Enabling hydrogen blending

From industrial clusters

The voice of the networks

1 Executive summary

Low carbon hydrogen forms a vital part of the UK government's strategy for achieving net zero carbon emissions by 2050 (or 2045 for Scotland). It can help decarbonise large sectors of the economy, including industry, heat, power and transport. Analysis by BEIS has found that 250-460 TWh of hydrogen could be needed in 2050, representing 20-35% of the UK's energy consumption.[1]

Blending hydrogen into the transmission and distribution gas networks would support the transition to a sustainable, net zero system by:

- providing a reliable source of demand for hydrogen producers, even for variable residual production;
- immediately decarbonising a portion of the gas flowing through the gas networks; and
- delivering learnings and incremental change (both in terms of physically adapting the network and making necessary changes to commercial and regulatory frameworks) towards what could potentially become a 100% hydrogen gas network.

This study has been commissioned by the gas transporters as part of the Gas Goes Green (GGG)[2] work programme, to develop and report a 'gas transporter view' on how to facilitate hydrogen blending from industrial clusters, which are likely to form the initial source for hydrogen blending in the gas network. This view has been developed through engagement carried out with industrial clusters and other stakeholders, as well as drawing on learnings from a previous hydrogen blending study.[3]

The key takeaways of this study are that:

- Enabling hydrogen blending from industrial clusters can be done in a pragmatic way, with limited need for change to existing gas frameworks.
- Where frameworks do need to change, the changes are incremental rather than involving overhaul of existing frameworks, and are highly workable.
- While there remain uncertainties as to the nature of blending at each cluster (e.g. the volume and profile of hydrogen injections), in general the changes required to commercial and regulatory frameworks are the same, implying that they are low regret.

Below we summarise gas transporters' preferred approach to facilitating hydrogen blending from industrial clusters, including both the policy decisions needed, and the changes required to commercial and regulatory frameworks. We note that this work has not involved a legal review, and that one will be required as part of the process of implementing the framework changes described below.

Policy decisions required

1. **Funding.** BEIS will need to provide hydrogen producers in industrial clusters with clarity around the nature of funding for blending into the gas networks, and conditions attached to it. This clarity is needed before producers can make their final investment decisions.

[1] HM Government (2021) UK Hydrogen Strategy, **link**, p.9

[2] ENA, **link**. To enable the move towards hydrogen blending, the GB gas transporters are taking forward a Gas Goes Green (GGG) work programme, and recently published 'Britain's Hydrogen Blending Delivery Plan'. This sets out how the GB gas transporters will get the gas networks ready to transport 20% hydrogen from 2023, and recommends that further work be undertaken to understand how blending can work in practice. This study has been commissioned as part of developing that understanding.

[3] Frontier Economics (2020) Hydrogen blending and the gas commercial framework, **link**

1 Executive summary

Framework changes

2. **Coordination of injection locations.** The framework will need to provide for close coordination between the transmission and distribution network operators when engaging with industrial clusters to agree suitable connection locations.[4] This will help ensure that a total gas system view is taken when providing industrial clusters with location guidance, avoiding situations where industrial clusters limit, or are limited by, the overall hydrogen blending capacity in the networks. In due course a view can be taken on whether, and in what circumstances, this coordination role should be supported by a centralised entity such as the Future System Operator.

   Gas transporters' view is that hydrogen from industrial clusters would be best injected into the LTS (local transmission system, the high pressure pipelines of the distribution networks) or the NTS (national transmission system), to maximise overall hydrogen blending capacity, avoid constraining hydrogen injections from industrial clusters, and avoid the need for reform to settlement and billing regimes. This is consistent with industrial clusters' desire to ensure that their connection location has sufficient capacity to accept their hydrogen.

   However each project will have varying factors that influence connection location so the gas transporters are of the view that a capacity allocation methodology needs to be developed to provide fair access to the network while maintaining the ability to manage gas quality and ensure compliance with regulations.

3. **Assessment of connection applications.** The framework needs to provide for enhanced impact assessments as part of the connection process. As part of these assessments, networks will need to evaluate impacts of hydrogen injections on network blends, settlement and billing, etc.

4. **Determination of entry conditions.** Cluster-specific limits for injection flow rates and profiles can already be incorporated into Network Entry Agreements (NEAs). However, gas transporters and connecting parties would benefit from a standardised template NEA for hydrogen connections. This should also set out default ownership boundaries (assuming minimum control from the gas transporters), with scope for connection-specific adjustments.

Hydrogen blending can commence while maintaining compliance with the Gas Calculation of Thermal Energy Regulations. Analysis has shown that significant blending capacity is available at higher flow locations such as the local and national transmission systems.

The remainder of this report sets out in detail the work carried out to reach this recommended approach to enabling blending from industrial clusters.

Although this report has been written with a view to blending hydrogen from industrial clusters, we have not identified anything materially distinct and the outputs would generally apply to all production sources and locations.

[4] A legal review will need to confirm whether such arrangements are consistent with Gas Act obligations in respect of non-discrimination and accepting reasonable request to connect.

2 Introduction

2.1 Objectives of this project

The government's energy security strategy sets 2023 as a target date to take a final decision on blending up to 20% hydrogen in the gas distribution networks.[5] To meet this target, BEIS is currently looking to understand the safety case and economic case for hydrogen blending, due to be completed in 2023.

Furthermore, in November 2021, the government announced that it had selected two industrial clusters, HyNet and the East Coast Cluster, for 'Track 1' negotiations for government funding to deploy Carbon Capture, Usage and Storage (CCUS) technology by the mid-2020s.[6] Linked to this, the government expects that the first CCUS-enabled hydrogen production facilities are likely to be deployed in industrial clusters by the mid-2020s, with a main source of demand being industrial users located in the industrial clusters, as well as potential for blending hydrogen into the gas networks.[7]

Industrial clusters could therefore form the initial source for hydrogen blending in the gas networks. If blending into the gas networks is to be a credible source of hydrogen demand for these early producers, there needs to be clarity on whether and how existing gas commercial and regulatory frameworks need to change, such that these changes can be made in time for the first hydrogen injections to be made in the mid-2020s.

This piece of work focuses specifically on delivering a view from gas transporters on:

- the roles and responsibilities of relevant industry parties in the context of blending from industrial clusters; and
- the changes needed to gas commercial and regulatory frameworks in order to enable blending from industrial clusters.

In parallel, the gas transporters are taking forward a technical project to understand the physical changes needed to the gas networks in order to enable hydrogen blending from industrial clusters.[8]

While the main objective of this work is to deliver a 'gas transporter view', this has been heavily informed by engagement we have carried out with a wider stakeholder group including industrial clusters. This stakeholder group was made up of over 60 representatives from:

- gas transporters: the five GB gas transmission and distribution network operators and the Energy Networks Association (ENA);
- Industrial clusters:
  - HyNet, specifically Progressive Energy (consortium lead) and Inovyn (storage);
  - East Coast Cluster, specifically Shell (hydrogen production), Uniper (hydrogen production), and Sembcorp (storage);
  - Scottish Cluster, specifically Storegga (hydrogen production);
  - South Wales Industrial Cluster (SWIC), specifically Costain (deployment lead) and CR Plus (plan lead);
- BEIS: representatives from Future Gas Systems Strategy, and Energy Security, Networks & Markets teams;
- Other organisations: Energy UK, Major Energy Users Council (MEUC), Ceres Energy (gas shipper for biomethane and small scale producers), and CNG Services.

