Department for
Energy Security
& Net Zero

Funding mechanism for the Hydrogen Production Business Model

Consultation on the proposed Gas Shipper Obligation

Closing date: 9 April 2025

January 2025

Any enquiries regarding this publication should be sent to us at: GasShipperObligation@energysecurity.gov.uk

Introduction

The climate and nature crises are the greatest global challenges that we currently face. The transition to a low-carbon, clean energy system represents a huge opportunity to generate green growth, tackle the cost-of-living crisis and support our energy security. That is why the Clean Energy Superpower Mission is one of Government's national priorities, to achieve clean power by 2030 and accelerate the transition to net zero. The Government has already launched GB Energy, a publicly owned clean-power company that will help cut bills for good and boost energy security; removed the *de facto* ban on onshore wind; and announced the biggest renewable energy auction to date, increasing our total low carbon electricity Contracts for Difference (CfD) portfolio to around 39GW[1]. Low carbon hydrogen will play an important role in supporting the delivery of our Clean Energy Superpower and Growth missions, as a key enabler of a low carbon and renewables-based energy system. DESNZ whole energy system modelling and external analysis (such as the National Grid Electricity System Operator's Future Energy Scenarios[2]) indicate that hydrogen is expected to play an important role in our path to net zero. In the absence of hydrogen deployment, alternative decarbonisation technologies would need to be deployed in its place, to help contribute towards our carbon budgets, and we expect that these alternatives would be more expensive.

Low carbon hydrogen can make our energy system more flexible, resilient, and independent, and could lead to billions of pounds of savings by 2050[3]. Hydrogen fuelled power generation coupled with long duration energy storage could provide £13bn to £24bn in savings to the power system between 2030 and 2050. Government sees hydrogen to power (the conversion of low carbon hydrogen to produce low carbon electricity) as a key technology in supporting our commitment for a decarbonised and secure power system. The Clean Power 2030 Action Plan recognised the value hydrogen to power can add to a clean power system and set out practical steps to deliver on clean power and accelerate towards net zero[4]. Government analysis also shows that having hydrogen available in the power system could achieve lower emissions at a lower cost than scenarios without hydrogen[5]. The Government has recently published the hydrogen to power market intervention consultation response which commits to the implementation of a new hydrogen to power business model[6].

Today, hydrogen is mainly used in the refining and chemical sectors and almost all is derived from fossil fuels using steam methane reformation, without capture and storage of the resulting carbon emissions. As well as displacing existing carbon intensive hydrogen use, low carbon hydrogen has the potential to be used as a fuel to decarbonise hard to abate industrial processes that are energy intensive or require a direct flame, for example, chemicals and glass, complementing our wider electrification efforts to accelerate progress to net zero. Low carbon hydrogen can also help to decarbonise some transport modes. For example, transporting heavy goods over long distances is very difficult to achieve with batteries alone, and therefore hydrogen and its derivatives are likely to be used in shipping. Hydrogen can also be combined with a source of carbon to produce a more sustainable aviation fuel or else used directly as a fuel onboard the aircraft.

[1] DESNZ (2024) Press release: Government secures record pipeline of clean cheap energy projects
[2] National Grid Electricity System Operator (2024) Future Energy Scenarios
[3] DESNZ (2022) Benefits of long duration electricity storage
[4] DESNZ (2024) Clean Power 2030 Action Plan
[5] DESNZ (2020) Modelling 2050: electricity system analysis
[6] DESNZ (2024) Hydrogen to power: market intervention need and design

Hydrogen is a significant industrial opportunity for the UK, and we are well equipped to become a global leader in the production and use of low carbon hydrogen, drawing on strong domestic expertise and favourable geology, geography, and infrastructure. Government is committed to leaving no community behind by investing in a new era for the clean energy industry and supporting good, skilled jobs as the sector matures. Low carbon hydrogen provides opportunities for UK companies and workers, reigniting our industrial heartlands by investing in the industries of the future.

To deliver low carbon hydrogen production in the UK, the Government is supporting producers through the Hydrogen Production Business Model (HPBM). The business model is designed to provide revenue support to hydrogen producers, to overcome the operating cost gap between low carbon hydrogen and high carbon fuels. It is intended to incentivise investment in low carbon hydrogen production and usage, and to deliver security of supply to end users, recognising that both cost and supply security are key considerations for switching. This will help to scale up delivery of the UK hydrogen economy and achieve our Clean Energy Superpower and Growth Missions. A similar approach was taken for the Contracts for Difference (CfD) scheme, which is the Government's main mechanism for supporting low-carbon electricity generation. The lessons learnt from low carbon electricity show that funding to cover the cost gap is an effective tool to reduce uncertainty for investors and developers to enable private investment, bring down costs in the long-term, and create a strong pipeline of projects. In adopting a similar approach to the design of the HPBM, we aim to repeat the success seen in UK low carbon electricity generation[7].

We are supporting multiple production routes for low carbon hydrogen, with electrolytic and CCUS-enabled hydrogen playing the largest roles. The Government is also developing business models to support hydrogen transport and storage[8], which are key to delivering the benefits of hydrogen. Hydrogen transport and storage infrastructure will be vital to delivering these benefits and growing the hydrogen economy as it will connect producers with end users and balance misalignment in supply and demand. These business models could create high quality jobs, grow hydrogen supply chains, and deliver carbon savings which help meet net zero. Securing this investment will help ensure the UK remains a global leader in low carbon hydrogen.

We have begun signing contracts with successful projects from the first electrolytic Hydrogen Allocation Round (HAR1), enabling them to be among the first commercial scale hydrogen production projects in the world to take Final Investment Decisions. In December 2023, DESNZ announced 11 successful projects from HAR1[9], which provides joint HPBM revenue support and Net Zero Hydrogen Fund (NZHF) capital support to electrolytic projects. At the time, this was the largest number of commercial scale low carbon hydrogen production projects announced at once, anywhere in Europe, strengthening the UK's position as a global leader on hydrogen. The successful projects will invest £413m of private capital between 2024-2026 and create over 700 jobs, in addition to the millions of pounds we anticipate will be spent by the offtakers, as they convert their operations to hydrogen. The successful HAR1 projects are estimated to deliver 125MW of new electrolytic hydrogen production capacity in addition to the estimated 32.5MW through the first two rounds of strand 2 of the NZHF, which offered capital support for projects that do not require revenue support[10]. The second Hydrogen

[7] The Climate Change Committee (2024) Progress Report to Parliament
[8] DESNZ (2023) Proposals for hydrogen transport and storage business models
[9] DESNZ (2023) HAR1 successful projects
[10] DESNZ (2022) NZHF strands 1 and 2

Allocation Round (HAR2), which aims to support up to 875 MW of capacity, subject to affordability and value for money, is now underway.

The Energy Act 2023 enables two options for funding the HPBM as well as the Hydrogen Transport Business Model and the Hydrogen Storage Business Model: a levy on gas shippers (the Gas Shipper Obligation (GSO)) and government funding. The Government intends for the GSO to be the long-term funding mechanism for HPBM payments to initial hydrogen production projects. This consultation, and the accompanying analytical annex, provide a snapshot of GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects, given that these are the only projects which are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it, as well as decisions on the funding arrangements for the hydrogen transport and storage business models. However, we expect subsidy costs per unit of hydrogen to fall over time, due to technological maturity, learning-by-doing and economies of scale. Further deployment of hydrogen would also be expected to result in wider benefits to the energy system which, as mentioned above, could result in future electricity bill reductions.

We expect to introduce the GSO in 2027, subject to legislation being in place. Prior to the GSO's implementation, HPBM payments are intended to initially be funded by Government. The GSO will initially be placed on licensed gas shippers in Great Britain only. The powers that provide for the GSO in the Energy Act 2023 also enable it to be placed on gas suppliers in Northern Ireland who, in the opinion of the Secretary of State, carry on activities of gas shipping similar to those of licensed GB gas shippers. Government may consider the potential expansion of the GSO to NI gas suppliers in the future, subject to further engagement with relevant stakeholders and decisions on the funding of future hydrogen projects. More detail on this is set out in *Section 1.1.1*.

To guarantee our energy security and protect vulnerable households permanently, we need to speed up the transition away from unabated fossil fuels and towards homegrown clean energy. An over-reliance on fossil fuels increases our exposure to price shocks from global gas price spikes. Any delay to building new low carbon generation poses future risks to consumers, especially vulnerable households who are the most affected by high energy bills. In the short term, we will support vulnerable consumers this winter. We will continue to deliver the Warm Home Discount which provides a £150 annual rebate on energy bills for eligible low-income households. We expect that more than 3 million households will benefit from this support over the winter. In addition, Government and industry have worked together to deliver the £500m Winter Support Commitment to provide a range of support for vulnerable consumers. The Government's ambitious Warm Homes Plan will upgrade millions of homes across the country by making them cleaner and cheaper to run, from installing new insulation to rolling out solar and heat pumps. As the first step towards the Warm Homes Plan, Government has committed an initial £3.4 billion over the next 3 years towards heat decarbonisation and household energy efficiency, with £1bilion of this allocated to 2025. The £3.4 billion includes £1.8 billion to support fuel poverty schemes, helping over 225,000 households reduce their energy bills by over £200.

In designing the GSO, the Government aims to minimise costs and administrative burden on all parties wherever possible, and we welcome views from stakeholders, including gas shippers, on the design proposals outlined in this consultation.

Contents

Introduction 3
General information 8
Why we are consulting 8
How to respond 9
Confidentiality and data protection 9
Quality assurance 9
Executive Summary 10
1. Scope and design principles 11
1.1 Support for low carbon hydrogen production 11
1.1.1 Territorial scope of the Gas Shipper Obligation 11
1.1.2 The role of gas shippers in the energy market 12
1.2 Design Principles 13
2. Impacts on energy users 14
2.1 Assumptions regarding the pass through of costs 14
2.1.1 Impacts on energy users 14
3 Charging approach 17
3.1 Charging approach options 17
3.2 Determining the quantities of gas shipped 19
3.2.1 Underlying data set 19
3.2.2 Interconnectors 20
3.2.3 Gas reconciliation 21
3.2.4 Hydrogen transport, blending and biomethane 21
4 Operation of the Gas Shipper Obligation 23
4.1 Calculating gas shippers' collection amounts 23
4.2 Length of the obligation period and collection frequency 25
4.3 Alignment of charging periods 28
4.4 Long-term "signal" forecasting 30
4.5 Managing uncertainty 31
4.5.1 Under-collection mitigation 32
4.5.2 Overcollection 33
5 Administration of the Gas Shipper Obligation 35
5.1 Administration 35
5.2 Compliance, enforcement and non-payment 37
5.2.1 Credit cover 37

5.2.2 Mutualisation 40
5.2.3 Compliance and enforcement arrangements 41
5.2.4 Appeals 44
6 Consideration of a potential exemptions scheme in respect of non-domestic gas users 45
7 Next Steps 49

General information

Why we are consulting

The purpose of this consultation is to set out our proposed design for the Gas Shipper Obligation (GSO), a funding mechanism for the HPBM and related costs. The GSO is intended to be the long-term funding mechanism for initial hydrogen production projects. It may also fund further hydrogen projects, subject to future decisions on the hydrogen programme and the funding of future hydrogen production projects. We are seeking views from stakeholders on proposed design choices.

Issued: 16 January 2025

Respond by: 9 April 2025 11:59pm

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Consultation reference: Funding Mechanism for the Hydrogen Production Business Model

Audiences:

We welcome any respondents with an interest in the design of the Gas Shipper Obligation. However, in particular we are seeking views from gas shippers, hydrogen production projects, other relevant participants in the gas market and consumer groups.

Territorial extent:

We welcome respondents from across the UK.

The Gas Shipper Obligation (GSO) will initially be placed on licensed gas shippers in Great Britain. The powers that provide for the GSO in the Energy Act 2023 also enable it to be placed on gas suppliers in Northern Ireland who, in the opinion of the Secretary of State, carry on activities of gas shipping similar to those of licensed GB gas shippers. Government may consider the potential expansion of the GSO to NI gas suppliers in the future, subject to further engagement with relevant stakeholders and decisions on the funding of future hydrogen projects. Even though the GSO is to be placed on GB gas shippers, subject to considerations regarding the calculation of the collection amounts, and assumptions regarding pass-through of costs, the GSO may still have an impact on NI gas users. The department will continue to work with the devolved administrations as the design of the GSO develops.

How to respond

Responses should be provided online where possible at:
https://energygovuk.citizenspace.com/industrial-energy/gas-shipper-obligation-consultation

Alternatively, responses can be submitted via the email or postal addresses below:
GasShipperObligation@energysecurity.gov.uk

Industrial Decarbonisation and Hydrogen Revenue Support Team
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6th Floor
3 Whitehall Place
London
SW1A 2AW

When responding, please state whether you are responding as an individual or representing the views of an organisation.

Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

Confidentiality and data protection

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

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

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy. Your responses, including any confidential information, may be shared with a contracted provider where they are appointed to undertake the evaluation of the consultation responses.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the Government's consultation principles.

If you have any complaints about the way this consultation has been conducted, please email: bru@energysecurity.gov.uk.

Executive Summary

The purpose of this consultation is to set out DESNZ's proposals on the design of the Gas Shipper Obligation (GSO) and gather feedback from a range of stakeholders, including gas shippers, other gas market participants and consumer groups. We ask for feedback from respondents in respect of sections 2 to 6 of this consultation.

Section 1 sets out fundamental aspects of the GSO, including its scope, interactions with the energy market and potential impacts on gas users. Section 1.1 explains the rationale for placing the GSO on gas shippers to fund hydrogen projects and the intended territorial extent of the GSO. Section 1.1.2 outlines the role of gas shippers and their interactions with other aspects of the gas market. Section 1.2 presents the design principles that have been developed to guide the design of the GSO.

Section 2 sets out the potential impact of the GSO on energy users, however further detail on this can be found in the analytical annex.

Section 3 discusses the charging approach options and our proposed approach to determining the quantities of gas used to calculate collection amounts. In section 3.1 we explore the broad design options for the operation of the GSO and explain the rationale for our preferred option. In section 3.2 we set out our proposed approach to determining the quantities of gas shipped for calculating the collection amounts, including our proposed data source and our rationale for the preferred data source, what is considered within scope of the data, and the merits of reconciling gas quantities as part of the GSO.

Section 4 explores the operation of the GSO. In section 4.1 we present our proposal for calculating gas shippers' collection amounts. Section 4.2 sets out the proposed length of the obligation period and collection frequency. Section 4.3 lays out the proposals for the charging periods and section 4.4 sets out our proposed forecasting approach. Finally, section 4.5 presents options for how uncertainty in the collection amounts can be mitigated to minimise the risks of under- and over-collection.

Section 5 concerns the administration of the GSO. Section 5.1 explains the role of the administrator and other bodies who we intend to have key roles in the operation of the GSO and the HPBM. It also covers considerations of administrative costs associated with the GSO for the administrator and shippers. Section 5.2 sets out proposals which aim to minimise the risk of under-collection in the event of non-payment by shippers. Section 5.2.1 sets out a potential credit cover lever and our proposals if this is included in the design of the scheme. Section 5.2.2 sets out a proposed process of mutualisation to collect outstanding amounts from defaulted payments. Section 5.2.3 sets out our proposed compliance and enforcement arrangements should a shipper fail to fulfil an obligation under the scheme.

Section 6 relates to a potential exemption scheme for non-domestic gas users and seeks initial views on sectors which may need to be considered for such a scheme (this includes, but is not limited to, those specifically mentioned) and how it could be implemented.

1. Scope and design principles

1.1 Support for low carbon hydrogen production

The Energy Act 2023 provides powers to introduce revenue support for hydrogen production, transport, and storage, through either levy or government funding. The Act provides powers to require licensed gas shippers in Great Britain (GB) and licensed gas suppliers in Northern Ireland (NI) (who, in the opinion of the Secretary of State, carry on activities similar to those that may be authorised by a GB gas shipper's licence), to comply with a levy by making payments to a levy administrator ('the Administrator'). This levy will be referred to as the 'Gas Shipper Obligation' (GSO) in this document. As set out in the Introduction, the HPBM is designed to provide revenue support to hydrogen producers to overcome the operating cost gap between low carbon hydrogen and high carbon fuels and is intended to incentivise investment in low carbon hydrogen production and use. The Government is also developing business models to support hydrogen transport and storage, which are key to delivering the benefits of low carbon hydrogen production and use. It is possible that the GSO will fund these hydrogen transport and storage business models in future. However, as Government has not yet decided on the long-term funding arrangements for these business models, this consultation focuses on the GSO as a mechanism to fund the HPBM and related costs.

Energy levies have a track record of providing robust funding streams for successful decarbonisation policies, such as the Contracts for Difference (CfD) scheme and the Green Gas Support Scheme (GGSS). The CfD scheme, which supports low carbon electricity generation, is funded through the Supplier Obligation (SO), a levy on GB electricity suppliers. The first 5 CfD allocation rounds have awarded contracts totalling around 30GW of low carbon capacity[11]. The recently concluded sixth allocation round supported over 9.6GW, enough to power 11m homes. The GGSS supports the injection of biomethane into the gas grid and is funded by the Green Gas Levy (GGL), a levy on licensed GB fossil fuel gas suppliers. The scheme is expected to contribute 10.7 MtCO2e of carbon savings via natural gas displacement over its lifetime[12]. Coupling these schemes with a reliable levy funding mechanism provides confidence to industry and helps to create a strong pipeline of projects.

Low carbon hydrogen, alongside electrification, can help to displace existing uses of fossil fuels, such as natural gas. Shippers play a central role in the gas market and so by placing a levy on gas shippers, costs can be spread across the vast majority of gas users.

1.1.1 Territorial scope of the Gas Shipper Obligation

The Energy Act 2023 enables the Secretary of State to make provision in regulations for a levy on licensed GB gas shippers and licensed NI gas suppliers (who, in the opinion of the Secretary of State, carry on activities similar to those that may be authorised by a GB gas shipper's licence) for the purpose of funding revenue support contracts for the relevant hydrogen business models and related costs. In NI, gas shipping is not carried out under a separate licence, in contrast to the licensing arrangements for shippers in GB; instead, companies engaged in gas shipping in NI generally carry out their activities under a gas supply licence.

[11] DESNZ (2023) Contracts for Difference (CfD) Allocation Round 5: results
[12] DESNZ (2024) Green Gas Support Scheme Mid-Scheme Review: Government Response

The Gas Shipper Obligation will initially be placed on licensed gas shippers in GB only, and the design considerations set out in this consultation relate only to how the GSO will operate in respect of GB gas shippers. Government may consider the potential expansion of the GSO to NI gas suppliers in the future, subject to further engagement with relevant stakeholders and decisions on the funding of future hydrogen projects. GB and NI operate separate gas networks, with different system operators, transmission and distribution network owners, regulators, and licensing arrangements. Any decision to expand the scope of the GSO to NI gas suppliers would need to take into account these separate arrangements as well as whether the calculation of the collection amounts include gas shipped to NI via the Scotland-Northern Ireland Pipeline (SNIP) interconnector. As discussed above, just because the GSO is to be placed on GB gas shippers, this does not preclude it from potentially having an impact on NI gas users. Further detail can be found in *Section 3.2.2*.

The HPBM is open to all regions of the UK, and this decision on the initial scope of the GSO will not preclude NI low carbon hydrogen production projects from being successfully awarded contracts under the HPBM. However, it is worth noting that successful HPBM projects announced to date through HAR1 are all located within GB.

1.1.2 The role of gas shippers in the energy market

In GB, the role of a shipper in the gas market is to buy gas from producers, trade gas on wholesale markets, and sell it on to gas suppliers.[13] They operate on a Gas Shipper Licence, which allows the licensee to arrange with a gas transporter for gas to be introduced into, conveyed through, or taken out of a pipeline system operated by that gas transporter.

To arrange for the transportation of gas from producers to suppliers, shippers use a high-pressure transmission network, known as the National Transmission System (NTS).

Gas can be taken off the NTS at NTS Exit points in supply of a premises directly connected to the NTS, at an Interconnection Point (where the gas is conveyed to outside GB), or to be conveyed further downstream for consumption at premises within a Local Distribution Zone (LDZ) or Independent Gas Transporter (IGT).

Premises that are directly connected to the NTS tend to be storage facilities or large gas users that consume gas for industrial purposes or power generation. Gas taken off the NTS at Interconnection Points is conveyed through connecting pipelines to outside of GB. The gas is either transported to other parts of the UK, such as Northern Ireland, or exported to other countries (or the Isle of Man[14]), such as the Republic of Ireland, Belgium and the Netherlands. For more information on the scope of the GSO in relation to gas storage sites and interconnectors, see *Section 3.2*. Premises directly connected to the NTS will have their own meter, which will record the quantity of gas known as a Supply Meter Point (SMP)[15].

When gas is taken off the NTS into the LDZs or IGTs, it is for the purpose of conveying gas to domestic and non-domestic premises that are not directly connected to the NTS. Gas consumption at these premises is also recorded by SMPs.

[13] We understand that shippers may also sell gas directly to end users without holding a Gas Supplier Licence under certain circumstances.
[14] The Isle of Man is connected via a spur line from the interconnector which connects GB to the Republic of Ireland.
[15] As set out in the Uniform Network Code (UNC), Transportation Principal Document (TPD), Section A, 4.1.1.

Shippers may also purchase gas from producers who deliver gas quantities directly into LDZs or IGTs at LDZ System Entry points or IGT System Entry Points respectively. Shippers who purchase gas from these producers will not use the NTS to transport gas.

For the purposes of this document, the term ‘meter point’ is used to refer to SMPs and Interconnection Points, as defined above. We recognise that not all licensed gas shippers are necessarily engaged in arranging for gas to be taken off the NTS, LDZ, or IGTs through meter points (i.e., shipping to meter points).

1.2 Design Principles

This section presents a set of overarching principles that have been developed to guide the design of the Gas Shipper Obligation (GSO). The design of the GSO should, wherever possible, align with these principles.

Solvency: The funds raised by the GSO should provide a robust funding stream to the relevant hydrogen business models, allowing for long-term certainty on revenue support.

Simplicity: Operational simplicity will help ensure additional costs on energy users are minimised over the long term, and that the administrative burden of the GSO is minimised. The GSO also needs to be simple to deliver, to ensure that it can be operational and able to collect funding from 2027.

Affordability and fairness: The GSO should minimise the cost to energy users.

Policy coherence: The GSO should align with wider HMG decarbonisation and energy affordability objectives.

Market stability: The GSO should not create perverse incentives or destabilise the energy market.

Flexibility: The GSO should be flexible to future changes in the energy market.

Compliance: The GSO should minimise the likelihood of non-compliance.

2. Impacts on energy users

The Government believes that the only way to guarantee our energy security and protect vulnerable households permanently, is to speed up the transition away from fossil fuels and towards homegrown clean energy. New, clean, low carbon generation, as part of our Clean Energy Superpower mission, will reduce our exposure to the volatile gas market. A low carbon energy system is the only way to guarantee our energy security and protect billpayers permanently.

2.1 Assumptions regarding the pass through of costs

Charges like energy levies are often incorporated into charges from energy companies to their customers, which can lead to a pass-through of these costs to end users. The extent to which these costs are passed through depends on several economic factors. These include the sensitivity of end users to price changes, the level of competition and the market's structure, the scope and duration of policy costs, the types of contracting arrangements used, and the regulatory environment.

It will be a commercial decision for gas shippers whether they choose to pass on some or all the costs of the GSO to their customers. However, it is our assumption that gas shippers, and suppliers, will pass on costs directly to their customers. This is based on the precedent set by existing levies, such as the GGL and SO, where costs have been passed through to gas and electricity users. Interviews with gas suppliers, conducted as part of the evaluation of the GGL, suggested that suppliers typically passed on the full cost of the GGL to their customers (where this was possible)[16]. Specifically, we have assumed that 100% of the GSO costs will be passed through by gas shippers to end users of gas (either directly to end users or via suppliers).

We note that the GSO is placed on a different point in the supply chain compared to other levies, which could affect how costs are passed through. We are therefore keen to test our assumption around the pass through of GSO costs to end users by shippers and suppliers, to understand how much of the amount levied on shippers might be passed through to end users. This could be influenced by the risk management strategies of shippers to account for the potential variability in GSO payments and how market dynamics might influence cost pass-through between shippers' different customers. We want to ensure that the costs of the GSO which are passed through to end users, fairly reflect the costs borne by shippers, to minimise excessive pass-through of costs. We encourage respondents to consider factors such as fairness, timeliness, and proportionality when providing responses related to the pass-through of GSO costs.

2.1.1 Impacts on energy users

As discussed in the introduction, the GSO is intended to be the long-term funding mechanism for initial hydrogen production projects and the analytical annex includes costs and quantitative impacts for HAR1 projects only, given that these are the only projects which are in the final stages of contract signature. On the basis of HAR1 projects only, we estimate the GSO would need to raise approximately £150m per annum from 2028 to fund those contracts and related

[16] DESNZ (2024) Green Gas Support Scheme (GGSS) and Green Gas Levy (GGL): evaluation (p43)

costs. Under a volumetric design (which is our proposed charging approach, as described in *Section 3.1*), we estimate this could add approximately £2.60 - £4.50 per annum to the average dual fuel household energy bill over the 10-year period we have assessed (2028-2037). For non-domestic gas users, we estimate an increase in the average gas price of up to 2% over this period (2028-2037), dependent on business size, because larger businesses pay a lower base price for their energy. The Government regularly engages Energy Intensive Industries (EIIs) on energy costs and pathways to decarbonisation, to understand the opportunities and the challenges they face, as discussed in *Section 6*. This analysis does not account for the impact of a potential exemption scheme. It also only accounts for the main high-level design options of a volumetric vs meter point levy and does not account for other design variables, such as contingency and credit cover requirements. Please see the analytical annex for further detail regarding the approach to estimating these costs and impacts.

