national gas transmission

PROJECT UNION: EAST COAST HYDROGEN SYSTEM OPERABILITY

Report on Market Frameworks

National Gas Transmission (NGT) operates the National Transmission System (NTS) in Great Britain, facilitating the safe and efficient transportation of gas. As the UK transitions to a low-carbon energy system, NGT seeks to evolve to transport 100% hydrogen, as such we are active in the development of both Project Union and the Humber Hydrogen projects.

In 2023 we published a report on our initial positions for a potential Commercial Framework for a hydrogen network[1], using Project Union as a case study, under the Gas Market Plan (GMaP). With funding from the Project Union: East Coast FEED Study, we have since undertaken further development work which we present here.

We draw on National Gas's experience operating the National Transmission System (NTS) and on developing processes in other relevant emerging markets, such as CCS, to identify an approach that is flexible in the early years but capable of evolving into a formal regulated regime as the market matures. The work contained in this report has been carried out with the aim of understanding and developing the framework needed to enable the safe and efficient operation of the first phase of Project Union; this would support development of hydrogen hubs at Teesside and Humber by bringing together two of the largest industrial centres in the UK and enabling cross cluster production, transport, storage and use of clean hydrogen up and down the east coast of England.

This report reflects National Gas' updated positions on Access, Balancing & Charging and how we might expect to operate Project Union as a first step towards a national hydrogen backbone, bringing together regional networks, clusters and hubs to provide greater opportunity to access a variety of hydrogen production methods, and enhancing resilience through links to more storage opportunities and increased linepack.

During this period of internal development, National Gas has been a regular contributor to the Hydrogen Delivery Council Working Groups on Transport & Storage and the Sub-Group set up to look at the wider Market Frameworks. Through this forum we have begun to share some of these ideas with the wider industry and the discussion in those groups has been hugely beneficial to ourselves and the wider industry. Through that subgroup, a report[2] was produced; this report began to explore the balancing frameworks required to operate each of the three complex, i.e. multi-producer and multi-offtaker, hydrogen networks proposed to date (HyNet, Humber Hydrogen Hub, and East Coast Hydrogen).

We have used that report and the subsequent DESNZ consultation as the basis for many of the assumptions made in furthering our positions and developing this report, which delves deeper into the structures needed to develop coherent Access, Balancing and Charging regimes and provides the next level of detail following on from our initial GMaP funded report.

This report does not represent any official government position or constitute any final decisions. The aim of this report is to share the work carried out in relation to PU: East Coast with a wider audience, including other potential hydrogen Network Operators, DESNZ and OfGEM, both to inform their own decision making and to further the wider industry discussion, in turn helping to further develop our own thinking. The ultimate goal being to support development of a Uniform Network Code for Hydrogen (HUNC) which will facilitate development of a hydrogen market both within, and eventually across, all GB Hydrogen Networks, including the potential for import and export of Hydrogen to mainland Europe and the Island of Ireland.

[1] GMaP - Commercial Frameworks for Project Union

[2] HDC Transport & Storage Market Framework Sub-group report on Hydrogen Market Frameworks for Initial Hydrogen Networks

Assumptions: In addition to those assumptions stated in the balancing paper, we have made the following further assumptions for clarity when talking about stages of network development.

Throughout this and previous documents we have referred to "**Day-One**" operations; for this report we have defined Day-One as the Commercial Operation Date (COD) of the first Hydrogen Transport Business Model (HTBM) funded Hydrogen Network, currently expected to commence operation on or before the 31st December 2033 based on the most recent published HTBM timescales.

We propose that the Hydrogen Year be set up to align with the Financial Year, in part for simplicity, but also to aid in reduction of the sawtooth effect we see in transportation prices on the NTS.

We also propose to align the Hydrogen Balancing Day with the Electricity Half-Hourly Balancing Mechanism, i.e. 00:00 – 00:00 CET (23:00 UTC), rather than starting at 05:00.

Defining Day-Two

In discussing Day-Two, we need to understand more about the Hydrogen Business Model agreements, specifically, do all agreements end on the same date?

Are the agreements due to expire:

a) 15 years from date of agreement? (i.e. successful HAR application)
b) 15 years from COD of the first network?
c) 15 years from an individual's first use of network?
d) 15 years from connection of the last successful HAR applicant?

Our assumption is that Option b. 15 years from COD i.e. the first use of the network, would be the cleanest in terms of transfer from Hydrogen Business Models to the HUNC as the overarching governance tool. We know from the recent extension to the Green Gas Support Scheme[3] (GGSS), that projects coming online in the two years after the initial deadline date will be granted 13 years of price protection, aligning the end dates for all support. We have assumed that a similar arrangement will be applicable to the hydrogen projects funded via HTBM rounds.

Option d. would provide for a clean cutover by delaying the move to an open market until all connectees had benefited from a minimum of 15 years of support under the HPBM, rather than cutting short the support offered to later connectees.

Options a. and c. while balanced in terms of the period of support provided to them, would create staggered implementation of a uniform code, meaning that there are periods, either before (Option a.) or after (Option c.) the provisional Day-Two, where a two-tier regulatory structure is in place rather than a single rule set; this could lead to confusion across rule sets, discrimination and cross subsidy.

Day-Two: the first Hydrogen Day, of the first Hydrogen Year, following expiry of the initial HPBM contracts begins

00:00* on 1st April 2049

This is the first point at which we would expect that a market *could* begin to develop outside the confines of the Hydrogen Business Model agreements

*BST (01:00 CET or 23:00 UTC)

[3] Green Gas Support Scheme (GGSS) - GOV.UK

Key Proposals:

Capacity

We are proposing a move away from the traditional Capacity concept for the early phases of hydrogen. However, we support using a format which would be compatible with a "Capacity Based" Charging regime as we believe this allows for a balance of short-term predictability while enabling future transition to a simplified Capacity Regime from Day-Two when the market begins to open-up following expiry of the initial HPBM agreements which limit the resale of hydrogen.

The proposal uses the limited range of inputs available ahead of the first hydrogen year, including the Technical Capabilities of connected sites and the network as a whole, to calculate a Contractual Maximum Volumetric Flow (CMVF or "Con Max"). This figure will represent the peak in site capability, tempered by any potential for network constraint, giving a consistent figure for use in processes designed to recover the Allowed Revenues associated with Transmission Ownership (TO) in lieu of a capacity market and associated bookings.

Charging

Using Con Max as the basis for recovery of the TO Allowed Revenues give a consistent and predictable cost basis which is adaptable for future use in a Capacity based regime and aligns with the principles of the EU Tariff Network Code which, despite its applicability to methane only, is influencing the decisions of likely cross border trading partners such as Germany and Denmark.

We expect that, in a drive to keep hydrogen competitive with methane in the early phases of operation, a capped unit rate, potentially indexed to methane transmission, or a similar methodology, will be put in place to limit charges incurred by hydrogen network users. The Revenue Support Arrangement (RSA) proposed by Government would then ensure that any outstanding revenue balances, the equivalent to "k" and "SOk" in the current methane regime, are made up to the transporter via an RSA top up payment.

Charges should still be calculated annually based on the Allowed Revenue and Con Max volumes, with the expectation that this would be the prevailing methodology beyond the life of the support arrangements. Those calculated rates would be assessed and compared to the methane prices, and as the values converge, the need for a price cap can be reassessed and potentially removed along with the RSA.

The System Operation charging methodology would remain ostensibly the same as on the methane network, with revenues recovered via a p/kWh/day unit rate applied to the actual flow, as this is more closely linked to the day-to-day operation of the network and associated costs than Con Max would be. We expect however that in a nascent network, with little to no compression related costs, the SO Allowed Revenue and subsequent rate would be comparatively lower than on the NTS. This is in line with the reduced network resilience and expected service levels that will be provided by the Hydrogen SO and means an SO linked price cap is unlikely to be triggered.

This approach supports rapid deployment under government backed business models while providing a clear pathway to a more structured, capacity-linked regime as the market evolves. By embedding transparency, fairness and technical realism from the outset, the framework will foster investor confidence, encourage innovation and ensure efficient network development aligned with national decarbonisation objectives.

Connections

Most connections prior to Day-Two are expected to be progressed through one of the governments hydrogen business models and the Hydrogen Allocation Rounds. However, the development of a hydrogen connections framework is pivotal to enabling the UK's hydrogen economy and achieving net zero goals, and so we would also propose that National Gas Transmission (NGT) make available an alternative route for connectees to access Project Union outside of the HPBM process, where users are given the ability to connect where there is no requirement for wider network investment.

While the gas regime offers useful precedents, hydrogen's early-stage characteristics demand a proportionate, flexible approach which can evolve over time. A hybrid model, combining the simplicity of a non-capacity linked process with the strategic coordination of cluster-led planning, strikes the right balance between agility and long-term discipline; a Minimum Connection process similar to the A2O process currently in place where NGHT would provide a valve at an existing Hydrogen Above Ground Installation (HAGI) with the connectee expected to build and manage all other equipment between connection and site.

Balancing

The overarching balancing proposal has been developed with the Hydrogen Delivery Council's Transport and Storage subgroup for Market Frameworks and can be found in greater detail in the linked report[4], but to provide context to this document we include a brief overview here.

The expectation is that primary balancing responsibilities will be assigned to producers, and willing offtakers, expected to be large industrial or Hydrogen to Power users who want the ability to control their portfolios. These primary balancers will be granted "shipper" licences to enable them to contract with the transporter for transportation of hydrogen across the network.

The Transporter will act as System Operator (TSO) and take ownership of residual balancing, carrying out any actions required to resolve imbalances between supply and demand. It is expected, that to enable this activity in a smaller, less resilient network such as a nascent hydrogen cluster, the transporter will require a small store of hydrogen to be made available to resolve imbalances and shrinkage issues. The cost of which will be allocated to the balancing neutrality account and recovered via a flow-based charge applicable to network users.

Building on this, NGT have refined a set of balancing tools appropriate to a nascent hydrogen network. While these would give the System Operator greater control over safe network usage, this will be mitigated by stricter control of a simplified notification/nomination process, requiring all primary balancers to notify us of their flows in balance across Entry and Exit, giving the holder of the shipper licence the ability to minimise the need for the TSO to issue flow advice.

A central Hydrogen Data Hub would support data transfer between the TSO, Shippers and the regulator, as well as provide a platform for publication of any appropriate reporting requirements.

Network Resilience and Neutrality

To ensure network balancing doesn't exacerbate potential teething issues in a nascent hydrogen network, the hydrogen regime must operate as a coordinated operability framework creating the right incentives and environment rather than operating as a set of standalone charges which penalise rather than incentivise. Hydrogen's tighter technical constraints mean, Con Max, scheduling controls, storage reserves, linepack and cash-out, all need to function with clear intent to help shift emphasis away from

[4] Balancing Report

end-of-day correction and toward proactive behaviours that help maintain system operability throughout the more granular balancing periods.

Each charge provides for a distinct role within a sequential escalation pathway, designed to support early-stage operability while enabling the longer-term transition to market-led balancing.

- Con Max provides the agreed upper edge of the standard operating envelope at the point of connection, helping define the boundary conditions for normal system operation.
- Scheduling charges offer the primary within-day behavioural control, reinforcing discipline as deviations emerge.
- Explicit treatment of storage and linepack ensures that while limited, access to flexibility is transparent, cost-reflective & not cross subsidised

By designing a layered and integrated control system NGT, in the role of System Operator, can support secure and reliable operation during the early development of the hydrogen market while laying the foundations for a disciplined, efficient, and progressively more market-driven balancing framework. Any costs and benefits incurred by NGHT in the act of residual balancing to maintain the safe and efficient operation of the network will be redistributed via a balancing neutrality mechanism.

Hydrogen Day

Our expectation is that peaks in usage of the hydrogen network will be more closely linked to activities on the electricity network than they are with methane.

- The triggers for production of green hydrogen and subsequent transportation and input to storage will be excess renewable generation on the electricity network.
- The triggers for Hydrogen to Power Generation and storage withdrawal will be a shortfall in electricity supply vs demand.

As a result, we would seek to align the Hydrogen Day, to the electricity HH Balancing Mechanism settlement period, starting and ending at midnight Central European Time (GMT-1) or 23:00 GMT. While this is less relevant for a network balanced in 2-hour blocks, it is still a useful measure for use in billing and settlements at Day-One, as well as providing a clear cut-off and handover point in a later stage network where the ability to change shipper or supplier is not restricted.

Hydrogen Year

Blue hydrogen producers and some smaller scale offtakers are likely able to aim for a level of consistency and year-round predictability in their daily usage of the hydrogen network. With the increasingly unlikely need for hydrogen to be used in home heating, we are also unlikely to see the same scale of winter peaks and summer lulls as the methane network experiences currently. As a result, we don't feel there is a particularly strong need to link the Hydrogen Year to the existing methane Gas Year, and so it is our proposal to instead align the Hydrogen Year with the Financial Year, both for simplicity and to try and avoid the associated price setting issues generated by the two years being out of alignment. Historically this has created a significant seesaw effect in published prices which UNC0796[5] & UNC0857[6] sought to mitigate for Transmission Service and General Non-Transmission Service charges respectively.

[5] UNC0796: Revision to the Determination of National Grid NTS Target Revenue for Transportation Charging

[6] UNC0857: Revision to the Determination of Non-Transmission Services Gas Year Target Revenue

1. Capacity

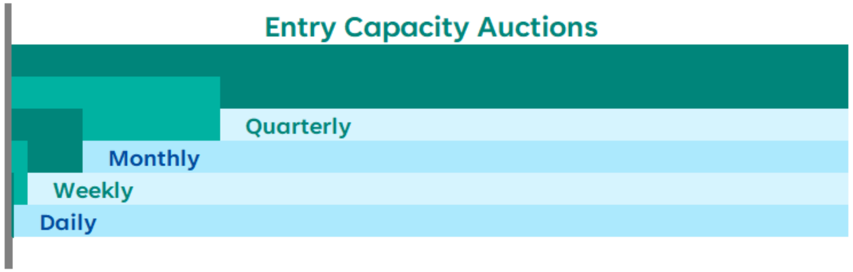
Methane Regulatory Framework

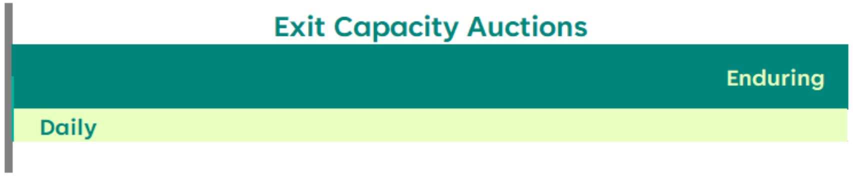
The Capacity Regime governs how users acquire rights to flow gas into (Entry) or out of (Exit) the NTS. The rules of the Capacity Market have been developed, over a number of years and numerous modifications to the original Uniform Network Code, to align with principles laid out in the Gas Act 1986[7] and Gas Transporter Licences (The Licence)[8] granted by OfGEM, as well as ensuring compatibility with later changes such as the EU Capacity Allocation Mechanisms Network Code (CAM NC)[9].

The right to flow gas on or off the NTS is sold via capacity products, secured through regulated auctions and application processes; this right to flow is known as the Ticket-to-Ride Principle.

Capacity is sold in various tranche sizes, measured in kWh/day, they give the holder the commercial rights to flow up to that volume gas for the period of the tranche. System Entry and Exit Capacity rights are sold separately via the GEMINI platform, so users have the ability to tailor their portfolio in line with their commercial profile. Producers who input gas into the NTS at System Entry Points need only purchase rights to enter the network, and offtakers need only purchase rights to take gas from the network at designated System Exit Points.

Capacity is sold as either, Firm or Interruptible. Firm Capacity rights guarantee availability, subject to system constraints, whereas the discounted Interruptible (or Off-peak when purchased at an Exit Point), can be scaled-back if system limits are reached. At Entry Points, Capacity is available to be purchased in quarterly, monthly, weekly or daily tranches. At Exit Points, Capacity is available in enduring annual or daily blocks.





This is governed by the Uniform Network Code (UNC) and Gas Transporter Licence. Regulated by Ofgem under the RIIO price control framework (Currently RIIO-T2 2021–2026).

Capacity obligations are defined in the Licence, including baseline and incremental levels.

Interconnection Points (IPs) are treated slightly differently to ensure alignment with the EU Capacity Allocation Mechanisms Network Code (CAM NC[10]). Capacity across interconnectors is sold via

[7] Gas Act 1986

[8] Gas licensing (from October 2025) - Publications - Ofgem Public Register

[9] Capacity Allocation Mechanisms NC | ENTSOG

[10] COMMISSION REGULATION (EU) 2017/ 459 - of 16 March 2017 - establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984 / 2013

PRISMA rather than GEMINI and offered in either bundled, i.e. matching volumes at both ends of the interconnector, or unbundled products. Auctions follow the ENTSOG calendar with Ascending Clock and Uniform Price mechanisms.

Capacity Methodology Statements

Capacity Methodology statements are written and published by National Gas Transmission. They describe the methodology used to fulfill the Licence Obligations associated with Capacity Release, Transfer & Trade and Substitution. The methodologies are reviewed annually and opened for consultation with industry before being approved by the Regulator.

Due to the influence of factors such as User Commitment, Annual Baselines and the 1 in 20 booking requirements for GDNs etc. the current capacity regime doesn't give the level of flexibility, accuracy and granularity that an early-stage Hydrogen network will require. The principles, however, still hold true, and the desire to replicate these positives in a more appropriate way for a nascent hydrogen network, underpins our thought process.

Intended Benefits of a Capacity Regime

Efficient and Secure Network Operation:	Capacity bookings should ensure predictable and planned usage of the National Transmission System (NTS), support system integrity and reducing congestion risks. Allowing for new connections without need to reinforce.
Market Access and Fairness:	Transparent auctions and application processes provide non-discriminatory access to capacity, enabling shippers to tailor bookings to short- and long-term needs.
Revenue Recovery and Investment Signals:	Capacity charges are the primary source of Transmission Services Revenue, supporting infrastructure investment and signalling system expansion needs.
Operational Flexibility and Responsiveness:	A range of capacity products and mechanisms (e.g. UIOLI, discretionary releases) promote efficient utilisation and responsiveness to market conditions.
Regulatory Stability and Incentives:	Embedded within the RIIO framework, the regime incentivises performance, innovation, and cost-efficiency under Ofgem oversight.

Interactions with the Wider Market Framework

1. Revenue Recovery

Revenues recovered via the Capacity based charges at Entry and Exit, form the bulk of regulated revenue. The Postage Stamp Methodology applies a uniform reference price across Entry and a reference price at Exit, with discounts applicable to Storage sites and a select few scenarios. This simplifies cost allocation rather than requiring a complex calculation based on Capacity Weighted Distance. Overrun charges incentivise accurate booking, in line with utilisation, while shrinkage costs are recovered through commodity charges.

