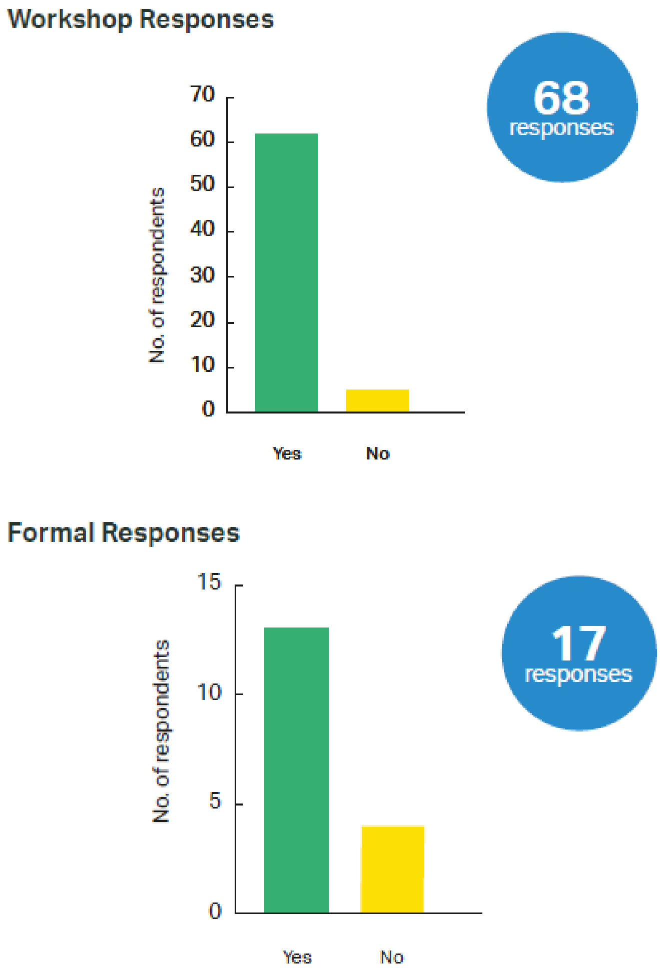


Consultation Q4 – Consultees were asked whether they would support progressing work on a detailed feasibility assessment to deliver Option C Online CV Modelling.

Outcome
The majority of respondents were supportive of progressing to a feasibility study for Option C, with 76% of formal consultation responses and 91% of workshop poll responses supporting the move.

In general, respondents welcomed the possibility of more accurate data, presenting an opportunity to feed into meter point CV allocation for settlement and billing. Some suggested working on the feasibility study in conjunction with implementation of other options.

Fig 6-7 – Responses to consultation question 4



FBM Project View
Option C was developed following a detailed review of the original field trials, which focused on Options B, D and E. Concerns over the potential complexity of the original options, as well as the difficulty of installing and operating CV determination devices (CVDDs) at large scale gave rise to Option C, which focuses on modelled CV data for billing purposes.

Outside of the UK, model-based CV attribution is being pursued, offering a precedent from which learning can be gained. FBM proposes using online operational hydraulic models, where CV and supervisory control and data acquisition (SCADA) data is available. Today, offline hydraulic modelling is widely used for network modelling.

System development would be needed. Option C requires continually updated hydraulic models of the LTS, using actual measured CV and volume data. Additional data inputs would need to be integrated from:

1. Embedded green gas supply sources
2. Large daily metered sites

FBM recommends progressing to a feasibility study to better understand the system and data requirements, and an optimal means of testing and validating CV data on an ongoing basis. We know that widespread installation of CVDDs is not practical to achieve, in terms of cost, access to land and the requirement for venting devices. The study should consider the possibility of installing far fewer CVDDs at strategic network points, as well as emerging technologies in this field that could better enable ongoing measurement.

FBM recommendation is for Option C feasibility study to be started urgently, in parallel with implementation of Option A. This is due to the high likelihood that immediate availability of hydrogen in regional networks will be restricted to certain locations.

It should be noted that in respect of very large gas users, which presently have site-specific CV measurement for billing purposes, this would remain the case under any future billing framework. These sites would continue to be deemed separate to any charging area under the GCoTER.

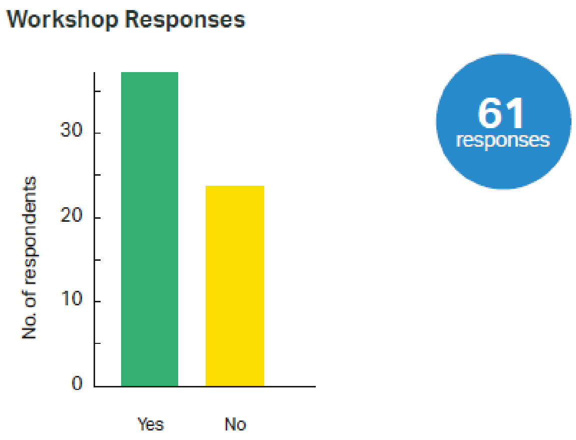
Option B: Embedded Zone Charging

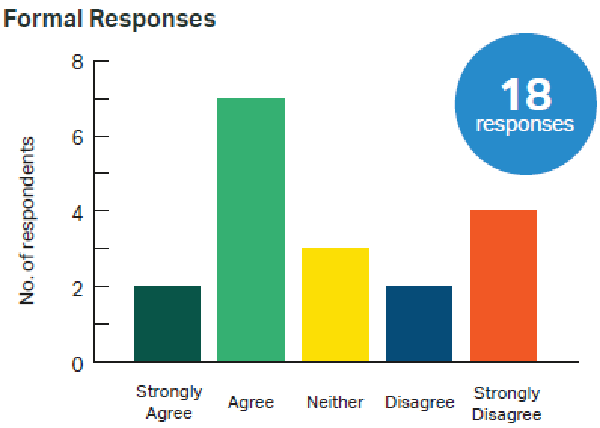
Consultation Q5 – Would you support exploring Option B further as part of development work towards delivery of Option C (Online CV Modelling)?

Outcome
There was no clear consensus view from respondents regarding the exploration of Option B, even within stakeholder groups.

Opinions were divided, with some respondents seeing the potential for Option B delivering an early output of Option C. Others felt that it could prove an unnecessary distraction from delivering Option C, risking a delay in the delivery of decarbonisation benefits, and resulting in additional costs.