The analytical annex includes details of impacts of the GSO on fuel poverty relating to HAR1 projects. Our estimates show that the impacts of the GSO in relation to HAR1 projects, from 2028 to 2037, for both a volumetric and per meter point levy, are expected to have a minimal impact on England's fuel poverty metrics[17] and the number of households in England facing energy costs greater than 10% of income (after housing costs)[18]. The Government is currently reviewing the fuel poverty strategy and intends to publish the outcome of the review and a consultation on an updated strategy in due course. The main support schemes providing energy efficiency upgrades are the Warm Homes: Social Housing Fund, Warm Homes: Local Grant, Home Upgrade Grant and the Energy Company Obligation. The Warm Home Discount provides bill support to fuel poor households.

The analytical annex includes further detail on GSO costs and impacts, including distributional analysis and a Small and Micro Business Assessment (SaMBA).

As mentioned in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects, given that these are the only projects which are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. We intend to publish strike price and cost information following the announcement of successful hydrogen production projects, and, to the extent those projects are to be funded by the GSO, further analysis of costs and impacts, when available. The affordability of energy bills, including for businesses and those considered fuel poor, remains a key priority for the Government. Decisions on funding for HPBM projects will consider energy bill affordability, value for money, and fairness. It is our intention that our monitoring and evaluation plan for the GSO will include monitoring costs to end users and impacts on fuel poverty. Whilst the amount of funding raised by the GSO would increase with the funding of further hydrogen projects beyond HAR1, as set out above, in the long-term we would expect subsidy costs per unit of hydrogen to fall over time, due to technological maturity, learning-by-doing, and economies of scale.[19]

The analysis presented in the analytical annex only quantifies the estimated 'gross' impacts of implementing the GSO, meaning the costs and impacts are estimated against a zero-cost

[17] In England, a household's energy efficiency rating is calculated using the Fuel Poverty Energy Efficiency Rating (FPEER) methodology. A household in England is considered 'fuel poor' if it has a disposable income (after housing and energy costs) below the poverty line and an energy efficiency rating D or below. The definition of a fuel poor household varies across the Devolved Administrations (DAs), with each DA having specific strategies and schemes to help protect those in fuel poverty.
[18] In Scotland, Wales and Northern Ireland, a 10% threshold forms part of the fuel poverty measurement (ONS)
[19] DESNZ (2021) Hydrogen production costs report

counterfactual. These impacts therefore do not account for the cost of funding alternative decarbonisation technologies that would need to be deployed to contribute towards meeting our legally binding Carbon Budgets in the absence of the projects funded through the GSO, nor for the wider system benefits that could occur as a result of hydrogen deployment.

The hydrogen programme, and electrolytic hydrogen production in particular, could offer wider system benefits, such as from hydrogen providing long duration energy storage and reducing the cost of operating the electricity network (by reducing network constraint costs associated with electricity supply). We expect these benefits could significantly lower the cost of a future decarbonised power system in the mid-2030s.

The hydrogen production funded through the GSO will help contribute towards our legally binding Carbon Budget targets. Therefore, in the absence of hydrogen deployment, funded through the GSO, alternative decarbonisation technologies would need to be deployed in its place, to contribute towards meeting these targets. Internal DESNZ whole energy system modelling and external analysis (such as the National Grid Electricity System Operator's Future Energy Scenarios[20]), indicate that hydrogen is expected to play an important role in our path to net zero. We expect that the deployment of alternative decarbonisation technologies in place of hydrogen would be more expensive. If the increased cost of funding alternative technologies, in place of hydrogen, were also passed on to end users (in a similar way to the GSO), the 'net' bill impacts of the GSO are likely to be positive. This would mean that to meet net zero, bill impacts would be expected to be higher in the absence of funding this hydrogen deployment.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

1. **Do you agree with the assumption (as stated above and in the analytical annex) that gas shippers and suppliers will pass on 100% of the cost of the Gas Shipper Obligation to their customers? If you do not agree with this assumption, what do you think is a more appropriate assumption? Please explain your answer with supporting evidence.**

[20] National Energy System Operator (2024) Future Energy Scenarios

3 Charging approach

This section sets out the Government's proposals for how Gas Shipper Obligation (GSO) costs should be allocated between shippers. As set out above, we assume that shippers will pass on costs through the supply chain to suppliers (or in some cases directly to gas users), who will in turn pass these on to gas users.

3.1 Charging approach options

There are two lead options that we have considered for how to charge shippers, both of which would follow the precedent of other low carbon energy levies: 1) a 'meter point design', whereby shippers are charged based on the number of meter points they ship gas to; and 2) a 'volumetric design', whereby shippers are charged based on the quantities of gas they ship to these meter points. Compared with other options, we consider these options represent two feasible means of charging gas shippers, which are aimed at reflecting the extent to which a shipper is responsible for shipping gas to meter points (and ultimately end users). We do not intend to levy other activities undertaken by gas shoppers which do not reflect this (and therefore a fair distribution of costs in that regard), or those which may create distortive effects on the gas market.

A volumetric design is similar to the way in which the SO charges electricity suppliers, based on the amount of electricity that they supply to end users (in MWh). A meter point design is the charging approach used for the GGL. A volumetric design is our preferred option, for the reasons set out below.

For both options, we assume 100% of costs would be passed on to end users. On a meter point design, the allocation of these costs between shippers would make it necessary for a shipper with more meter points to manage a greater cost. Under this design option, we assume that a gas shipper and gas supplier would likely pass through costs to their customers such that they are charged the same amount, irrespective of the amount of gas they consume. This would mean that small domestic gas users could end up facing the same increase in costs as large industrial gas users, despite consuming significantly less gas. This would lead to disproportionately higher payments for smaller gas users. Furthermore, it does not provide an incentive for users to reduce their gas consumption, unless the user is able to switch away from gas entirely. However, it is possible that shippers (and suppliers) choose to pass costs through on a volumetric basis, by increasing the price per unit of gas. If this was the case, we would expect gas users to be subject to highly variable impacts. This is because, as above, each shipper would be required to manage different costs depending on the number of meters they ship gas to. For example, for two shippers shipping the same quantity of gas, a shipper with a greater number of domestic gas meters would likely be required to increase the price per unit of gas significantly more, compared with a shipper with a lower number of industrial gas meters. Therefore, we consider that a meter point design could result in an unfair distribution of costs across gas users, irrespective of whether shippers and suppliers pass through costs on a meter point or volumetric basis.

We consider that a volumetric design would better reflect the extent to which a shipper is responsible for shipping gas to meter points, since it would be charged on the quantities of gas they ship to these meter points. This is because we understand that a shipper's revenue (and ability to make profit) is correlated to the quantity of gas they are able to sell, and therefore ship, rather than the number of gas users they serve. A shipper that only serves a small number of industrial gas users, therefore shipping to a small number of meter points, could still be shipping more gas than a shipper that serves a large number of domestic meter points. Under a volumetric design, a shipper who ships greater quantities of gas would have to manage a greater cost. We assume that costs would be passed through the supply chain on a volumetric basis, by increasing the price per unit of gas. This is based on our understanding of how costs are passed through under the SO. We therefore expect the price per unit of gas to remain similar across gas users, reflecting a fairer distribution of costs. We expect this to result in reduced costs for households (and other low quantity gas consumers), when compared to a meter point design, since this cost would be determined by the quantity of gas consumed (use more, pay more), rather than the customer portfolio of the shippers.

The analytical annex provides a detailed comparison of these two design options and their potential impact on gas users. As set out there, the share of domestic meter points is forecast to remain constant at approximately 98% of all meter points, however by 2030 we project only 32% - 43% of gas consumption will be by domestic gas users. As such, subject to the assumptions set out above about pass-through of costs, under a meter point design, we consider that domestic gas users would be required to cover a far greater proportion of the costs of the GSO than under a volumetric design.

Although a meter point design would be simpler to design and operate, we consider the benefits of a volumetric design in potentially enabling a fairer pass-through of costs through the supply chain, to outweigh the benefits of a meter point design. A volumetric design is therefore our preferred option for the GSO. The remaining discussion in this consultation, including our options for the calculation of collection amounts in *Section 4.1*, assumes a volumetric design. We recognise that this design may lead to increased impacts on gas intensive users, potentially increasing risks such as carbon leakage, i.e. the movement of production and associated emissions from one country to another due to different levels of decarbonisation effort through carbon pricing and climate regulation. Therefore, we are considering the potential need for exemptions, as discussed in *Section 6*.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

2. **Do you agree that a volumetric design is more likely to facilitate a fairer distribution of costs than a meter point design? Please explain your answer and provide supporting evidence. If you disagree, please provide an explanation with supporting evidence for how a meter point design can equally or better facilitate the pass-through of costs compared with a volumetric design.**

3. **Do you agree with our proposal to proceed with a volumetric design for the Gas Shipper Obligation? Please explain your answer and provide supporting evidence.**

3.2 Determining the quantities of gas shipped

As set out in *Section 3.1*, we propose to charge the GSO on a volumetric basis. This section outlines our preferred option for determining the quantities of gas shipped which would feed into the calculations proposed in *Section 4.1*, for calculating how much a gas shipper will be charged.

3.2.1 Underlying data set

Bearing in mind the design principle of simplicity, we have considered whether the underlying data sets of existing charges within the GB gas charging arrangements might be used to identify the quantity of gas shipped. We consider the underlying data set of the General Non-Transmission Services (GNTS) charge on Exit[21] could be used for this purpose. This charge is payable by shippers via the Commodity invoice administered by Xoserve, where it may be referred to by various NTS Exit Commodity charges (e.g., NCO NTS Exit Commodity Charge). This charge has the following features:

- The GNTS charge on Exit is a transportation charge issued by National Gas Transmission (NGT) to a GB gas shipper in respect of the quantity of gas that it ships to meter points, excluding gas storage sites in certain circumstances, as described below. Each shipper's charge is invoiced monthly by multiplying the relevant rate by the total quantity of gas that the shipper offtakes from the total system. This is a type of commodity charge, which is closely related to consumption of gas by end users. Quantities of gas used to determine this charge are expressed in units of energy (kWh, MWh or GWh).
- Quantities of gas shipped to gas storage sites are excluded from this charge, unless used as part of the operation of the storage facility. This avoids the double charging of those quantities of gas stored which are expected to eventually be shipped to another meter point for consumption.
- The GNTS charge on Exit, is calculated one month in arrears, a fixed number of working days after the start of each month, i.e. the charge is calculated and applied in the month after the gas is shipped.
- The quantities of gas shipped, as described above, are derived from a combination of meter readings and gas consumption forecasts, depending on the availability of data. Readings at meters with daily read capability (which are usually larger sites, such as gas fired power stations or factories, using a significant amount of gas), are taken directly on a daily basis. For meters without daily meter read capability (which are usually smaller sites, like offices or households), these are estimated using the most recently available meter reads, in combination with a correction to account for weather conditions.
- Differences between estimated and 'actual' gas consumption, especially for non-daily metered sites, become known as further meter readings are submitted. Once received, these meter readings correct or 'reconcile' the estimated gas consumption to more accurately reflect actual gas consumption. This ongoing process is known as gas reconciliation and lasts for up to four years. It is used to adjust the GNTS charge (and other commodity charges applied to shippers), and also by suppliers when finalising gas

[21] As set out in the Uniform Network Code (UNC) [Transportation Principal Document (TPD), Section Y, Part A, 4.7](#).

consumption of their customers. Other adjustments to the gas data, for example disputed meter readings (which can affect all meters), will also affect the quantity of gas shipped and require reconciliation.

We are proposing to use the underlying data set to the GNTS charge on Exit (potentially with modifications – please see below) to determine the quantity of gas shipped, as the basis for allocating costs between shippers as detailed in *Section 4.1*. This is because we consider it to contain the best existing available data for us to determine quantities of gas shipped and appropriately allocate costs between gas shippers. The GNTS charge on Exit is administered by Xoserve, the Central Data Services Provider for GB's gas market. This means that, on behalf of the network owners, they collect and process the relevant data and apply the charge to shippers. We intend to work with Xoserve, and the relevant industry bodies, with a view to enabling the sharing of relevant data with the Administrator, for the purpose described above.

3.2.2 Interconnectors

We acknowledge that we will need to consider the interaction with gas interconnectors. Gas interconnectors connect gas transmission systems in Northern Ireland and other countries (or the Isle of Man) to the National Transmission System (NTS) in GB. Further work is needed to consider whether gas shipped to interconnectors for conveyance outside of GB could and should be excluded from the calculation of the GSO, potentially requiring modifications to the data set.