2. Connections

A key process in developing a new connection to the network, is ensuring that the network can accommodate the additional flow volumes. The PARCA process enables the user and the network to agree an expected level of additional capacity required and booking of that capacity provides a level of user commitment and a guarantee of revenue to the project which provides the network with the appropriate certainty that network reinforcement will be cost effective and the cost will eventually be recovered.

3. Commercial Tools and Regulatory Framework

Constraint management tools such as capacity buybacks and interruptible scaling support efficient system operation. The regime is governed by the Uniform Network Code (UNC) and aligns with licence obligations and EU network codes, ensuring compliance and harmonisation.

4. Network Balancing

Shippers are expected to balance inputs and outputs daily, with imbalance charges applied for deviations. National Gas acts as the residual balancer using the On-the-day Commodity Market (OCM). Accurate capacity bookings could support forecasting of Predicted Closing Linepack (PCLP) though in reality flows and notifications are a much more accurate guide.

5. Network Maintenance

Accurate Capacity bookings would provide visibility into future flows, aiding in maintenance planning and minimising disruption. Revenue from capacity charges funds asset replacement and compressor maintenance. Maintenance schedules are coordinated with shippers to align with capacity rights and avoid constraints.

6. Network Planning

Historically, future bookings, either via auction or confirmed through the connections processes, gave the network operator advance notice of potential network constraints, and were used in the development of network expansion plans.

While, this is no longer the case for methane, as network usage has levelled off following the Dash for Gas seen post privatisation, in early hydrogen networks we expect forecasts to play a key role in future network planning as will capacity bookings once the market evolves to that stage.

Capacity Methodology Statements:

Entry Capacity Release

- To determine the amount of Firm and Interruptible NTS Entry Capacity to be released to meet obligations under the Licence and Uniform Network Code (UNC). Applies to all entry capacity including Non-incremental, Incremental and Obligated capacity.
  - Defines conditions for accepting applications for incremental entry capacity.
  - Outlines financial commitments required from shippers.
  - Ensures efficient and economic development of the NTS.
- Capacity is released based on shipper demand and when considering new connections, investment lead times, including accelerated release incentives and economic tests using transportation models to derive step prices.

Exit Capacity Release

- To determine the amount of Exit Capacity to be released to meet obligations under the Licence and UNC. Covers both existing and incremental exit capacity.
  - Details commitments required from shippers and DN users.
  - Supports long-term allocation of exit capacity.
  - Ensures compliance with regulatory requirements.
  - Includes mechanisms for buy-back and flexibility.

Entry Capacity Substitution

- To substitute unsold entry capacity from one Aggregated System Entry Point (ASEP) to another where incremental capacity is demanded. Applies to long-term capacity released via QSEC auctions or PARCA/IP PARCA.
  - Minimises the need for new investment by reallocating existing capacity.
  - Ensures compatibility with physical system capabilities.
  - Facilitates competition among shippers.
- Network analysis enables identification of substitution opportunities. Includes capacity retainer mechanisms and refund processes. Defines donor and recipient ASEP selection criteria.

Exit Capacity Substitution & Revision

- To substitute or revise exit capacity in response to demand or infrastructure changes. Covers substitution of unsold exit capacity and revision due to entry capacity releases.
  - Promotes efficient use of network assets.
  - Avoids unnecessary investment.
  - Supports competition and regulatory compliance.
- Defines substitution from donor to recipient exit points. Includes revision of baseline capacities based on network analysis and process flow to determine eligibility.

Entry Capacity Transfer & Trade

- To facilitate the transfer of unsold and trade of sold entry capacity between ASEPs. Applies to monthly capacity auctions and short-term reallocations.
  - Ensures efficient and economic use of the NTS.
  - Avoids material increases in constraint management costs.
  - Supports competition among shippers.
- Uses exchange rates to reassign capacity. Includes modelling and analysis of network scenarios. Supports reallocation of capacity in constrained periods.

Interactions with the Hydrogen Business Models

Purchase of Gas

Under the guidelines set out by the Hydrogen Production Business Model (HPBM), Offtakers are only able to contract with a single producer for their hydrogen needs. Under these regulations there is no market for the resale of hydrogen.

The HPBM acts as an agreement between producer and end user and will, for the first 15 years of operation, be the sole route for network users to buy and sell hydrogen.

As new producers and offtakers come online, their pathway to hydrogen regulation will need to be understood. Successful applicants via the HPBM process and Hydrogen Allocation Round (HAR) applications will be subject to the HBM rules. If there is a viable route to connection via Network Operators, this would bypass the Hydrogen Business Models, the associated regulations and subsidies, but would still require the network user to abide by the Hydrogen Uniform Network Code (HUNC) as well as requiring them to source volumes of hydrogen outside of the HPBM process, potentially via a spot market. This would require an auction or sale platform to be in place.

Licence Obligations

It is expected that the Licencing structure used for methane and the NTS will be replicated in Hydrogen, and so a Regulator will devise a set of obligations to be placed on TSOs that will ensure their network can transport hydrogen from Producers to Offtakers safely and efficiently.

The existing licence obligations are extensive and require methodology statements to turn those objectives into real world processes for the TSO to follow and be held accountable against.

There is a question mark over who will produce these in future as multiple, disparate, networks are developed. Would each network operator produce their own methodology statements based on individual Licence obligations, or will there be enough consistency across Licence Conditions so that a single set of methodology statements would work for all discrete networks. In that instance, is a collaborative approach across Hydrogen Network Operators the preferred option?

Day-One Operation

From Day-One and during the first 15 years of operation, HTBM provides successful HAR applicants with the "Ticket-to-Ride", i.e. the right to flow gas through the hydrogen network. As those agreements expire, we expect users will migrate to a centralised set of cross-network rules set out in the HUNC and associated Network Entry/Exit Agreements.

Capacity Release

Given that the sale of hydrogen is so tightly controlled by the Hydrogen Production Business Model (HPBM), and the network will have been constructed to ensure that all expected Day-One flow can be accommodated, it is unlikely that network availability will be constrained during this period, even if supply and demand peaks for all network Entry and Exit Points simultaneously.

If the HTBM agreements are set and managed in accordance with Network Capability there will be no significant need for a capacity market on Day-One.

The HPBM agreements between Producers and Offtakers give us an idea of the expected volumes, the expectation is that the network will be built to accommodate these levels as a minimum.

Introduction

Assumptions

Proposals

Section 1
Capacity

Section 2
Balancing

Section 3
Charging

Section 4
Neutrality

Section 5
Connections

Section 6
Appendix

Capacity Auctions

As no network constraints are expected early in the lifecycle of the networks, due to the level of inbuilt capability vs. hydrogen supply and demand, there will be no real need to compete for and secure firm capacity in the short to medium term. If the expected level of network space is available and provides flexibility based on user projections when compared against physical network capabilities, auctions would not provide any real benefit and instead would be an expensive and time-consuming addition to the framework on Day-One.

Long term we support the development of an auction platform; it may be prudent to begin to offer long term capacity ahead of, but effective from, Day-Two, during a transitional period as the Hydrogen Business Model agreements come towards their expected end date.

Transfer & Trade

Under the current rules, the sale of hydrogen outside of the HPBM agreement will be minimal if not zero. The restriction on intermediaries means hydrogen is unlikely to move between parties post the purchase defined in the initial agreement, it is not expected that there would be need for network capacity to be moved, and so a Transfer and Trade or Assignment equivalent for Day-One of operation is also unnecessary. Should the HPBM rules evolve, this may become a requirement prior to Day-Two, but current expectation is that this will be developed after the initial HUNC in preparation for the migration from HPBM agreements.

Substitution

The hope would be, that the financial tests and the project validation carried out throughout the HPBM, HTBM, HSBM, H2PBM and HAR processes mean it is highly unlikely that a site will disconnect from the network prior to Day-Two.

However, some mechanism would be required to correct for the potential for site closure which minimises the impact on other network users.

Overruns

Currently, users of the NTS are able to flow above their booked Capacity level, this undermines the ticket-to-ride principle and comes with additional risks to network resilience and so penal charges are raised at either three or six times the original capacity bookings, dependant on whether the overrun occurs at Entry or Exit, and are calculated based on the amount by which flow exceeds booking.

Network Planning

In lieu of capacity auction data, site technical details and usage profiles, including details of the expected volumes, peaks, troughs, flow rates etc. described in HPBM arrangements should be shared with the network operator via the Hydrogen Data Portal. Commercially sensitive details such as price can be redacted if they don't influence flow expectations.

Advanced user forecasts will be required to ensure the network is technically capable of supporting the expected connection, with the ability for users to update forward looking as they better understand the physical operation of their sites. Day ahead Hydrogen Flow Notifications (HyFN) submitted for both Entry and Exit via the Hydrogen Data Portal will allow the Network Operator the ability to monitor and manage any potential supply constraints and assist with planning of network maintenance windows.

Future HPBM applications effectively fill the gaps in long term signals which would be lost by the lack of a PARCA regime for Day-One, however, we will explore evolution or replacement of the PARCA process for future new connections in the Connections chapter.

NESOs long term planning reports (RESP, SSEP & CSNP), will also provide some guidance on potential network expansion, though DESNZ have made clear that through the HT&SBM application process, they will prioritise projects which may not fall within the expectations of the NESO planning reports, if those projects are well developed and show a clear use case for hydrogen.

Network Constraint Management

While it is not anticipated that there would be network constraints early in the lifetime of the network, a Constraint Management process should be in place to ensure preparedness for all eventualities, meaning that a process is available when future development on the network means constraints do became a more significant possibility.

We expect that production will peak during periods of high renewable generation and proactive management of those periods of increased flows within agreed levels will benefit the electricity network, reducing the level of curtailment costs incurred when forced to turn down renewable electricity generation.

The appropriate portions of Sections I (Entry) & J (Exit) of the UNC, which detail the Entry and Exit Requirements, could potentially be transposed and modified for use in the HUNC from Day-One, providing a backstop in the unlikely event that a network constraint occurs, while other areas are developed in more depth, with a view to reviewing and modifying those arrangements prior to implementation of HUNC v2.0 on Day-Two.

Supply or Demand Constraints are to be managed via operational applicable to the Capacity Regime.

Proposals

Con Max

In lieu of Capacity bookings, we propose a Contractual Maximum Volumetric Flow (CMVF or "Con Max") to be calculated based on a range of inputs taking precedent from other tools commonly used across the industry:

- Forecast Contracted Capacity (FCC[11])
- Practical Maximum Physical Capacity (PMPC[12])
- Electricity Maximum Import Capacity (MIC[13])

Taking elements of these existing methodologies and revising them for use in Hydrogen, we can create a process to generate a Con Max figure.

Initially we would expect HAR applicants to submit flow profiles to a central Hydrogen Data Hub, which we would combine with:

- Network Technical Capability
- Site Technical Capability
- Connection Point Technical Capability
- Max Flow
- Apportionment of Network Capability based on Site Capabilities

From this we can validate Con Max values for each Entry and Exit point to ensure there are no constraints preventing the connection of the site and agree values with the connectee. This figure which will form a part of their Network Entry or Exit Agreements and set an upper limit for flow on to or off the network.

Overtime, as more usage data becomes available, this can also be incorporated into the forecasting process for Con Max, using as much relevant information as we have available, ensures the best view.

Maximum Import Capacity

- MIC also known as ASC (Authorised or Available Supply Capacity) is the maximum amount of electricity that a site is permitted to draw from the network at any given time. It is agreed between an offtake and its Network Operator based resulting in a monthly minimum charge with penalties applied for exceeding that level.

Practical Maximum Physical Capacity

- The process used to determine baselines at NTS Exit Points; set lower than the maximum technical capacity but calculated as a reasonable level of guaranteed capacity when accounting for network wide factors and predictable external influences.

Forecast Contracted Capacity

- The FCC uses historical flow and booking, along with future commitments to estimate an expected total booking level. This is done monthly by site level and aggregated up for use in price setting.

The Apportionment of Network Capability would change with each additional connection or with adjustments to the capability of existing sites, and so a process to review this figure and its impact on Con Max, potentially annually, but certainly at each new connection, would be required to ensure Con Max figures remain reflective. This ensures the Network can continue to support

[11] Forecasted Contracted Capacity (FCC) Methodology v3.1.pdf

[12] TPC 2023 v0.4.pdf

[13] National Grid - Capacity change

approved levels, particularly as sites expand or new connections come online. Where calculations indicate a potential for network usage to exceed technical capability, this should trigger a process to review the network size and the potential need for reinforcement, but it would also trigger an early stage commercial opportunity as the existing holders of the Con Max could be given the opportunity to Reallocate a portion of their network space to an incoming user, reducing their own costs, without impacting the rates paid by other network users.

As a result, we would suggest that, unlike baselines for methane, these figures are not initially added to The Licence, but are maintained elsewhere, until Day-Two and the introduction of a HUNC as the primary rule set for the network at which point Con Max levels would be transposed, with User agreement, into the Licence as a Baseline equivalent.

We do however expect that The Licence would generate an obligation to ensure the agreed Con Max level is made available whenever possible, i.e. outside of maintenance windows, network constraints or force majeure.

We would also expect that the Con Max level will remain, at or above, the value agreed in Year 1 for the first 15 years post Commercial Operation Date (COD) in line with the HPBM period, except in instances where Con Max has been Reallocated, with a review expected in preparation for Day-Two operations and the migration to HUNC as the primary set of network rules.

Reallocation

We propose a new methodology which allows for users to give up Con Max to another user, via a process similar to Assignment.

The Reallocation process would be offered when users are looking to disconnect or decommission their sites, some or all the existing Con Max agreement would have to be matched to an incoming or expanding user to be Reallocated.

Should no matching partner be found, the original holder would retain liability for the costs associated with their agreed Con Max, and where a recipient is matched with a donor, liability will be reassigned to the new party to ensure costs are borne by the relevant party and the overall Con Max figure is retained, meaning prices would still be relevant and revenues still recovered.

Over time, should the HPBM rules be relaxed, the Reallocation process could be expanded and used to match unused portions of Con Max with network users wishing to exceed their agreed Con Max without penalty, like a temporary assignment of capacity. This could be released daily via a methodology similar to interruptible capacity.

Overruns

In the early days of the network, where Apportioned Network Capability is unlikely to the be the limiting factor when agreeing a Con Max value, Con Max will be set at a level close to, if not matched with, the peak of a site's capability. Exceeding Con Max is likely to result in a significant safety issue rather than a manageable overrun situation as some element of the local infrastructure, the peak capability of which helped to define Con Max, has exceeded tolerance, and so we would look to explore alternate options when looking to incentivise accuracy in flow vs forecast. We explore this further in the section on Balancing Neutrality Charging later in this document.

Introduction
Assumptions
Proposals
Section 1
Capacity
Section 2
Balancing
Section 3
Charging
Section 4
Neutrality
Section 5
Connections
Section 6
Appendix

How can Con Max help guarantee Revenue Recovery?

Allowed Revenue (adjusted for any temporal cost sharing or revenue profiling) to be divided by Aggregated Con Max figures to calculate a pence per unit rate

Expectation that the calculated Rate will be overwritten by a government directed price cap to ensure it is competitive vs natural gas

Adjusted Rate multiplied by Con Max per site per month should align with the TO Allowed Revenue

The capped rate multiplied by Con Max per site per month creates a monthly invoice value for users, but also a forecast for Revenue Recovery which enables HMG to forecast under recovery and therefore the Revenue Support Allowance

Period where “Con Max” can be uplifted but not downgraded ensuring a minimum revenue recovered

Day-Two Summary

We expect that a Capacity Regime would be required for Day-Two. There is, therefore, a need to have alternative arrangements in place from that point in time, with enough notice to enable network users to adapt systems and processes.

A Capacity Release Methodology, including details of Capacity Auctions, Transfer & Trade processes, a decision on whether there is need for the ability to Assign Capacity either at Entry and/or Exit and a process to deal with disconnections, new connections, substitution etc. may all be necessary.

Given the potential step up in complexity and the likelihood that the Hydrogen Market could attract participants not currently engaged with the methane market, a runway period may also prove beneficial. Opening a capacity market ahead of Day-Two and providing for mock auctions or an allowance of reserved capacity for the first few years of operation post Day-Two would give network users time to get comfortable with the more open market, following on from up to 15 years of guaranteed availability.

A Modification will need to be raised at that time to implement the new, Capacity Regime and enable the direct replacement of Con Max in the Tariff setting process, New Connections Agreements and any other sections of HUNC v1.0 which reference Contractual Maximum Volumetric Flow.

A market based Capacity Regime is not required for Day-One, but due to the current complexity of the methane Capacity regime, time should be taken as early as possible to fully review and simplify the processes for a hydrogen market, introducing consistency across Entry and Exit, automating auction processes and streamlining as much as possible prior to Day-Two implementation.

Conclusion

The right to access the network is managed via the Hydrogen Business Models for Day-One, and we expect the market for hydrogen to be illiquid at this point in development.

We therefore propose a stripped-down regime, based on Con Max, to replace the existing Capacity Regime for Day-One of network operation. This would remain in place for, at least, the first fifteen years of operation, with the expectation that all Users will migrate to the HUNC and a more recognisable Capacity Regime post Day-Two.

Con Max provides for a basis which is compatible with a market based Capacity based regime and while this document discusses the way in which Con Max would support Access, Balancing and Charging, each of these could easily be adjusted prior to Day-Two, or even earlier should industry consensus be to implement a more traditionally recognisable Capacity booking based framework, allowing for the option of a phased transition rather than a hard stop and reset.

Introduction
Assumptions
Proposals
Section 1
Capacity
Section 2
Balancing
Section 3
Charging
Section 4
Neutrality
Section 5
Connections
Section 6
Appendix

2. Balancing

Introduction

We don't intend to revisit the works previously completed by the Hydrogen Delivery Council: Transport & Storage sub-group on Market Frameworks but we have built on the work completed in those sessions, the outputs of which are available to view via the website of the UESO[14].

Primary and Residual balancing

The expectation is that Producers will hold the responsibility of Primary Balancers by default, with the option for those offtakers, with the desire to manage their own portfolio, to also take on the role of a Primary Balancer. These parties will be issued with Shipper Licences to enable them to contract with a TSO who will hold the Residual Balancing responsibility.