Fig 6-8 – Responses to consultation question 5





FBM Project View

Option B involves similar cost and effort to option C - this is reflected in the CBA.

Learning from the field trials showed that establishing a clear boundary for charging is problematic. The area receiving lower CV gas varies significantly depending on network demand, creating difficulties in maintaining fair and accurate billing. As a result, Option B would require regular zone review, with high potential to be on a daily basis to get this right.

The characteristics of each network around an embedded supply differ, so a 'one size fits all' approach doesn't work. This adds cost and complexity to implementation.

System development would be required to disaggregate the embedded charging zone and ensure the FWACV for the rest of the LDZ is carefully managed, to avoid an increase in Unidentified Gas (UIG).

However, there are instances where the configuration of an LDZ lends itself to sensible physical separation. For instance, where it is fed by different 'legs' of the NTS, or where additional CVDDs can be fitted into the feed-in pipe. In these instances, creating separate physical charging areas can work within existing regulations, but would still require changes to billing systems.

Option B requires significant system development both in central systems and within individual operational or billing systems to accommodate a change in CV allocation. On this basis the FBM Project recommends that the development of Option C should be prioritised, but that it considers the aims of Option B, for earlier implementation if deemed feasible and appropriate.

Option D: Zonal CV Measurement and Option E: Local CV Measurement

FBM Project View
Options D and E have been included in the consultation for completeness against the original FBM Project remit. However, the project does not recommend either of these approaches, primarily due to the cost and complexity associated with utilising CV measurement technology at high scale within Local Distribution Zones.

Other Consultation Questions

Consultation Q6: Client systems costs in CBA – Shipper/ Supplier consultees were asked whether they could assist the consultation by providing a high-level cost estimate for the changes to client systems in respect of Options B and C to assist development of the final cost benefit analysis (CBA).

IGTs were also invited to review potential cost impacts during the consultation workshops.

Outcome
At the time of consultation, none of the respondents were able to provide high-level cost estimates for these changes. Reasons for this included, lack of time and other competing resource priorities. Currently there is not enough detailed data for industry parties to provide a meaningful estimate of implementation costs. However anecdotally the feedback shared gives expectations that costs of this nature to billing systems would be high.

FBM Project view
The FBM Project understands that it is very difficult to provide meaningful cost estimates for potentially highly detailed changes while those changes are still at concept level. A feasibility study should be undertaken for Option C to better inform cost estimates. This process will require a high level of collaboration between gas networks, the central data services provider, and Shippers / Suppliers, with oversight by Ofgem and in consultation with the wider industry.

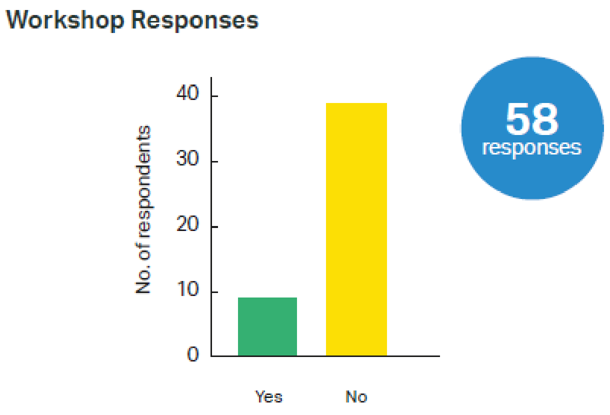
The actual costs of making these changes for Shipper / Supplier organisations will be a matter of commercial confidentiality, but it is hoped a way can be found to generate meaningful indicative costs, to inform an industry impact assessment as part of the development work for Option C.

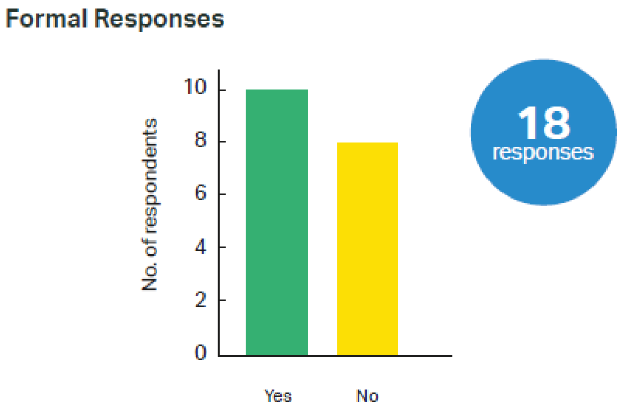
Consultation Q7 – Regional application of options – Cadent recognises that the ability to blend green gases at scale will be likely to have significant variations from one region to another. Consultees were asked: Would you consider it to be acceptable and/ or practicable to apply different billing options in different regions?

Outcome
There were very mixed responses to this question. In general, producers were largely in favour of regionalised billing methods. Gas Network Operators, Independent Gas Transporters (IGTs) and Metering Companies were almost equally split in opinion and the Shipper/ Supplier community was inclined to vote against it. The main concerns centred around the cost and complexity of implementation. It was also noted that careful review and communication would be necessary to eliminate any disparity in bills from region to region, ensuring fairness and equitability.

Some networks felt that regionalised billing would be an appropriate extension to the work that has already been undertaken to support individual projects.

Fig 6-9 – Responses to consultation question 7





FBM Project View

Regardless of the billing option that is pursued, the most practical way forward is a phased regional rollout by LDZ. Option A should be considered as the primary approach because it could be implemented swiftly under the current regulatory regime and with minimal system change.

Should a feasibility study for Option C prove favourable, it is anticipated that the regulations, systems, and processes could be set up in such a way that it could be "switched on" for each LDZ at the point that each is ready. This would allow changes to be rolled out regionally without impact to consumers.

Consultation Q8 – Consultees were asked: Do you have any alternative views on the green gas scenarios and projections set out in section 6.3 of the consultation document?

Outcome
Several respondents reiterated their views on the consultation options. These responses have been captured within the commentary above in relation to Options A, C and B.

One Shipper/ Supplier felt that the potential for embedded hydrogen solutions had been omitted from the options, as the FBM project focused on a core assumption of centralised hydrogen production.