The HAR1 impacts set out further above and in the analytical annex are based on UK-wide data on gas consumption and so should be considered for all UK gas users, including NI gas users. As explained in the analytical annex, we do not have gas demand forecasts covering our appraisal period (2028-2037) that disaggregate between NI and GB gas consumption and do not have data on gas shipped specifically to NI from GB (via the SNIP interconnector). We are therefore unable to set out the estimated quantitative impacts for a scenario where gas shipped to NI from GB is excluded from the calculation of the GSO. However, given that NI accounts for roughly 3% of the UK population, under both options assessed, this variation in the size of the levy base, and corresponding impact, is thought to be minimal.

The HAR1 impacts do not currently account for quantities of gas shipped to other countries (or the Isle of Man) through the interconnectors (except those which are transported to NI, as described above) as we do not currently have data on those quantities. We are therefore unable to set out the estimated quantitative impacts for a scenario where gas shipped to those other countries (or the Isle of Man) through the interconnectors is included in the calculation of the GSO. However, if in scope of the GSO, we would expect this to increase the size of the levy base that shippers recover costs from under this option, reducing the impacts to gas users compared to the estimates set out in this analysis.

Further below we invite suggestions of any data or evidence that could be used to determine current and future quantities of gas shipped to NI and other countries through the interconnectors.

As set out in *Section 1.1.1*, Government may consider the potential expansion of the GSO to NI gas suppliers in the future. Any decision to expand the scope of the GSO to NI gas suppliers, would need to consider whether the calculations of the GSO include gas shipped to NI via the SNIP interconnector.

3.2.3 Gas reconciliation

As mentioned above, there may be differences between estimated and ‘actual’ gas consumption recorded by meter readings, and cases where meter readings are disputed. Once received, meter readings are used to derive the actual gas consumption from the estimated gas consumption initially calculated, and this provides a more accurate reflection of gas shipped. ‘Reconciling’ gas quantities in this way is common for most commodity-based charges in the gas market. This process more fairly reflects gas consumption at meter points, and therefore the charge amounts allocated to each shipper are proportionate to the quantities they shipped.

We therefore intend to include reconciled gas quantities as part of the GSO payments. This would require adjusting shippers’ collection amounts based on updated gas data for previous obligation periods (this is the period over which the quantity of gas shipped would be determined using the data set as described above to calculate a shipper’s allocation of GSO costs, in respect of which please see *Section 4.2* for more detail).

However, we acknowledge that reconciliation of gas quantities and the adjustments to shippers’ collection amounts in respect of previous obligation periods could add additional complexity to the operation of the GSO. We are considering how best to include reconciled gas quantities within the design of the GSO, including whether the cut-off date for reconciliations should extend to the standard four years for meter reading submissions, or if earlier data of gas consumption is sufficiently accurate to use as ‘actual’ gas consumption and therefore apply an earlier cut-off date for reconciling gas quantities. Due to the diminishing improvements in accuracy over time, we consider that an earlier cut-off date could reduce the ongoing administrative burden to reconcile the gas volumes without significantly reducing the final accuracy of the data used.

We are also considering whether to align the gas reconciliation process and adjustment of shippers’ collection amounts with the collection frequency, as described in *Section 4.3*, or to run the gas reconciliation process and to correct shippers’ collection amounts less frequently than this. The latter option would mean that shipper charges would reflect inaccuracies in the data for longer periods of time between updates. However, this could also reduce the administrative burden of the GSO, without reducing the final accuracy of the data used.

The reconciliation of gas quantities and adjusting shippers’ collection amounts in respect of previous obligation periods, considerations on the cut-off date for reconciliations and how best to align reconciliation to other GSO processes, are subject to further assessment of data availability, feasibility and the administrative burden, as well as through feedback received through this consultation.

3.2.4 Hydrogen transport, blending and biomethane

As above, we intend for the GSO to only be charged on gas quantities shipped to meter points. This gas is currently primarily composed of methane but also includes other gases. In August 2023, Government set out a minded-to position on the high-level design of the Hydrogen Transport Business Model, which would support infrastructure for the transportation of hydrogen. We note that the design of the GSO may need to be updated in the future – for example, to avoid the GSO potentially undermining the intention of the HPBM to incentivise the production and use of low carbon hydrogen, were volumes of 100% hydrogen to fall within its scope.

The scope of the GSO may also need to be reviewed in the light of future decisions on blending hydrogen with natural gas into the NTS and LDZs/IGTs, as well as the future role of biomethane injection within these networks.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects which are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

4. **Do you agree with the proposal for the Administrator to use the underlying data set for the GNTS charge on Exit (potentially subject to modifications as set out above) as a basis for determining the quantity of gas shipped for the calculation of collection amounts? Please explain your reasoning with any supporting evidence. If you disagree, please set out any alternative approaches which could be used and explain why you consider them to be preferable and how they align with the design principles.**

5. **Please provide suggestions of any data or evidence that could be used to determine current and future quantities of gas conveyed outside of GB through interconnectors? Please explain your answer and provide evidence to support your response.**

6. **What are your views on the possible exclusion of gas shipped to interconnectors for conveyance outside of GB from the determination of quantities of gas shipped for the calculation of collection amounts? Please explain your answer and provide any supporting evidence.**

7. **Do you agree with our intention to use reconciled gas quantities to derive actual gas consumption when calculating the collection amounts? Please explain your answer and provide any supporting evidence.**

8. **Do you have any views on how best to include reconciled gas quantities within the GSO, including whether to implement an earlier cut-off date than the standard four-year process, and whether you have any views on running the gas reconciliation process and correction of payments less frequently than the collection frequency? Please explain your reasoning with any supporting evidence.**

4 Operation of the Gas Shipper Obligation

This section considers the operation of the Gas Shipper Obligation (GSO). We have aimed to align our proposals with existing market practices where possible, recognising the importance that this would have on minimising the administrative burden on gas shippers and the gas market as a whole.

4.1 Calculating gas shippers' collection amounts

Section 3 sets out our proposal to charge the GSO in proportion to the quantities of gas shipped, and our proposed approach to determine those quantities. In this section, we set out the options we have considered for calculating gas shipper collection amounts based on quantities of gas shipped, as well as our proposed approach.

Option A – Market share approach (preferred)

It is our intention that the GSO should be charged to shippers in proportion to their market share of quantities of gas shipped. Over the obligation period, each shipper's market share would be calculated based on their quantity of gas shipped, as a proportion of the total quantity of gas shipped by all shippers[22] (the scope of which is detailed in *Section 3.2*). Each shippers' collection amount would then be calculated based on their market share (ms_a) multiplied by the estimated total collection amount. The total collection amount would include an estimate for the HPBM payments for the relevant HPBM billing period and potentially administrative/operational costs (these costs are discussed further in *Section 5.1* as well as the potential for a separate obligation to account for administrative/operational costs calculated in a similar way). This is broadly shown below for an obligation period:

$$market\ share\ for\ gas\ shipper\ a\ (ms_a) = \frac{shipper\ a\ quantity\ of\ gas\ shipped}{total\ quantity\ of\ gas\ shipped}$$

$$collection\ amount\ for\ gas\ shipper\ a\ (c_a) = ms_a \times estimated\ total\ collection\ amount$$

As set out in *Section 3.2*, our proposal for determining the quantities of gas shipped for any obligation period would involve the use of some estimated meter readings and there may be some differences in data owing to, for example, disputed meter readings. We intend to account for reconciled gas quantities as part of ongoing payments, as discussed in *Section 3.2.3*. We also propose that the obligation period precedes the relevant HPBM billing period by at least two months, as described in *Section 4.3*. This would allow for more accurate initial charges to be made and therefore a reduction in the amount of reconciliation required.

As explained in *Section 4.3*, we also consider it necessary for the collection period to precede the relevant HPBM billing period. This is to allow time for payments to be collected from shippers before the Low Carbon Hydrogen Agreement (LCHA)[23] Billing Statement is issued to hydrogen producers. This should help ensure a robust, reliable, and timely funding stream for the HPBM. It will therefore be necessary for the Administrator to determine a gas shipper's

[22] The calculations may need to consider the removal of quantities of gas exempt from the GSO, as discussed in *Section 6*. The calculation presented here is illustrative.
[23] The Low Carbon Hydrogen Agreement (LCHA) is the contract which underpins the Hydrogen Production Business Model (HPBM).

collection amount for an obligation period and invoice shippers before the total amount of monies required to fund the HPBM payments for the relevant HPBM billing period is finalised (however we propose that there is a reconciliation process to reflect the actual HPBM payments required, please see *Section 4.5* for more details on managing instances of overcollection). Therefore, a gas shipper's collection amount for an obligation period is calculated based on an estimate of the total collection amount required to fund relevant HPBM payments and costs (as shown in the formulae above). Given the uncertainty in these estimates, we consider that the Administrator will require the collection of contingencies to mitigate the risk of under-collection, which is discussed further in *Section 4.5*, alongside managing instances of overcollection. This means that the collection amounts for each shipper would be different to their final obligation, but the same market share methodology would apply when these are finalised.

Option B – Setting a pre-determined obligation rate

An alternative approach we have considered is setting a pre-determined obligation rate in pounds per unit of gas shipped in advance of the obligation period. This approach would require the Administrator to determine an estimate of total quantity of gas shipped during an obligation period (ahead of receiving the relevant underlying data from the GNTS charge on Exit), as well as the estimated total collection amount, to calculate the obligation rate. At the end of the obligation period, the obligation rate would be multiplied by the quantity of gas shipped over the obligation period by a gas shipper (using the relevant underlying data set from the GNTS charge on Exit which would by that point be available). This is to determine that gas shipper's collection amount. This is broadly shown below for an obligation period:

$$obligation\ rate (or) = \frac{estimated\ total\ collection\ amount}{estimated\ total\ quantity\ of\ gas\ shipped}$$

$$collection\ amount\ for\ gas\ shipper\ a\ (c_a) = or\ \times\ shipper\ a\ quantity\ of\ gas\ shipped$$

As with option A, it would be our intention to determine the quantity of gas shipped by an individual gas shipper after the obligation period in line with our proposals in *Section 3.2.* As mentioned in respect of option A, our proposal for determining the quantity of gas shipped by an individual gas shipper for any obligation period may involve the use of some estimated meter readings and there may be some differences in data, and so we intend to account for those specific reconciled gas quantities as part of ongoing collections as described in *Section 3.2.3.*

The distinguishing feature of option B is that the obligation rate would be announced prior to the obligation period, to help shippers manage the upcoming collection amounts. This means that an estimate of the total quantity of gas shipped over an obligation period would need to be determined, without any metered data ('actuals') underpinning it. This would prevent us from using the relevant data from the GNTS charge on Exit data set for determining the obligation rate, creating an additional administrative burden and reducing the accuracy of initial charges. Charging in this way (with a predetermined obligation rate) carries an increased risk of under-collection compared with option A, since there would be an additional dependence on an accurate estimate of the total quantity of gas shipped (and not just on an accurate estimate of the total collection amount) to mitigate the risk of under-collection.

We believe this approach would require the Administrator to collect even more contingency funds from shippers, compared with option A, to manage the increased risk of under-collection. Please see *Section 4.5* for more details on how these contingency funds might be calculated and collected. Whilst under our preferred option (option A), shippers would be responsible for forecasting their own market share to manage the upcoming collection amounts, we consider that, on balance, it is more important to minimise the amount of contingency funds that need collecting and minimise the risk of under-collection. We also consider that gas shippers are best placed to forecast quantities of gas shipped and therefore their own market share.

For either option, we recognise that shippers will also need a longer-term view of upcoming costs, which is discussed in *Section 4.4*. We also acknowledge that special consideration is needed for managing cases where gas shippers enter or exit the market. In this event we would want to ensure that the transition period minimises the operational risk for new shippers but also minimises the disruption in collections for the Administrator and impact on the remaining gas shippers. We welcome views on how best to manage these events.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

9. **Do you agree with the proposal to take the Market Share approach set out in Option A to calculate gas shippers' collection amounts for an obligation period? Please explain your answer and provide supporting evidence.**
10. **Are there any other options for calculating gas shippers' collection amounts for an obligation period that you think should be considered? Please explain your reasoning and provide any supporting evidence.**
11. **What are your views on how shippers will manage the uncertainty under each option? Please explain your answer and provide supporting evidence.**
12. **Do you have any views on how we should manage new gas shippers entering the market when calculating gas shippers' collection amounts for an obligation period? Please explain your answer and provide any supporting evidence.**
13. **Do you have any views on how we should manage gas shippers exiting the market when calculating gas shippers' collection amounts for an obligation period? Please explain your answer and provide any supporting evidence.**

4.2 Length of the obligation period and collection frequency

There are several options for the length of the obligation period and frequency of collection. The obligation period is defined as the period over which we determine the quantities of gas shipped to calculate a shipper's allocation of the costs to be collected to fund HPBM payments due for the relevant HPBM billing period. For more information on how the obligation period relates to the different time periods within the GSO and HPBM, see *Section 4.3*.