Our findings capture views from across this group where relevant. We recognise that this stakeholder engagement, while wide, will still not be sufficiently broad to capture views of all parties across the gas industry (and beyond) that are likely to have an interest in how hydrogen blending evolves. Further discussions with the wider industry around the findings in this report will therefore be beneficial.

[5] BEIS (2022) British energy security strategy, **link**

[6] Support is also planned for a further two industrial clusters to deploy CCUS by 2030: **link**

[7] HM Government (2021) UK Hydrogen Strategy, **link**, p.34

[8] Functional Specification: Hydrogen Blending Infrastructure, **link**

2 Introduction

2.2 Our approach

Our approach to this work was to first identify a list of questions and challenges that would need to be resolved in order to enable hydrogen blending. This was based on our knowledge of the existing gas commercial and regulatory frameworks, and our understanding of the challenges posed by blending.

We also drew on learnings from prior work in the area,[9] as well as discussion with the stakeholder group and the Gas Goes Green Advisory Group.[10] The questions we identified fell into seven key topic areas:

- What could blending from industrial clusters look like in practice?
- What roles and responsibilities will relevant parties have in relation to blending from industrial clusters?
- What change is required to current connection processes and agreements?
- What change is required to system operation and capacity arrangements?
- How will the charging framework and methodologies need to change?
- What interactions are there with potential changes to the settlement and billing regimes?
- What types of amendments might be needed to legislation, codes and licences?

We then worked with the stakeholder group, through detailed workshops and bilateral discussions, to collect views and develop solutions to these questions. In doing so, a key guiding principle has been to deliver a practical, low cost and low regrets approach to enabling blending from industrial clusters.

We have identified a set of key changes that need to be made to commercial and regulatory frameworks to enable hydrogen blending from industrial clusters, as well as areas where further work needs to be taken forward by government and the gas industry.

2.3 Assumptions and limitations to scope

There are some important assumptions and limitations to the scope of this work that are worth briefly setting out. We list these below.

- **Funding.** Considering different support mechanism options for hydrogen production within industrial clusters (whether for blending or otherwise) is outside the scope of this work.
- **Arrangements within industrial clusters.** While this work focuses on blending of hydrogen produced in industrial clusters, we do not consider arrangements within industrial clusters. For example, questions around who owns the hydrogen pipeline within the cluster, who owns the hydrogen before it enters the gas network, and how hydrogen changes hands between different entities within the cluster, can all vary by cluster and do not need to be answered for the purposes of this work. We assume simply that there are 'cluster entities' that carry out these various roles, and focus instead on how those entities interface with the existing gas network and its operators.
- **Settlement and billing.** The introduction of low-carbon gases such as non-propanated biomethane and hydrogen into the gas networks leads to challenges around settlement and billing due to the lower energy content ("calorific value", or "CV") of these gases. Under the current regime, the CV used for billing in a local distribution zone must be capped at 1MJ/m3 above the lowest CV gas in the zone. Therefore even a small volume of biomethane or hydrogen can lower the billing CV and lead to under-recovery of energy, and this cost is ultimately socialised across consumers. The Future Billing Methodology (FBM) project has been considering options for addressing these challenges, and has now published its recommendations.[11]

[9] Frontier Economics (2020) Hydrogen blending and the gas commercial framework, **link**

[10] More on Gas Goes Green: **link**

- **Settlement and billing (continued).** It is outside the scope of this work to provide views on whether and how the settlement and billing regimes should change. Instead, we consider whether there are any interactions between the solutions recommended by FBM and the other parts of the gas frameworks that we are looking at. In particular, we consider interactions with two main settlement and billing options: no change to the current regimes, and an approach involving gas flow modelling (although we understand that the latter is likely to take some time to implement, if it is implemented at all, meaning the 'no change' approach is most likely to be used in the near term).
- **Trading.** We assume that blended gas can be traded at the National Balancing Point (NBP) on the basis of energy content (e.g. MWh of blended gas), without a need for differentiating between different gas types (methane versus hydrogen). We also assume (for simplicity) that a single shipper will buy hydrogen from each cluster.
- **Blend caps.** Throughout this report, where we refer to a 'blend cap', this is an upper limit on the percentage of hydrogen that can be blended into the gas network. This cap will be driven primarily by what is deemed to be a safe limit (currently expected to be 20% by volume), but we also assume that this cap could potentially vary across network locations to reflect any further restrictions that may be needed in order to limit impacts on the settlement and billing regimes (e.g. due to the Gas (Calculation of Thermal Energy) Regulations 1996).

2.4 Structure of this report

The remainder of this report is structured as follows, covering each of the seven key topic areas discussed above in turn.

- Section 3 discusses how blending from industrial clusters may work in practice in order to ensure that the changes set out in the later sections are fit for purpose under a range of scenarios.
- Section 4 covers how roles and responsibilities of relevant industry parties will need to change to enable hydrogen blending from industrial clusters.
- Section 5 covers key changes required to the connections process and agreements.
- Section 6 covers key changes required to system operation and the capacity regime.
- Section 7 covers key changes required to the network charging framework.
- Section 8 covers interactions with different settlement and billing approaches.
- Section 9 covers potential areas of change to industry codes and licences.

[11] FBM project webpage: link; recommendations: **link**

3 What could blending from industrial clusters look like in practice?

In order to identify the required changes to enable hydrogen blending from industrial clusters, an important starting point is to understand how that blending could work in practice.

In particular, understanding the answers to questions like 'which parts of the gas network will be affected by blending?' and 'how material are hydrogen injections likely to be (at least initially)?' helps to understand the scale and nature of the resulting challenges, and to identify the changes needed to address them.

Based on our stakeholder engagement, we have identified the following key features of blending from industrial clusters. These are:

- **Injection location:** which pressure tier of the gas networks the cluster hydrogen is injected into.
- **Location selection:** on what basis hydrogen cluster connection locations are agreed.
- **Injection materiality:** whether the amount of hydrogen injected is large enough to potentially breach the blend cap.
- **Injection profile:** to what extent injections from the industrial cluster are stable and predictable.
- **Blending technique:** whether the hydrogen is pre-blended with methane (up to the blend cap) before being injected into the gas network, or whether it is injected directly into the network as pure hydrogen.

These features, and the different options within each, are summarised in Figure 1 below.

It is worth noting that for most of these features, multiple options could co-exist; for example different industrial clusters could connect at different pressure tiers, and could have different injection profiles.

In the sections below we set out more detail about each of these features, discuss some of the pros and cons of different options, and where relevant, identify which of these options might be more likely or preferable from gas transporters' and industrial clusters' perspective.

We note that in most cases we have found that the changes proposed to gas frameworks in the rest of this report are robust to a number of different outcomes, and are therefore low regret to implement. In the few instances where commercial framework changes are specific to one option (mostly in the case of blending technique), we make this clear in the relevant sections of the report.