FBM Project View
Option A includes a projection for the potential impact of Cadent's biomethane connections blending strategy that aims to minimise dependence on propane for gas enrichment. The final high-level CBA for this report has been adjusted to take full account of the potential interaction between this and blending hydrogen at up to $20\%_{VOL}$, to avoid double-counting of benefits under this option.

While Option A gains more in terms of an earlier implementation; Option C, evaluated at the same scale, gains more in terms of carbon abatement, as it enables higher blend rates from the point of implementation. As such, the combination of Options A and C could provide the most advantageous route.

The CBA also included a scenario for embedded hydrogen generation under Option B, based on historical size and growth rates for biomethane supply sites, as a proxy. In practice, the fact that hydrogen blend is limited to within $20\%_{VOL}$ for existing appliances could constrain embedded blending, either downstream of a strategic blending point, or where multiple embedded blending sites share the same network.

Q9 – Consultees were asked if they had any other comments or questions relating to potential options for decarbonising gas distribution networks.

Outcome
There was some further reiteration of the key points made within previous consultation questions. One network company endorsed the work undertaken by the FBM Project and recognised that much of the impact of future changes would be felt by the distribution networks.

One respondent commented that current regulations should not be considered a barrier to change and welcomed the chance for early engagement with regulators to discuss improvement of customer equity and the green agenda.

The removal of propanation from biomethane was highlighted by several as a key move for greening the gas grid today. FBM analysis has shown that there are credible and quick-to-implement solutions that will allow progress with multiple green gases in the grid. It is clear from this consultation that there is an eagerness from the industry to do so.

FBM Project View
The responses clearly illustrate the urgency felt across the gas industry to make the changes necessary to move forward on the journey to net zero. The FBM project considers biomethane to be an important part of achieving net zero. With hydrogen blending offering a highly effective way to build a sound future supply base for future 100% hydrogen gas networks.

Implementing Option A can start this process as soon as hydrogen is available for blending at primary gas supply locations into the distribution network, whether this is via the NTS, or at NTS/LDZ offtakes. It minimises the investment at risk and provides an opportunity to further investigate Option C.

Widespread CV measurement at high scale throughout the gas network is too costly and impractical in reality. Option C could deliver the existing level of consumer protection under a green gas transition with a carefully targeted population of CVDDs. Further investigation of new CV measurement technology could support this.

7 Consultation Summary

Cadent appreciates the time taken by stakeholders across the gas industry in familiarising themselves with FBM, participating in workshops and responding to this consultation.

The responses demonstrate a wealth of knowledge and experience from across the industry, which has been valuable in determining project recommendations. While some of the questions delivered mixed responses, they did produce a majority consensus that Option A represents a logical first step, given its relatively small investment and speed to implement. Although Option A alone cannot go far enough, quickly enough across all areas of GB networks.

In principle, Option C was endorsed by respondents. With recognition that a dedicated, cross-industry taskforce would be required to keep costs and related implications for consumers under close review.

Consultation respondents expressed a desire to decarbonise and a recognition that system development and closer cross-industry collaboration will be required. Some respondents were open minded over whether that system development might ultimately support Options B, C, D or E. However, a feasibility study for Option C was deemed the most pressing first step by the majority.

8 Cost Benefit Analysis of Options

The basis for the hydrogen and biomethane scenarios for the CBA remain unchanged on those presented in section 7 of the MS14 consultation document issued on 1st February 2022. 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.

8.1 Basis of CBA model

The CBA model assesses the cost and benefit of each of the future billing options on a GB basis, which would be across the 13 LDZ networks. The rationale for working to a 2050 horizon on a national basis in the CBA is as follows:

i. It is relevant to do so since a transitional gas phase could potentially last for some time in areas of the network where 100% hydrogen, electrification or alternative heat delivery vectors remain problematic.
ii. At this stage, there is uncertainty around 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% 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 that have been consulted on.

8.2 Hydrogen Blending Scenarios

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 below:

Table 8-1 – 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

The CBA model assumes that the 2030 capability levels for each scenario shown are achieved in 2035 and maintained level through to 2050. The high scenario 31TWh figure broadly aligns with the 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

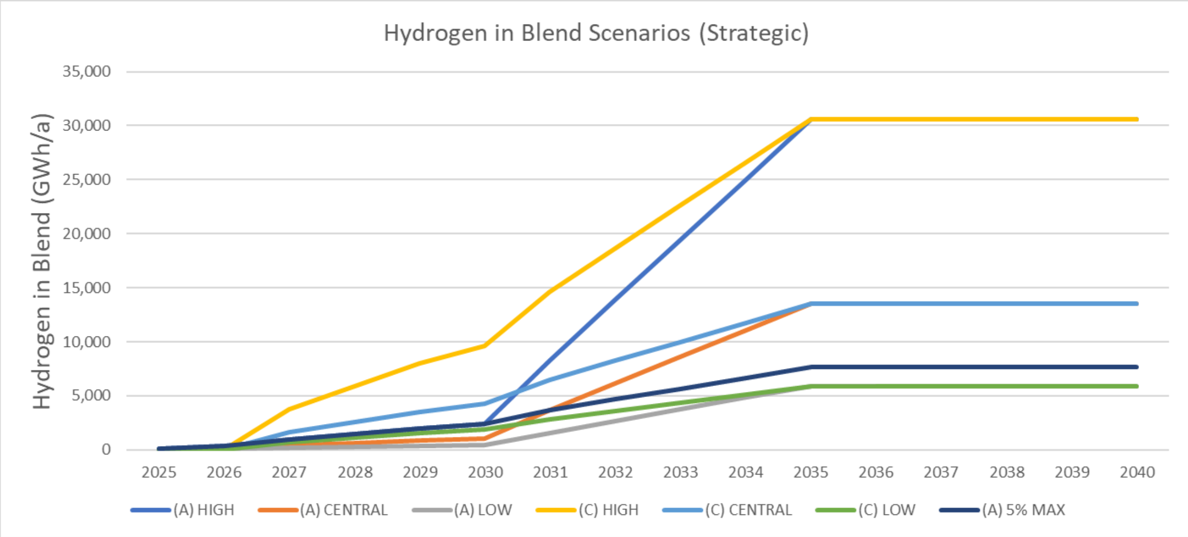
The simplified projection in the CBA model assumes five blending tranches of equal scale, based on a larger-size LDZ.

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 ca. 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 below.