Proposals

Hydrogen Flow Notifications (HyFN)

Hydrogen Flow Notifications, are expected to be sent daily, detailing 30-minute intervals for the full or remaining balancing periods within the applicable Hydrogen Day. Primary Balancers would be required to submit notifications which are in balance across both Entry and Exit, i.e. where expected production outstrips demand, we would expect there to be a clear indication of when the excess hydrogen will be sent, likely to storage, and where the situation is reversed, notifications of withdrawal from storage would be expected to balance in the aggregate.

Notifying the SO of flows that are in balance reduces the likelihood of the Residual Balancer needing to act, and those balanced notifications make it possible to compare actual flow to notifications and identify where Users are not acting in line with prescribed rules. This allows the SO to target both instruction and relevant charges and incentives to the correct Primary Balancing entity.

It is expected that the Hydrogen Hub, into which HyFNs will be submitted, would have the ability to automatically assess the validity of the notification and issue a rejection where submitted flows are not balanced, or do not provide the expected information. It is also expected that where a Primary Balancer is acting on behalf of a non-balancing party, i.e. an offtaker who has deferred their balancing responsibilities back to their HPBM linked producer, the offtaker will receive a notice enabling them to query, or ascent by default, to the submitted flow notification.

Any unidentified imbalances, shrinkage for example, will be resolved by Residual Balancing actions and costs associated with these actions will be socialised via a Balancing Neutrality arrangement.

Balancing Periods

A minimum 2-hour balancing period would be required based on the initial analysis undertaken for Project Union East Coast using the forecasts provided to us by potential connectees. It should be understood that this will vary massively network by network but is primarily a function of the size of the network when compared to the size of the largest user and/or producer. The 2-hour period in this instance provides an operational linepack range which also allows for a controlled rundown of the network should the largest producer or offtaker cease activity.

Note: No Nominations would be required under this proposal. Notifications would be the only method of updating flow expectations and would be the basis for any balancing related charges incurred.

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[14] HDC Sub-Group Report on Hydrogen Market Frameworks for Initial Hydrogen Networks - Aug 2025.pdf

3. Charging

Introduction

Under RIIO-3, National Gas Transmission (NGT) operates in two regulated roles. As the Transmission Owner (TO), NGT is responsible for maintaining and upgrading the physical gas transmission network. As the System Operator (SO), it ensures the real-time balance of gas supply and demand across the system and the ongoing safe and efficient operation of the NTS.

Revenue streams

The Licence separates the NGT business into Transmission Owner and System Operator, this approach has been a long-established element of the NGT charging regime and a version of this structure is something we would want to see carried forward into the hydrogen market. Maintaining the split provides several benefits:

- Greater flexibility for the owner/operator;
- Better reflects the differing costs and drivers of the TO and SO functions;
- Supports a smoother pathway to a potential future single TSO model; and
- Ensure transparency for network users.

Revenues are recovered via two distinct and independently managed streams as set out in UNC:

Transmission Services Charges (TS)

These charges recover the costs of maintaining and investing in the physical gas transmission network. This covers infrastructure such as pipelines, valves and pressure reduction stations, along with capital investment in network upgrades, depreciation and business support functions related to asset management. The costs are recovered from gas shippers and distribution networks through a capacity-based charge, which are split between entry and exit points.

General Non-Transmission Services Charges (GNTS)

GNTS covers the operational costs of running the system, including costs for compressor fuel and maintenance, system balancing, shrinkage gas (to account for losses), operational control systems, customer interface functions and incentives. They are primarily flow-based and paid by gas shippers. GNTS Rates are published in July and take effect from October.

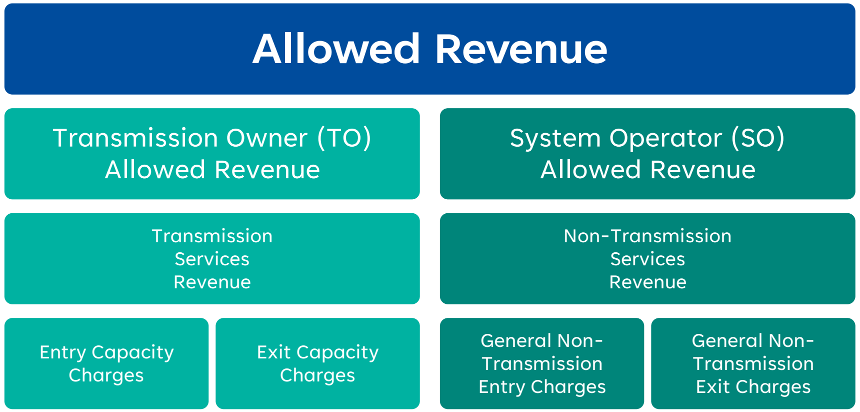
This split aligns with the requirements of the EU Tariff Network Code, and while they broadly align, it does mean adjustments need to be made between the TO/SO split defined in The Licence.

At present, both revenue streams are reviewed annually through the Price Control Financial Model (PCFM), which is published each December, though this can be re-published as part of an annual iteration process up until rates are set in May for the following October. The regulatory year runs from April to March, whereas the charging year runs from October to September. This six-month offset has existed since the creation of the modern GB gas market and Network Code arrangements.

TO revenue is recovered through capacity-based charges at entry and exit points on the network. If there is an over or under-recovery in a given year, a correction mechanism known as Kt is applied in the following year, with adjustments made separately for entry and exit charges. Similarly, SO revenue, by contrast, is recovered through commodity-based charges based on the volume of gas transported. Any discrepancy between forecast and actual revenue is corrected using a separate adjustment called SOKt.

Introduction
Assumptions
Proposals
Section 1 Capacity
Section 2 Balancing
Section 3 Charging
Section 4 Neutrality
Section 5 Connections
Section 6 Appendix

Make up of Allowed Revenue



Looking ahead to a future hydrogen charging framework, we would propose alignment of the regulatory and charging years, while maintaining the separation of TO and SO revenue recovery. Doing so would simplify processes, reduce complexity for stakeholders and better link revenue setting with charge recovery. This alignment would preserve the transparency and flexibility of the existing split between TO and SO revenues while making the regime more efficient and easier to navigate.

Methane Regulatory Framework

Charging methodology

NGT sets its charges using a top-down approach. This means that the allowed revenues for both TO and SO functions are divided by forecasted usage volumes to determine unit prices. Further steps are currently in place to realign the revenues with Transmission Services and General Non-Transmission Services as stipulated in the EU TAR NC. The methodology and application of these charges are governed by the Uniform Network Code (UNC), specifically Section Y for methodology and Section B for application as well as retained EU Law, as transposed into UK Law by the Brexit Agreement.

Forecasting and Denominators in Charge Calculation

To accurately set transmission charges, National Gas Transmission (NGT) must first estimate how Shippers will interact with the network in the upcoming year. This involves forecasting two key metrics:

1. **Forecast Contracted Capacity**[15] – These are forecasts of how much capacity users will reserve at entry and exit points on the National Transmission System (NTS). Capacity is measured in kilowatt-hours per day (kWh/day) and is used to calculate Transmission Owner (TO) charges.
2. **Gas Throughput Volumes** – This refers to the total volume of gas expected to flow through the system, measured in kilowatt-hours (kWh). It is used to calculate System Operator (SO) charges, which are typically volume-based.

At a high level, these forecasts serve as denominators in the charge-setting formula. The total allowed revenue, set by Ofgem, is divided by the forecasted capacity or volume to determine a unit rate. This ensures that the charges applied to users will collectively recover the full amount of revenue that NGT is permitted to collect.

There are additional complexities around forecasting across multiple Gas Years as they are not aligned with the Financial Year, meaning a period of 18 months is now used to calculate the rate over 12 months following the implementation of UNC0796[16], and temporal adjustments can be made or requested by either HMG or NGT to try and balance the charges and avoid the see-saw effect seen historically.

[15] Forecasted Contracted Capacity (FCC) Methodology v4.0.pdf

[16] UNC0796 - Revision to the Determination of National Grid NTS Target Revenue for Transportation Charging

This approach ensures that the charging system is both fair and financially balanced. If actual usage differs from forecasts, adjustments are made in the following year to correct for any over or under-recovery, maintaining alignment with regulatory expectations, this is done via the "k" or "SOk" elements of the Allowed Revenue.

A full break down of the allowed revenues is published by Ofgem in the Price Control Financial Model, and the calculated rates are published annually, along with indicative rates up to five years ahead on the National Gas website[17].

Postage Stamp Charging Regime

The Postage Stamp Charging Regime[18], introduced on 1 October 2020, is a simplified method for setting gas transmission charges in the UK. It was designed to align with the EU Tariff Network Code[19], which requires that charges be transparent, cost-reflective, and non-discriminatory.

Under this regime, all users of the National Transmission System (NTS) pay a uniform unit rate for capacity at Entry and a uniform rate at Exit, regardless of their location on the network. Similar to how a postage stamp works, everyone pays the same price to send a letter within Great Britain, no matter how far it travels. The aim is to remove locational pricing complexities and make the system more accessible and predictable for market participants.

This regime replaced the previous location pricing model, where charges varied according to a user's position on the network and the associated cost of transporting gas. While more cost-reflective, the locational model was more complex, required detailed knowledge of the network to enable Shippers to validate the calculated rates and added administrative burden for Shippers.

The Postage Stamp Regime is now embedded in UNC and offers several benefits:

- **Simplicity**: Easier for users to understand and forecast costs.
- **Transparency**: Charges are clearly defined and uniformly applied.
- **Market facilitation**: Encourages competition by removing regional cost disparities.

For the hydrogen market we would want to mirror this Postage Stamp approach. The same benefits (simplicity, transparency and facilitation of market entry) are especially valuable in a developing market where ease of access and predictability will encourage investment and participation.

That said, there are some trade-offs to be mindful of:

- A uniform charge does not incentivise connections at physically efficient locations, which could affect long-term network efficiency. However, this is something that a charge similar to short haul[20] could overcome; and
- It introduces an element of cross-subsidy, as some users may pay more, or less, relative to the actual cost of their location.

Overall, while the postage stamp model may not be perfectly cost-reflective, it strikes the right balance for a nascent hydrogen market by keeping the regime straightforward, transparent and accessible, helping to build early confidence and participation.

[17] Charging | National Gas

[18] (Urgent) - Amendments to Gas Transmission Charging Regime | Joint Office of Gas Transporters - Gas Governance

[19] Tariff NC | ENTSOG

[20] (Urgent) Introduction of a Conditional Discount for Avoiding Inefficient Bypass of the NTS | Joint Office of Gas Transporters - Gas Governance

Benefits for gas suppliers

The Postage Stamp Regime offers several advantages for gas suppliers. It simplifies cost forecasting and reduces administrative burden, as shippers no longer need to account for locational differences in charges. The uniform pricing structure enhances market accessibility and supports competition by creating a level playing field. Additionally, the transparency of the regime fosters greater confidence in the regulatory framework.

Where locational elements are deemed appropriate, they can be introduced and managed through a range of discount options available to the Transporter, for example, the ability to discount Storage, use Seasonal Multipliers or Short haul [21] discounts (Conditional NTS Capacity Charge Discount, CNCCD), all of which are currently allowable under retained EU Law.

Capacity Weighted Distance (CWD) regime

The Capacity Weighted Distance (CWD) regime is an alternate charging methodology allowable under the EU TAR NC, retained in GB Law, where transmission tariffs are determined by two key factors:

1. The amount of capacity booked; and
2. The distance the gas must travel across the network to reach its destination.

This approach is designed to be cost-reflective as users who transport larger volumes over longer distances contribute proportionally more to the costs of operations and maintaining the network. It was a core feature of the EU's tariff Network Code and is used in several European markets to ensure locational price signals are clear and efficient.

The benefits of the CWD regime include:

- **Cost-reflectivity** – users pay charges aligned with their actual network use;
- **Efficient locational signals** – encourages connections closer to demand or supply centres, potentially reducing system costs; and
- **Fairness** – reduces cross-subsidisation between network users.

However, there are clear trade-offs. CWD requires more detailed modelling of network distances, capacity flows and costs; therefore, making it more complex and difficult for Shippers to forecast charges. Additionally, there is an administrative burden due to the regime being more resource intensive to implement and maintain.

Implications for the hydrogen market

In the early years of a UK hydrogen network, the CWD regime would not be required. Early hydrogen networks are expected to be regional and cluster-based, with relatively short transportation distances between production and demand centres. As such, the benefits of distance-based charging would be minimal while the complexity and administrative efforts of implementing CWD could act as a barrier to market entry.

By contrast the postage stamp regime offers a simpler and more transparent way of charging in the early hydrogen market, supporting participation and providing market facilitation at a time when the priority is encouraging uptake rather than fine-tuning locational efficiency.

In the longer term, however, as hydrogen networks expand into larger, interconnected systems with greater transport distances and more diverse connection points, the CWD approach may become a

[21] (Urgent) Introduction of a Conditional Discount for Avoiding Inefficient Bypass of the NTS | Joint Office of Gas Transporters - Gas Governance

more relevant discussion point. It could provide stronger locational signals, help optimise network usage and better reflect the true costs of transporting hydrogen across the system.

Hydrogen Charging Options

As we prepare to operate Project Union East coast, the charging regime would likely undergo significant changes to reflect the unique physical, economic, and regulatory characteristics of hydrogen as a fuel. The core objectives in the development of this regime are to ensure simplicity in the market, with accuracy and transparency in forecasting paramount to enable stakeholders to plan with confidence. In addition, the regime will be designed to align with the government's Hydrogen Transportation Business Model (HTBM), promote efficient use of the network, encourage system balancing and avoid the need for capacity auctions. It will further uphold the principle of neutrality, ensuring compliance and alignment with existing licence conditions by remaining non-discriminatory and treating all users fairly, regardless of size, location or production profile.

Based on current research, pilot projects, and strategic planning, here's how the charging regime could evolve:

Fundamental Shift in Cost Base

The current charging methodology is built around the physical and operational characteristics of natural gas. Hydrogen, however, has different properties, such as lower energy density, higher diffusivity, and different safety requirements, which could necessitate infrastructure upgrades. which may include pipeline replacement or retrofitting, new compression technologies, and hydrogen-compatible metering systems.

As a result, the Transmission Owner (TO) Allowed Revenue would increase significantly to reflect these capital investments, increasing the rates in relation to volumes. The System Operator (SO) Allowed Revenue would also change, as hydrogen will require different balancing strategies and operational controls. These changes would need to be reflected in the HTBM and ultimately in the unit charges.

Redefining Forecasting and Denominators

Currently, charges are calculated by dividing allowed revenue by forecasted capacity bookings (for TO charges) and gas throughput volumes (for SO charges). These forecasts are based on the energy content of natural gas, measured in kilowatt-hours (kWh).

Hydrogen delivers less energy per unit volume than methane, so the same physical volume of gas would result in fewer kWh. This means that physical volumes are likely to increase significantly. Maintaining a denominator which uses energy in the unit rate calculation, rather than volume, would avoid inadvertently inflating p/unit charges. Forecasting models would need to be revalidated to ensure that hydrogen-specific energy density and demand patterns don't impact calculations and the models remain reflective of energy usage.

Revising Revenue Recovery Types and Structures

In a hydrogen-only system, existing charge types, designed around the properties and market dynamics of methane, would need to be restructured to reflect the technical, commercial, and regulatory realities of hydrogen transport. A breakdown of how each major charge type could evolve is as follows:

Transmission Owner Charges (TO)

In the current regime, capacity charges are based on users booking rights to flow gas at specific entry and exit points, measured in kWh/day. For hydrogen, there are a few options where this model could still apply or, with important modifications, be redeveloped and simplified:

- **Hydrogen-specific charging zones** could be introduced to reflect the location of production hubs, industrial clusters and storage facilities. While this may provide stronger locational signals, it would be too complex for the early stages of market development and risks creating barriers to entry. Instead, in the near term we would look to offer discounted short haul charges for hydrogen moving within the same cluster, supporting local flows and early regional uptake without adding unnecessary complexity.

- **Dynamic pricing** could be introduced to reflect the variable availability of hydrogen, especially in systems reliant on intermittent renewable electricity for green hydrogen production. This, however, is something we would develop and seek to implement at a more mature stage in the market as is would be too complex for Day-One.

It is important to note from the outset that we do not see the capacity regime existing in the same format that we currently have for methane. Therefore, in the early stages of the hydrogen network we will need to consider alternatives, such as:

- **Flow-based charging** could provide an option whereby charging users based on actual volumes transported rather than reserved capacity. The key advantage of this model is that it would not discourage intermittent or variable users, such as green producers or seasonal consumers, thereby promoting broader market participation. However, it is important to note that this would offer less certainty around network utilisation, which would impact long-term infrastructure planning and investment signals.
- **Technical Capability** could be an alternative approach where users are charged according to the highest flow rate, rather than their actual day-to-day usage. This model would encourage efficient use of the network by incentivising users to develop flow capability, while also improving predictability of revenues and charges for both users and the network operator.

These approaches would likely require more complex connection agreements. For example, users would need to enter into contracts specifying their site and metering capabilities to enable calculation of their maximum volumetric flow entitlement, and code will need to highlight the penalties for breaching agreed limits. Additional provisions could be required around:

- **Overrun charges** – for hydrogen this will mean clear mechanisms for how users are charged if they exceed their contracted maximum flow, differing from current overrun arrangements where users flow in excess of their booked capacity
- **Flexibility clauses** – options to adjust maximum flow levels within agreed parameters, with notice periods to ensure price setting isn't impacted, or amendment fees
- **Seasonal or profile-based agreements** – tailored terms for users with variable or intermittent flows, such as green hydrogen producers, allowing them to align contracted levels more closely with production cycles; and
- **Max flow trading or transfer mechanisms** – enabling users to trade unused portions of their maximum flow rights with others to avoid stranded costs.

While these measures would provide structure and predictability, they could also disadvantage producers or consumers with less stable profiles. A phased implementation, accompanied by periodic reviews, would therefore be necessary to maintain flexibility and fairness as the hydrogen market develops.

- **Hybrid hydrogen charging model** is an alternative option, combining a fixed charge based on the user's maximum contracted connection capability with a variable charge linked to actual hydrogen flow. This approach offers a balance between predictable revenue and efficient network utilisation, while also providing flexibility for users with variable or intermittent demand, such as green hydrogen producers. It aligns with principles from the flow-based charging model, but it introduces greater complexity in billing and contract structures and may still pose challenges for users with highly unpredictable flows. Again, a phased implementation, supported by stakeholder engagement and regular review, would be required to ensure fairness, adaptability, and operational feasibility as well as further engagement with stakeholders on which option would work best for them in the long term should implementation take place from Day-One.