We consider that the most administratively simple approach would be to match the collection frequency with the length of the obligation period. This would mean that gas shippers are required to pay the collection amount after each obligation period, rather than less frequent invoices covering multiple obligation periods or more frequent invoices charging instalments of the payment. We consider that more complex options, where the collection frequency does not match the length of the obligation period, would add complexity with little advantage. For example, we consider that these options would add complexity and challenges for determining the quantities of gas shipped, calculating gas shippers' collection amounts and managing the uncertainty in estimated costs.

We consider the potential options for collection frequency (aligned with the length of the obligation period) to be annual, quarterly, monthly, or daily. Any less frequent or more frequent payment options would be impractical, with constraints on data availability or complications with the size of collection amounts.

Collection frequency (and aligned length of obligation period)	**Assessment**
Annual	An annual collection frequency would be administratively the least burdensome option for shippers and the Administrator given that there would be fewer transactions. However, despite these fewer transactions, there would still be an administrative burden for the Administrator and shippers which may not be reduced as much as expected because this option would extend the intervals for reconciling larger payments. Annual collections would mean requesting more infrequent, but larger, payment amounts from gas shippers. This larger size of collections and financial unpredictability could cause budgeting issues for gas shippers. In turn this could lead to an increased risk of defaulted payments. Collecting payments less frequently could also lead to challenges for the scheme with cashflow or the accumulation of unaddressed issues, as it lengthens the time between the Administrator collecting funds which could potentially strain cashflow and present challenges for HPBM funding. Estimating collection amounts over a longer period may also lead to an increased level of uncertainty in the forecast. We consider that the increased risks of an annual collection outweighs the possible administrative benefits of this option.
Quarterly	A quarterly collection frequency would mean smaller, more frequent collections with greater certainty in comparison to an annual collection. We expect forecasting for a quarterly option would have a reduced level of uncertainty and greater accuracy than an annual frequency. While a quarterly frequency would have a higher administrative burden associated with the collection in comparison to an annual frequency, the administrative burden would be lower than a monthly frequency.

Monthly (proposed option)	It is expected that more frequent, but smaller payments in a monthly option would reduce cashflow challenges and as such reduce the defaulting risk for shippers. We have also considered the frequency of payments to hydrogen producers through the HPBM and the availability of gas data, as discussed in *Section 3.2*. A more frequent monthly collection would reduce the uncertainty in estimates used in the calculation of shippers' collection amounts and so carries a lower risk of under-collection for the Administrator. A monthly collection would also align with the monthly payment to hydrogen producers. Therefore, this option would help to establish more accurate and predictable cycles. However, a monthly frequency would have a higher administrative burden than less frequent options. We consider that the benefits of a more frequent monthly collection outweigh the possible administrative benefits of less frequent collections.
Daily	We do not consider this option to be easily compatible with the proposed approach outlined in *Section 3.2*, or any other existing charges which, as far as we understand, are not administered on a daily frequency. This may therefore create a significant administrative burden on the Administrator (and other industry bodies) to establish a data set to facilitate a daily collection frequency. A daily collection would result in a substantial volume of invoicing statements with a high administrative burden for the Administrator and shippers in the collection process (including to calculate the collection amounts, generate the invoices, and pay daily amounts). This higher administrative burden could also increase operational costs of the GSO. We consider that for the GSO, a daily frequency of collection would not provide a significant benefit in terms of accuracy of estimates and reduced risk of defaults when compared to monthly collections to justify the additional administrative burden and operational costs it would entail.

We propose that the GSO should operate on a monthly collection cycle, which means the length of an obligation period would be a month (for the purposes of calculating a gas shipper's collection amount) and shippers would be invoiced monthly. This aligns with the current approach under the HPBM for payments to be made to hydrogen producers on a monthly basis. A monthly collection frequency of the GSO would reduce uncertainty in the estimate for the HPBM payments used to inform the estimated total collection amount and the corresponding invoice calculations, compared with a quarterly or annual frequency where there is greater uncertainty in forecasting events further in the future. This would reduce the risk of under collection (where the Administrator collects too little money) and therefore minimise the contingency required (the amount of additional funding required from shippers to compensate for the uncertainty inherent in the estimates used to calculate a shipper's collection amount and with a view to covering any unforeseen costs – please see *Section 4.5* for further detail). It would also reduce the risk of over-collection. We anticipate that smaller, more frequent collection amounts would be easier for gas shippers to manage compared to larger, more infrequent payments as it would allow them to plan and budget more effectively. We particularly welcome views from gas shippers on this point. Increased frequency of collection also helps mitigate the impact of any defaulted collection amounts which could be subject to a mutualisation event (see *Section 5.2.2* for more detail on mutualisation), given the defaulted amounts would be smaller rather than larger amounts that have accumulated over a longer period of time.

Therefore, we consider that monthly collection frequency strikes the best balance between administrative burden and accuracy of estimates and reduced risk of defaults when compared with daily, quarterly and annual collection frequency.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

14. **Do you agree with the proposal for the Gas Shipper Obligation to operate on a monthly obligation period and collection frequency? Please explain your answer and provide supporting evidence.**

4.3 Alignment of charging periods

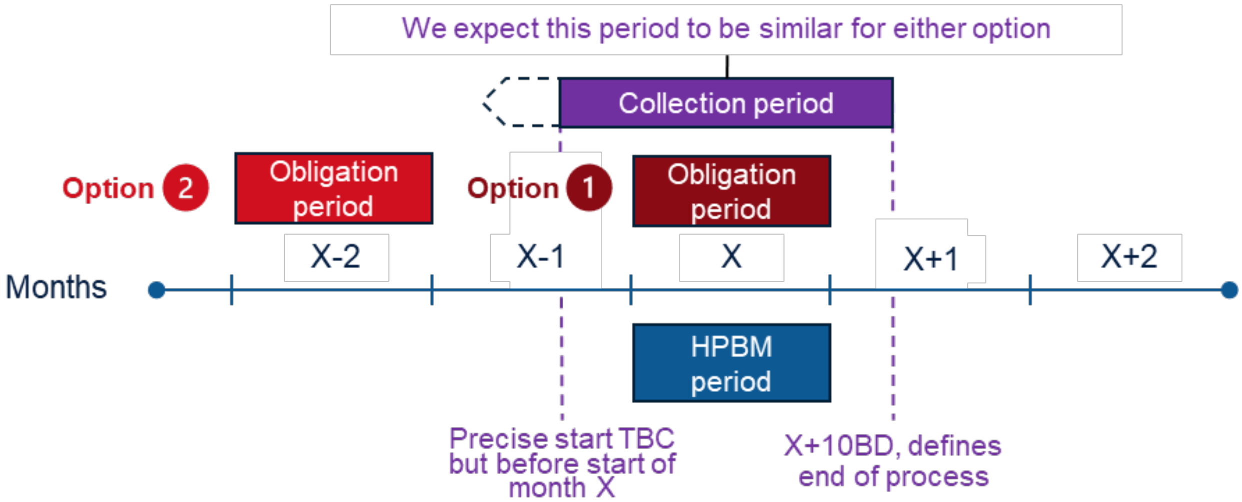
We are considering options for the alignment of the different time periods relevant to the calculation of the GSO. These time periods can be summarised as the following:

- The HPBM billing period: The period over which the hydrogen production volumes are measured to determine the total sum of HPBM payments needed. These have already been defined in the LCHA as monthly periods, with payments being made to hydrogen producers in the following month.
- The obligation period: The period over which we determine the quantities of gas shipped to calculate a shipper's allocation of costs to be collected to fund HPBM payments due for the relevant HPBM billing period.
- Collection period: The period of time the Administrator requires to undertake and complete the process of collecting shippers' collection amounts to fund the payments due in respect of an HPBM billing period. Core processes in this period include calculating shipper collection amounts, invoicing shippers, collecting payments and recovering unpaid sums if necessary.

We consider that the collection period would need to start before the relevant HPBM billing period to allow sufficient time to complete this process. We consider that this process would likely last over a month. The precise length of the collection period will depend on the basis for the calculations, including what data will be used and when this becomes available. The latest point at which the funds collected through the GSO must be known is the point at which the LCHA Billing Statement is issued, which is up to 10 business days after the relevant HPBM billing period. We have therefore considered the following options considering the need for the collection period to precede the relevant HPBM billing period.

Figure 1 illustrates the broad options considered, where 1) is an aligned obligation and HPBM billing period, and 2) represents moving the obligation period earlier by 2 months (although this is one illustrative example based on an obligation period of a month, and could be moved earlier by any number of months, in particular dependent on the length of the obligation period which is considered in further detail in *Section 4.2*). There is further discussion of these options below.

Figure 1: An illustration of the options for alignment of the HPBM billing period and obligation period.



Option 1 is to align the HPBM billing period and obligation period. A potential benefit of this approach would be that a shipper's allocation of costs to fund a HPBM billing period could be based on the most current picture of the shipper market during that billing period. This is the precedent used by the Supplier Obligation. However, since we need to start the collection period (and therefore the calculation of shipper collection amounts) before the HPBM billing period, we would need to rely entirely on forecasts of quantities of gas shipped during the obligation period to calculate a shipper's allocation of costs. Forecasting quantities of gas shipped entirely, rather than using an existing data set (which, as described in *Section 3.2*, includes a mix of actual and estimated data of quantity of gas shipped), would be more administratively burdensome and would not necessarily accurately reflect the actual picture of the shipper market during the HPBM billing period, undermining the key potential benefit from aligning the HPBM billing period and obligation period and potentially leading to more reconciliation.

Option 2 would be to set the obligation period earlier than the HPBM billing period to allow time for the latest data set on gas quantities shipped in respect of that obligation period to become available and for the collection period to complete before the LCHA Billing Statement is issued (up to 10 business days after the HPBM billing period). This approach would mean a shipper's allocation of costs to fund a HPBM billing period is based on a picture of the shipper market preceding the billing period and allows for greater initial accuracy when determining quantities of gas shipped during an obligation period, more accurate initial charges, and a reduction in the amount of reconciliation required. Ultimately how far in advance an obligation period would need to precede the HPBM billing period to enable the benefits of this option will depend on the length of the obligation period, which is considered in *Section 4.2*, and the length of the collection period. If we were to proceed with our proposed approach to a monthly obligation period and based on our assumption that the collection period would likely last over month, we consider that the obligation period would need to precede the HPBM billing period by at least two months. If the obligation period and/or collection period were longer, then that would mean the obligation period would need to precede the HPBM billing period by more than two months. However, the greater the gap between the obligation period and the billing period, the more outdated the shipper allocations would be, potentially leading to unwanted distortions as shippers' collection amounts would not be a current reflection of the shipper market during the HPBM billing period.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

15. **Do you agree with our proposal for the obligation period to precede the HPBM billing period by at least two months, dependent on the length of obligation period and collection process? Please explain your answer and provide supporting evidence.**

4.4 Long-term "signal" forecasting

We recognise the importance of long-term forecasts for gas shippers to be able to build the costs of the GSO into their business planning. It is our intention to publish a "Signal Forecast" that would provide longer-term indications of total aggregated business model costs and other costs associated with the GSO. We consider that this forecast would be important for gas shippers – and potentially the wider market – to incorporate the costs of the GSO into price setting activity. We need to balance the desire for gas shippers to have long term sight of GSO costs with the accuracy of a long-term forecast and have considered the timespan, breakdown (for example, monthly or quarterly) and update frequency with which to forecast these costs and welcome views from respondents.

We consider a 12-month timespan would be appropriate to provide long term visibility of estimated costs. The selected timespan must balance the benefits of providing long term visibility against the decreasing accuracy with forecasts further into the future. The signal forecast could provide a shorter-term forecast with a timespan of less than 12 months, for example 6 or 9 months, although this may not provide sufficient sight of potential costs. We believe a forecast longer than 12 months would have diminishing usefulness as the forecast would become less accurate over a longer timescale, particularly with the nascency of the hydrogen market. As the scheme matures and the hydrogen market develops, the time horizon of the signal forecast could be reviewed.

We also propose that the 12-month signal forecast would show a monthly breakdown of costs and would be updated on a rolling monthly basis. Given the proposed monthly collection frequency, showing a monthly breakdown of costs would reflect estimates aligned with the invoicing timescale and updating the forecast monthly would help to ensure estimates of costs are informed by the latest data.