A sense-check was carried out which shows that the hydrogen “low” scenario closely aligns with the high-level estimate of the maximum achievable hydrogen uptake where the LDZ FWACV mechanism under option A, in a scenario where a "majority energy flow" is unachievable, limiting hydrogen blend to to ca. 5%$_{VOL}$. The low scenario could be applied for assessing Option A, if capped to a 'minority energy flow' into the LDZs, for example at ca. 5%$_{VOL}$.

For Option C – It is assumed that the same maximum amount of 31 TWh of hydrogen is achieved. The benefits start later due to development of the required billing system, but a higher amount of hydrogen is projected in the growth phase, as 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.

Fig 8-1 – Hydrogen scenarios for Options A and C



Option B – This billing option would deliver specific CV billing for embedded green gas supplies only. The CBA includes an embedded hydrogen scenario for Option B, based on an assumed average plant capacity of around 1,000 standard cubic metres per hour of blended gas, which equates to around 5 GWh hydrogen per site, per annum, with 10 new plant connections per year, between 2026 and 2050, so reaching a total of just over 1.5 TWh p.a. by 2050.

The central case for this scenario is based on historical information on typical network capacity for historical biomethane plants and approximate average number of connections per annum, with high and low cases derived 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 above chart due to scale.

Note that likely future 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.

8.3 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 the table below:

Table 8-2 – 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 is 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

Biomethane Blending Connections Strategy

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 future blending connections strategy has been applied (further detail on which is provided in section 5.4 of the MS14 consultation document) as shown in the table below.

Table 8-3 - Projected percentage abatement of propane energy achieved through biomethane blending connections

Projected % propane energy abated via biomethane blending connections	2025	2031	2035
Target % 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.

8.4 Implementation Costs for Billing Options

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

8.5 Updates to Final FBM Project CBA

Following Cadent's engagement process, the final high-level CBA shown in this report has been updated from the previous version presented in section 6 of the MS14 consultation document.

Option A implementation costs – These have been updated to include a high-level estimate of the capital cost of hydrogen gas calorimeters. A small readjustment has been made to the calculation of operating costs.

Option A benefits adjustment – The mechanism for estimating the impact on propanation for biomethane sites under Option A has been improved. Exclusion of double-count benefits at the point of wide scale hydrogen blend up to $20\%_{VOL}$, has resulted in a 6% reduction in the projected carbon abatement.

Inclusion of a Zero hydrogen scenario – The model now incorporates a "Zero Hydrogen" scenario, so that the benefits of propane abatement for biomethane can be evaluated within all options.

Inclusion of a hydrogen blending scenario constrained to 5%$_{VOL}$. – The model now incorporates a 5%$_{VOL}$ hydrogen blending scenario, for the case where the blend is limited to a minority flow into the LDZ. As described in section 8.1 the 'low' hydrogen scenario could be applied for assessing this.

Option D embedded hydrogen – The embedded hydrogen scenario developed for Option B has also been applied within Option D, so they are directly comparable. This increases the maximum projected carbon abatement for option D by 2050 by 11%.

Implementation costs, go-live year, NPV and maximum potential performance of each of the future billing options have all been updated accordingly.

8.6 Final High-level CBA Results

Table 8-4 below sets out implementation costs for each option, together with projections of NPV, benefit to cost ratio, break-even year, total carbon abated to 2050, cost per tonne of carbon abated and an indicative cost per customer, based on a static population, under a high scenario for hydrogen and biomethane blending.

Table 8-4 – Final CBA results: High – high scenario

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	Implementation Costs			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 (£)	Option cost per consumer to 2050 (£)
	CAPEX (High case) (£M)	OPEX (Set-up) (£M)	OPEX (Ongoing) (£M/a)			2030 (£M)	2040 (£M)	2050 (£M)					
A: Work within existing frameworks	4.94	0.52	0.52	N/A	2023	294.4	8,063.9	16,765.4	1480 : 1	2025	93.559	0.12	0.46
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	7.99
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	11.60
D: Zonal CV Measurement	499.40	1.2	7	33.2	2030	-346.2	2,194.8	6,774.2	8 : 1	2033	40.209	25.05	40.78
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	97.26

Table 8-5 follows on from above to show projected performance measures, including total carbon abated by 2050 and cost per tonne abated for each option, under "central" and "low" scenarios for hydrogen and biomethane, with an additional scenario to show the impact of removing hydrogen blending altogether.

Table 8-5 – Projected total carbon abated by 2050 under each option / scenario

Hydrogen Blend Scenario:	CENTRAL				LOW				ZERO			
Hydrogen within blend peak reached at 2035:	13.5 TWh/a				5.9 TWh/a				0.0 TWh/a			
Biomethane Scenario:	CENTRAL				LOW				LOW			
Biomethane peak reached at 2050:	62.5 TWh/a				31.3 TWh/a				31.3 TWh/a			
Option	Final benefit : cost ratio	Break-even year	Total carbon abated at 2050 (mtCO2e)	Carbon abated: cost per tonne (£)	Final benefit : cost ratio	Break-even year	Total carbon abated at 2050 (mtCO2e)	Carbon abated: cost per tonne (£)	Final benefit : cost ratio	Break-even year	Total carbon abated at 2050 (mtCO2e)	Carbon abated: cost per tonne (£)
A: Work within existing frameworks	699 : 1	2025	44.107	0.26	323 : 1	2025	20.383	0.56	79 : 1	2026	4.900	2.31
B: Embedded Zone Charging	22 : 1	2028	23.338	8.46	11 : 1	2030	12.039	16.40	10 : 1	2030	10.614	18.60
C: Online CV Modelling	37 : 1	2028	57.827	4.96	17 : 1	2029	26.806	10.69	7 : 1	2032	10.339	27.72
D: Zonal CV Measurement	4 : 1	2035	19.743	51.03	2 : 1	2040	8.819	114.23	2 : 1	2041	7.438	135.44
E: Local CV Measurement	4 : 1	2036	39.559	60.73	2 : 1	2040	13.600	176.63	-	-	-	-

In the absence of upstream hydrogen, the analysis shows Option B outperforming Option C. For modelling purposes, this is based on a simplistic assumption that all embedded biomethane supplies would be able to benefit from the application of an Option B arrangement. In practice, option B would not work for all network configurations so a case by case assessment would be needed. Note that Option E fails to break even prior to 2050 in a zero hydrogen, low biomethane scenario.