Figure 1 – key features of blending from industrial clusters, and possible options in each

Injection location	Location selection	Injection materiality	Injection profile	Blending technique
NTS	Unconstrained	Significantly below blend cap	Flat	Pre-blending
LDZ: LTS	Criteria-based	Headroom to cap	Variable but scheduled	Blending occurs in the network
LDZ: lower tiers	Coordinated (total system)	Close to blend cap	Sporadic	

3.1 Injection location

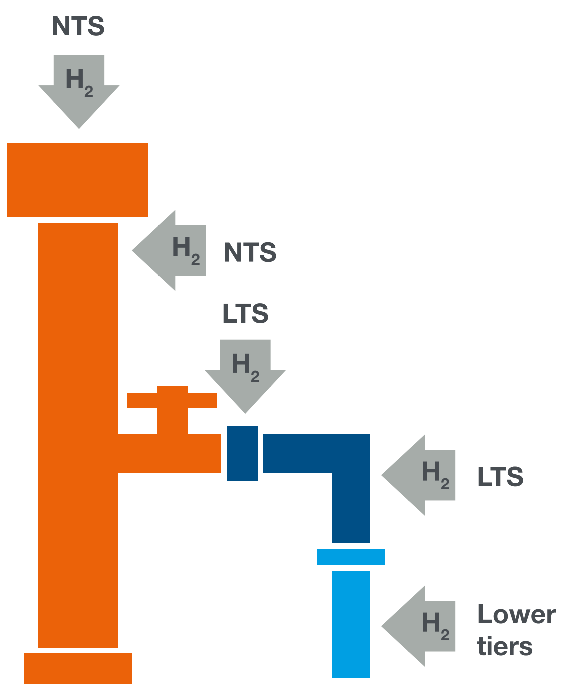
Hydrogen injection from industrial clusters can take place at different parts of the gas networks. The main options that were discussed with the stakeholder group were the following (also illustrated in Figure 2).

At the national transmission system (NTS): this could be at an NTS entry facility located at a gas terminal, or along the NTS;

At a local transmission system (LTS): this refers to the high pressure pipelines within local distribution zones (LDZs). Hydrogen injections on an LTS could be at an NTS/LDZ offtake, or along an LTS pipeline;

At lower pressure tiers of the LDZs: this includes intermediate pressure, medium pressure and low pressure pipelines.

Figure 2 – Injection location options



The main benefits discussed with stakeholders of injecting higher up the pressure tiers (i.e. at the NTS or LTS) were as follows.

- Due to higher gas volumes at these levels:
  - from a cluster perspective, there is more capacity available for hydrogen injection, meaning a lower likelihood of injections needing to be constrained; and
  - from a gas transporter perspective, there is potentially less likelihood of the blend cap being breached, meaning the role of the gas transporter in managing blend levels is less complex.
- Blending hydrogen on the NTS/LTS could help deliver a more homogenous blend of hydrogen within a given LDZ billing zone, meaning there may be less need for complex settlement and billing regime reform (although this is subject to the configuration of the pipelines and NTS/LDZ offtakes).

Conversely, stakeholders raised the following potential challenge in relation to blending higher up the pressure tiers.

- It could be the case that there is some sensitive users connected to the higher pressure tiers. This is subject to ongoing technical work, but if it is found to be the case, blending on the NTS and LTS could mean that there is more need to carefully manage hydrogen injections to limit impacts on those users.

3 What could blending from industrial clusters look like in practice?

3.1 Injection location (Continued)

The pros and cons of injecting lower down the pressure tiers are the reverse of the above. The gas transporters raised particular concerns around the fact that, because gas volumes are far lower at the low pressure tiers, even limited hydrogen injections at this level could quickly use up available blending capacity.

This could prevent further hydrogen injections in future – even if there is significant available blending capacity upstream in the pressure tiers. By taking a strategic approach to blending at the higher pressure tiers, gas transporters identified that overall blending capacity in the gas networks can be significantly increased.

Furthermore, there can be large seasonal variations in gas volumes on the lower pressure tiers, meaning that capacity for hydrogen injection could be very limited at certain times, for example during summer months.

Hydrogen producers in industrial clusters said that one of their primary considerations when looking at different connection locations (subject to what is geographically feasible) would be having sufficient capacity to inject their hydrogen, suggesting that connecting higher up the pressure tiers might also be preferable from a producer perspective as well.

In fact the gas transporters have informed us that key industrial clusters (HyNet, East Coast Cluster, the Scottish Cluster and the South Wales Industrial Cluster) are all currently planning to inject hydrogen at either the NTS or LTS level.

Given these considerations, the gas transporters are of the view that a strategic approach should be taken to connection locations for industrial clusters, such that they connect at the NTS or LTS level, and not at pressure tiers below this.

However, the most suitable location for a given cluster will depend on site-specific considerations, which we discuss in the next section.

In any case we note that the commercial framework changes proposed in the remainder of this work allow the possibility of injecting hydrogen at any pressure tier, and so are low regrets in that they do not close the door to any locational options.

3.2 Location selection

There could be a number of potential approaches to selecting where on the network a new cluster hydrogen entry point can connect:

- **Unconstrained:** Industrial clusters can apply for connections anywhere on the gas network within a reasonable distance from the cluster, and all applications would be assessed and accepted on a first-come-first-served basis. This is the current approach for connections.
- **Criteria-based:** Gas transporters, along with Ofgem and/or BEIS, would agree a set of criteria which cluster connection applications would need to meet in order to be approved.
- **Coordinated:** This would involve transmission and distribution network operators working together to understand the total system impacts of different connection location options, and communicating these to industrial clusters seeking to connect. This could also involve support from a centralised entity (potentially the proposed Future System Operator) who would have oversight of total system impacts.

As explained above, connections in certain network locations (particularly below the LTS) could create challenges for settlement and billing, system operation, and could significantly limit overall capacity for hydrogen blending in the gas network (for example a cluster connecting low down the pressure tiers could use up all of the hydrogen headroom at that level, even with small injection volumes, and prevent a large cluster upstream from injecting). Therefore, gas transporters are of the view that a capacity allocation methodology needs to be developed to provide fair access to the network while maintaining the ability to manage gas quality and ensure compliance with regulations.

The gas transporters noted however that a legal review will be needed to ensure that such arrangements for agreeing connection locations are consistent with Gas Act obligations in respect of non-discrimination and accepting reasonable connection requests (see section 9).

3.3 Injection materiality

Another important factor to consider is how material hydrogen injections from industrial clusters will be. The key outcome of interest is how likely injections from a particular connection are to result in a breach of the blend cap.[12] For example, even relatively large injection volumes (in absolute terms) on the NTS may be immaterial compared to the gas volumes flowing past the connection point. Materiality can also vary by season, with breaches of the blend cap being more likely in summer months when methane volumes are low.

A connection that results in gas blends significantly below the blend cap is unlikely to require as much intervention by the relevant gas transporter. It would also be easier to provide industrial clusters with more certainty over availability of blending capacity for a ‘low materiality’ connection. On the other hand, the gas transporters highlighted that blending ‘at scale’ would help to reduce the per-unit cost of fixed costs such as connection costs.

3.4 Injection profile

The hydrogen injection profile from a given cluster could be:

- **flat volumes** over time;
- **variable but scheduled volumes**, based on the hydrogen producer’s planned output and the cluster’s planned needs. Variations in volumes could potentially also be scheduled such that they deliver a broadly flat blend ratio; or
- **sporadic volumes**, depending on when the hydrogen producer has excess output that can be blended.

[12] We note that this interacts with the blending techniques covered in section 3.5 below. Breaching the blend cap, even with large hydrogen injection volumes, is only a material concern if hydrogen is not pre-blended with methane before being injected.

3 What could blending from industrial clusters look like in practice?

3.4 Injection profile (Continued)

Hydrogen producers agreed that injections would ultimately be driven by commercial considerations. The conditions of any government funding would be a key consideration, in particular whether support is provided for all hydrogen injected into the gas networks, or only hydrogen injected as a 'backstop'. In the latter case, injections are much more likely to be sporadic.

Some producers also said that they could have the capability to keep volumes relatively stable, for example with use of storage, but again this would need to be consistent with commercial considerations.

Producers stressed that the rate of hydrogen injection into the network is ultimately part of their investment decision, and to be able to commit to a constant rate, they require more certainty over the funding arrangements for blending and for storage.