We would also like to hear any other considerations that stakeholders feel would be necessary to ensure that the market is sufficiently informed of the anticipated liabilities of the GSO. For example, this could be how we present and update the underlying assumptions of the signal forecast or sharing information on portfolio related metrics such as expected start dates. When responding, please consider the Government's response[24] in relation to the data already required to be shared within the project register for agreed HPBM contracts.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

16. **Do you agree with the proposal for the signal forecast to include aggregated monthly costs projected over a year, and for it to be updated on a rolling monthly basis? Please explain your answer and provide supporting evidence.**

17. **Are there any other considerations that should be taken into account to help improve sight of anticipated costs and shipper readiness? Please explain your answer and provide supporting evidence.**

4.5 Managing uncertainty

As discussed in *Section 3.1*, we propose that a gas shipper's collection amount is calculated using an estimated total collection amount. The use of estimates increases the risk of under-collection (i.e. not collecting sufficient funds to meet HPBM payments) and over-collection (i.e. collecting more funds than are needed to meet HPBM payments). In *Sections 3*, *4.1*, and *4.2*, we have considered how the risk of under-collection can be mitigated in the way that we calculate GSO collection amounts and how we set the frequency of the payment schedule. In this section we consider further ways to mitigate and/or manage these risks to help ensure there is a robust and reliable funding stream for the HPBM. *Section 5.2* considers ways to mitigate the risk of under-collection by reason of defaulted payments.

We recognise that longer-term indications of levy costs are important for gas shippers to incorporate the GSO into their price-setting activities and set out our proposals for the Signal Forecast in *Section 4.4*. For the options set out in the following sections, we encourage

[24] DESNZ (2023) Hydrogen production and ICC business model revenue support regulations: government response

respondents to consider how these different approaches may influence factors related to the pass-through of GSO costs such as fairness, timeliness, and proportionality and how the predictability of GSO costs and smoothness of collection amounts may affect pass-through. We consider that an administratively simple approach would minimise operational costs and therefore help to minimise GSO costs overall.

4.5.1 Under-collection mitigation

Through the HPBM, low carbon hydrogen producers are paid the difference between an agreed 'strike price' and the price at which they sell their hydrogen. This is paid for each qualifying unit of hydrogen they produce. This means that there are a number of factors which will lead to variation in monthly payments – including hydrogen production volumes, achieved sales prices, and gas prices. It is critical that the Administrator collects sufficient funds for the business model payments; while also ensuring collections are as smooth and predictable as possible so they are manageable for gas shippers.

To mitigate the risk of under-collection of the GSO, we propose that a contingency amount is collected as an additional amount of funding to compensate for this uncertainty in cost estimates and to help to cover any unforeseen costs. We propose that the calculation of shippers' contingency payments would follow a similar approach to the collection amount (for example, market share or levy rate as discussed in *Section 4.1*), which would be in proportion to the quantities of gas shipped. This section sets out options for collecting contingency on this basis.

Option A – Headroom

One option would be to include an additional amount of 'headroom' in the collection amounts. This would be similar to the approach that is taken for the Green Gas Levy (GGL). The GGL operates on an annual levy rate basis with quarterly collections. The GGL rate is calculated using the Green Gas Support Scheme (GGSS) Overall Scheme Expenditure Budget (OSEB) cap, which is based on expected scheme expenditure for the following financial year, as a basis. The GGL rate also includes additional headroom to cover under-collection risks and ensure there is sufficient funding available for GGSS payments. We consider this option to be the most administratively simple, as it could be combined with the main collection as described in *Section 4.1* into one invoicing process. This approach could also include the operational costs of the GSO (see *Section 5*).

Option B – Separate upfront reserve for multiple obligation periods

An alternative option would be to collect a separate lump sum 'reserve' pre-payment from gas shippers before the obligation periods. This reserve would be collected to cover multiple obligation periods and would be collected less frequently than the main collection amounts. This would be similar to the approach taken on the Supplier Obligation which funds the Contracts for Difference scheme. The Supplier Obligation places an obligation on electricity suppliers in GB to pay a daily and quarterly period contribution to the levy. The Supplier Obligation sets an interim levy rate (ILR), which is collected on a daily basis, and a quarterly total reserve amount (TRA), which is invoiced at the beginning of each quarter. This payment is held as a "Reserve Fund" and is reconciled at the end of the subsequent quarter with collections invoiced as the Net TRA. The purpose of the Reserve Fund is to provide upfront assurance of funds for cashflow given the associated uncertainty of the CfD's costs (due to inherent volatility in the CfDs, e.g. wind-dependent electricity production), for more information on the key factors which create uncertainty in HPBM costs see *Section 4.7* of the accompanying analytical annex. This option would provide greater upfront assurance of funds for the GSO. However, we consider this option may present a higher administrative burden for shippers and the Administrator compared with option A, as this option would involve two separate payment collections. We also consider this option to be more complex, where the upfront reserve is intended to cover multiple obligation periods which would result in the two separate collection processes running on different timescales (one process for the main collection amount, proposed to be monthly in *Section 4.2*, and one process for the 'reserve' – for example, on a quarterly basis if the main collection has a monthly frequency). This could lead to complications with the different timings and separate processes. For example, for the calculation of shippers' reserve amounts the reserve payment would cover a longer time period than the main collection amount and so we consider that there might be complications in splitting the reserve amount by the market share or obligation rate approach due to the difference in timescales.

4.5.2 Overcollection

Overcollection occurs when the GSO collects a greater amount of money than required to fund the HPBM payments and associated costs. Due to the use of estimates in the collection amount calculations and the need to collect some contingency to mitigate the risk of under-collection (as discussed above), we expect there to be some degree of overcollection in most months.

We consider that overcollection may occur within the scheme due to the uncertainty in the HPBM costs estimate, inaccuracy in the estimates of gas quantities shipped, or the collection of contingency payments (as set out above). We intend for there to be reconciliation of the HPBM cost estimates against the actual HPBM spend, with overcollected amounts attributed to shippers in the same proportion as the collection amount during the relevant obligation period. We are also considering how to manage the reconciliation of gas quantities shipped (as described in *Section 3.2.3*) and how the processes for reconciliation of HPBM costs and gas quantities shipped may interact – for example, as separate processes or if there can be efficiencies realised by joining up these processes through the same invoicing procedure.

We are considering the following options for how we can manage instances of overcollection.

Option A – Rollover and netting off (offsetting overcollection)

Rollover of funds across periods is the process of carrying forward the unspent surplus funds from one period to the next. Netting off is the process of calculating the difference between the rolled over funds and the amount payable in the following period. This is often done to simplify the settlement process by consolidating multiple transactions into a single net invoice. In an instance of overcollection, surplus funds could be rolled over and then netted off, which would result in an offset of the overcollected amounts where the surplus reduces the amount payable in a following period. Therefore, one possible approach would be to rollover and offset overcollection against a subsequent collection amount. This could cover main collection amounts and could also be applied to manage the collection of contingency by maintaining (or topping up if contingency funds have been drawn down previously) a consistent level of headroom or 'reserve'. This means over-collected funds could be rolled over and netted off on a monthly basis (or quarterly as concerns any 'reserve' payments). In practice this means surplus funds from overcollection are factored into the subsequent invoicing period. This approach could lead to smoother collections where rolling-over funds could help to manage month-to-month variability.

Option B – Returning over-collected sums

Another possible approach would be to return any overcollection to the respective gas shippers as a reimbursement. There are different options for how frequently over-collected sums could be reimbursed. For example, reimbursements on a yearly basis would help ensure accurate financial reporting and minimise administrative burden and may help mitigate undercollection risks. However, more frequent reimbursements may be beneficial for the Administrator to proportionately and appropriately manage the amount of surplus funds and the extended period of time the Administrator is holding these funds for.

A key consideration when selecting an approach is the extent to which customers of the gas shippers, and ultimately energy users, would receive benefit from returned funds. Option A may help to ensure the costs are passed through to customers more accurately and in a more timely manner, in comparison to Option B where the return of funds may be slower or to a lesser extent. We consider this to be a key advantage of option A, though we seek wider views on these options and note that the overcollection approach would be subject to government accounting decisions and the Administrator's management of funds before making a final decision. Another consideration is the administrative burden of handling the overcollection. We would welcome stakeholders' views on these approaches.

Questions

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18. **What are your views on the options for further mitigating the risk of under-collection (option A – headroom, and option B – separate reserve pre-payment)? Please explain your answer and provide supporting evidence.**

19. **Are there any other options for mitigating the risk of under-collection that you think should be considered? Please explain your answer and provide supporting evidence.**

20. **What are your views on the handling of overcollection (option A – offsetting, and option B – returning over-collected sums)? Please explain your answer and provide supporting evidence.**

21. **Are there any other options for the handling of overcollection that you think should be considered? Please explain your answer and provide supporting evidence.**

5 Administration of the Gas Shipper Obligation

5.1 Administration

We will appoint an administrator of the Gas Shipper Obligation (GSO) using the power set out in section 69 of the Energy Act 2023, ahead of the GSO implementation date. This body is referred to throughout this document as 'the Administrator'. We expect that the Low Carbon Contracts Company (LCCC) will fulfil this function, subject to successful completion of administrative and legislative arrangements. The main role of the Administrator will be to calculate and manage the collection of GSO payments from shippers and pass these funds on to the HPBM counterparty (responsible for the management of the contracts with, and payments to, hydrogen production projects), which is also LCCC.[25] We also propose that the Administrator uses compliance and enforcement levers if a gas shipper does not meet its obligations – further details are set out in *Section 5.2* below. The Administrator may also request information from shippers for the purpose of the operation of the GSO as well as for monitoring and evaluation purposes.

The GSO will also fund certain administrative and operational costs of the HPBM and the GSO itself. The HPBM counterparty and the Administrator will both receive funding through the GSO in connection with the performance of their functions. We expect this to be a smaller and more stable portion of the total collection amount.

For the Administrator, the cost of operating the GSO has been estimated to be in the range of £2.5m to £4m annually. The range in operating costs reflects the fact that policy design decisions (that will impact operating costs) are still to be made.

The GSO is also expected in the future to support the costs of any Hydrogen Production Allocation Body appointed under section 73(1)(a) of the Energy Act 2023 and responsible for administering future Hydrogen Allocations Rounds. Other industry bodies may be required to support the Administrator in the operation of the GSO. The exact role and duties of each body is yet to be determined, as well as any funding which may be required through the GSO. Below is a non-exhaustive list of some of these bodies:

- Xoserve –the central data service provider for the gas market. Xoserve collects and holds gas consumption data across GB. It is our intention to use the relevant underlying data set from the GNTS charge on Exit, which is managed by Xoserve on behalf of the distribution and transmission networks, to calculate gas shippers' collection amounts.
- Ofgem is the energy regulator for GB (the Regulator). It is our intention that the Administrator will work with the Regulator as required in cases of shipper non-compliance. Please see *Section 5.2* below for further details.

Agreement on the role of each body, any required funding, and data sharing arrangements will be determined before the introduction of the GSO. The costs to other bodies (outside of the

[25] DESNZ (2024) Low Carbon Contracts Company: counterparty for hydrogen production revenue support contracts

Administrator) are expected to be small in comparison to both the Administrator's costs and the total cost of the GSO we have estimated.

We are considering whether the GSO should account for HPBM and administrative costs separately in the invoices sent to shippers to provide a distinction between these two broad functions, by being included as a separate line item on the same invoice. This may help to provide greater transparency over costs. Separate levies would operate in very similar ways, consistent with the positions in this consultation (as described in *Section 3*), though administrative and HPBM costs would be calculated separately. A similar approach has been taken for the Supplier Obligation which has separate charges for operational costs.

We also acknowledge that there will be administrative costs for gas shippers when complying with their obligations. These costs will not be paid for with the GSO, but we anticipate that gas shippers will pass these costs on to their customers. We have made an initial estimation of the administrative burden on gas shippers, based on estimates for administrative burden of the Green Gas Levy (GGL). Under a volumetric design, we estimate that each shipper would require the equivalent of between 6 and 12 months for one member of staff for familiarisation, and between 6 and 12 months per year for recurring administrative activities, including reconciliation activities. The central estimate for the cumulative administrative burden on all gas shippers under the proposed design of the GSO would be £2.2m for the initiation cost and £2.2m annual costs thereafter. Administrative costs incurred by gas shippers are very small when compared to the total collection amount. If these costs are passed down through the supply chain, as we assume they will be, the impacts on end users are expected to be minimal. More detail on how we have estimated this administrative cost can be found in the analytical annex.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. However, we do not expect the administrative costs of the GSO or administrative burden to shippers to materially change with the funding of further hydrogen production projects, given the administrative requirements would remain the same.