Assumptions and factors applied in the FBM Billing options final CBA model is listed in Appendix B.

9 Recommendations

9.1 Recommended Approach

1. **Implement Option A –** Options for billing reform require further work and there is an urgent need to make policy decisions on heat, such as the decision on hydrogen blending in 2023. It is therefore recommended that gas distribution networks should immediately proceed with developing the minimal changes required to deliver Option A. This will facilitate the development and growth of hydrogen supply from clusters to develop and gain the benefits of the blending connections strategy for biomethane connections, with least investment at risk.

2. **Commence feasibility study for Option C –** Option A has limitations of scale, with current regulatory constraints capping blending rates to within ca. $5\%_{VOL}$ until hydrogen can deliver blend volumes as the majority of gas energy in the LDZ. Billing reform is needed to accelerate the benefits of biomethane and hydrogen blending for heat and Option C could deliver one consistent methodology to achieve this. It is therefore recommended that the feasibility of Option C is explored immediately in parallel to Option A.

3. **Consider Option B within development of Option C –** With regard to Option B, it is recommended that the development of this option should be explored as part of the feasibility study for Option C, to determine whether it could be delivered in a way which avoids conflicting systems changes, redundancy, and associated cost stranding.

9.2 High Level Implementation Plan

1. Utilise cross-industry decarbonisation groups to collaboratively determine the functional requirements for Option A.

2. Engineer the monitoring and control requirements for Option A into the detailed design of early hydrogen blending projects

3. Deploy a biomethane blending strategy for new connections and assess existing connections opportunity to blend without enrichment where feasible.

4. Mobilisation of a central task force, with Ofgem oversight, to initiate a feasibility study for Option C, including:

    a. Develop plans, estimate costs and work with Ofgem to agree the appropriate funding mechanism for the study.

    b. Engage Ofgem to determine the scope for a modelled CV approach and agree a minimum level of consumer protection. For example, at least maintain the existing level of consumer protection afforded by the LDZ FWACV regime.

    c. Develop a functional specification to support competitive procurement of systems and measurement devices.

    d. Review online and offline pipeline simulation products suitable for application across system tiers, including specification of optimal online modelling requirements and data integration from embedded gas suppliers.

    e. Assess impacts and requirements for integrating actual demand data for large daily metered consumers.

    f. Review of asset data processes to determine how updates can be dynamically reflected in system models.

g. Design network trials: work with Ofgem to develop regulatory derogation to allow CV modelling to be tested with a hydrogen blend, and/ or unpropanated biomethane.

h. Implement trials, measure, and validate CV modelling

i. Develop required amendments to GCoTER, allowing for a phased regional roll-out across LDZs

j. Specify changes to the central billing system, including interfaces with network systems, in collaboration with Shippers/ Suppliers

k. Develop industry codes to facilitate and regulate the new regime

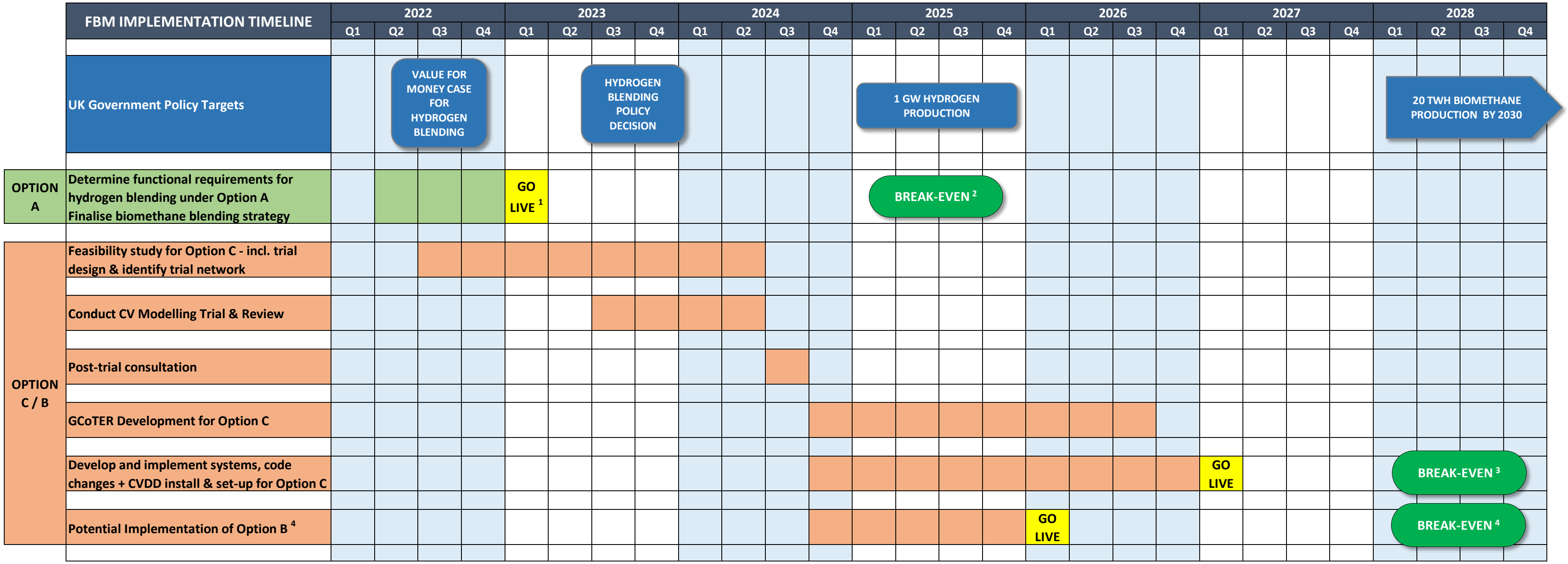
l. Consider whether a Significant Code Review would better support the scale of changes needed to industry systems and processes

5. Further investigate advancements in CV measurement technology to provide a detailed whole-life assessment of costs, robustness, and accuracy in a live gas network setting with live data communications.

9.3 High Level Implementation Timeline

A high-level implementation timeline for the recommended FBM options is shown in Fig 9-1 below.