Gas transporters highlighted that, for a given average volume of hydrogen injections, a flat or scheduled profile (ideally delivering a roughly stable hydrogen blend) would be easiest for blend management purposes.

It would also enable gas transporters to provide industrial clusters with more certainty around available connection capacity, and would help avoid potential issues around metering ranges and CV measurement.

However, they recognised that, if blending does end up playing a 'backstop' role, then hydrogen injections will inevitably be sporadic.

The gas transporters are confident that they would be able to manage sporadic injections using existing local operating procedures (e.g. input notifications) to manage flow profiles.

Given that the decision on injection profile will ultimately depend on funding arrangements, and should ideally be made taking into account whole system costs or on a customer cost basis, in the rest of this study we have assumed that any injection profile is possible.

4 Roles and responsibilities

We focused on the following key questions in this area:

- Who are the key relevant parties that play an active part in blending from industrial clusters?
- What assets are they responsible for?
- What activities are they responsible for?

Overall we have found that the roles of existing parties such as gas transporters and gas shippers can remain very similar to today. And the roles of new parties, such as operators of hydrogen delivery facilities at industrial clusters, can be very similar to current equivalent roles in relation to methane.

4.1 Relevant parties

There are four key parties that will play an active role in hydrogen blending from industrial clusters. The first two are the parties that own and operate the physical assets that will connect with the gas network, and the third and fourth are the parties that buy and sell the hydrogen that is blended into the network.

- **The cluster delivery facility operator:** within the industrial cluster, the delivery facility comprises the physical assets that interface with the gas network. For our purposes, we do not define exactly who would own these assets, since it could be any of a number of different entities (and can vary by cluster).
- **The relevant gas transporter:** The existing network assets that receive the hydrogen would be owned by either the gas transmission network operator if the gas is injected into the NTS, or the relevant distribution network operator if the gas is injected into a distribution network.
- **The hydrogen owner in the cluster:** within the industrial cluster, hydrogen can be owned by any of a number of parties, including the hydrogen producer, one or more industrial users, or a third party (which could be a gas shipper acting outside its currently licensed activity). Again, for our purposes we do not define who owns the hydrogen within industrial clusters, but rather simply acknowledge that there will be a 'cluster entity' that owns hydrogen and sells it to a gas shipper.
- **The gas shipper:** under the current framework, shippers buy gas from producers and importers, contract for it to be transported, and sell it to suppliers who then sell it to end consumers. We would expect shippers to carry out the same role for blended gas.

Below we set out the key roles and responsibilities of these four parties.

4 Roles and responsibilities

4.2 Roles and responsibilities of relevant parties

Cluster Delivery facility operator

The cluster delivery facility operator and the relevant gas transporter would agree the ownership boundary between the delivery facility and the gas network. The cluster delivery facility operator would then own and operate the equipment on its side of the ownership boundary. We discuss ownership boundaries for cluster connections in detail in section 5.

Most of the responsibilities of the cluster delivery facility operator can be taken from those relevant for a methane delivery facility operator today, i.e.:

- be a party to a Network Entry Agreement (NEA), where the other party is the gas transporter that owns the network to which the delivery facility is connected;[13]
- physically inject gas (in this case hydrogen or a hydrogen blend) into the existing gas network;
- operate relevant entry point equipment on their side of the connection boundary (e.g. pressure unit and odorisation equipment). These responsibilities would be specified in the NEA;
- meet all other Network Entry Provisions in the NEA, for example:
  - any capacity threshold and profile requirements for flowing gas onto the network;
  - gas compression and quality requirements (ensuring that gas meets GS(M)R upon entry);
  - measurement and equipment maintenance provisions; and
  - rules to limit blending when remote monitoring or other assets are unavailable, either planned or unplanned.

Relevant gas transporter

The gas transporter would own and operate the equipment on its side of the agreed ownership boundary. Most of the gas transporter's roles and responsibilities would remain unchanged when receiving hydrogen rather than methane, i.e.:

- be a party to an NEA with the delivery facility operator;
- operate relevant delivery facility network equipment as specified in the NEA; and
- accept gas (in this case hydrogen or a hydrogen blend) from the entry point subject to it meeting safety requirements and any constraints set out in the NEA.

As discussed in the previous section, the gas transporter will also need to engage with the cluster, and with other upstream or downstream networks, ahead of a connection request being made in order to ensure a total system view is taken when selecting a suitable connection location.

Another incremental activity for the gas transporter will be monitoring of hydrogen blends in the network, to ensure that these do not breach the blend cap. Gas transporters are already responsible for monitoring and managing gas quality, so this does not require a change to formal responsibilities, but it will add some complexity to the activities carried out in order to meet those responsibilities.

Cluster hydrogen owner

The role and responsibilities of the party that owns the hydrogen in the cluster do not need to be different to those of a methane or biomethane producer today, i.e. this party would enter a gas supply agreement to sell gas to a shipper at the relevant delivery point. This agreement would also set out arrangements in cases when the relevant gas transporter is not able to accept gas.

The precise rights and obligations of the hydrogen owner would depend on the contractual arrangements with the relevant shipper. They are not relevant to the gas commercial framework, so we do not consider them further here.

[13] We note that if the party connecting is itself a gas network, a Network Interface Agreement may be needed in place of a Network Entry Agreement. However, in this document we assume that the agreement will be between the delivery facility operator and the gas transporter, and therefore the relationship will be governed by an NEA.

4.2 Roles and responsibilities of relevant parties (Continued)

Gas shipper

Similarly, the role and responsibilities of gas shippers in relation to arranging for transport of blended hydrogen and its trading downstream of the entry point do not need to change relative to the shipper's role in relation to methane today. This is because we assume that blended gas can be traded at the National Balancing Point (NBP) on the basis of energy content (e.g. MWh of blended gas), rather than differentiating between different gas types (methane versus hydrogen).

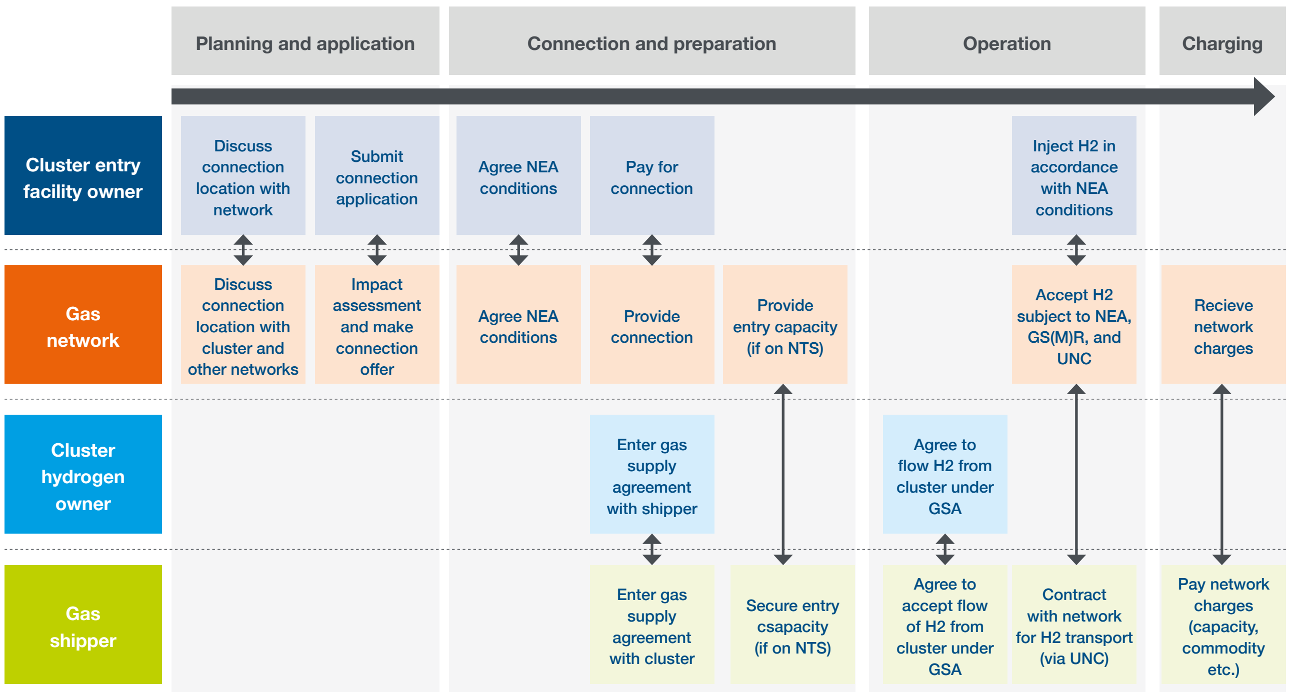
Therefore, the key roles and responsibilities of a shipper would be:

- being party to a gas supply agreement with the cluster entity;
- securing capacity: if the hydrogen is injected into the NTS, securing sufficient NTS entry capacity to bring the hydrogen onto the network, subject to any capacity restrictions and other constraints in the delivery facility operator's NEA (there are no capacity requirements for injections into an LDZ); and
- buying hydrogen at the entry point from a cluster hydrogen owner, and then trading that gas as they would any other gas in their portfolio, on the basis of energy content.

4.3 Summary of roles and responsibilities

Figure 4 below shows the four key parties that will play an active role in hydrogen blending from industrial clusters, and the key activities and interactions of these parties in a timeline spanning different phases of the hydrogen injection process. This shows that roles and responsibilities do not need to change relative to today (although parties will be handling hydrogen or hydrogen blends, rather than methane).

Figure 4 – Key activities of relevant parties to enable blending from industrial clusters



5 Connections

We considered the following key questions in this area. Note that we have considered connection charging separately in section 7.

- What will the connection application and evaluation process for hydrogen injections from industrial clusters look like? Does anything need to change relative to current processes?
- Do any specific restrictions need to be placed on hydrogen injection connections from producers in industrial clusters? And how do existing agreements need to change to reflect this?

5.1 Connection process

The current process for establishing a new entry connection requires the delivery facility operator to apply for a connection to the gas transporter that operates the network to which they wish to connect. The gas transporter then carries out a pre-connection evaluation, which focuses mainly on establishing whether there is sufficient capacity available to accommodate the connection.

If the application is approved, the physical connection assets can be built either by the respective gas transporter, or by a third party. Once the connection is established, the conditions of entry are governed by a Network Entry Agreement (NEA) between the delivery facility operator and the relevant gas transporter.

In the same way as today, we would expect that industrial clusters would engage with gas transporters prior to submitting a formal connection application, in order to understand the economics of different connection options.

However, as discussed in section 3, gas transporters will need to engage closely with industrial clusters and with one another to provide a total system view on the impacts of different location options, taking into account available hydrogen blending capacity (e.g. to avoid small downstream connections using up all of the hydrogen headroom in that location, and preventing larger volumes being blended upstream) and potential impacts on settlement and billing.

Gas transporters could also provide open source information on suitable connection points.[14]

Over time, as more industrial clusters connect, the gas transporters can take a view on whether (and in what circumstances) this coordinating role, including system-wide analysis, could be supported by a centralised entity such as the Future System Operator.

Once a suitable connection location has been identified and a cluster has decided to formally apply for a connection, there will need to be change to the pre-connection evaluation process to ensure that additional impacts of hydrogen injections on the system are taken into account, as set out below.

What is the likely volume and profile of hydrogen injections from the cluster?

How much hydrogen blending capacity is available, given methane flows past the injection point?

What would the likely impact of the connection be on settlement and billing, i.e. could the connection cause significant under-recovery of energy?

In summary, the following changes and further work will be needed:

Gas transporters will need to provide guidance to industrial clusters on suitable locations to connect, and work together to provide a total system view on blending capacity and settlement/billing impacts. This role could ultimately be supported by a centralised entity (e.g. the Future System Operator).

Connection requests will require enhanced impact assessments to evaluate impacts on network blends (e.g. to avoid small downstream connections using up all of the hydrogen headroom in that location, and preventing larger volumes being blended upstream), settlement and billing.

[14] Cadent have published a list of preferred connection locations where blending capacity can be maximised, which can be accessed at: link. Electricity network operators also provide 'heat maps' of their networks' capability to accept connections in different locations, e.g. **link**.

5.2 Connection agreements and restrictions

Once a connection application has been accepted and the connection has been built, the roles and responsibilities of the connecting party and the gas transporter are set out in a Network Entry Agreement (NEA) for entry connections, and a Network Exit Agreement (NExA) for exit connections.

Stakeholders agreed that these agreements can continue to be used to govern the conditions of industrial clusters' entry connections (and exit connections in the case of pre-blending), and that new types of agreements are not needed.

However, specific conditions within NEAs will need to be adapted on a case-by-case basis, to reflect site-specific characteristics. First, gas transporters and industrial clusters will need to agree the delivery facility ownership boundary, and reflect this in the NEA. Second, NEAs will need to reflect any agreements between the cluster and the gas transporter required to manage network blend levels.

We cover each of these points below. We note that provisions already exist to reflect these types of site-specific conditions in NEAs (e.g. for biomethane connections), so implementing these conditions does not formally require any change to gas frameworks.

Ownership boundary

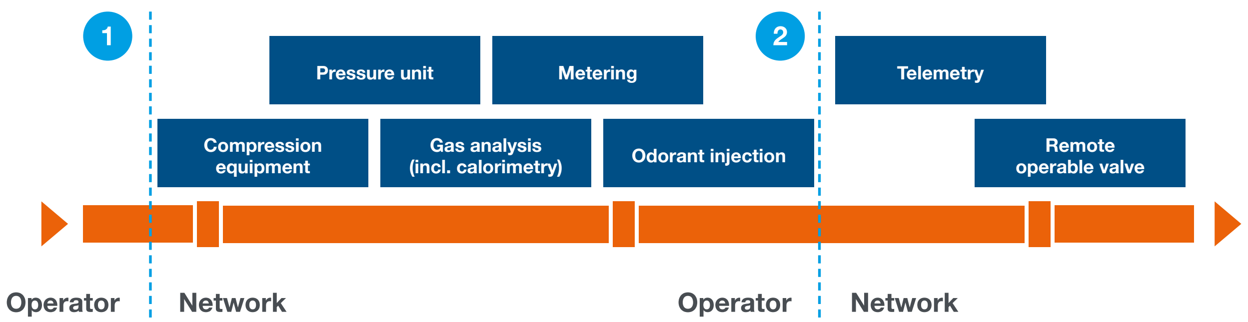
Existing delivery facilities for injection of methane or biomethane into the gas network generally include the following equipment:

- pressure control unit;
- compression equipment;
- volumetric metering;
- gas analysis equipment (e.g. to measure gas quality and calorific value);
- odorisation equipment;
- remote telemetry unit (RTU);
- remote operable valve (ROV); and
- a section of pipeline from the remote operable valve to the gas network.