System Operator Charges (SO)

Commodity charges are currently levied based on the volume of gas transported. We support maintaining a commodity charge for hydrogen however, in a future system, these charges would need to account for:

- Lower calorific value[22].: Hydrogen contains less energy per unit volume than methane, so transporting the same energy requires more physical volume. This could lead to recalibrated unit rates or a shift to charging based on mass (kg) or energy content (MJ or kWh).
- Energy equivalence adjustments: To ensure fairness, commodity charges might be normalised to reflect the energy delivered rather than the volume transported.
- Short haul transportation: In the early stages of the network could be discounted tariffs for short distance flows to reflect the lower network costs but primarily to incentivise local production and support early regional clusters. This would also avoid unduly cross-subsidising long-distance users.

[22] It is important to note that we would seek to develop charges based on assumed CV, as we would not expect there to be significant variation across the network. This would also simplify calculations.

Introduction
Assumptions
Proposals
Section 1
Capacity
Section 2
Balancing
Section 3
Charging
Section 4
Neutrality
Section 5
Connections
Section 6
Appendix

Conclusion

The development of a 100% hydrogen network requires an evolution of charging that preserves the clarity and transparency of the existing RIIO framework while recognising hydrogen's distinct technical and market characteristics.

We agree with the work carried out in the HDC sub-groups, that the split between TO and SO revenue remains the right foundation for transparency and accountability.

Aligning the regulatory and charging years will further simplify processes and strengthen the link between revenue setting and recovery.

For the formative years of the hydrogen market, a simple, non-discriminatory postage-stamp approach, mirroring today's gas regime, with prices and charges based on Con Max rather than Capacity bookings, offers the best balance of predictability, accessibility and market facilitation.

While a flow-based model (charging on actual volumes) would provide inclusivity for intermittent producers, it weakens revenue certainty. A maximum-flow charge improves predictability and investment signals, it does necessitate more complex agreements (overruns, flexibility bands, profile terms and trading of headroom) but is the better option overall provided it is phased in with clear guardrails and reviewed regularly.

Within this, there is the option for targeted short haul discounts to mitigate the lack of locational signals and support regional cluster development without embedding cross-subsidies.

Hydrogen storage will be fundamental to delivering net zero and energy security objectives, supporting the HTBM by enabling system balancing, resilience and efficient market operation. As the hydrogen market and network develop, storage will play a pivotal role in integrating intermittent production with variable demand, ensuring stability and reliability for consumers and industry alike. To recognise this strategic importance, charging arrangements for storage connections and flows should initially be discounted, at least on a par with the NTS, lowering barriers to entry and encouraging early utilisation of the network. Such incentives would help stimulate market liquidity and ensure storage is embedded as a core component of the hydrogen system from the outset. NGT would support a discount for storage from Day One, with regular policy reviews, which would then enable a smooth transition towards cost-reflective charging as the market expands and matures.

As the system scales, capacity arrangements should evolve pragmatically.

In parallel, commodity (SO) charges should be retained and recalibrated for hydrogen's lower calorific value, using assumed CV/energy equivalence adjustments to keep billing straightforward and fair.

Taken together, the recommended path, at this stage, is a phased approach to framework implementation: start simple, with a postage stamp charge based on the Con Max values with storage discounts along with a calibrated commodity charge. This will be followed by the introduction of more cost-reflective elements under a transparent roadmap with periodic reviews, as the market matures.

This approach upholds neutrality and transparency, aligns with licence obligations and HTBM objectives, supports early investment and market entry and creates a controlled glide path to long-term efficiency as the hydrogen network expands and matures.

4. Balancing & Neutrality

Introduction

In a nascent hydrogen network, the neutrality and balancing regime must evolve from a structure built around methane's inherent flexibility to one capable of operating safely under much tighter physical and commercial constraints. Hydrogen networks will feature significantly reduced linepack flexibility, narrower pressure tolerances, more clustered and less diversified supply–demand patterns, and, particularly in early phases, limited within-day liquidity and forecasting capability. Under these conditions, neutrality mechanisms cannot function primarily as end-of-day cost-recovery tools. Instead, they must operate as an integrated, layered system of operability controls that shape user behaviour throughout the gas day.

The existing balancing neutrality regime under the Uniform Network Code (UNC) provides a valuable structural reference point. Capacity overruns, scheduling charges, storage and revenue-neutrality mechanisms, and SMP Buy/Sell cash-out all target distinct behaviours and collectively discourage reliance on the System Operator (SO). However, hydrogen fundamentally changes how these tools interact. With far less ability to absorb deviations ex post, a hydrogen system must place much greater emphasis on ex ante discipline, within-day accuracy, and clear escalation when operational limits are approached or breached.

In Day-One hydrogen networks, the **Contracted Maximum Volumetric Flow (Con Max)** would reflect the expected upper range of flow under normal operating conditions, expected to be congruent with the Users technical capability at each connection point. Similar to the Maximum NTS Exit Point Offtake Rate (MNEPOR) used on the methane network, Con Max serves as both a commercial capacity reference and a guide to the system's physical operating envelope. Under typical circumstances, flows would not be expected to exceed this level. Where flows do go beyond Con Max, this may prompt closer operational review and, if required, targeted intervention, rather than being treated solely as a matter of financial settlement. This represents a shift from methane's capacity-based incentives and highlights the potential need for a more robust approach to upstream flow management.

Below Con Max, **Scheduling Charges** take on a more critical role as a within-day operability control. With limited hydrogen linepack, deviations from notifications must be corrected earlier and with tighter tolerances than in methane. Options include retaining gas-style tolerances, adopting hydrogen-specific narrower thresholds, or applying dynamic or location-based tolerances in response to system conditions.

As flexibility will be scarcer, storage and linepack mechanisms must also evolve. Unlike the methane regime, which does not price linepack, hydrogen may require dedicated, revenue neutral, charges to ensure that reliance on system-provided flexibility, such as a System Operator storage reserve, is transparent and cost-reflective. The distinction between residual balancing actions within normal linepack bands and constraint-driven actions taken when system limits are threatened is central to determining how costs should be socialised or targeted.

At end-of-day closeout, Imbalance Charges (SMP Buy and SMP Sell) are unlikely to form part of the Day-One hydrogen regime. If users are required to submit inherently balanced notifications and if deviations are already dealt with through scheduling charges and storage charges, the case for a separate imbalance cash-out mechanism materially weakens. In early hydrogen markets with limited liquidity, it is therefore likely to be simpler and more proportionate to remove SMP entirely. A more developed imbalance pricing framework may become relevant in later phases as the network grows, liquidity improves and the system gains more flexibility, but this should be seen as a future evolution rather than a day-one requirement.

Taken together, the charge types form a sequential and integrated operability framework. Con Max establishes the connection-based maximum flow and physical operating limit. Scheduling charges enforce accurate paired notifications and within-day discipline. Storage costs linked to residual balancing and more targeted operational actions, where a user's behaviour forces intervention, will be recovered through the neutrality charge. Any future closeout pricing mechanism, if introduced as the market matures, would sit only as a backstop rather than as a routine balancing tool.

Each layer is designed to reduce the likelihood of triggering the next, allowing the user to take control of their balancing actions and preventing over reliance on the SO as the default balancer of last resort; this supports safe and predictable operation in a physically constrained hydrogen system.

The overarching policy challenge is balancing system protection with market participation. A regime that is too permissive risks embedding SO dependency and cross-subsidy; one that is too punitive risks constraining early market development. A phased, transitional approach therefore offers the best route forward, retaining gas-aligned structures where appropriate, tightening controls where hydrogen risk is materially higher, and establishing clear triggers for progression toward market-led balancing as liquidity and operational data improve.

This section sets out design options for each element of this framework and describes how they interact in a hydrogen system. The objective is to support a neutrality regime that safeguards operability and safety from Day-One while enabling the gradual evolution toward a disciplined, efficient, and ultimately market-driven hydrogen balancing system.

Methane Regulatory Framework

The NTS is operated under a contractual framework (UNC) requiring users to:

1. Book capacity rights,
2. Nominate expected flows, and
3. Remain in balance within the gas day.

When users act outside expected parameters, National Gas applies charges that reflect the cost and risk imposed on the system. Each charge type targets a distinct behaviour:

Aspect	What they penalise	Focus	Purpose	Charging basis	UNC location
Capacity Overruns	Exceeding booked capacity	Contracted rights	Ensure adequate forward looking	Multipliers of capacity price	TPD Section B
Scheduling Charges	Deviating from nominated flows	Operational behaviour	Ensure accurate flow forecasting	Balancing cost methodology	Section F (Balancing)
Imbalance (SMP Buy & SMP Sell) Charges	Ending the gas day out of balance (short or long portfolio)	System wide balancing at day close	Ensure users internalise the true cost of balancing actions taken on their behalf	Cash-out prices determined by marginal SO balancing actions (SMP Buy = highest action; SMP Sell = lowest action)	Section F (Cash-Out Arrangements)

Design Objectives for Hydrogen

A future hydrogen transmission system is expected to operate under conditions that differ materially from today's methane system:

- Reduced linepack flexibility and tighter pressure tolerances.
- More clustered supply and demand, particularly in early phases.
- Limited liquidity and reliance on policy-supported revenues (e.g. HTBM).

Against this backdrop, the balancing regime must achieve four objectives:

1. Protect system operability and safety, particularly in early market phases.
2. Maintain cost causation and neutrality, avoiding cross-subsidy between users.
3. Provide clear behavioural incentives, discouraging reliance on the System Operator.
4. Support market evolution, allowing a transition from administered to market-led balancing.

How methane charge types currently interact

Charge type	Trigger	What it addresses	Storage impact
Capacity Overrun	Flow > booked capacity	Contractual discipline	✓
Scheduling Charges	Flow ≠ nomination	Operational predictability	✓
Storage Charges	Injection/withdrawal behaviour	Fair cost recovery	✓
Imbalance (SMP Buy/Sell) Charged	User ends day out of balance	System-wide balancing	✓

These mechanisms are complementary: they target different behaviours that could otherwise drive costs, inefficiency, or operational risk.

Implications for Users and National Gas

For Shippers and Storage Operators

- Must contract to a sufficiently high Contractual Maximum Volumetric Flow value, nominate accurately, and remain balanced.
- Overruns, scheduling deviations, and imbalance exposures could be significant if unmanaged.
- Active trading on the OCM and proactive within-day management minimise SMP exposure.

For National Gas

- Overrun and scheduling charges reinforce predictable flows.
- Storage charges ensure neutrality while recovering variable costs.
- SMP Buy/Sell ensures cost-reflective balancing and protects the system from disorderly user behaviour.

Implications for a hydrogen system

Taken together, the balancing charges form a coherent control framework rather than a set of isolated financial penalties. Each charge targets a different stage of user behaviour across balancing periods and the hydrogen day, and in combination they protect system operability, enforce cost causation, and limit reliance on the System Operator. In a hydrogen context, this interaction becomes even more critical, as reduced physical flexibility means that failures at one stage are far less likely to be absorbed elsewhere in the system.

Overrun Charges

Under the gas transmission capacity regime, the fundamental 'ticket to ride' principle requires shippers to acquire sufficient capacity rights to cover their gas flows on and off the NTS. This ensures that capacity is booked before gas is flowed, maintaining system integrity and fairness among users.

While both entry and exit capacity charges apply for booking and usage, they are applied differently in calculating the charges. NTS Entry overrun charges are applied to any user that flows more gas than the capacity they have booked, while exit overrun charges are applied to flows above the aggregate capacity booked at specific exit points. Negative overruns occur when users trade or transfer capacity beyond their holdings, creating both a negative Capacity holding and imbalances that require a charge by the System Operator.

Purpose

The purpose of Capacity Overrun Charges is threefold:

- **Promote disciplined capacity booking** by ensuring users nominate and secure sufficient capacity for their requirements.
- **Support network constraint management** by discouraging unplanned overruns that could compromise system stability.
- **Maintain fairness among network users** by ensuring that those who exceed their contractual limits bear an appropriate cost, reflective of the additional strain placed on the system.

Application & calculation

Different multipliers exist because the NTS charging regime is designed not just to recover costs, but to allocate risk and shape behaviour in proportion to the impact users have on system operation. Importantly, multipliers provide a way to meet evolving regulatory changes, enabling consistency without continually redesigning charge types.

Prior to October 2020 overrun charges were calculated using a flat 8x multiplier for both Entry and Exit points. However, this was amended with UNC 0716[23] which split and reduced these multipliers:

- **Entry overrun multiplier:** reduced from 8x to 3x
- **Exit overrun multiplier:** reduced from 8x to 6x

The change was a direct response to implementation of UNC 0678A[24], which introduced a 'postage stamp' charging regime, which had a consequential impact on the reserve prices for capacity at many points.

Had the original 8x multiplier remained, when combined with the higher reserve prices it would have caused total overrun charges to increase to excessively penal levels.

The Capacity Access Review (UNC0705R25) identified that lowering the multipliers was the appropriate way to keep the financial incentive on shippers to book capacity at an appropriate level at roughly the same level as it was before the 2020 pricing overhaul.

Compliance and Governance

Capacity Overrun Charges are governed by the UNC and subject to periodic review to ensure they remain effective in promoting compliance and safeguarding system integrity. Users are expected to monitor their capacity holdings and flows to avoid incurring these charges.

[23] Revision of Overrun Charge Multiplier | Joint Office of Gas Transporters - Gas Governance

[24] (Urgent) - Amendments to Gas Transmission Charging Regime | Joint Office of Gas Transporters - Gas Governance

[25] NTS Capacity Access Review | Joint Office of Gas Transporters - Gas Governance

Calculation & Worked Examples

The charges are calculated in accordance with the Uniform Network Code (UNC) and are designed to deter non-compliance. The calculation methodology is as follows:

- **Entry Overrun**: Charged at three times (3×) the highest prevailing Entry capacity price on the day of the overrun.
- **Negative Overrun**: Charges apply when users trade more capacity than they hold, with the rate determined by the UNC provisions.

Example 1: Entry and Exit Overrun

Assume:

- Contracted Entry capacity: 100,000 kWh/day
- Actual Entry flow: 110,000 kWh/day (overrun of 10,000 kWh)
- Highest Entry capacity price that day: £0.02 per kWh

Entry Overrun Charge

Overrun quantity = 10,000 kWh

Charge rate = 3 × £0.02 = £0.06 per kWh

Total charge = 10,000 × £0.06 = **£600**

For Exit:

- Contracted Exit capacity: 80,000 kWh/day
- Actual Exit flow: 85,000 kWh/day (overrun of 5,000 kWh)
- Highest Exit capacity price that day: £0.015 per kWh

Exit Overrun Charge

Overrun quantity = 5,000 kWh

Charge rate = 6 × £0.015 = £0.09 per kWh

Example 2: Negative Overrun

Assume:

- User holds 50,000 kWh/day of Entry capacity.
- User trades 70,000 kWh/day (i.e., sells 20,000 kWh more than they hold).
- Highest Entry capacity price that day: £0.02 per kWh.
- Negative overrun charge rate: 3× the highest Entry capacity price (same multiplier as Entry overrun).

Negative Overrun Charge

Overrun quantity = 20,000 kWh

Charge rate = 3 × £0.02 = £0.06 per kWh

Total charge = 20,000 × £0.06 = £1,200

This example demonstrates how negative overruns can result in significant charges, reinforcing the importance of accurate capacity management.

Hydrogen Overrun Charges: Con Max overrun

Design Question

In a hydrogen transmission system without traditional capacity allocation, users do not hold flexible, tradeable capacity rights. Instead, they operate within a Con Max, which reflects the technical capability and expected upper range of flow at each connection point. The key design question is therefore: how should any flow above Con Max be recognised, even if unlikely, and what charging or operational responses are appropriate when the indicative upper range is exceeded?

Key considerations

Con Max is not a commercial capacity product. It is most accurately understood as the hydrogen-system analogue to the Maximum NTS Exit Point Offtake Rate (MNEPOR) used on the current methane network or a version of Technical Capacity as referenced in the EU TAR NC, in either case, it would be applicable to both Entry and Exit. For Day-One operation Con Max would:

- provide an indicative upper bound derived from network capability, metering assumptions and safety margins,
- be defined in the connection agreement and describe the expected operating envelope for safe and measurable flow; and
- guide network usage within a defined tolerance, rather than serve as a tradable entitlement.

On the methane NTS, MNEPOR governs the maximum permissible hourly offtake at an exit point. It is used to validate notifications and Offtake Profile Notices, and values above MNEPOR are typically rejected by National Gas' control systems to maintain metering integrity, manage shrinkage and support UNC compliance.

In hydrogen, Con Max serves a similar guiding role; under normal operating conditions, flows would not be expected to exceed this level. Where exceedance does occur, it should generate alerts and would prompt a proportionate, operational response, i.e. instruction to immediately scale-back flows to a safe level followed by a review of operations, equipment and potentially a recalculation of the agreed Con Max value, rather than being treated solely as an overrun.

We expect that that the use of the Con Max value would begin to evolve as we move away from Day-One. With the potential for new connections to the network and adjusting of the distribution of the network's technical capability, as well as the potential for Reassignment of the originally approved Con Max level, over time, Con Max begins to act more like a baseline or a booked capacity limit rather than a hard technical stop. To future proof the use of Con Max in an evolving market, we propose a role for Overrun charges, even if the likelihood of them being triggered early in the lifetime of the network is minimal.

Hydrogen Overrun Proposals

Gas-Style Tolerance Bands (continuity approach)

Under this option, hydrogen exceedance charges would adapt the existing gas framework, applying equivalent multipliers to Con Max exceedance events. This approach prioritises continuity with current UNC charging arrangements and provides a familiar commercial environment for market participants.

This would require calibration to reflect the characteristics of the hydrogen network versus the NTS as well as the evolution of Con Max's guiding (rather than hard-limit) role

Risk-based penalty linked to scheduling charge framework

Under this option, flows above Con Max are treated as an enhanced scheduling deviation, applying a materially escalated multiplier to the prevailing scheduling charge rather than a capacity-overrun construct. The exceedance is addressed as a significant divergence between notified flows and the agreed operating envelope.

- Multipliers would be higher than those applied to standard scheduling deviations;
- Charges would reflect aggregated system risk imposed rather than solely the marginal volume exceedance; and
- A narrow tolerance band (e.g. ≤ 0.5%) may be permitted to account for metering uncertainty.

This approach maintains conceptual consistency with a notification-based regime while clearly differentiating Con Max exceedances from routine scheduling errors. Depending on meter configuration, measurement accuracy may diminish above the calibrated range, so policy and calibration practices should account for potential uncertainty in recorded volumes.

Severe penalty for Con Max breach (early-phase deterrent)

Under this option, any flow above Con Max triggers a fixed, high charge—potentially scaled by duration or severity—to reflect the potential need for urgent operational attention in early-stage networks.