Fig. 9-1 – FBM Recommended options: High-level implementation timeline



1. Ability to go live, but actual implementation subject to specific live projects from this point.
2. Break-even year for Option A under all cases except Zero Hydrogen - assuming national roll-out of option alongside hydrogen blending
3. Break-even year for Option C under central case - assuming national roll-out in year 2027
4. Break-even Year for Option B - assuming delivery as early output of Option C and national roll-out in year 2026

10 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	A 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

Term	Meaning
GWh	Gigawatt-hour – a measure of thermal energy equivalent to one million kilowatt-hours
IGEM	Institute of Gas Engineers and Managers
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 x 10^9)
UMS	Unmetered (electricity) Supply
UNC	Uniform Network Code (the common contract for all system users of the GB gas grid)

Appendix A: FBM Project findings: Collation of Outputs from Project Work Packs 1 – 4

FBM Project Work Pack 1 – Industry Engagement

Following the conditional Project Direction from Ofgem on 16th December 2016, this work pack comprised the following elements:

Work Pack 1a – Industry engagement Phase 1 – This took the form of an initial gas industry engagement exercise by Cadent to explore:

- Views on the desire for change to the current approach.
- Views on:
    - What level of modelling validation would be required; and
    - What regulatory (or other) changes would be required to support the continuation of the project beyond Work Pack 1.
- An initial Cost Benefit Analysis of the three future billing options – *Pragmatic, Composite* and *Ideal* (noting that this would be finalised under Work Pack 4) to demonstrate that, following industry engagement, there was a strong case to proceed with the FBM Project.

SDRC 1a – Industry engagement phase 1 – Results from the initial industry consultation were set out in a Stage Gate report which:

- Confirmed industry support for progressing the project,
- Addressed views on the level of modelling validation and
- Confirmed that, due to the use of molecular oxygen sensors to track the presence of biomethane, the field trials could progress without any impact on thermal energy regulations or existing processes
- Presented a strongly positive initial CBA for all three future billing options

Based on this report and the initial CBA, Ofgem approved on 20th September 2017 that the project could progress from the initial stage.

The project Stage Gate report submitted to Ofgem can be accessed using the following link:
https://futurebillingmethodology.co.uk/wp-content/uploads/2022/03/2017.08.11-FBM-Stage-Gate-Report-Final-3.pdf

Work Pack 1b – Industry engagement phase 2 – This completed the initial industry engagement for the project and comprised initial work with Xoserve and National Grid's Gas Transmission business to begin identifying the necessary changes to billing-related systems and processes. This early work identified the need for daily meter point specific CV attribution via a system node to meter point cross reference file and signalled the requirement for changes to LDZ energy tracking processes and impacts on the definition and management of charging areas, presently defined as LDZs within the Offtake Arrangements Document.

SDRC 1b – Industry engagement phase 2 – The findings from this initial work with Xoserve and National Grid were set out in a report which can be accessed via the following link:
https://futurebillingmethodology.co.uk/wp-content/uploads/2018/04/SDRC-9-1b-Report-Final.pdf

FBM Project Work Pack 2 – Project Field Trials

Headed as "sensors & measurement, network modelling and CV allocation" in the FBM Project submission, this stage comprised the major element of the project, with field trials undertaken around two embedded biomethane entry sites, one in Lincolnshire network (Hibaldstow) and another in Cambridgeshire network (Chittering).

Preparation and execution of the field trials had to overcome a number of challenges, including optimisation of measurement sites both to avoid delays and excess costs due to land ownership issues. The project also had to overcome a range of technical issues and a delay to installation, testing and commissioning works during the 2019 Covid pandemic. These delays resulted in having to extend the project by one year. Field trials were substantially completed at the end of 2020, but the measurement phase was further extended until the end of March 2021 to ensure full capture of winter data.

SDRC 9.2 – Novel tracking of unconventional gases by measurement – The field trials ultimately completed successfully, with the novel tracking of unconventional gases by measurement being confirmed in the MS12 Final Report on Field Trial Progress. The main findings of this report are summarised below:

- **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.

The MS12 Final Report on Field Trial Progress can be accessed via the following link:
https://futurebillingmethodology.co.uk/wp-content/uploads/2021/04/FBM-Report-MS12-Rev1.pdf

SDRC 9.3. Report on novel validation of network modelling for embedded and network charging areas – During the latter stages and following completion of the FBM field trials, the verified data was collated, analysed, and replicated using network analysis models, and the findings were used to develop a range of potential methods for charging area creation.

The findings from this work were set out in the MS13 Report on novel validation of network modelling for embedded and network charging areas. The key findings of this report are summarised as follows:

- **Representative body of data –** The body of data obtained from the field trial provided a representative base for seasonal effects to be analysed (noting extension of the measurement window 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 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, together with a fourth option – fully modelled CV.
- **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.

Development of the MS13 Report – The FBM Project had started in an industry where biomethane was the only green gas, but the development of the MS13 report and the three options it presented had to be reviewed in terms of practicability, and in light of the prospect of hydrogen blending. In late 2020, the draft report findings were discussed informally with the other gas networks as part of Xoserve's gas decarbonisation forum and, because of those discussions, a fourth future billing option was developed, which proposed a fully modelled approach to CV attribution. This fourth option followed the principle which had been established by the FBM field trial, that network modelling could reliably simulate the travel and mixing of gases under varying demand conditions and with the right software, could be used to derive gas CV at system node level.

Extensions to project outputs – During the above development and review process, further extensions to the project were negotiated with Ofgem to enable a complete and up-to-date project output. Completion of this report required extensive further work to take account of developments in thinking around hydrogen blending, and informal joint review with gas networks and Xoserve.

The MS13 report can be accessed via the following link: https://futurebillingmethodology.co.uk/wp-content/uploads/2021/12/Final-FBM-MS13-Report-v1.2.1-002.pdf

FBM Project Work Pack 3 – Smart Meter Field Trials

In support of the original Ideal option for future billing and alongside the main FBM Project field trials, DNV set up a laboratory-based smart meter installation which aimed to prove the concept and assess the practicality of transferring measured CV data captured from specific field trial sites which had also been equipped with "GasPT" CV measurement devices for this purpose.

SDRC 9.4 – Report on Smart Metering Laboratory Trials – The smart meter field trial proved that, although possible in principle, the transfer and use of locally-measured CV data for smart meters would not be practicable in reality. The main findings of the report are summarised below:

- **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.