The view of gas transporters and stakeholders was that much of this equipment will be the same at a hydrogen delivery facility. The specific infrastructure needs to enable hydrogen blending are being considered by ongoing technical work.[15] Currently, for biomethane delivery facilities, there are a number of different ownership models offered to customers by different gas transporters. Two possible models are illustrated below, though there are other options in between these two.

The first option (with the boundary marked '1'), is where the gas transporter owns and operates all of the entry point equipment. This involves 'maximum control' from the gas transporter. The second (with the boundary marked '2'), is where the gas transporter only owns and operates the most critical equipment: the remote telemetry unit and the remote operable valve.[16] This involves 'minimum control' from the gas transporter.

Figure 5 – two connection model options based on biomethane



5 Connections

Within the stakeholder group there was general consensus that a minimum control model is the direction of travel for biomethane entry points, as well as for entry points connected to the NTS. Stakeholders noted that it tends to deliver more efficient procurement and control of assets, as well as giving the customer more control over the construction of those assets. It was therefore felt that this was also likely to be most suitable for hydrogen entry points.

We explored whether there should be a standardised ownership boundary model across gas transporters. While there was agreement across the stakeholder group that this would have benefits, gas transporters flagged that they would need to do their own case-by-case assessments of individual connection requests, and then decide on a suitable model that the gas transporter considers provides sufficient control to address any risks.

Therefore the most suitable solution could be a standardised template NEA setting out default ownership boundaries, but with scope for adjustments to be made to reflect the characteristics of specific connections. As there are already provisions in place for gas transporters and delivery facility operators to agree NEAs as required on a case-by-case basis, framework changes are not required to implement this action.

Managing blend levels

Stakeholders agreed that NEAs for cluster hydrogen connections will need to include conditions to enable hydrogen blend levels to be safely managed. These conditions will relate to injections (e.g. flow rates and blend levels) and to enabling the gas transporter to interrupt injections for blend management purposes.

The exact conditions required will vary on a cluster-by-cluster basis, and will need to be established through the enhanced impact assessment described above. In particular, they will vary based on the blending technique used and the injection location.

The stakeholder group agreed that conditions in NEAs may need to include:

Limits on injection flow rates and profile, and/or a requirement for provision of information from the cluster to the gas transporter on forward-looking injection profile information. Flow rate limits already exist in current NEAs, but may need to be more stringent for hydrogen injections, and may need to vary with seasonal methane flows.

An ability for the gas transporter to reduce or interrupt hydrogen injections beyond the typical flow rate limits set out in the NEA in specific instances where downstream blends are at risk of breaching the blend cap.

With respect to injection location, different locations will have different implications for the volume and profile of hydrogen that can be injected. As part of the pre-connection evaluation, location specific criteria would need to be identified, and these would then need to be reflected in NEAs.

In summary, the following changes and further work will be needed, neither of which formally require framework changes:

Network entry agreements (NEAs) will need to include conditions to address the risks identified through the pre-connection assessment, specifically limits on injection flow rates and profiles, and an ability for the gas transporter to reduce or interrupt injections.[17]

A 'minimum control' connection ownership boundary is recommended, though gas transporters and industrial clusters will need to work together on a case-by-case basis to confirm whether this is acceptable, given the characteristics of the specific connection.

[15] Functional Specification: Hydrogen Blending Infrastructure, **link**

[16] Remote telemetry equipment transmits critical telemetry data to the network control centres, and the remote operable valve allows the gas transporter to shut off injections if needed for safety reasons or if gas quality requirements are breached.

[17] There would be benefits to the gas transporter providing the cluster with an indication of the likelihood of interruptions across a typical year.

6 System operation and capacity

We considered the following key questions in this area:

- How will the gas transporter manage hydrogen injections from industrial clusters for safety and blend management purposes? Does this have any financial consequences (e.g. interruption payments)?
- How should entry/exit capacity for hydrogen injections be secured?
- Should hydrogen blending access for industrial clusters be protected from curtailment due to future hydrogen connections? If so, how?

6.1 System operation

As set out in section 4, gas transporters are already responsible for monitoring and managing gas quality.

The stakeholder group were of the view that this role can be carried out using existing tools in the regulatory framework (for example restrictions in NEAs, discussed above, and gas flow management).

6.2 Capacity allocation

Here we considered whether current capacity booking arrangements need to change for hydrogen injections from industrial clusters. Given that these arrangements differ across the NTS and the LDZs, we cover the two separately below.

NTS capacity

Under current arrangements, the transmission system operator specifies the amount of capacity it has available at entry points, and shippers must secure NTS entry capacity (measured in kWh/day) through auctions for the right to physically flow gas from a delivery facility onto the NTS.

Stakeholders agreed that no change is needed to this approach in relation to hydrogen injections from industrial clusters onto the NTS.

- Shippers can continue to book ex ante entry capacity, subject to any constraints set out in the cluster delivery facility operator's NEA. Capacity for hydrogen injections can be nominated on an energy basis in the way that it currently is for methane, and with no need to distinguish between the two gas types.
- While 1kWh of hydrogen has a larger volume than 1kWh of methane, meaning that booking 1kWh of hydrogen capacity implies booking more physical space in the NTS pipes than 1kWh of methane, this was considered not to be a material issue given that the volumes of hydrogen injections from industrial clusters are not expected to create capacity constraints on the NTS.

LDZ capacity

On the LDZs there is currently no capacity booking regime for shippers, so gas injections into an LDZ (currently mainly biomethane in relatively limited quantities) are only constrained by the limits specified in a given delivery facility operator's NEA.

Stakeholders agreed that this approach could continue to be used for hydrogen injections from industrial clusters, and that it would be disproportionate to attempt to create any new capacity booking regime for the LDZs.

Any constraints or guarantees on capacity for hydrogen injections on the LDZs can be reflected in NEAs, as set out in section 5.

6 System operation and capacity

6.3 Protection of Blending Access

A critical question for industrial clusters is whether hydrogen blending access for industrial clusters should be protected from interactions with other hydrogen injection points, and if so how.

The potential issue is that a hydrogen producer in a cluster could plan its investment expecting to blend a given amount of hydrogen over a period of several years, but another hydrogen producer could later connect upstream or downstream, and use up some or all of the available blending headroom.[18]

Producers were clear that they need to have certainty over whether their blending access will be protected, in order to build their financing case.

Therefore, gas transporters are of the view that a capacity allocation methodology needs to be developed to provide fair access to the network while maintaining the ability to manage gas quality and ensure compliance with regulations.

Any approach to protecting access for industrial clusters through the gas frameworks should involve a legal review to consider any read-across for other network users such as biomethane producers (e.g. in light of non-discrimination provisions in the Gas Act).

In summary, protection can be provided through the gas frameworks, subject to ensuring that this does not cause any discrimination against other network users.

[18] This issue cannot be resolved through the entry capacity regime, as the constraint in this case is not around absolute gas volumes but the percentage hydrogen blend in the network. For example, there could be significant spare capacity in the network, but if that gas is already at the blend cap, there is no scope to inject further hydrogen.

7 Charging framework

In relation to charging, we consider changes in NTS and LDZ arrangements separately, and specifically asses interactions between charging frameworks and the other commercial framework areas discussed in previous sections.