22. **Do you have any views on whether the administrative and operational costs of the Gas Shipper Obligation should be separated from the other costs of the HPBM, such as payments under relevant contracts? Please explain your reasoning and provide supporting evidence.**

23. **Do you agree with our estimates of the administrative burden to shippers, including the types of costs identified, the impact on small shippers, and the assumptions underpinning them, including in relation to gas suppliers, as set out in the analytical annex? Please explain your reasoning and provide supporting evidence.**

5.2 Compliance, enforcement and non-payment

Regulations to establish the GSO are expected to impose various obligations on gas shippers, including in relation to the making of payments to the Administrator. To help ensure there is a robust and reliable funding stream for the HPBM, it is important that the design of the scheme helps ensure compliance and addresses cases of non-compliance. Additionally, in the event that a gas shipper defaults on their obligation to make payments due under the GSO (i.e. defaulted payments), or to pay mutualisation payments (as discussed in *Section 5.2.2*), mechanisms need to be in place to collect the defaulted payment to avoid under-collection. The two proposed mechanisms to collect alternative funding are credit cover and mutualisation, which are discussed below.

5.2.1 Credit cover

The main financial risk mitigation tool that we are considering for managing defaulted payments is credit cover (sometimes referred to as collateral). Gas shippers would be required to lodge credit cover with the Administrator, which could be drawn down in the event that a shipper fails to make payments due under the GSO.

We recognise that there are arguments for and against the inclusion of a credit cover lever in the design of the scheme. Credit cover is used in other levy funding schemes (for example, the GGL and the Supplier Obligation (SO), described in further detail below), and could be a useful risk mitigation tool for a number of reasons.

1. A robust credit cover mechanism will, as far as practicable, reduce the likelihood that the Administrator has to consider running a mutualisation exercise (see *Section 5.2.2* for more detail on mutualisation).
2. Without a credit cover process to mitigate the risk of under-collection arising from defaulted payments, we would need to look at alternative tools to manage this risk. Without credit cover as an option, the alternative would be requiring significantly increased contingency payments, provided in cash only, to mitigate the risk of defaulted payments – please see *Section 4.5.1* on contingency options. Whereas credit cover would be a tool designed specifically to deal with the risk of defaulted payments, contingency is designed to mitigate the risk of under-collection arising from HPBM-related uncertainties, as described in *Section 4.5.1*. Using contingency funds to fill the gap in funding caused by defaulted payments would mean the burden of these costs falls across the levy base rather than with the defaulting shipper which raises fairness implications.
3. By allowing shippers to lodge credit cover in multiple forms (see below), individual shippers would have a choice about how to comply with this requirement according to their particular needs and circumstances. This is compared to contingency, which would have to be provided in cash.
4. Credit cover is an established feature of existing energy market levies, which have operated well.

However, these benefits need to be balanced against the potential administrative burden to shippers of complying with credit cover requirements. We also recognise that, should we proceed with credit cover requirements, we will need to consider how to best minimise non-compliance and avoid the creation of perverse incentives (such as those which could encourage non-compliance), in accordance with the design principles as described in *Section 1.2*). We are considering enforcement arrangements for credit cover, for example, interest on defaulted credit cover sums, as a way of minimising non-compliance. This could work in a similar way to interest charged on other payments under the GSO, see *Section 5.2.3.*

The following discussion sets out proposals for credit cover, should we proceed with it.

We propose that credit cover may be lodged by shippers either in cash, in the form of a standby letter of credit, or a mix of these two methods. It is anticipated that letters of credit should be issued on terms the Administrator considers appropriate, for example, regarding the way a demand for payment, or payment itself, is to be made. The bank issuing the letter of credit should also meet a required minimum credit rating to be valid. On both the SO and the GGL, letters of credit must be issued on appropriate terms and be issued by a bank with a minimum credit rating, as specified in regulations and guidance.[26] We are still considering how we would set credit cover levels. On some other energy market schemes, such as the GGL and the Capacity Market, credit cover is set by reference to the costs of that scheme over the next billing period, such that it covers the next forecast collection amount plus a buffer to account for uncertainties. On the GGL, this buffer is 15%, while on the Capacity Market, it is 10%. We anticipate replicating this method for setting credit cover levels on the GSO but are still considering how this could work depending on the credit cover period used in the final design (see below for more detail).

We also propose that credit cover may be drawn down by the Administrator upon failure by a shipper to make full payment of sums due under the GSO.

We are considering what the appropriate credit cover period would be, which includes how frequently credit cover is recalculated by the Administrator and lodged by shippers, and the length of the time period the credit cover supports. We are considering the options of a monthly and a non-monthly (for example, quarterly, 6-monthly, or annual) credit cover period, which are set out below.

Option A - Monthly

A monthly credit cover period would align with the proposed monthly invoicing cycle and result in smaller and smoother increases in required credit cover levels month on month. However, a monthly period would be more administratively burdensome on shippers and the Administrator. Given the smaller and smoother increases in required credit cover levels each month, the administrative burden of a monthly period could be disproportionate. Furthermore, letters of credit can take around 3 weeks to amend, which may be difficult to accommodate within the time constraints of a monthly period.

Option B - Quarterly

A quarterly credit cover period would reduce administrative burden in comparison to a monthly period, as credit cover would be recalculated and lodged less frequently. This would also allow more time to amend letters of credit where needed. Furthermore, in comparison to a monthly period, a quarterly period would enable greater accuracy when projecting in which credit cover period larger hydrogen projects will become operational (increasing collection amounts and therefore required credit cover levels).

[26] For more details on the SO, please see Contracts for Difference (Electricity Supplier Obligations) Regulations 2014, SI 2014/2014, reg 20 and WP42 – Supplier CfD and Nuclear RAB Credit Cover: EMRS Working Practice v16.0, section 3 and Appendices 1-2. For more details on the GGL, please see Green Gas Support Scheme Regulations 2021, SI 2021/1335, reg 43 and Green Gas Levy Guidance v3.0, paras 4.20-4.29 and Appendix 1.

Option C – Longer than Quarterly (e.g. 6-Monthly or Annual)

We do not consider that a 6-monthly or annual credit cover period would be appropriate. This is because there is a greater risk of more significant changes to costs and market shares occurring over these longer periods, compared to over a month or a quarter, which would make accurately setting appropriate credit cover levels significantly more difficult. This is particularly important given the decreasing accuracy of forecasts further into the future (see *Section 4.4* for more information on forecasting). This would increase the risk that the amount of credit cover lodged by a shipper may not be sufficient to respond to a defaulted payment. In our view, while a quarterly period does share these downsides, it does so to a much lesser extent than the 6-monthly or annual options. We therefore consider that a quarterly period best manages these trade-offs against the benefits of a non-monthly period.

Therefore, if we were to proceed with credit cover, we propose that we would either apply a monthly period or a quarterly period and are keen to understand stakeholders' views on this.

As a point of comparison, the GGL operates on a quarterly basis and requires suppliers to lodge sufficient credit cover ahead of each quarter. Meanwhile on the Capacity Market, which operates on a monthly basis, suppliers are required to lodge sufficient credit cover no later than 12 working days before the start of each month.

There are also further features of credit cover which are under consideration. Firstly, we are considering how a mechanism for the return of excess credit cover might work. This would allow shippers to have any credit cover lodged in excess of the minimum requirements to be returned to them. In particular, we are considering how often, and how quickly these returns should be issued to shippers. On the GGL, for example, excess credit cover is returned to suppliers annually and suppliers can additionally request the return of excess credit cover ahead of the start of each quarter, which is a discretionary process. Returns take place within approximately 3 weeks. On the SO, a supplier can request return of excess credit cover at any time, and they will receive the return within 2 business days of the request. Secondly, we are considering how often interest earned on credit cover held by the Administrator should be transferred to shippers. On the GGL, interest earned is paid back annually, while on the SO, it must be paid within 15 business days of the Administrator receiving the interest. On the GGL, return of excess credit cover and interest is subject to a de minimis threshold, which is set annually by the Secretary of State and is subject to a maximum amount set out in regulations. Finally, we are also considering how credit cover requirements would work for shippers joining the GSO after initial launch.

If the GSO were to include credit cover requirements, it would help mitigate the risk of under-collection arising from payment default. It would also reduce the likelihood of a mutualisation event occurring, which is discussed in more detail below, and would avoid the need for increased contingency payments to counter the risk of payment default. However, another consideration is the administrative burden of credit cover on shippers and the Administrator, particularly if the process were to operate on a monthly basis.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this *in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.*

24. **Do you think credit cover should be used as a mechanism to mitigate against the risk of defaulted payments bearing in mind the alternative measure of significantly increased contingency payments, should credit cover not be used? Please explain your answer and provide supporting evidence.**

25. **If the design of the scheme includes a credit cover process, do you have any views on how to best minimise non-compliance with credit cover obligations, including enforcement arrangements? Please explain your reasoning and provide any supporting evidence.**

26. **Are letters of credit and cash feasible options for lodging credit cover? Please explain your answer and provide supporting evidence.**

27. **What are your views on the appropriate credit cover period (options A-C above)? Please explain your answer and provide supporting evidence.**

28. **If the design of the scheme includes a credit cover process, are there any other considerations we should take into account? Please explain your reasoning and provide any supporting evidence.**

5.2.2 Mutualisation

Mutualisation is a process through which outstanding payments due under the GSO can be recovered from the non-defaulting levy base. In practice this would mean that if a shipper fails to make a payment, the defaulted amount could be redistributed proportionally across other shippers that are subject to the GSO. We propose that the Administrator should have the power to run a mutualisation exercise following a failure by a shipper to make payments due for each obligation period. However, before a mutualisation exercise can be run, we propose that any credit cover lodged by the defaulting shipper must first be fully drawn down and completely exhausted.

We consider it appropriate that a mutualisation exercise is triggered at the Administrator's discretion to enable the Administrator to consider whether running a mutualisation exercise is the most appropriate approach to collect the shortfall. In addition to the requirement for the Administrator to exhaust a defaulting shipper's credit cover before considering mutualisation, we also intend for the Administrator and Regulator to have compliance and enforcement levers available to them to recover any unpaid sums from a defaulting shipper. These levers are discussed in more detail in *Section 5.2.3*.

Once the decision to trigger a mutualisation exercise has been taken, it is intended that the Administrator would calculate the mutualisation payments owed by each non-defaulting shipper. The Administrator would then generate formal mutualisation notices and individual mutualisation invoices, which set out how much each shipper's mutualisation payment is. It is intended that mutualisation payments would be charged to shippers in proportion to the quantities of gas shipped by non-defaulting shippers (similar to how the main collection amounts are determined) during the obligation period to which the mutualisation event corresponds. The mutualisation invoices and notices would then be issued to shippers. Where any costs are later recovered from defaulting shippers, it is intended that these would be allocated to the non-defaulting shippers in proportion to each shipper's contribution to the mutualisation event – in effect reimbursing (to the extent possible) non-defaulting shippers for any additional funds that had been collected through the mutualisation process. We are also considering how quickly these reimbursements should be made once payment from the defaulting shippers has been received by the Administrator, including whether reimbursements should take place on a set frequency.

Other similar funding schemes use mutualisation exercises to address shortfalls in payments where credit cover has already been exhausted. For example, in the GGL, the Regulator, which acts as the levy administrator, must run a mutualisation exercise if certain conditions are met following a shortfall in quarterly levy payments. On the SO, LCCC as the levy administrator has the discretion to recover the unpaid amount from non-defaulting suppliers through a mutualisation exercise.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

29. **Do you agree with the proposed mutualisation process? In particular, that mutualisation would be exercised at the discretion of the Administrator with calculations of mutualised amounts based in proportion to quantities of gas shipped (similar to the main collection amount)? Please explain your answer.**

30. **Do you have any views on how quickly reimbursement of mutualisation payments should take place where costs are later recovered from the defaulting shipper and whether they should take place based on a set frequency? Please explain your answer and provide supporting evidence.**

5.2.3 Compliance and enforcement arrangements

This section seeks views on our proposals for the compliance and enforcement arrangements for the GSO. The proposals below have been designed to align with the principles set out in *Section 1.2*. In particular, the arrangements should support scheme compliance, enable funding stream solvency, and be simple to administer. The arrangements proposed here should also align, where appropriate, with the compliance and enforcement arrangements for existing levies, such as the Supplier Obligation. These levies are tried and tested and have a track record of minimal non-compliance issues. We have also considered whether the arrangements proposed are proportionate to the non-compliance they aim to address.

The Administrator's role in compliance and enforcement

We intend for the Administrator to monitor gas shippers' compliance with the GSO and have the ability to take action in response to cases of non-compliance. Section 72(6) of the Energy Act 2023 already stipulates that any sum that a relevant market participant is required to pay to the Administrator by virtue of GSO regulations, and that has not been paid by the date required by those regulations, may be recovered from the relevant market participant by the Administrator as a civil debt due to it. In addition to this lever, we propose that the Administrator has powers to take the following actions to ensure scheme compliance:

- Requesting information required to enable the administration and/or enforcement of the GSO;
- Issuing notices of non-compliance;
- Applying interest to late or incomplete GSO payments;
- Where appropriate, engaging the Regulator regarding cases of non-compliance; and
- Reporting relevant information to the Regulator, DESNZ and/or shippers. This could include information on shippers that have been non-compliant with obligations or have had debt written off, as well as details of any enforcement action taken. This information may be made publicly available.