- Charges could be linked to indicative emergency response and coordination costs; and
- Particularly suited to early hydrogen networks with limited operational flexibility or tolerance for error.

This option provides a clear deterrent signal and avoids complexity. It should be calibrated to remain proportionate in exceptional circumstances and to accommodate documented metering tolerances.

Locationally differentiated multipliers

Under this option, charges for Con Max exceedances vary by location, recognising that exceedances at constrained points or within hydrogen clusters may pose greater local system risk.

- Higher charges apply where exceedances materially affect local integrity or safety margins; and
- Lower charges apply at locations with greater resilience.

This improves cost and risk alignment but introduces additional complexity and may reduce transparency and predictability for users in an emerging market.

Graduated operational escalation (tolerance-based approach)

Under this option, Con Max is treated as an operational control threshold with defined tolerances. Exceedances trigger staged responses, such as notification, review, and where warranted, targeted curtailment, alongside proportionate charges.

- No automatic trading or ex-post offsetting for material exceedances that present operational risk, but routine variances within tolerance are managed through standard scheduling processes;
- Exceedances prompt formal review and may lead to updated operating procedures or revised Con Max values; and
- Financial charges complement, rather than replace, operational responses and are managed under the connection agreement.

This option preserves system protection while avoiding an inflexible "zero-tolerance" stance, aligning with the safety-critical context and the guiding nature of Con Max.

Option	Description	Advantages	Risks
Dynamic capacity booking	Users book varying levels of hydrogen capacity over time	Greater flexibility for users	Poor fit with early hydrogen network design; weakens connection-based cost recovery; adds complexity
Fixed Con Max with overrun tariff	Users are assigned a maximum flow and charged for it, with separate overrun charge for breach	Simple charging model	Risks turning operational breach into a financial optimisation choice
Fixed Con Max with operational enforcement & contractual consequence	Users are assigned a maximum flow and charged on that basis; exceedance is managed operationally and contractually	Best aligns with early hydrogen market structure, long-term certainty and physical network constraints	Requires robust contractual drafting and operational governance
Ratcheted/optional firming-up model	Users pay for a lower baseline and face ratchet-style charging when they exceed it	May suit later stage market refinement	Not well suited to Day-One simplicity and certainty; introduces complexity before market maturity

Framing

Con Max should therefore be framed as both:

- the basis for charging users for the level of network capability made available to them; and
- the maximum physical and contractual operating boundary for normal system use.

It is not intended to recreate methane-style short-term capacity markets. Rather, it is a more static, connection-based construct suited to the early hydrogen environment.

The preferred hydrogen approach is therefore a fixed Con Max regime with operational enforcement and contractual backing.

Under this approach:

- each connection point is assigned a single Con Max value;
- users are charged on the basis of that agreed maximum flow, rather than booking flexible tradable capacity rights;
- Con Max reflects the connection size made available to the user and provides the basis for a more stable and predictable charging framework in early market phases;
- users are not expected to exceed Con Max under normal operating conditions;
- where flows do exceed Con Max, the primary response is operational, including review, user contact and, where necessary, rejection, throttling or other intervention; and
- exceedance is treated as a breach of the relevant contractual arrangement, with any financial or legal consequence considered through the broader contract framework rather than through a standalone overrun tariff.

This approach best reflects the physical and commercial realities of an early hydrogen network.

Scheduling Charges

Overview

Scheduling charges are incurred when a user's actual gas flow deviates from their nominated flow beyond allowed tolerances. These charges are applied independently at entry (supply into the system) and exit (offtake from the system) points. Tolerance thresholds ensure minor variances are exempt, but charges apply when deviations exceed these limits.

The purpose of scheduling charges is to incentivise accurate and reliable nominations by encouraging users to align their nominated and actual flows. These charges help reduce operational uncertainty, maintain safe and stable system pressures and minimise the costs associated with System Operator interventions. This mechanism supports the efficient and secure operation of the gas network.

The charges are applied when deviations exceed tolerance thresholds prescribed in the Uniform Network Code (UNC). These thresholds define acceptable variances between nominated and actual flows, beyond which charges become payable. The application of these charges ensures that users contributing to system imbalance bear an appropriate share of the associated costs.

The level of the charge reflects the balancing costs incurred by the System Operator as a direct consequence of the deviation. Charges are calculated using the methodology set out in the UNC, which considers the magnitude of the deviation and the prevailing market conditions. This approach ensures transparency and cost-reflectivity in the charging process.

All scheduling charges are governed by the provisions of the UNC (the methodology is laid out under UNC TPD Section F, paragraph 3) and are subject to periodic review to ensure they remain effective in promoting accurate nominations and maintaining system integrity. Users are expected to comply with nomination requirements and monitor their flows to avoid unnecessary charges.

Methodology

1. **Entry (input) scheduling charges**
   - **Tolerance levels:**
     - Inner tolerance: 3% of the nominated input
     - Outer tolerance: 5% of the nominated input.
   - **Charge tranches:**
     - Deviation beyond 3%, up to 5%: charged at 2% of the system average price
     - Deviation beyond 5%: charged at 5% of the system average price

2. **Exit (output) scheduling charges**
   - **Tolerance varies by point type:**
     - Standard DN demand point: 25%
     - VLDMC/CSEP: 3%
     - Firm supply group: 20%
     - Interruptible group: 25%
   - **Charge:**
     - Any deviation exceeding tolerance -> 100% of that excess x 1% of the system average price.

Illustrative example

Parameter	Value
Nominated input	**1,000 kWh**
Actual Input	**920 kWh**
System Average Price	**3.0 pence/kWh**
Calculation steps	
Input deviation	**80 kWh (8%)**
Inner tolerance (3%)	**30 kWh**
Outer tolerance (5%[1])	**50 kWh**
First tranche (80-30=50, capped at 20)	**50-30 =20 kWh**
Second tranche (80-50=30)	**30 kWh**
Charge = 3.0p/kWh x (20 kWh x 2% + 30kWh x 5%)	**(0.4+1.5) x 3.0 = 5.7p**

Here the scheduling charge for the input deviation is £0.057 (5.7 pence). If expressed per kWh, it's 0.057 p/kWh across the nominated volume. If a 25% tolerance applies on exit with outgoing volumes deviating similarly, 1% x System Price would be applied to the excess.

Hydrogen Scheduling Charges

Design Questions

How tightly should hydrogen notifications be enforced, given reduced within-day flexibility; when do they apply and what would they look like?

It is key to note is that for hydrogen there would be no commercial nominations at Day-One, we have proposed, in the Balancing Section of this report, that only notifications would be submitted, via the Hydrogen Flow Notification process, rather than both a notification and a nomination. Therefore, any charges applied would be where actual flow is inconsistent with the ***notification*** as opposed to the ***nominations***.

Hydrogen Scheduling Charge Proposals

Gas-Style Tolerance Bands (simplified)

This option would retain a scheduling tolerance threshold broadly aligned with those used in the gas system. These tolerances are based on nominated versus actual physical flows, not energy content, reflecting the operational need to manage pressure and flow stability. The approach would minimise change for market participants and simplify implementation. However, stakeholders may wish to consider whether gas-style tolerances would adequately protect hydrogen system operability, given hydrogen's reduced linepack flexibility and tighter pressure constraints.

Hydrogen-Specific Narrower Tolerances

Under this option, scheduling tolerances would be set more narrowly than in gas, increasing the likelihood that deviations between notified and actual flows would attract scheduling charges. This approach would strengthen incentives for accurate forecasting when submitting notifications. Stakeholders may consider the trade-off between improved system protection and increased commercial exposure for users, particularly in early markets where forecasting capability and flexibility options may be limited.

Dynamic or Location-Based Tolerances

This option would allow scheduling tolerances to vary by system condition or location, tightening during periods of constraint or at sensitive network points. The approach could improve alignment between charges and operational risk. Stakeholders may wish to consider the implications for transparency and whether users would be able to anticipate and manage exposure under a more dynamic tolerance framework.

Two-tier out of tolerance charges

To strengthen incentives for compliance a two-tier charging structure could be introduced:

- **Tier 1:** A base charge for deviations beyond the initial tolerance band, replicating gas-style scheduling charges.
- **Tier 2:** A secondary, higher charge applied at a more extreme deviation threshold, mirroring gas overrun multipliers. This tier would serve as the primary deterrent, ensuring users actively manage notifications and avoid significant imbalances that could compromise system operability.

Paired-notification model with strengthened scheduling charges

Under this approach, users are required to submit paired balanced notifications, and scheduling charges become the primary behavioural tool. Deviations from the notified balanced position attract charges that are materially more meaningful than current methane scheduling charges. The framework can also distinguish between deviations that partially offset from a system perspective and deviations that compound imbalance or force SO action.

Policy Consideration

Scheduling charges in hydrogen are likely to function as operability controls as much as cost recovery mechanisms, particularly in the absence of deep within-day markets.

Option comparison

Option	Description	Advantages	Risks
Gas-style tolerances (simplified)	Replicate methane scheduling thresholds	Familiarity; regulatory continuity, simpler implementation	May not fully reflect hydrogen system risk; deterrent strength may be limited where exceedances pose operational concerns.
Tighter hydrogen-specific tolerances	Reduce tolerance bands to better reflect hydrogen constraints	Consistent with notification-based design; scales penalties with system risk; and avoids capacity style constructs. Provides better operational protection.	Higher exposure for users: increased SO monitoring
Dynamic tolerances	Location or system state dependent thresholds	Highly cost-reflective	Complexity; transparency challenges
Two-tier framework	Base charge for initial deviation plus higher charge at extreme threshold (replicates gas overrun multipliers)	Strong incentive for compliance; clearer escalation pathway	Increased commercial risks for users; potential predictability concerns
Paired notifications with tighter tolerances	Balanced notifications are required and scheduling becomes the primary behavioural tool	Best aligns with early hydrogen design; simple but robust; supports removal of routine cash out	Requires clear methodology and materially stronger charging levels than methane

Network Resilience: Storage, Linepack & Operating Margins

Overview

The methane regime is benefitted greatly, by access to a huge reserve of gas which always sits ready in the NTS pipes. The use of linepack as an implicit balancing tool provides for a significant level of flexibility in the methane network, one for which the SO does not apply any explicit charge. Linepack is instead treated as a system-wide operational tool, with associated costs recovered through the SO allowed revenue and the associated General Non-Transmission Services charging arrangements.

Operating Margins are a mechanism used by the SO to ensure the safe and secure operation of the NTS by maintaining access to gas that can be deployed at short notice in response to system stress. It is designed as a security and resilience tool rather than a routine balancing mechanism.

Under Operating Margin arrangements, the SO contracts with market participants to make gas available when predefined system conditions are met, such as unexpected supply loss, compressor failure, pipe break and orderly rundown. These arrangements typically involve:

- Contracted availability of gas, regardless of whether it is ultimately used;
- Procurement through competitive tender processes; and
- Conditional deployment only during periods of heightened operational risk.

The costs associated with Operating Margin, including availability payments and any utilisation costs, are recovered through SO revenue recovery and are socialised across network users. This reflects the system-wide benefit provided and distinguishes Operating Margins from charges linked directly to individual user behaviour.

While Operating Margins are not limited to storage assets, storage facilities are well suited to provide these services due to their responsiveness and flexibility. It therefore provides a useful reference point for how the availability value of storage is currently recognised in the methane regime, despite the absence of an explicit storage charge.

In the current methane market, storage supports system operability by contributing to balancing, managing demand variability, enhancing security of supply and reducing the need for more intrusive or costly operational interventions.

As the network transitions to hydrogen, this approach is expected to evolve. Hydrogen networks are likely to exhibit materially lower inherent linepack flexibility, particularly in early deployment phases. As a result, storage is expected to play a more central role in maintaining system balance, managing operational risk, and responding to supply or demand shocks.

In this context, storage and linepack should be recognised as distinct sources of system flexibility, with their costs and value considered explicitly. The SO holding a small reserve of hydrogen in storage means there is a neutral party, operating solely with a focus on safety and efficiency, without specific financial exposure. It is likely that the SO would only need access to a small quantity of stored hydrogen to replicate, to a lesser extent, the linepack inherent in the NTS. The storage-related costs would then be accounted for within a specific licence term and recovered via a cost sharing, balancing neutrality charge, rather than embedded within general SO revenue recovery. This would improve transparency, cost reflectivity and investment signals in a system where flexibility is scarce and valuable.

The Operating Margins mechanism being the closest existing analogue to a future hydrogen storage charging approach, under which the SO contracts for gas availability to protect system resilience, with costs socialised across users due to the system-wide benefit provided.

Purpose

The Network Resilience charging framework seeks to ensure that network users contribute appropriately to the operational costs related to the system, while avoiding excessive recovery of fixed transmission costs.

In a hydrogen context, introducing an explicit storage neutrality charge aims to preserve those benefits while improving transparency and cost reflectivity. In hydrogen, storage is expected to be used relatively frequently for routine residual balancing and more selectively for true system constraints. The framework should therefore distinguish clearly between:

- **Residual Balancing**, where small differences are managed as part of normal operation and costs may be socialised; and
- **Constraint Actions**, where user behaviour pushes the system into a more stressed operating condition and targeted intervention is required leading to targeted cost recovery.

Methane Storage Charges

On the NTS, transmission charges apply when gas is injected into or withdrawn from storage facilities connected to the network. Currently an 80% discount is applicable to both Entry and Exit Transmission Services charges. No commodity charges apply at storage sites.

The initial 50% discount proposed under UNC0678 [26] prevented double charging for the same gas as it both entered and exited the storage facility. The enhanced 80% discount approved in UNC0727[27], combined with the exemption to the SO charges, reflects the benefit storage provides to the wider network. These charges are governed by the Uniform Network Code (UNC) and are updated twice yearly to remain cost-reflective and consistent with the allowed revenue framework set by Ofgem.

Additionally, Storage Operators charge shippers for renting the space within their facilities as well as a small charge to bring the gas in or take it back out, an additional cost, outside of those charges prescribed by the UNC, which would need to be considered and socialised via the neutrality arrangement.

The expectation based on initial analysis, is that ≈2-4% of the capacity available in a facility of a similar scale to Aldborough is all that would be required to provide enough gas to safely rundown a Day-One hydrogen network in the event of a complete loss of a single supply point.

[28] Studies have overstated hydrogen-storage costs and understated its system value. Salt-cavern storage can often be repurposed from existing gas infrastructure with modest adaptation.

Hydrogen storage should be treated as a strategic system asset. Early projects should benefit from discounted or simplified connection charges to reflect their contribution to balancing intermittent production and supporting energy security.

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[26] UNC0678: (Urgent) - Amendments to Gas Transmission Charging Regime | Joint Office of Gas Transporters - Gas Governance

[27] UNC0727: (Urgent) - Increasing the Storage Transmission Capacity Charge Discount to 80% | Joint Office of Gas Transporters - Gas Governance

[28] MIT: Assessing the technical feasibility of converting U.S. salt caverns used for natural gas storage into hydrogen storage facilities

Hydrogen Network Resilience and Neutrality Proposals

No Explicit Linepack Charging

Hydrogen linepack would continue to be treated as a system-wide operational tool, with no specific charges applied to users relying on it for balancing and flexibility. This may support early market development but could result in implicit cross-subsidies where reliance on system-provided flexibility is uneven.

Linepack Neutrality Charges

A revenue neutral, charge would apply where user behaviour leads to sustained reliance on hydrogen linepack or increased operational risk. These charges would recover the costs associated with providing linepack flexibility, subject to the feasibility of measuring and attributing usage in a transparent and robust manner.

Strategic Storage Cost Recovery

SO storage-related costs would be recovered through a dedicated neutrality balancing charge, reflecting storage as a distinct and valuable source of hydrogen flexibility. This could include costs associated with system-held or policy-directed storage, such as strategic reserves, with appropriate governance to distinguish operational neutrality from wider policy support mechanisms.

Where storage actions are taken following small imbalances within the normal linepack operating range, and where attribution to individual users is not robust, costs would be socialised across all users through neutrality charges. Where actions are taken outside the residual balancing zone, reflecting a system constraint, there may be scope for more targeted charging where fault-causing behaviour can be clearly evidenced.

Preferred approach

The preferred hydrogen approach is:

- no explicit day-one linepack charge;
- explicit recognition of storage as a balancing and flexibility service;
- socialisation of residual balancing costs or credits; and
- targeted recovery, including premium treatment, where user behaviour forces constraint-driven intervention.

Under this approach, National Gas would hold or contract for hydrogen storage capability in a manner analogous to an Operating Margin-type service, though adapted to the hydrogen context. Because residual balancing is expected to be needed relatively frequently, storage is not simply an emergency reserve; it becomes part of the operational architecture of the system. However, the framework must still distinguish between routine use and more penal, user-driven intervention.

Option comparison

Option	Treatment of storage	Treatment of linepack	Cost recovery approach	Advantages	Considerations
No explicit linepack or storage charging	Storage continues to be treated as a system-wide operational asset. No standalone storage charge; costs recovered through general SO revenue recovery, similar to the current methane regime.	Linepack treated as an operational tool with no explicit charging, consistent with current methane arrangements.	Costs socialised across all users through SO revenue recovery.	Simple to implement; supports early market development; mirrors existing methane framework.	Limited transparency on the value of flexibility; potential for implicit cross-subsidies; weak cost signals as hydrogen flexibility becomes scarce.
Explicit linepack neutrality charges	Storage remains uncharged explicitly, with costs recovered via SO revenue recovery, reflecting its net system benefit.	Linepack usage attracts neutrality charges where users' behaviour leads to sustained reliance or increased operational risk.	Targeted neutrality charges for linepack, alongside residual SO recovery.	Improves cost reflectivity for linepack; discourages free use of system flexibility.	Requires robust measurement and attribution of linepack usage; increased complexity; storage value remains implicit.
Strategic storage costs	Storage costs recovered through a standalone neutrality balancing charge, recognising storage as a distinct and valuable source of hydrogen flexibility. Charge structure could draw on Operating Margin–type arrangements, including availability and/or usage-based components.	Linepack continues to be treated as a system-wide operational tool with no explicit charging in early stages.	Combination of targeted storage neutrality charges and residual SO recovery.	Improves transparency; recognises both costs and net benefits of storage; provides clearer investment and operational signals.	Requires new charging design and governance; need to clearly distinguish operational neutrality from wider policy support.

Residual Balancing and Constraints

In a hydrogen system, non-Primary balancing actions are expected to fall into two distinct categories:

- Residual balancing actions, which address small imbalances within the normal linepack operating range and form part of routine system operation; and
- Constraint balancing actions, which are taken when linepack approaches or breaches defined thresholds associated with elevated operational risk.