7.1 NTS charging framework

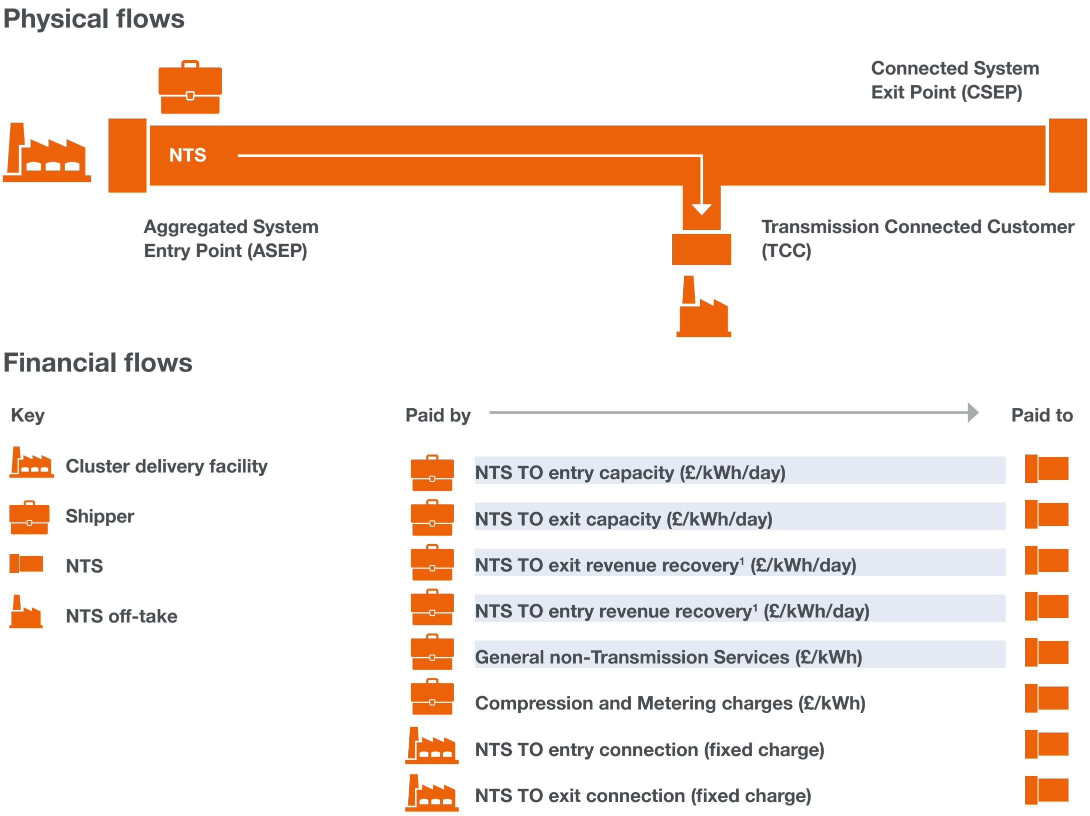
Figure 6 provides an overview of the NTS charging framework, showing the key NTS charges that are paid by shippers and/or delivery facility operators in order to convey gas from an Aggregated System Entry Point (ASEP) to a Transmission Connected Customer (TCC).

This 'net-entry' principle is already reflected in modifications made to charging arrangements for NTS commingling facilities.[19]

Commingling facilities take gas off the network, blend in lower-quality gas that does not meet GS(M)R specifications, and reinject the mixture which does meet GS(M)R.

The commingling modifications were made to avoid double charging for the exit and entry of the gas taken off the network. They apply where gas taken off the NTS is redelivered within-day and, consequently, not expected to alter peak-system capacity requirements.[20]

Figure 6 – NTS Charging framework



Note 1: This diagram shows the end-to-end charges incurred by shippers that enter and exit gas
Note 2: A replacement 'Optional NTS Commodity Charge' is available for large loads located near entry terminals

[19] UNC modification 0363

[20] Ofgem (October 2012) Modification proposal to UNC for Commercial Arrangements for NTS commingling Facilities

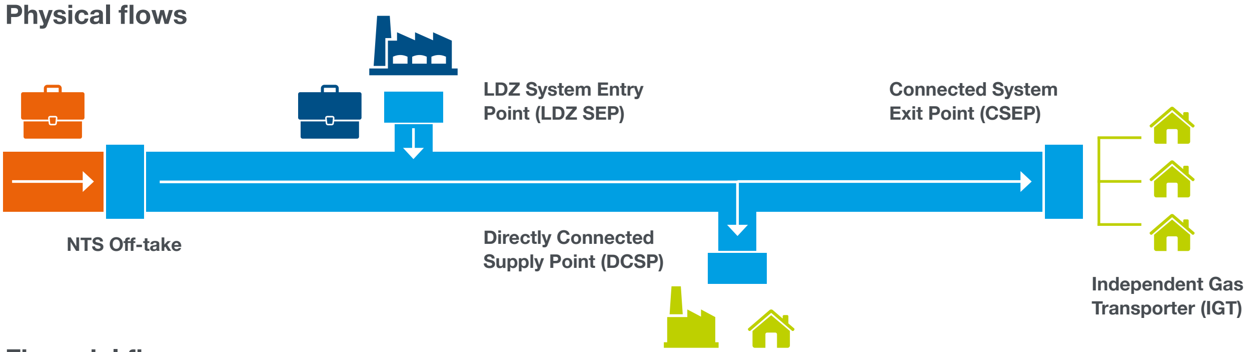
7 Charging framework

7.2 LDZ charging framework

Figure 7 provides an overview of the LDZ charging framework, showing the set of network charges paid by shippers and/or delivery facility operators to enable gas to be conveyed via an NTS offtake (illustrated in red) or from a direct entry connection at the LDZ (illustrated in teal) to a Directly Connected Supply Point (DCSP).[21]

Figure 7 – NTS Charging framework

Physical flows



Financial flows

Key

- Shipper entering NTS
- NTS
- Shipper entering LDZ
- LDZ
- Cluster delivery facility
- Residential customer
- Industrial customer

Paid by		Paid to
Shipper entering NTS	All applicable NTS charges	NTS
LDZ	NTS exit capacity (£/peak day kWh/day)	NTS
Shipper entering NTS	NTS exit capacity pass-through (£/peak day kWh/day)	LDZ
Shipper entering NTS, Shipper entering LDZ	LDZ capacity system charge¹ (£/peak day kWh/day)	LDZ
Shipper entering NTS, Shipper entering LDZ	LDZ commodity system charge¹ (£/kWh)	LDZ
Shipper entering NTS, Shipper entering LDZ	LDZ customer capacity charge (£/peak day kWh/day)	LDZ
Shipper entering NTS, Shipper entering LDZ	LDZ customer fixed charge (£/day)	LDZ
Cluster delivery facility	LDZ connection charge (fixed charge)	LDZ
Shipper entering LDZ	LDZ SECC (£/kWh)	LDZ

Note 1: This diagram shows the end-to-end charges incurred by shippers that enter and exit gas
Note 2: A replacement 'Optional LDZ Charge' is available for large loads located close to the NTS
Note 3: Only applicable to supply points with Annual Quantity ('AQ') consumption above 73 MWh

[21] For simplicity, we do not set out additional charges associated with conveying gas to a Connected System Exit Point (CSEP) but note that additional administrative charges also apply.

7.2 LDZ charging framework (continued)

Components highlighted in dark blue indicate where stakeholders agreed that change is required.

In relation to connection charges, LDZ connection charges are based on a ‘deep connection boundary’ (i.e. covering the costs of connection assets and any deeper reinforcement).[22] This approach was considered by stakeholders to remain suitable for hydrogen connections from industrial clusters.

In cases with pre-blending, if the blending facility is built by the gas transporter, the costs of building the facility would be recovered from the cluster through the connection charge. In cases without pre-blending, if the GT needs to install and operate its own blending equipment as a result of the connection, then those costs would again be included in the connection charge.