The MS11 Report on the smart metering laboratory trials can be accessed via the link: https://futurebillingmethodology.co.uk/wp-content/uploads/2021/04/MS11-Report-on-completion-of-Smart-Meter-Laboratory-Trials-Rev-1.pdf

FBM Project Work Pack 4 – Final Industry Engagement on the Options, with Cost-Benefit Analysis and a Recommended Solution

Following issue of the project technical reports, preparations were made for the final project industry engagement in Q1 2022, with invitations sent to 258 industry members across sectors including gas production, gas networks, shippers / suppliers, independent gas transporters, metering and gas technology organisations.

An FBM Project consultation document (MS14) was issued on 1st February 2022, sharing the findings of the project, together with five future billing options for consultation and inviting responses from the industry on the options proposed. The process adopted for the consultation is described in the main body of this MS15 Final FBM Consultation report. The MS14 consultation document can be accessed via the link: https://www.xoserve.com/media/43026/fbm-consultation-paper-01-feb-22-final-v3.pdf

SDRC 9.5. Future Billing Methodology Recommendation – A summary of the consultation responses, together with FBM Project views, final CBA outputs for each of the future billing options, recommendations to industry and supporting rationale, together with a high-level implementation plan is provided in the main body of this MS15 Final FBM Consultation report, which will be submitted to Ofgem on 31st March 2022, in line with the final agreed extension to the project term.

Appendix B: Billing Options Final CBA model: List of Assumptions and Factors Applied

BILLING OPTIONS UPDATED CBA MODEL: LIST OF ASSUPMTIONS & FACTORS APPLIED

CBA Model basis: The CBA model assesses NPV costs v benefits of the five options within a 2022-2050 timeline and on a GB basis. The reasons for this are as follows:

i	We believe that it is relevant to do so since a transitional, diverse-CV gas phase could potentially endure for some time in areas of the network where electrification or alternative heat delivery vectors remain problematic.
ii	At this stage we are unable to identify which areas of the GB gas distribution grid would switch to alternative heat provision and when.
iii	Billing systems implementation costs for Options B - E include a significant central systems element, which is difficult to reflect meaningfully in a region-specific assessment.
iv	The switch either to 100% hydrogen networks, electrification or alternatives will be the subject of separate assessment.
v	This approach provides a consistent basis for comparative assessment of the options.

Model Assumptions & Factors: This model focuses on comparing the NPV costs & benefits of 5 options for enabling the maximisation of "green" gases (biomethane and hydrogen) to support a transitional gas phase towards Net Zero, as above. It therefore assumes / excludes:

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 the CBA section the main consultation report.			
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 "high-high" scenario CBA output table within the main consultation report.			
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 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:** 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.	

APPENDIX C: Impact Assessment for Options B – E on Regulations, Billing Systems & Processes, Industry Codes and Other Factors for Consideration

1. General

The gas thermal energy regulations, covered in section 2 below, have undergone a detailed assessment in relation to potential future billing options. Gas safety management regulations in section 3 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 are the initial views of the FBM project, 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 the FBM 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 were 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 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.

High-level summary of GCoTER review

Initial view:	Charging areas not geographically defined, so could be modelled, with CV for billing based on measurement at relevant input points.
Detailed review:	Regulation 4A(3)(b) appears to mandate CV and volume measurement at all input / output points for any charging area.
Conclusion:	Use of modelling to create charging areas within LDZs and/or to apply modelled CV for billing would require changes to GCoTER.

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 natural gas (predominantly 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 an enduring 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 vol.

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 in those charging areas. 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 level, using the applicable LDZ FWACV. This would result in a significant increase in the volume of system calculations and data storage.

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.

High-level summary of billing system impacts for future billing options B – E

Sub-LDZ charging areas:	Requires changes to energy tracking systems and to Gemini to keep energy attribution whole at LDZ level and for energy balancing
Meter Point specific CV:	Variable zones of influence from LDZ inputs → varying CV at system nodes → system nodes could switch between charging areas* → Meter Point specific CV required
NDM Settlement & AQ update:	• Currently uses an energy factor at LDZ/EUC level • Meter Point specific CV would require energy factor to be calculated at Meter Point Level
CV Data:	• Requires daily CV data provision at Meter Point Level to Shipper / Supplier systems

5. Billing Process – "Back-end" & "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 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, for example single-fed sub-networks at the extremities of the system, or discrete sub networks fed by different legs of the NTS. These could potentially be configured as separate charging areas, with the former requiring a CV measurement device on the feed-in pipe. Although compliant with the existing GCoTER, the action of physically separating out these zones for billing purposes would involve changes to billing systems to recognise and attribute gas energy for billing, settlement, and the quantification of UIG within the new charging areas.

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.

Within Option C, the potential requirement to draw on actual consumption data for larger I&C consumers, whose demand levels can affect the gas flows and therefore CV within local areas of the gas network, would also likely require some change to the UNC.

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. 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.

Future CV measurement technology – The FBM Project notes advances in compact, low-power gas quality and flow measurement technology which could obviate gas venting and significantly reduce capital costs. Further investigation of this new technology could bring significant cost efficiencies, if proven for GCoTER purposes in a gas network setting. Learning from the FBM field trial has shown that other factors require very careful consideration, as follows.

Land ownership – The GB gas network has evolved alongside changing land ownership over more than two centuries. Installing CV measurement technology within existing gas installations (where power is required and / or modification to buildings), or by creating new locations within the network, can require obtaining legal access to third party owned land. The ability to grant this remains the gift of the landowner, and this can lead to uncontrollable delays and significant additional costs.

Powering remote equipment – The experience of installing the FBM field trial sensors at existing gas control sites has shown that powering CV measurement devices and remote telecommunications equipment in remote locations can be highly problematic. Photo-voltaic arrays are vulnerable to damage / theft and may become unreliable in sustained poor conditions. Obtaining connections to the regional power grid is expensive and gaining legal access to land for cabling and maintenance, etc., can involve high cost and uncontrollable delays, as above.

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.

13. 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.

14. Other Factors to Consider

Future Billing Option roll-out – Any of the future billing options proposed would require a phased geographical roll-out on an LDZ-by-LDZ basis. Option A can be achieved within the existing regime, with minimal changes to systems. For Option C, once fully validated and with the necessary changes to central systems in place, including a system node to meter point interface for CV attribution, the billing CV could be set at default status to LDZ FWACV in LDZs which had yet to implement Option C.