The distinction between these actions is determined by the establishment of a residual balancing zone, defined by linepack targets and buffer thresholds. Actions taken within this zone are treated as residual balancing.

Actions taken beyond this zone, where system integrity is at risk, are treated as constraint actions.

This distinction is critical to ensuring that charging treatment aligns with operational intent and system risk. Currently in the methane world, we are able to carry out these actions using the spot market; the expectation currently is that there will be no such service for hydrogen, with hydrogen only being readily available from those producers directly connected to the cluster, meaning the System Operator will require the ability to contract with those producers directly to fulfil such actions.

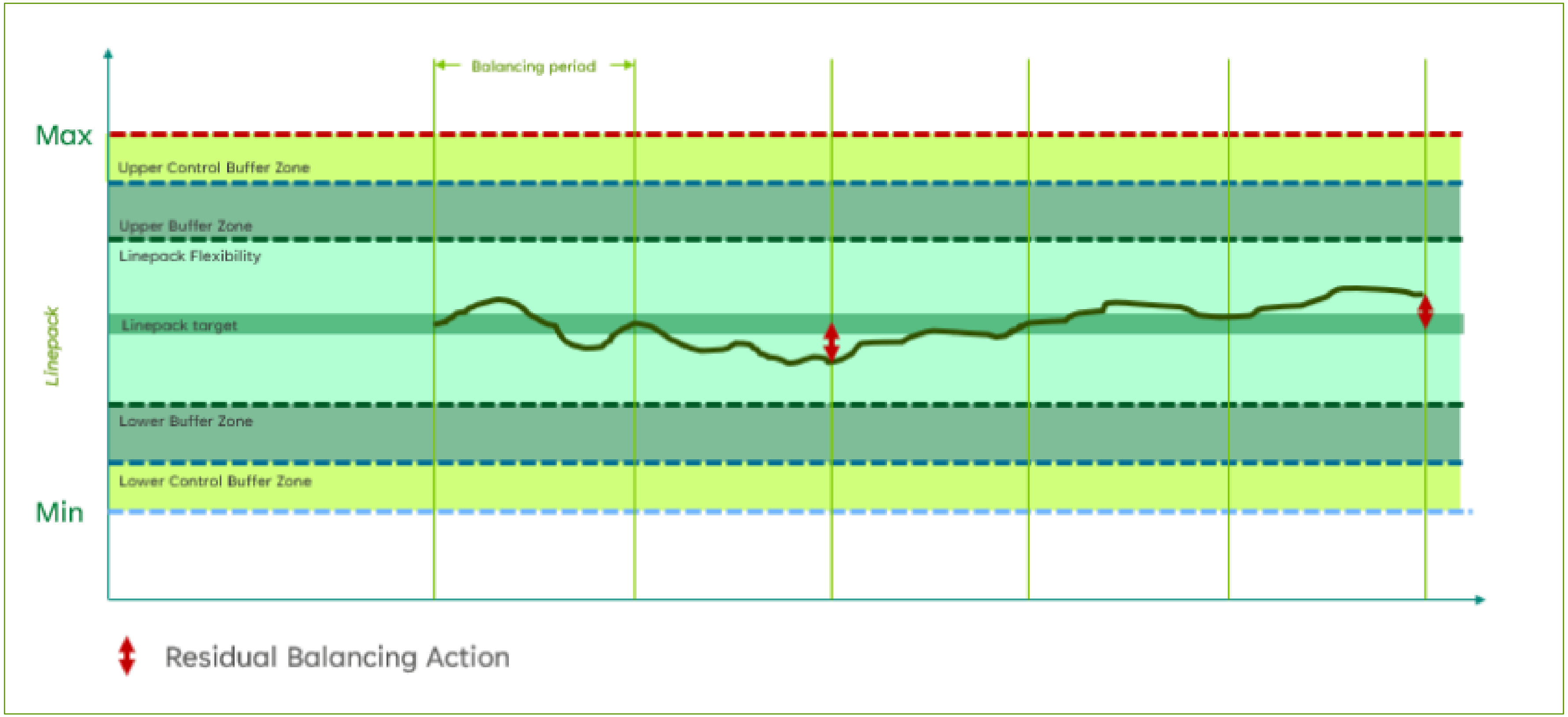
Design Question

How should the value and cost of scarce hydrogen flexibility be allocated between system users in a way that is operationally robust, transparent and proportionate?

Policy Consideration

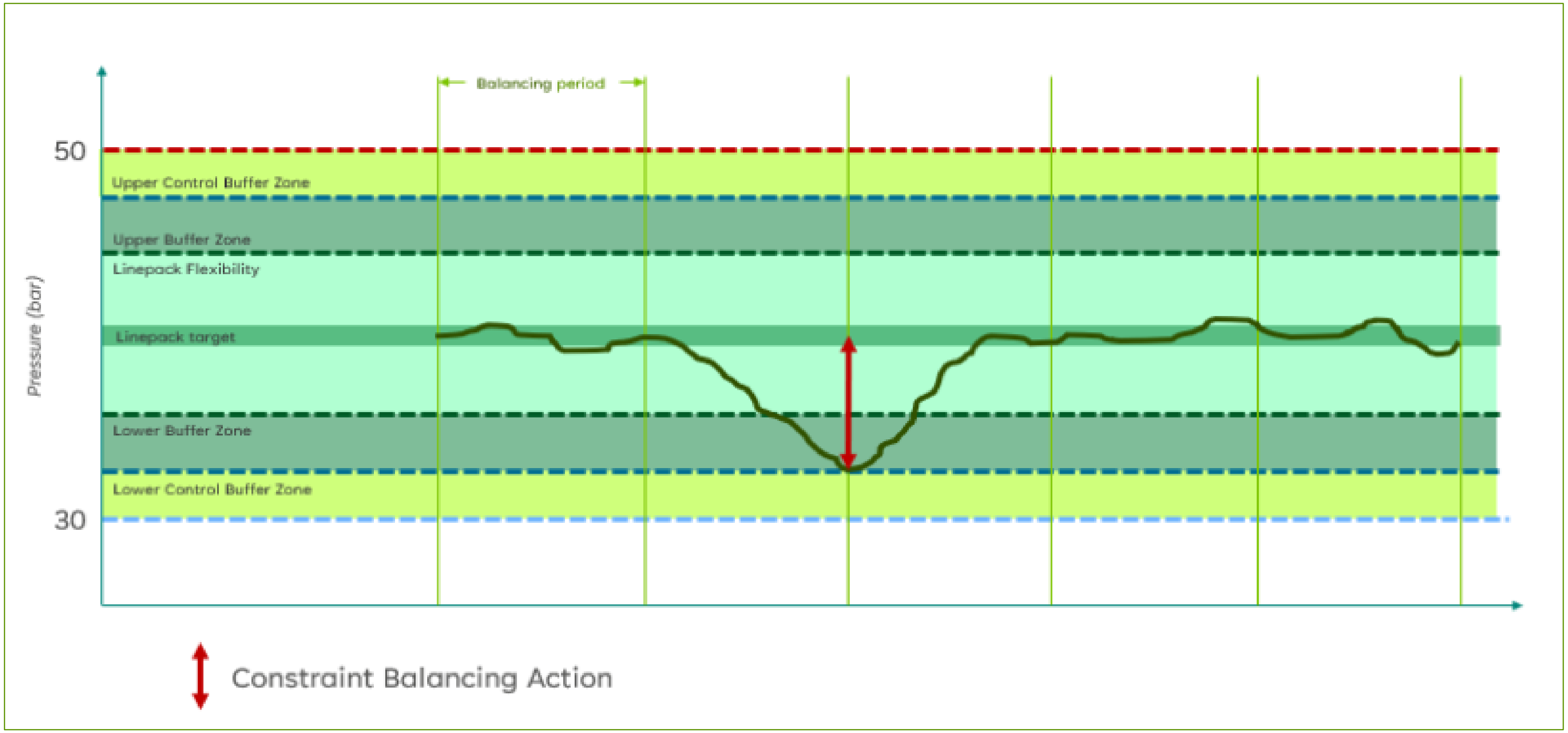
In the absence of explicit neutrality mechanisms, users may rely implicitly on system-provided flexibility, weakening cost signals and distorting investment incentives over time. Recognising storage and linepack as distinct sources of flexibility in a hydrogen system, and clearly distinguishing residual balancing from constraint actions, improves transparency while allowing proportionate and pragmatic charging arrangements as the market develops.

Residual balancing within the normal operating range



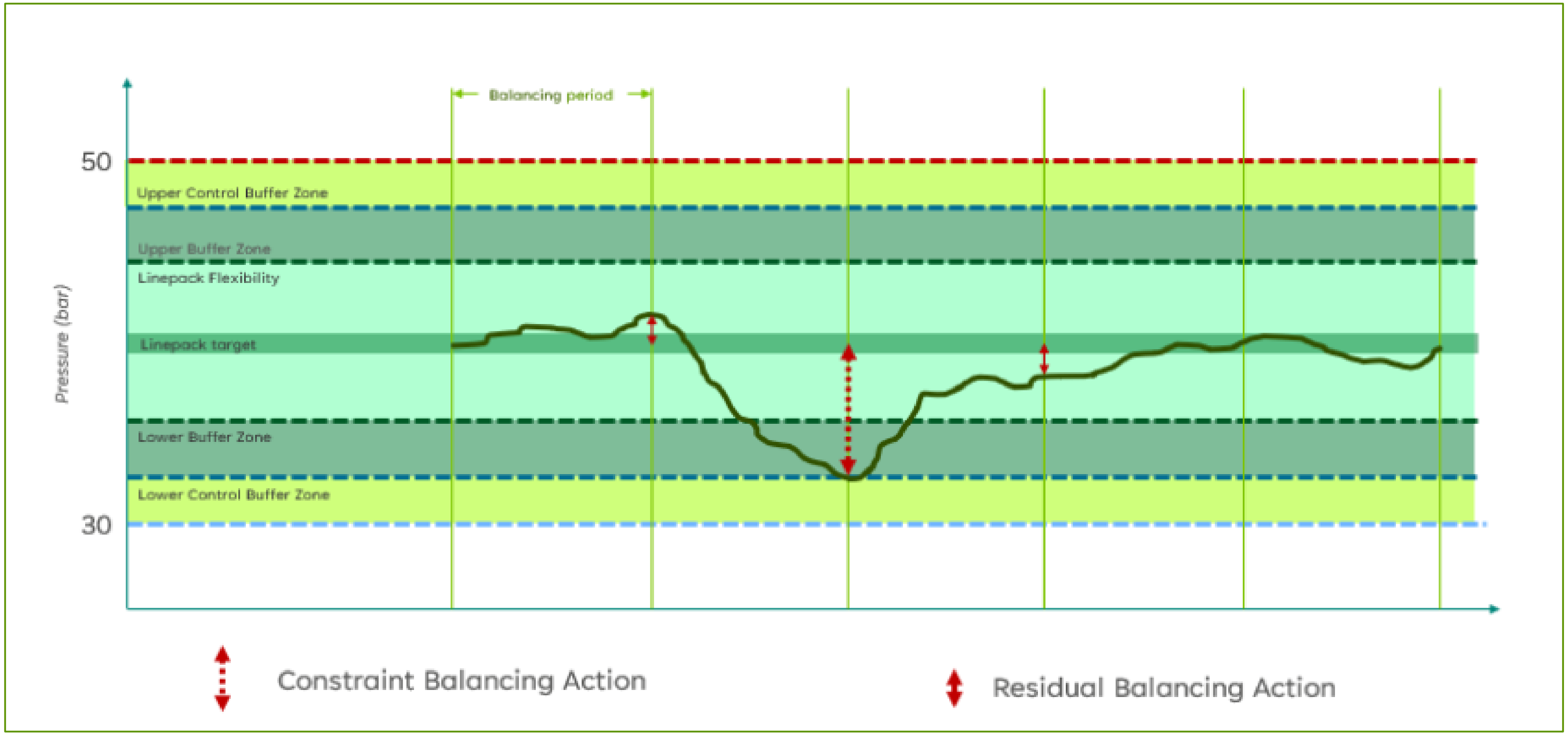
Residual balancing actions are taken when linepack deviates modestly from the SO's target within the defined flexibility zone. These actions are a normal feature of system operation and do not indicate system stress. Attribution to individual users may be possible in some cases (for example, scheduling mismatches) but will not always be robust. Costs will be recovered through socialised neutrality mechanisms.

Constraint driven balancing action



Constraint balancing actions occur when linepack moves beyond the normal operating range and enters buffer or control zones associated with heightened operational risk. These actions are taken to protect system integrity rather than to manage routine imbalance. Where specific users can be identified as contributing to the constraint, there is scope for targeted charging, subject to evidential robustness.

Interaction between residual balancing and constraint actions



Residual balancing and constraint actions may occur within the same operating day, depending on system conditions. Residual balancing actions are assessed at the end of balancing periods and address routine variability. Constraint actions arise only when predefined risk thresholds are breached. This framework provides a clear operational and charging distinction while recognising the practical limits of attribution in an early-stage hydrogen transmission system.

Imbalance Charges (SMP Buy and SMP Sell)

Overview

SMP Buy and SMP Sell are the system cash-out prices applied to shippers whose portfolios are out of balance at the end of the gas day. They ensure that shippers internalise the cost of any imbalance they cause and remove incentives to rely on National Gas to resolve an imbalance on their behalf making the Shipper the primary balancer. These prices apply after the SO has taken actions to balance the system, such as buying or selling gas on the On-the-Day Commodity Market (OCM).

When OCM activity isn't required or doesn't alter the imbalance a default differential is applied:

- **SMP Buy = SAP + 0.0642 p/kWh** (equivalent to ~1.88p/therm)
- **SMP Sell = SAP – 0.0642 p/kWh** (equivalent to ~1.88p/therm)

These differentials remain in effect as the established baseline (since January 2024):

- SMP Buy = **0.0642 p/kWh**
- SMP Sell = **0.0642 p/kWh**

When These Charges Apply

Every gas shipper should end the gas day balanced, but where they don't, they are subject to charges.

- If a shipper takes more gas from the system than they have delivered, they are in negative imbalance and pay SMP Buy for the amount they are imbalanced.
- If a shipper delivers more gas than they take, they are in positive imbalance and receive (or pay) SMP Sell, for the amount they are imbalanced.

The SMP Buy/Sell prices represent the marginal cost to the system operator of restoring the system to balance.

How SMP Prices Are Determined

The two prices reflect the most expensive and cheapest balancing actions taken by the System Operator:

SMP Buy = the higher of:

- The highest-priced gas purchased by the SO to correct an imbalance; or
- The market-derived price floor set by the UNC

SMP Sell = the lower of:

- The lowest-priced gas sold by the SO; or
- The market-derived price peak

If no SO balancing actions occur on a given day, the prices revert to default market-based proxies (e.g. reference market prices).

These mechanisms ensure:

- Users who rely on the SO to balance for them pay the true marginal cost of their imbalance.
- Compliant users do not cross-subsidise imbalanced ones.

Purpose of Imbalance (SMP Buy/Sell) Charges

The imbalance mechanism exists to:

a. **Promote Balancing Discipline**

Shippers are incentivised to act as Primary Balancers and match inputs and offtakes, or trade imbalances on the OCM before closeout.

b. **Reflect System Operator Costs**

Imbalance charges ensure the cost of SO balancing actions is recovered from those who caused the imbalance.

c. **Support Efficient Market Behaviour**

The SMP mechanism creates strong incentives for shippers to participate in the OCM rather than rely on default system balancing.

d. **Protect Security of Supply**

Unmanaged imbalances create system stress; SMP Buy/Sell charges discourage behaviour that could compromise system pressure or integrity.

Hydrogen Imbalance (SMP Buy and SMP Sell) Charges

Design Question

Is an end-of-day cash-out mechanism required at all in a hydrogen market where users are required to submit balanced paired notifications and where scheduling and storage charges already provide the main behavioural discipline?

In a hydrogen system, if notifications are structured such that each user's inputs and offtakes are inherently balanced at the point of nomination, then there should be no routine concept of a user being commercially long or short at the close of the balancing period. If a user fails to remain physically balanced, that failure will already be reflected through scheduling charges and, where relevant, storage neutrality charges. This materially weakens the case for retaining SMP Buy and SMP Sell as a separate day-one mechanism.

Proposed options

Inherently Balanced System (No SMP Buy/Sell)

An inherently balanced system would require hydrogen users to submit notifications that are fully balanced at the point of entry, with inputs and offtakes matched in real time or within tight operational tolerances so that no end-of-period imbalance can occur.

As proposals for Hydrogen should make a portfolio imbalance structurally impossible, SMP Buy and SMP Sell cash-out prices are no longer needed, and system discipline instead relies on upstream controls such as Con Max limits, scheduling accuracy, and explicit treatment of linepack and storage. This approach simplifies early-stage neutrality arrangements, removes dependence on SO-led cash-out mechanisms, and reduces exposure to volatility in a low-liquidity market environment.

However, it is highly restrictive, requiring robust metering, real-time validation systems, and strong operational flexibility, and it may limit the development of hydrogen trading unless loosened as the market matures.

Administered Reference Pricing

This option would set SMP Buy and Sell prices by reference to administered benchmarks, such as regulated reference prices or support mechanism strike prices. The approach would provide price stability and predictability in the absence of a liquid market for hydrogen though may not reflect true costs. Stakeholders may consider whether such pricing delivers sufficiently strong incentives for users to manage imbalances proactively.

SO-Action-Based Pricing

Under this option, SMP prices would reflect the cost of balancing actions taken by the System Operator, including directed production or curtailment. This would strengthen the link between user imbalance and system costs. Stakeholders may wish to consider the potential for increased price volatility and the implications for risk management in early markets where the hydrogen price could potentially be quite volatile.

Hybrid Pricing Framework

This option would combine administered price floors or caps with market or SO-action-based references. The approach aims to balance price stability with cost reflectivity and provide a transition pathway toward fully market-based pricing. Stakeholders may consider the complexity of implementing such a framework and the criteria that should trigger movement toward greater market reliance.

Policy Consideration

In a day-one hydrogen market, the simplest and most proportionate design is to remove SMP and instead rely on balanced paired notifications, strengthened scheduling charges and an explicit, neutrality aligned, storage reserve charge. A future transition to more developed imbalance pricing may become appropriate as the system grows and becomes more liquid.

As the market matures, there may be scope to revisit this position. Future options could include:

1. *Administered reference pricing*

   A benchmark or strike-price-linked imbalance mechanism could be introduced later if there is a policy desire to retain some explicit cash-out concept.

2. *Storage-proxy-based imbalance pricing*

   A future imbalance framework could use the cost of storage as a proxy for the cost of being out of balance, echoing some earlier gas market arrangements.