The stakeholder group did not consider that any further changes were required to the LDZ charging framework. However, previous work has highlighted that as the number of distribution connected hydrogen entry facilities increases, the cost-reflectivity of credits associated with LDZ System Entry Commodity Charge (LDZ SECC) may need to be revisited.[23]

This concern remains relevant and we recommend that gas transporters review the cost-reflectivity of this charge within further work.

In summary, the following changes and further work will be needed:

Gas transporters should review whether the ‘credits’ awarded to entry facilities within the existing LDZ SECC are likely to distort cost-reflectivity in a system with increasing share of hydrogen injections, and if so, signal any proposed changes to industrial clusters ahead of their final investment decision.

[22] Although we note that distribution network operators have recently launched a consultation on entry connection charges: **link**.

[23] Frontier (September 2020) Hydrogen blending and the gas commercial framework - report on conclusions of NIA study, section 3.2. The review found that LDZ SECC credits may result in injections receiving benefits which do not reflect historical rather than forward looking costs. This may distort incentives and change behaviour in a way that reduces efficiency, and this will increase in importance as more producers (both biomethane and hydrogen producers) connect to the network.

8 Interactions with settlement and billing

As explained in section 2, hydrogen has a lower energy content (calorific value, or CV) than methane. Under the current billing regime, which caps the billing CV of an LDZ at 1MJ/m3 above the lowest CV gas in the zone, even a small volume of hydrogen (or other low CV gases such as non-propanated biomethane) can lower the billing CV and lead to under-recovery of energy, the cost of which is ultimately socialised.

The Future Billing Methodology (FBM) project has considered different options for addressing this challenge, and has now published its recommendations, including two main billing solutions:[24]

- **No change to the current regime:** FBM has found that blends of hydrogen and biomethane can be achieved under the existing billing framework with no change. Under this approach, local hydrogen blends would be controlled to maintain compliance with FWACV.

  FBM has recommended that gas transporters immediately proceed with developing this option. FBM has highlighted that this scenario would benefit from 'blending at high volume locations', i.e. hydrogen should be injected higher up the pressure tiers such that the blend can be distributed more evenly across a given LDZ. This scenario will also require careful flow management of low CV gases, again to distribute these gases more evenly across the LDZ.

- **A modelled approach:** FBM has also recommended exploring two options involving network modelling to create separate charging areas within LDZs. The first would create separate billing zones in the local vicinity of any lower CV injections, and the second would deliver a much more granular modelled CV value at system node level.[25]

  Either of these options would help improve the accuracy of cost recovery in cases where low CV gases are unevenly distributed within an LDZ. A detailed feasibility study into a modelled approach will be undertaken by the gas networks, but is not a prerequisite to enable hydrogen blending.

The main interaction between the settlement/billing approach and the rest of the commercial framework changes is that under a 'no change' approach, hydrogen blends will be constrained by FWACV rather than just the GSMR limit.

There are also likely to be additional benefits from injections high up the pressure tiers (to avoid different gas blends entering different parts of an LDZ), and there may need to be more careful gas flow management, to ensure more homogenous blends across LDZs.

Hydrogen blending can commence while maintaining compliance with the Gas Calculation of Thermal Energy Regulations. Analysis has shown that significant blending capacity is available at higher flow locations such as the local and national transmission systems

[24] FBM project webpage: link, recommendations: **link**

[25] We understand that both of these approaches, while 'pragmatic' in that they use modelling rather than extensive investment in measurement equipment to determine more granular billing CV values, would still be time consuming and costly to implement, so are unlikely to be in place ahead of blending from industrial clusters commencing. Initial costs for FBM Options B and C range from c. £160m to c. £190m. Ibid, p.3.

9 Amendments to legislation and licenses

Our work has not involved an exhaustive review of codes and licences, nor has it involved input from legal experts. A detailed legal and technical review will eventually be needed. However, we have discussed with stakeholders the areas in which change (or further work) appears likely to be needed. We document here the areas that were identified.

We have already covered the relevant changes that may be necessary to the Uniform Network Code and so do not cover them again here. We also do not cover supplier licences, as they were not identified as a party that takes an active role in hydrogen blending from industrial clusters, when we discussed roles and responsibilities above.

9.1 Legislation and statutory instruments

Gas Act

The Gas Act 1995 (as amended, hereafter referred to as the Gas Act) is the legislation that provides the foundation for the GB energy regulatory framework and defines the licensable activities in which firms are prohibited to participate without holding the relevant licence from Ofgem.

The stakeholder group agreed that the current definition of 'gas' within the Gas Act is likely to be sufficiently broad to include hydrogen, and specifically a blend of up to 20% hydrogen.[26]

One area raised for consideration relates to existing provisions of the Gas Act that prevent gas transporters from denying any 'reasonable request' to convey gas through the network, or showing 'undue discrimination' in respect of connections.[27]

Depending on the legal interpretation of these provisions, this may be something that Ofgem and gas transporters need to assess for future hydrogen connections, including in relation to pre-connection location selection (see section 3) and protecting industrial clusters' hydrogen injection access (see section 6).

Gas Safety (Management) Regulations (GS(M)R)

The Gas Safety (Management) Regulations 1996 (GS(M)R) is a statutory instrument that sets out the content and characteristics of gas that can be transported in the gas networks.

The current regulations limit hydrogen content of gas in the networks to a level of 0.1%, and contain other requirements that will not be compatible with material amounts of hydrogen entering the networks from industrial clusters.

It will be necessary to amend these requirements to enable hydrogen blending from industrial clusters. Safety evidence for hydrogen blending up to 20% into the LDZs is currently being generated by the HyDeploy project, which is scheduled to conclude by Q2 2023. This evidence will then feed into subsequent work with BEIS and HSE to amend the safety requirements in GS(M)R.[28]

If amendments are not implemented in time to enable blending from industrial clusters, exemptions from these requirements will need to be granted by HSE to enable these initial hydrogen connections.

[26] In particular, Section 48(1) defines gas as 'any substance in a gaseous state which consists wholly or mainly of (i) methane, ethane, propane, butane, hydrogen or carbon monoxide, or; (ii) a mixture of two or more of those gases.

[27] Section 9, Gas Act 1995

[28] Britain's Hydrogen Blending Delivery Plan, Gas Goes Green

9 Amendments to legislation and licenses

We note that, further to GS(M)R being updated, gas transporters will need to carry out various processes to ensure their readiness for blending, for example updating their Safety Cases with HSE, and revisiting relevant risk assessments.

9.2 Gas Transporter licence

The Gas Transporter licence allows the licensee (i.e. the gas transmission and distribution network operators) to convey gas through a network within the particular authorised area subject to a set of standard licence conditions.

The only area of change highlighted by stakeholders related to any new or enhanced processes and conditions through which licensees assess and decide whether or not to accept new hydrogen connections, as set out in section 5.

While not within the scope of this work, we note that gas transporters could potentially have a role in operating hydrogen pipelines and/or blending facilities within industrial clusters.

Further work by BEIS, industrial clusters and gas transporters to understand what arrangements will be in place within industrial clusters will need to consider whether such activities would need to be licenced and whether existing Gas Transporter licensees would have a defined role in relation to them.

9.3 Shipper Licence

Shipper licences permit licensees to enter into arrangements with gas transporters for the purposes of conveying gas to end-customer premises.

Discussions with stakeholders did not identify any clear changes needed to the existing Shipper licence to enable purchase and sale of hydrogen, or contracting for the transmission of blended gas via gas networks.

While not within the scope of this work, we note that entities with shipper licences could potentially have a new role involving trading of hydrogen within industrial clusters. However we expect that this would be a purely commercial activity falling outside the current shipper licence, and would not impact gas frameworks.

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