Competition in Gas Supply – A vital point here is that the systems capability to attribute CV at meter point level would need to be delivered nationally within central and all Shipper / Supplier billing systems as standard, to avoid any impediment to competition in gas supply.

By configuring the changes to the GCoTER to support Option C within a new part of the regulations, a phased transition could be achieved and effectively regulated by means of GDNs adopting the new part of the GCoTER at the same time as implementing Option C. In this way, the changes could be rolled out regionally with a neutral impact on consumers.

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 may have counter-seasonal or other atypical gas usage patterns. These would need to be accounted for in the demand modelling to derive the correct average Gas Day CV at system node level for billing purposes.

15. 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 and potential impact on industry codes suggest the development process towards implementation might best be supported within the bounds of a Significant Code Review, but this would be a matter for Ofgem to determine.

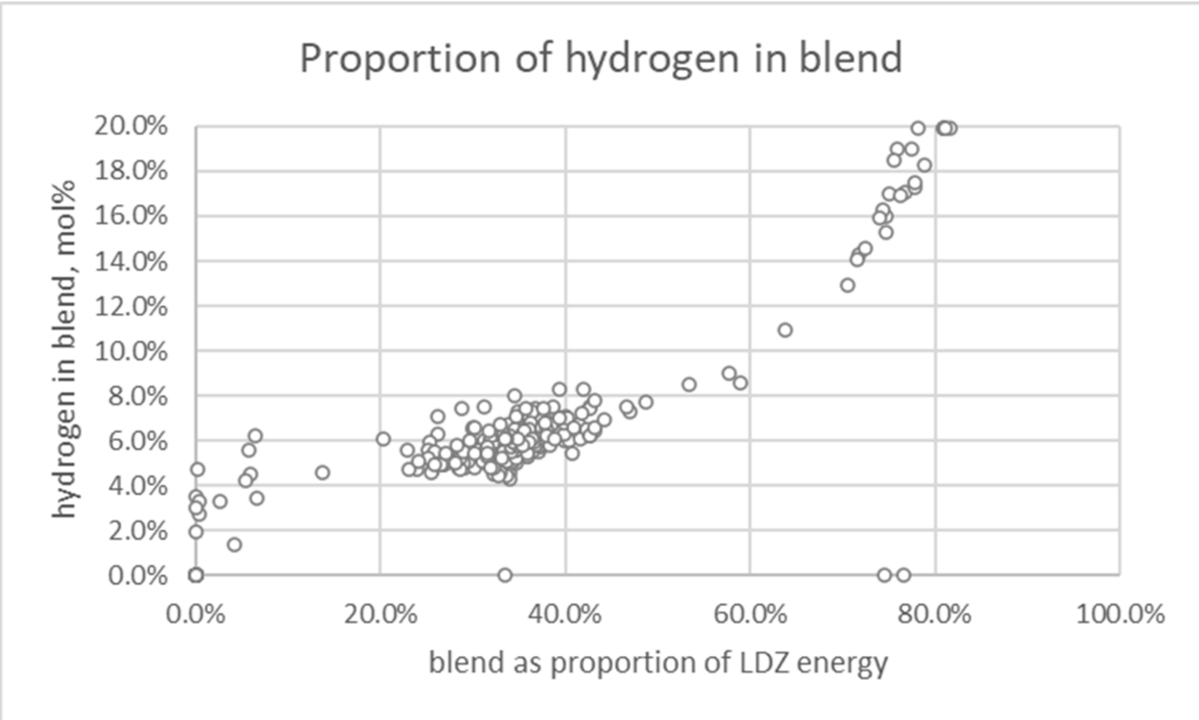
Appendix D: Key Blending Principle Applied in Option A (Work Within Existing Frameworks)

Cognisant of the time and effort that would be required to make necessary changes to develop and deliver any of the “billing reform” options B – E developed at concept level in the FBM project, a separate NIA project was undertaken to assess the potential for blending of green gases such as hydrogen or biomethane whilst working within the existing GCoTER and the existing billing systems which are configured to conform with those regulations.

The NIA project: *Calorific Value and Gas Quality Impact Assessment of Hydrogen and Biomethane Blends* concluded 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 could enable blending of low-CV green gases to begin and progress without the immediate need for changes to the existing billing regime and systems, and with potential to reduce or remove the need for biomethane enrichment, where bulk upstream hydrogen blending could be achieved in a Local Distribution Zone. The key principle applied in this approach is demonstrated by the chart below.

Percentage hydrogen blend in natural gas achievable within LDZ FWACV cap, dependent on blends proportion of total LDZ energy



The chart above uses historical gas data for certain NTS/LDZ offtakes on Cadent’s systems as a basis to depict the relationship between two things:

- On the “X” axis - the proportion of LDZ energy delivered as hydrogen blend and
- On the “Y” axis - the volumetric percentage at which hydrogen can be blended in natural gas.

Looking at the curve in the graph, the principle is that the more of the LDZ energy which can be supplied to the LDZ as blend, the greater the percentage of low-CV green gas (in this case hydrogen) that can be added into that blend, as the increasing share of blend in the network acts to reduce the overall LDZ FWACV.

This suggests that, if the upstream supply of hydrogen is sufficient, and blending can be delivered at enough key LDZ offtakes, it should be possible to deliver blend into the LDZ as a majority flow and so control the LDZ flow-weighted average CV to avoid capping, whilst ramping up hydrogen blending levels.

Where hydrogen blend remains a minority flow into the LDZ, the volumetric percentage of hydrogen would be limited to ca.<5%. However, if the injection point is located at strategic high flow locations, such as NTS/LDZ Offtakes, this would equate to significant amounts of hydrogen energy, which could act as a stable demand for early producers.

Implementing this option would require minimal upgrading of network control systems and simple parameter changes to central billing systems to deliver and could provide a "least-regret" means to initiate decarbonisation of local gas distribution networks, while the more complex changes required for other viable options are developed.

End.

Project partners:

Cadent
Pilot Way,
Ansty Park,
Coventry,
CV7 9JU

DNV
Ashby Road
Holywell Park
LE11 3GR
Loughborough

Supported by:

davelanderconsulting