3. *More market-based balancing arrangements*

   As the network becomes larger, more diverse and more liquid, the market may evolve toward more familiar buy/sell or marginal-pricing approaches.

However, these should be treated as future-phase options rather than day-one requirements.

Option comparison

Option	Description	Advantages	Risks
Inherently balanced system	Notifications structurally balanced; SMP eliminated	Simplifies early regime; prevents SO dependency	Restrictive; requires high operational discipline
Administered reference pricing	SMP links to benchmarks or strike prices	Stability; predictability	Weak market signals
SO actioned based SMP	Prices reflect cost of SO interventions	Strong cost causation	Volatility; potential disputes
Hybrid approach	Administered floors/caps with market reference	Balanced incentives	Design complexity

Proposals

Con Max discipline

Con Max is expected to operate as both the charging basis for the level of connection capability made available to a user and the maximum physical operating boundary for normal system use. Users would not book short-term hydrogen capacity in the methane sense. Instead, they would be assigned a single maximum capability and be charged on that basis, reflecting the connection size the network must be able to serve.

This gives the early hydrogen regime a more certain and static structure, aligned with longer-term contractual arrangements and with the practical reality that the network must be built to meet the agreed connection capability whether or not the user utilises it continuously.

At the same time, Con Max is not merely a charging parameter. It is also an operability boundary. Exceeding it should trigger operational review and, where necessary, intervention by National Gas, with any contractual consequences considered separately. This ensures that maximum flow discipline is treated as a core part of operating the network safely rather than as a routine commercial choice.

Scheduling accuracy (within-day operability control)

Scheduling charges are the principal mechanism for enforcing within-day accuracy. In methane, wider tolerances allow linepack to absorb modest deviations. In hydrogen, with reduced linepack and tighter pressure margins, tolerances are expected to be narrower and/or dynamic. Scheduling charges therefore operate less as end-of-day settlement and more as an early corrective signal to drive user action during the day.

Scheduling discipline reduces the likelihood that the SO must deploy flexibility tools (linepack or storage) to correct avoidable user-driven deviations and reduces the risk of linepack moving toward constraint thresholds.

Storage and linepack neutrality (system flexibility allocation)

In hydrogen, storage should become a more explicit part of the balancing framework, while linepack should remain primarily an operational system feature in the early phases rather than a separately charged service. Although charging explicitly for linepack is conceptually possible, it would represent a significant perceived change for users and risks adding unnecessary complexity to a market that is already nascent and uncertain.

The more proportionate day-one approach is therefore to distinguish clearly between residual balancing and constraint actions. Residual balancing costs, including routine use of storage, should be socialised. Constraint actions, where user behaviour pushes the system into a more stressed condition and National Gas must intervene, should be charged in a more targeted way. This may include recovering the cost of using and replenishing storage, potentially with a premium where the intervention was caused by identifiable user behaviour.

This framework preserves simplicity while still ensuring that users aren't reliant on implicitly system flexibility in a system where linepack is scarce.

Imbalance Charges - SMP Buy/Sell (end-of-day backstop)

Imbalance Charges are not expected to form part of the day-one hydrogen regime. If users must submit inherently balanced paired notifications, there is no routine scope for a conventional end-of-day long or short position in the methane sense. Any failure to remain physically balanced would instead be dealt with through strengthened scheduling charges and, where National Gas must use storage to respond, through storage neutrality charging.

A future imbalance pricing model may become relevant later as the network becomes larger, more diverse and more liquid. However, the day-one position should be that SMP is removed and replaced functionally by the combined effect of scheduling discipline and explicit storage charging.

System-wide interaction and escalation logic

Taken together, the interaction between charge types in hydrogen forms a clear escalation pathway:

- Con Max sets the agreed connection-based maximum flow and physical operating limit.
- Scheduling charges encourage accurate paired notifications and provide the primary within-day behavioural control.
- Storage neutrality arrangements recover the cost of routine residual balancing on a socialised basis and more serious constraint-driven intervention on a targeted basis where appropriate.
- Any future imbalance pricing mechanism would be a later-stage development rather than a day-one feature.

Each layer of the framework is intended to support the next: a clear maximum flow, tighter within-day discipline, transparent treatment of flexibility use, and a phased approach to more sophisticated market arrangements only when the system is ready.

Implications for users and National Gas in hydrogen

For users, the hydrogen regime places greater emphasis on knowing their connection requirement up front, accepting a clearer maximum flow, providing accurate and matched notifications as well as proactively managing deviations throughout balancing periods. Users will not have the same implicit balancing service provided by the extensive linepack available on the NTS, and so should be aware than any errors in primary balancing actions which effect network stability will result in NGHT calling on storage reserves or otherwise intervene, meaning they may face more targeted and more material cost consequences than under methane arrangements.

For National Gas, the regime provides a simpler and more physically grounded basis for early hydrogen operation. Con Max supports connection-based charging and system planning. Scheduling charges provide the main behavioural discipline. Storage neutrality arrangements create a clearer mechanism for recovering the cost of flexibility use. Together, these measures avoid over-engineering the early market while still maintaining sufficient operational control.

Conclusion

A hydrogen neutrality and balancing regime must operate as a coordinated operability framework rather than a set of standalone charges. While continuity with the methane regime provides a helpful foundation, hydrogen's tighter technical constraints mean that each mechanism, Con Max, scheduling controls, storage and linepack neutrality, and SMP cash-out, needs to function with clearer intent and stronger upstream behavioural influence. In practice, this shifts emphasis away from end-of-day correction and toward proactive behaviours that help maintain system operability throughout the gas day.

Each charge type contributes a distinct role within a sequential escalation pathway:

The broader policy challenge remains balancing system protection with market participation. The framework must be sufficiently strong to incentivise appropriate behaviour and avoid any over-reliance on SO flexibility, but sufficiently simple and proportionate to avoid deterring early participation.

The right day-one answer is therefore not to replicate the complexity of a mature methane regime, but to start from a more direct and operationally grounded model and allow the framework to evolve over time.

A phased approach remains the clearest route forward. Day-One should prioritise certainty, simplicity and physical operability. More complex concepts, such as standalone linepack charging, explicit incentive mechanisms or more developed imbalance pricing, may become relevant later as the hydrogen network grows, market liquidity develops and the system becomes more resilient. Until then, the regime should focus on clear maximum flow discipline, robust scheduling controls and transparent treatment of storage-backed balancing actions.

By designing the balancing regime as a layered and integrated control system, National Gas can support secure and reliable operation during the early development of the hydrogen market while laying the foundations for a disciplined, efficient, and progressively more market-driven balancing framework.

Con Max

provides the agreed upper operating envelope at the point of connection, helping define the boundary conditions for normal system operation.

Scheduling charges

these become the main behavioural tool, enforcing matched and balanced notifications, under tighter tolerances, and with materially greater force than today's methane charges.

Storage Reserve

The revenue neutral, storage reserve arrangements, should provide the mechanism for recovering the cost of routine residual balancing and targeted operational intervention, while a standalone day-one linepack charge is avoided in favour of simplicity and acceptability.

Imbalance Charges

SMP Buy and SMP Sell, meanwhile, are unlikely to be required in a day-one regime where users are already required to be inherently balanced and where deviations are dealt with upstream. .

5. Connections

This section sets out options for designing a future hydrogen connections process; the overarching aim of which is to provide a predictable, fair and efficient route for users to gain access to the network. The process should facilitate market entry, encourage competition and innovation, and underpin investment in new hydrogen supply and demand. It must also ensure that network development is efficient and coordinated, minimising the risk of stranded or under-utilised assets.

From a regulatory perspective, the process should align with the UK's evolving hydrogen economic regulatory framework and provide consistency across clusters and phases of Project Union. It should begin as a light-touch administrative mechanism suitable for PU: East Coast and progressively become more structured as the market expands. Above all, it should promote fair access and transparency for all potential users.

Methane Regulatory Framework

The Application to Offer (A2O) and Planning & Advanced Reservation of Capacity Agreement (PARCA) processes are key mechanisms within the UK gas transmission system, designed to manage network capacity efficiently.

The A2O process allows gas shippers and developers to formally request an offer for a physical connection to the NTS, ensuring that any new connection, whether supply or demand, is assessed and priced appropriately.

PARCA, on the other hand, provides a structured way for parties to reserve future capacity rights while the necessary network reinforcements or expansions are planned and delivered.

Together, these processes aim to facilitate timely investment, maintain system integrity and support market participants in securing the capacity they need for future operations.

Application to Offer (A2O) framework

Under the A2O framework, all connection requests are submitted through the Gas Customer Hub, NGT's digital platform for managing applications for new connections, modifications, disconnections and capacity reservations. Once an applicant submits an A2O request, NGT validates the submission to ensure that it is technically complete and that the required fee has been received. When these criteria are met, the process formally begins, triggering a defined assessment period. The standard timeline is six months from acceptance to the issue of a Connection Offer however this may be extended to nine months where additional feasibility work, such as reinforcement modelling or complex design, is required.

During this period, NGT determines whether the proposed connection qualifies as a Standard Design Connection (SDC) or a Bespoke Connection. Standard designs follow pre-defined templates for typical flows and pressures, while bespoke connections require detailed engineering and cost assessments. At the conclusion of the process, NGT issues a formal Connection Offer setting out the proposed design, estimated costs and commercial terms. Once accepted, the parties enter into a Construction Agreement and, where relevant, a Network Entry or Exit Agreement (NEA or NExA), establishing delivery milestones, ownership boundaries and operational responsibilities. This framework gives users clarity on timescales and outcomes while ensuring that network investment decisions are informed by consistent evaluation.

PARCA process

The PARCA framework begins with Stage 0, a non-binding preparatory phase that enables early engagement between the applicant and NGT. At this stage, the applicant provides high-level information about the project, such as expected capacity requirements, location, flow direction and timing, allowing NGT to conduct an initial network review. Stage 0 provides indicative information on likely constraints, costs and lead times but does not confer any contractual rights or obligations. If both parties agree that the proposal is viable, the applicant proceeds to Stage 1, submitting a formal application and fee.

In Stage 1, NGT undertakes detailed network modelling to determine whether the system can accommodate the requested capacity and identifies any reinforcement works required. The findings, costs and timescales are shared with the applicant in a Stage 1 report. Should the applicant wish to continue, the process moves to Stage 2, which formalises the reservation of capacity once key readiness conditions (such as financial close or planning consent) are achieved. The agreements then become binding and NGT proceeds with any required investment or construction. This stage structure ensures that reinforcement is triggered only by credible, financially committed projects, maintaining efficiency and avoiding stranded investment.

Customer Accessibility

Although A2O and PARCA are distinct contractual processes, they are closely coordinated in practice, and both are administered through the Gas Customer Hub. This shared platform enables applicants to manage both the physical and commercial aspects of their projects through a single digital interface, providing transparency, consistent communication and alignment between engineering design and capacity planning. The combined use of A2O and PARCA gives customers a coherent and predictable route from concept to operation, while ensuring that network integrity and investment efficiency are maintained.

Economic and financial viability assessments

Within both the A2O and PARCA processes, NGT applies economic and financial tests to ensure that any network investment triggered by new user requests is efficient and does not impose undue cost on existing customers. The two key calculations used for this purpose are the Long Run Marginal Cost (LRMC) methodology and the Net Present Value (NPV) test.

Long Run Marginal Cost (LRMC)

LRMC is used to estimate the incremental cost of providing capacity on the NTS over the long term. In practice, when a user applies for a new connection or incremental capacity, NGT models the physical network flows and reinforcement requirements to determine the cost of expanding capacity to meet the new demand. The calculated costs reflect the efficient, forward-looking cost of additional infrastructure (such as pipelines, compressors or valves) rather than historic sunk costs.

LRMC analysis is used within both A2O and PARCA to identify whether reinforcement is needed and to inform the indicative cost and lead-time quoted in the Connection Offer (A2O) or Stage 1 Report (PARCA). It provides the engineering and economic foundation for determining whether the user's request can be accommodated within the existing assets or if new capacity would require further investment.

Net Present Value (NPV) test

The NPV test, which applies only to entry connections, is then used to determine whether the proposed investment is financially justified. NGT compares the future revenues expected from the new user (through capacity and commodity charges) against the costs of the reinforcement required to accommodate them. If the NPV of revenues are positive, the investment is deemed to pass the test and can proceed within the regulated cost-recovery framework.

If the NPV is negative, meaning that user revenues would not recover enough of the cost of reinforcement, NGT may seek additional commitments or user contributions before proceeding. Under the current approach, user commitment is set at 50% of the adjusted reinforcement cost, while the remaining 50% is recovered from the wider market. In practice, NGT would adjust these contributions through capacity premiums, ensuring the project always passes the financial test. This process is designed so that the new investment is cost-reflective, avoids undue cross-subsidy from existing network users and aligns with Ofgem's principles of economic efficiency under the RIIO price control framework.

Together, the LRMC and NPV tests provide the analytical link between technical feasibility and financial justification. They ensure that each connection or capacity expansion triggered through the A2O or PARCA processed is both technically viable and economically efficient.

Ongoing review of the PARCA Process

NGT and Ofgem are currently reviewing the PARCA Process as part of a wider update to the Capacity Methodology Statements required under The Licence. The review, being delivered in phases through Ofgem, the UNC0901R[29] review group and follow up modification proposals, is examining how capacity reservation, commitment periods and financial tests operate in practice and how they can be simplified to better reflect market conditions.

The first phase, completed in early 2025, clarified the application of the NPV test and minor procedural aspects of capacity allocation. The second phase, expected to conclude in 2026, is considering more substantive reforms. These include potential changes to the minimum capacity commitment periods, simplification of the NPV methodology and measures to make the PARCA Process more flexible and proportionate. A related UNC modification proposal (UNC 0912S[30]) would reduce the minimum commitment durations for Quarterly NTS Entry Capacity from sixteen quarters to four where no NPV test applies, while UNC0920[31] looks at revisions to the PARCA Security Amount. The overarching objective is to reduce administrative burden, improve transparency and ensure the PARCA framework remains fit for purpose as the gas market evolves. Ther are lessons we can take form these working groups and modifications which will benefit the future hydrogen framework development.

Comparison with the CCS Framework

The Carbon Capture and Storage (CCS) Network Code, introduced in 2025, offers a fundamentally different approach to access and connections compared with the current UNC. While both serve to provide transparent, non-discriminatory access to infrastructure, the CCS Network Code (CCS NC) has been designed from the outset for a small number of large industrial users operating in an early-stage, government-backed carbon transport and storage market. As such, it replaces the market-heavy, auction-based processes of the gas regime with a simpler, more direct and time-bound connection model.

In contrast with the PARCA process, CCS NC adopts a more straightforward bilateral process between each user, such as a

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[29] Review of the arrangements for reservation of NTS Capacity | Joint Office of Gas Transporters - Gas Governance

[30] PARCA Quarterly NTS Entry Capacity minimum duration quantity | Joint Office of Gas Transporters - Gas Governance

[31] PARCA Security Amount | Joint Office of Gas Transporters - Gas Governance

carbon capture facility, and the relevant Transport and Storage Company (T&SCo). The connection process begins with the submission of a connection application, which includes key technical details such as the location of the proposed connection, expected CO_2 flowrates and compositional data. Once a valid application has been received the T&SCo is required to issue an 'Initial Offer'. This initial offer sets out the indicative technical feasibility, costs and timescales. If the user accepts the Initial Offer, the T&SCO must then issue a formal 'Connection Offer', which provides the definitive commercial and technical terms of connection, including capacity limits, pressure & temperature conditions and the works required to complete the link.

The formal Connection Offer triggers formalisation of three standardised legal agreements that are provisionally issued alongside the 'Initial Offer' and appended to CCS NC: the 'Construction Agreement', the 'Connection Agreement' and a 'Code Accession Agreement'. The Construction Agreement governs the delivery of the necessary physical works, defining responsibilities, timelines and cost recovery, similar to the role of the A2O process for gas, while the Connection Agreement sets out the ongoing operational parameters such as tolerances, metering arrangements and shutdown procedures. The Code Accession Agreement formalises a user's commitment to abide by the rules laid out in CCS NC.

Once connection is established, the user gains access rights to the network within the agreed technical and contractual limits. Crucially, CCS NC does not use the capacity auctions to guarantee the 'ticket-to-ride'. It is instead embedded in the physical connection and defined by technical capability rather than traded through a market mechanism. This represents a departure from the established GB methane regime but does align with the principles that govern methane through the retained EU TAR NC.

CCS further prioritises certainty and simplicity, providing users with long-term clarity over their access rights without exposing them to market volatility. Users must also provide a 'Required Security Amount' before connection or ongoing use, safeguarding the T&SCO against potential default. This mirrors the financial security provisions of the UNC but is likely to be simpler given the smaller user base and the long-term, strategic nature of CCS operations.

In comparing the two systems, CCS NC offers a much faster and leaner route to connection. While gas users may wait months for capacity allocations through the competitive processes, CCS applicants can expect a defined timetable and a direct bilateral agreement within weeks. The documents themselves are fewer in number and more standardised, reducing administrative complexity and negotiation time. Moreover, the process is specifically tailored to the technical realities of CO_2 transport, where factors such as purity, pressure and temperature are critical, and where network expansion will be strategically coordinated rather than market driven.

The simplicity of the CCS process is one of its key advantages. It lowers barriers to entry for early carbon capture projects, allowing emitters to focus on technical compliance and integrations rather than navigating intricate auction and balancing rules. It also ensures that new connections are planned coherently with the development of national storage capacity, rather than dictated by short-term commercial bidding behaviour. However, this same simplicity comes with trade-offs. The absence of capacity trading or nomination mechanisms means that the system lacks flexibility. Users cannot easily reallocate spare capacity or respond to operational fluctuations and there is less opportunity for market signals to optimise system use.

Overall, the CCS Network Code represents a deliberate simplification and modernisation of the access and connection process. It provides a clear, proportionate framework suited to a nascent, government-supported industry, while retaining the ability to evolve as the market matures, it can therefore be considered an improvement on the UNC in the context for which it is designed, offering greater speed, clarity and proportionality for early CCS deployment. In time, as the CCS sector expands and commercial participation increases, the code is expected to incorporate more of the sophisticated features that have long characterised the gas regime.

Hydrogen Connections Proposal

Design Considerations for Hydrogen

Hydrogen network development must balance early-stage flexibility with a clear route to long-term commercial discipline. In the initial phase, networks will be largely funded through the Hydrogen Transportation Business Model (HTBM) and other government mechanisms. With limited user revenues and strategic investment drivers, traditional financial tests such as Long-Run Marginal Cost (LRMC) analysis and Net Present Value (NPV) assessments will be less relevant.

As the market matures, economic tools will become more important, ensuring that new infrastructure is justified and cost reflective. Over time, this will introduce the same economic rigour that underpins investment decisions in the gas network.

The early hydrogen connections process should remain light-touch and proportionate to the network. The established principles of the gas frameworks (transparency, standardisation, and clear governance) should be retained but simplified. A "Hydrogen A2O" process could manage initial enquiries and offers through a digital portal with shorter timelines, later complemented by a more structured "Hydrogen O2O" (offer to operation) process as the market expands.

Technical Assumptions and Evidence Review

Robust evidence and realistic assumptions are essential to designing a credible connections regime. Recent analysis has identified several areas where existing hydrogen modelling, especially around costs, carbon intensity, and system design requires refinement.

Electricity price assumptions

A key observation is that many hydrogen cost models assume fixed or high electricity prices, failing to account for the system-balancing role hydrogen can play. In practice, green hydrogen producers are expected to operate flexibly, consuming electricity during periods of low or negative wholesale prices when renewable generation exceeds demand.

This flexibility means that hydrogen production could reduce rather than add to overall system costs by helping absorb surplus renewable energy and avoiding curtailment. Since a significant percentage of the levelised cost of hydrogen is linked to electricity, charging and investment decisions must reflect realistic assumptions about dynamic pricing, avoided curtailment payments and flexible operation.

More expensive connection options could be justified if the financial benefit of enabling hydrogen's system-balancing role exceeds the cost of the additional capacity, ensuring that network investment supports wider decarbonisation and efficiency goals.

Implications for hydrogen connections policy

Key design principles for the hydrogen connections process:

- **Dynamic cost modelling** – connection offers should incorporate realistic, time-varying electricity and system-balancing assumptions.
- **Integrate carbon certification** – carbon-intensity verification should be embedded within the connection application and approval process.
- **Recognition of flexibility** – connection terms should accommodate variable and intermittent operation without undue penalties.
- **Support for storage** – early connection incentives should recognise storage's role in system balancing and security of supply.
- **Technical realism** – network feasibility assessments should reflect actual system design parameter, not generic distance or compression metrics.

These principles would enable a proportionate, transparent and flexible hydrogen connections regime that supports early market formation while laying the foundation for a fully regulated framework as the sector matures.

Day-One and Day-Two Framework

During the initial "Day-One" phase, the hydrogen connections process should be simple, transparent, and centrally coordinated to support rapid rollout under government funding. Each user connecting to the network will agree a Contracted Maximum Volumetric Flow, defining the physical scale of the connection and the level of service that the network operator must provide. The Con Max will remain fixed for the first fifteen years, aligning with the expected HPBM agreement period.

As the market matures and transitions to Day-Two, the connections regime is expected to evolve toward a more commercial and market responsive structure. Future phases may introduce mechanisms for queue management (taking learnings from the electricity market), allocation of shared infrastructure and more dynamic adjustment of contracted rights. However, these would only be developed once there is sufficient diversity of users and network maturity to justify additional complexity.

Connection Adjustments, Surrender, and Disconnection

Over time, some users may wish to modify or reduce their connection. To protect system stability, significant changes should only be allowed after the initial fifteen-year term unless triggered by permanent site closure. Requests should follow the same structured process as new applications, allowing the operator to assess technical and cost implications.

If a connected user ceases operation early, its agreement will terminate and the associated network capability will become available for future connectees via the Reallocation process. This approach avoids maintaining dormant commercial contracts and ensures that existing infrastructure is efficiently utilised. Where new applicants seek to connect in areas already served by existing assets, the operator may invite nearby users to share or release infrastructure, promoting optimal use of the network and reducing the need for unnecessary reinforcement.

Assignment and Transfer of Agreements

The framework should allow the assignment of connection agreements to successor entities, subject to the operator's approval. The incoming party must demonstrate equivalent technical and financial capability to ensure continued safe and reliable operation. This flexibility supports mergers, acquisitions, and restructuring while maintaining oversight of network integrity.

Annual Validation of Connection Commitments

The network operator should undertake an annual validation of all connection commitments to ensure that the system continues to meet its contractual obligations. This is not a capacity test but a review of whether the network configuration, maintenance programme, and operating pressures remain sufficient to deliver the agreed flow rates and pressures.

This process is critical because there are risks that anticipated supplies or demands may not materialise as expected, this could lead to underutilised assets, stranded investment or localised pressure constraints if flows differ significantly from forecasts. Conversely, unexpected increases in demand or supply could create operational stress or require accelerated reinforcement. Potential risks could include, but are not limited to:

- **Delayed supply projects**
  Hydrogen production facilities or upstream sources fail to come online as planned, leaving capacity underutilised.
- **Early closure of connected sites**
  Industrial users or producers cease operations before the end of their contractual term, reducing expected flows.
- **Demand volatility**
  Offtake customers (e.g. Industrial clusters) consume significantly less or more than forecast, creating imbalance.
- **Mismatch between regional supply and demand**
  Localised surpluses or deficits lead to pressure management challenges and potential curtailment.
- **Infrastructure stranding**
  Reinforcement investments made for anticipated projects become stranded if those projects do not materialise.
- **Accelerated reinforcement needs**
  Unexpected growth in hydrogen demand requires urgent upgrades, increasing costs and operational complexity.

The assessment methodology for this validation is expected to be set out in the Hydrogen Transmission Planning Code (HTPC), ensuring consistency, transparency and alignment with regulatory standards. Findings from this process will inform investment planning and operational priorities, without altering users' rights during Day-One.

Queue Management and Application Windows

In managing multiple connection requests, two main approaches are available:

- **First come, first served (1C1S) –** a continuous 1C1S model offers simplicity and allows individual projects to process quickly, but it can lead to inefficiencies when several users in the same area request connections at slightly different times.
- **Defined application windows –** in contrast to 1C1S, an application window approach enables the hydrogen network operator to consider several proposals together, coordinate shared infrastructure and achieve better cost efficiency.

Given that early hydrogen clusters are being developed through government sequenced business models, the use of application windows aligned to those rounds would provide the greatest coordination and transparency. Applicants would be assessed together within each window, enabling each integrated design and reinforcing fairness between projects. Outside these windows, minor or straightforward connections could still proceed on a rolling basis where this does not compromise strategic planning.

Transparency and Coordination

Maintaining openness in the connections process will be vital for fairness and stakeholder confidence. The operator should publish a Connections Register, showing, at aggregated regional level, the projects that have applied for connection, their status, and indicative delivery timelines. This transparency will help applicants identify opportunities for collaboration, inform investment decisions, and support government and regulatory oversight.

Interaction with Government Business Models

The hydrogen connections framework must align closely with the government's suite of business models, particularly the Hydrogen Production Business Model (HPBM) and Hydrogen Transportation Business Model (HTBM). Projects supported through these mechanisms will use the same standardised connection process, with terms aligned to the relevant subsidy period.

Projects joining part-way through the programme should align with the common system wide end date rather than receiving an additional full term. This ensures consistency and a smooth transition to a future Day-Two regime. Projects outside these government support schemes will be assessed using the same technical standards but may require bespoke commercial arrangements, which we do not expect to be requested in the early years. However, as a matter of preparedness, a process for such an eventuality should be established as backstop.

Indicative Timelines for Connection Offers

Predictable timelines will be important to investor confidence. However, the indicative timelines for issuing connection offers, in the early stages, will be aligned with DESNZ's projected timescales, which have not yet been determined. Once these projections are clarified, the process can be established accordingly. In principle, following submission of a complete application, an initial feasibility response indicating whether a connection appears technically viable and offering indicative cost and schedule estimates, would be provided. Detailed connection offers would then follow-on standardised timescales that reflect project complexity. This approach ensure transparency for applicants while maintaining flexibility until government-led timelines are confirmed.

Policy Options

The hydrogen connections framework must deliver predictability, fairness, transparency and proportionality while supporting rapid early deployment and enabling a smooth transition to a fully regulated regime. Each option below is assed against these objectives, technical design principles and its ability to evolve from a light-touch and simplified day one approach to a more structured day two arrangement.

1 O2O Process (Capacity-Linked Connection)

This option builds on the gas PARCA model, linking technical feasibility to capacity reservation through a structured two-stage process. It offers strong investor confidence and aligns with Ofgem's regulatory precedent, ensuring cost reflective principles are maintained. However, it is resource intensive and slower to implement, making it less suitable for early cluster rollout where commercial structures remain uncertain. While this approach provides clarity and discipline, it is best introduced in later phases when market diversity and revenue streams justify capacity linked commitments.

2 Simplified Connection Process (Non-Capacity Linked)

A simplified process focuses on technical feasibility and indicative costs when a connection can be made without requiring significant asset investment. This approach is agile and imposes a lower administrative burden, supporting early-stage participation and rapid rollout under government backed business models. It is particularly suited to Day-One conditions, where flexibility is paramount. Importantly, it can incorporate key design principles such as carbon certification, dynamic cost modelling and operation flexibility.

3 Strategic Cluster-Led Connection Model

This option integrates the connections process into cluster-level planning, coordinating shared infrastructure and investment. It strongly supports efficient, strategic rollout and aligns with government cluster sequencing policy, ensuring that network expansion avoids duplication and maximises cost efficiency. While highly effective during early cluster development, it requires robust governance and may be less suitable for standalone projects. Its design naturally accommodates shared compression, storage incentives and coordinated feasibility studies, making it a strong candidate for early implementation.

4 Market-Led Bilateral Connection Regime

A fully market-led approach would allow users to negotiate bespoke agreements directly with the hydrogen network operator. This offers maximum flexibility and could encourage innovation for niche projects. However, it risks fragmented development, inequity and inefficiency; and is poorly aligned with government backed rollout objectives. It is therefore better suited to a mature market where bespoke solutions are justified.

Comparative Assessment and Preferred Approach

Each of the four options offers distinct benefits and challenges when assessed against the core objective, as well as their ability to support early deployment and evolve into a structured and enduring regime. The O2O-style model provides structure and certainty but is unlikely to be proportionate in the early market. The simplified approach offers speed and flexibility but provides less investor assurance. The cluster-led model best supports coordinated investment and government funding objectives but reduces user autonomy. A purely market-led approach, while innovative, risks inconsistency and inefficiency.

Preferred approach

Given these trade-offs, a hybrid approach is recommended, combining the strengths and simplicity of a Con Max linked process (option 2) with the coordination benefits of the cluster-led model (option 3). This would allow users to engage early through a straightforward technical connection route while enabling the hydrogen network operator, in partnership with government and regulators, to coordinate investment within and between clusters. This process would remain flexible and proportionate in the near term but provide a clear framework for the introduction of the more formal capacity-linked arrangement one the market reaches maturity.

Over time, this hybrid model could evolve naturally into a structure similar to Option 1 (O2O-Style) as the hydrogen economy becomes more commercial and capacity allocation becomes necessary. This stage evolution aligns with the principles of proportional regulation, investor confidence and strategic network rollout.

Implementation Pathway

Delivering a hybrid approach that combines the simplicity of a non-capacity-linked process with the strategic coordination of cluster-led planning requires a phased and structured implementation strategy.

Phase 1: Framework Confirmation and Design

Government and Ofgem should first confirm how the proposed connections process interfaces with the Hydrogen Transportation Business Model (HTBM), Hydrogen Production Business Model (HPBM), and related regulatory frameworks. This step ensures alignment with subsidy periods and cluster sequencing policy. The hydrogen network operator should then develop detailed procedural documentation, including standardised application templates, evaluation criteria, and indicative charging principles. These documents must embed key design principles such as carbon certification, dynamic cost modelling, and operational flexibility.

Phase 2: Pilot Deployment in Key Clusters

A pilot phase should be launched within one or two major clusters, such as the East Coast and HyNet. This will allow testing of the simplified technical connection process alongside cluster-level coordination mechanisms. The pilot should include queue management approaches, transparency measures such as a published Connections Register, and early integration of storage incentives. Lessons learned from this phase will inform refinements to governance, timelines, and technical standards.

Phase 3: Wider Rollout and Evolution to Day-Two

Following successful pilots, the process should be rolled out across all clusters and adapted for standalone projects where appropriate. As the market matures, the framework should gradually incorporate capacity-linked arrangements, queue management, and cost-reflective charging principles. This evolution will ensure a seamless transition from a light-touch Day-One regime to a fully regulated Day-Two structure, maintaining proportionality while introducing commercial discipline.

Phase 4: Continuous Review and Enhancement

The implementation pathway must include ongoing review to ensure the framework remains fit for purpose as hydrogen networks expand. This includes monitoring technical assumptions, updating carbon certification requirements, and refining economic tests such as LRMC and NPV as they become relevant. Regular engagement with stakeholders and publication of performance metrics will reinforce transparency and investor confidence.

Connections outside of HAR and HTBM

This process is being proposed to provide a clear and efficient route for customers seeking to connect to the hydrogen transmission network without going through the Hydrogen Allocation Rounds (HAR) or Hydrogen Transmission Business Model (HTBM). It aims to balance predictability and transparency, which are critical for investor confidence, while maintaining flexibility to accommodate evolving market conditions. Importantly, this option is necessary in addition to the HAR model because there is uncertainty about when an alternative connection process will need to be implemented. Specifically, it is unclear whether this would occur partway through the initial 15-year HTBM period or at the discretion of the customer. Ensuring that a simplified pathway is available provides resilience in the connection framework and supports timely market development.

Initial application

Customers seeking to connect to the network must first submit a completed application and pay an initial application fee. This fee would apply regardless of the pathway the customer ultimately follows.

Pathway determination

Following the initial application, NGT will assess a series of factors to determine whether the customer can proceed via the simplified connection process of must apply through the Hydrogen Allocation Rounds (HAR). These factors include:

- **Minimum connection requirements –** does the proposed connection meet baseline technical and regulatory criteria?
- **Network capability –** Is sufficient capacity available in the network to accommodate the new connection?
- **DESNZ approval:** Has DESNZ confirmed alignment with policy etc?

If all these conditions are met, the customer may proceed through the simplified process. If any condition is not met, the customer will be directed to apply through the HAR process.

Simplified Application to Offer (A2O) process

Where the simplified pathway applies, the customer will enter the A2O process, which requires:

- **User commitment:** A financial commitment to pay the ongoing capacity/commodity charges from a specified date.
- **Connection fee:** Payment of the applicable design and physical work.

This streamlined approach is designed to provide clarity and efficiency of qualifying projects.

Timelines and transparency

Predictable timelines are essential for investor confidence. Following submission of a complete application, the operator should provide an initial feasibility response in a reduced, but realistic timeline, potentially as low as thirty business days if it can be demonstrated to be viable. This response should indicate whether the proposed connection appears technically viable and offer indicative costs and schedule estimates. Detailed connection offers will then follow-on standardised timescales that reflect project complexity. This structured approach ensures transparency for applicants while allowing the operator to manage resources effectively.

Future access

There is currently uncertainty about when customers could seek to apply for a connection without going through a HAR. Specifically, it is unclear whether this option would only become available partway through the initial 15-year period covered by the HTBM or whether it could be at the request of the customer. If the latter, this option would need to be readily available throughout the initial 15-year period, ensuring flexibility for new entrants and supporting market development.

Conclusion

The development of a hydrogen connections framework is pivotal to enabling the UK's hydrogen economy and achieving net zero goals. While the gas regime offers useful precedents, hydrogen's early-stage characteristics demand a proportionate, flexible approach which can evolve over time. A hybrid model, combining the simplicity of a non-capacity linked process with the strategic coordination of cluster-led planning, strikes the right balance between agility and long-term discipline. This approach supports rapid deployment under government backed business models while providing a clear pathway to a more structured, capacity-linked regime as the market matures. By embedding transparency, fairness and technical realism from the outset, the framework will foster investor confidence, encourage innovation and ensure efficient network development aligned with national decarbonisation objectives.

Introduction
Assumptions
Proposals
Section 1 Capacity
Section 2 Balancing
Section 3 Charging
Section 4 Neutrality
Section 5 Connections
Section 6 Appendix

6. Appendix

Carbon intensity and certification

Uncertainty remains across published data sets regarding hydrogen's carbon intensity, particularly where green and blue hydrogen are compared without distinction.

- **Green hydrogen** produced from renewable electricity should achieve very low emissions reflecting the Low-Carbon Hydrogen Standard (LCHS).
- **Blue hydrogen** outcomes depend on carbon capture efficiency. Some analyses assume low capture rates (30-60%) whereas emerging UK projects are targeting efficiencies above 90%.
- **White hydrogen** remains an emerging area; future connection frameworks should retain the flexibility to accommodate such sources if they become commercially viable.

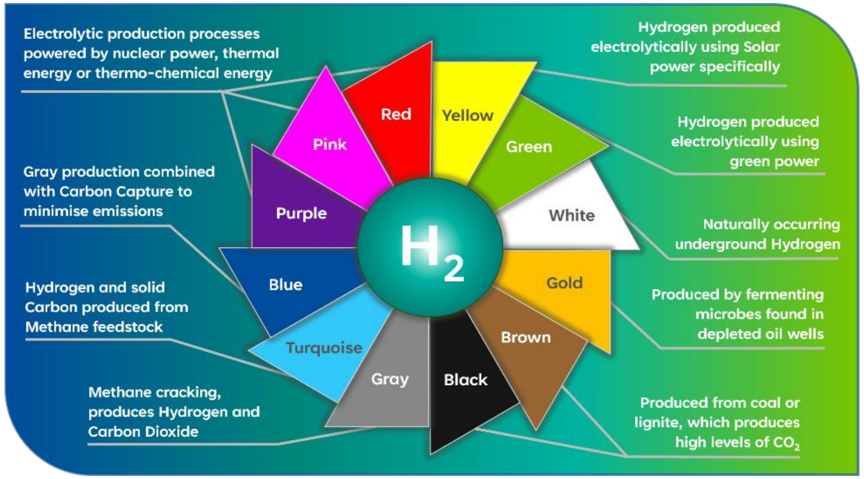
All hydrogen entering the network will need to be certified against the threshold/standard set by the LCHS. Connection and access agreements should therefore integrate carbon-intensity tracking and certification requirements to maintain compliance and enable market transparency.

Electrolyser flexibility and scale

Evidence suggests that electrolysers are becoming increasingly capable of flexible operation, with ramp rate compatible with the variability of renewable power. Early assumptions that electrolysers cannot cycle efficiently are now outdated[32,33].

Connection arrangements should recognise this flexibility by allowing producers to vary flow rates without punitive charges, especially during early market formation. Connection and queue management processes must therefore be capable of accommodating both small demonstration plants and large-scale installations under a common framework.

Colours of Hydrogen[34]



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