These enforcement arrangements are similar to those in place for the SO, which has a track record of successfully funding the CfD with minimal compliance issues. Further detail on proposed compliance and enforcement actions is set out in the table below.

Requesting relevant information required to perform functions	We propose that the Administrator and/or Regulator may request relevant information required to carry out its functions and/or to support enforcement decisions. For example, the Administrator may need information to assess whether further enforcement action is required.
Issuing of notice of non-compliance	Where the Administrator considers that a shipper is in breach of any of its obligations (such as missing a payment due date), we propose that the Administrator must issue a notice setting out the action that a shipper is required to take to remedy the non-compliance, and further potential enforcement action that could follow if the shipper remains non-compliant. Our intention is that the Administrator would be required to provide a copy of any notice to the Regulator.
Reporting compliance/ enforcement issues and debt written off	We propose that the Administrator should report relevant information regarding shipper non-compliance, enforcement action taken, and any debt written off to DESNZ, the Regulator and, where appropriate, shippers. This will help ensure sufficient visibility of non-compliance issues across government and the Regulator. It could also be beneficial to report information relating to outstanding GSO payments in advance of possible mutualisation events across non-defaulting gas shippers, to give visibility and warning of possible upcoming mutualisation costs. Further consideration will be given as to whether to require the Administrator to make non-compliance and enforcement information publicly available. The publication of such information could be an important deterrent and there is precedent for this in existing schemes. In the SO, the

	administrator may publish a copy of a non-compliance notice, and in GGL, the administrator must publish and maintain a default register.[27] The Administrator should utilise the arrangements available to it to recover outstanding amounts due under the GSO regulations to the best of their ability. However, we are considering whether the Administrator should have the ability to write off debt in exceptional circumstances and what those exceptional circumstances should be. Where wider scheme participants may be impacted by any debt write-off, we are also considering whether the Administrator should be required to communicate this and to whom.
Interest on late payments	Where payments from shippers are late or have not been paid in full by the required date, we propose that shippers would be charged simple interest on outstanding payment amounts if late or not provided in full. We consider that charging interest could be an effective deterrent to late or incomplete payments. We propose that interest would begin to apply from the day after the date payment was due. Interest would then continue to accrue on any outstanding amount until the full outstanding payment amount has been made. We propose that the annualised interest rate is in the range of 5% to 8% above the Bank of England Base Rate, in line with other government energy levy schemes.
Referring cases of non-compliance to the Regulator	Where a shipper has not complied with obligations under the regulations, the Regulator may use its powers to bring the business back into compliance (see the section below for further details). There are several ways the Regulator may become aware of a breach. As set out above, we intend for copies of any non-compliance notices to be provided to the Regulator. The Administrator may also take steps to refer cases of non-compliance to the Regulator. We intend that the Administrator would have discretion over whether to refer cases of non-compliance to the Regulator and that these are likely to be cases of serious, repeated non-compliance and/or those that the Administrator considers may cause a material risk to scheme integrity.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are

[27] Ofgem (2024) Green gas levy default register and LCCC (2024) Registers - Low Carbon Contracts.

in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

31. **Do you agree with the compliance and enforcement levers proposed above? Should the Government consider any other compliance and enforcement actions, in addition to those captured above? Please explain your reasoning and provide any supporting evidence.**

The Regulator's role in enforcement

It is critical that the GSO is supported by a suite of enforcement measures. This will help reduce the risk of defaults on GSO payments and help ensure that the Administrator can collect the monies required to fund the HPBM and cover related costs. We therefore intend to make provisions in the GSO regulations that enable the Regulator to use its enforcement powers under the Gas Act 1986 to enforce requirements imposed on GB gas shippers under those regulations. This would allow the Regulator to enforce such GSO requirements as they would any other requirements under a GB gas shipper's licence – enabling the use of robust enforcement levers such as orders from the Regulator to bring the entity back into compliance and the issuing of financial penalties. In addition, by enabling the Regulator to enforce GSO requirements, we are following the precedent set by the enforcement arrangements for the SO, a levy scheme that has had minimal compliance issues.

Where there are breaches by shippers in the delivery of their obligations (or the Regulator is alerted to potential breaches), the Regulator would be able to trigger their own investigations and enforcement processes.[28,29]

5.2.4 Appeals

We intend to establish an appeals process for shippers for some decisions made by the Administrator, including invoice amounts and enforcement action taken against them. We propose that this appeals process would be handled by the Administrator in the first instance. We expect to engage further with stakeholders on this part of the appeals process, including what decisions can be subject to appeal, in due course. We also expect GSO regulations to set out which decisions shippers can appeal and the process for doing so.

Appeals of enforcement decisions made by the Regulator would be handled through existing appeals processes set out in relevant legislation.

Question

32. **Do you have any views regarding the design and implementation of an appeals process? Please explain your answer and provide supporting evidence.**

[28] Ofgem (2023) Enforcement guidelines.
[29] Ofgem (2022) Statement of Policy with respect to Financial Penalties and Consumer Redress

6 Consideration of a potential exemptions scheme in respect of non-domestic gas users

This section relates to potential exemptions for non-domestic gas users. We are not currently considering exemptions for domestic gas users. This is in keeping with the arrangements in place for existing energy levy schemes, which do not make provision for exemptions for domestic gas users. There are several government policies in place to support the affordability of energy bills and to enable domestic gas users and vulnerable groups to transition away from fossil fuels and towards homegrown clean energy (as set out in *Section 2.1.1*). These schemes provide targeted support and are monitored and evaluated for their impact. The Government is currently reviewing the Fuel Poverty strategy and intends to publish the outcome of the review and a consultation on an updated strategy in due course. We also intend to develop a monitoring and evaluation plan for the Gas Shipper Obligation (GSO), which would include monitoring costs on both domestic and non-domestic gas users and impacts on fuel poverty.

Within the energy sector, exemption arrangements exist for some of the obligations required of certain non-domestic energy market participants. For example:

- Some Energy Intensive Industries (EIIs) are exempt from the Supplier Obligation, which is the levy that funds the CfD scheme, in order to reduce the risk of carbon leakage.[30]
- Gas suppliers who can evidence that they have serviced 95% to 100% of their gas portfolio with certified biomethane for the entirety of a levy scheme year (i.e. 1 April to 31 March) are exempt from paying the Green Gas Levy (GGL) for that year;[31] and
- In gas transportation charging, storage facilities are excluded from paying the General Non-Transmission Services charge (except for gas consumed as part of the operation of the storage facility) to avoid double charging the same molecule of gas.[32]

We are considering the case for arrangements that could exempt gas quantities shipped to certain non-domestic users, whose facilities are located in GB, from the obligation to pay GSO costs. These arrangements could apply whether that gas is shipped directly to the end user or via a gas supplier. We are seeking views on this issue and will use responses to develop our position on exemptions and we expect to engage further with stakeholders on more detailed designs of any potential exemptions.

If an exemption scheme were put in place for certain end users of gas, we would expect shippers and suppliers to ensure that GSO costs were not passed on to those end users that were the intended target of such a scheme. An exemption scheme would therefore have the effect of reducing the size of the levy base, resulting in higher GSO costs for gas users not within the scope of an exemption. It is important that this impact is taken into account when considering whether to take forward an exemption scheme. In addition, it will also be important to consider potential interactions between any different exemptions that form part of the

[30] DESNZ (2024) Energy Intensive Industries (EII) certificate guidance
[31] Ofgem (2023) Green Gas Levy Guidance v3.0
[32] Uniform Network Code (UNC), Transportation Principal Document (TPD), Section Y, Part A, 4.7, and UNC TPD Section B. 3.12.7.

scheme, as well as the incentives for decarbonisation in exempted sectors and compliance with any relevant subsidy control requirements.

We expect competition amongst shippers and suppliers to increase or maintain their share of the non-domestic market to be effective in ensuring that exempt end-users benefit from any exemption scheme. Such competitive pressures have been generally effective in delivering this outcome for the exemption schemes for EIIs. However, in the event that GSO costs are passed through to exempt users, Government would engage the sector, as well as the relevant shippers and/or suppliers to help address the issue if it was brought to our attention.

Gas Intensive Industries

The clean energy transition represents a huge opportunity to generate growth, tackle the cost-of-living crisis and make Britain energy independent. The Government regularly engages Energy Intensive Industries (EIIs) on energy costs and pathways to decarbonisation, to understand the opportunities and the challenges they face.

Some businesses will benefit from new export opportunities created by the transition to net zero, but there may be a risk that the objective of our decarbonisation policies – to reduce global emissions – could be undermined by carbon leakage, i.e. the movement of production and associated emissions from one country to another due to different levels of decarbonisation effort through carbon pricing and climate regulation. The risk of carbon leakage as a result of the GSO would depend on several factors including, but not limited to, the costs of decarbonising that industry, how intensively it uses gas, how much an industrial sector trades internationally, and climate policies in other countries.

Under the Contracts for Difference, Renewables Obligation and Feed-in Tariffs exemption schemes, the concept of an EII most at risk of carbon leakage is defined with respect to ‘electricity intensity’ and ‘trade intensity’. To ensure that support is targeted at those most at risk of carbon leakage, eligibility is limited to those sectors found to have electricity costs that amount to at least 7% or more of their Gross Value Added (GVA)[33] (electricity intensity) and have a trade intensity[34] of at least 4% using UK specific data from the Annual Business Survey. Alongside other criteria, a business level test of electricity intensity is also applied. Individual businesses need to demonstrate that their electricity costs amount to 20% or more of their GVA over a reference period to be eligible for relief.

We are seeking views on the impact posed by the GSO on certain industrial sectors (or ‘gas intensive industries') – in particular, the potential risk of carbon leakage, and whether these industrial sectors require mitigations, such as an exemption from the obligation to pay the GSO. We would expect the concept of ‘gas intensive industry’ to be defined based on gas intensity and to also take into account trade intensity. However, that concept itself – and any associated eligibility criteria, were Government to decide to take forward such an exemption – would need to be refined further, based on responses to this consultation and any further engagement with relevant stakeholders.

Consideration of whether to take forward an exemption scheme for gas intensive industries would need to consider other government policies, including those to address carbon leakage

[33] Gross Value Added is defined as earnings before interest, taxes, depreciation and amortisation (EBITDA) excluding items which are extraordinary and all staff costs including employers’ pension and national insurance contributions, directors’ salaries and bonuses, casual or agency staff costs and other arrangements where employees are paid indirectly.
[34] Trade intensity estimates international competition and the likelihood that firms in a sector would struggle to pass on additional energy costs without losing market share to imports or in export markets.

risks. This includes the current provision of 'free allowances' under the UK Emissions Trading Scheme, the development of the UK carbon border adjustment mechanism (which will be implemented from 1 January 2027 in respect of specific imported goods from certain sectors) and development of voluntary product standards and embodied emissions reporting.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

33. **Do you consider that gas intensive industries would be at risk of carbon leakage due to GSO costs? And if so, should government consider exempting gas quantities shipped to these industries from GSO charges? Please explain your answer and provide supporting evidence.**
34. **Are there any other factors besides carbon leakage that could be considered as grounds for an exemption for gas quantities used by gas intensive industries? Please explain your answer and provide supporting evidence.**
35. **Please provide suggestions for metrics that could be used to define 'gas intensive industries' (for example gas intensity and trade intensity) and any evidence or data that could be used to support that definition.**
36. **Please provide suggestions of any additional eligibility criteria that may be needed and any data that could be used/evidence that could be required to determine whether the criteria have been met.**
37. **Please provide suggestions for how an exemption for gas-intensive industries could be implemented and the lessons that can be learnt from how existing exemption schemes are delivered, including the British Industry Supercharger.**

CCUS-enabled hydrogen production

Hydrogen produced from natural gas with carbon capture, usage and storage (CCUS) is known as 'CCUS-enabled hydrogen', or 'blue hydrogen'. As set out in the introduction, the Government intends to provide HPBM and, where relevant, Net Zero Hydrogen Fund support for CCUS-enabled hydrogen projects capable of meeting the requirements of the Low Carbon Hydrogen Standard through the CCUS Cluster Sequencing programme.

As mentioned above, our assumption is that levy costs will be passed through the supply chain to the end users of the gas. In the absence of an exemption for gas shipped to CCUS-enabled hydrogen producers, the GSO would likely therefore impact the cost of producing CCUS-enabled hydrogen. This could further exacerbate the price differential between CCUS-enabled hydrogen and natural gas, as more than one unit of natural gas is required to generate an equivalent unit of CCUS-enabled hydrogen.

Placing the GSO on gas quantities shipped to CCUS-enabled hydrogen producers – particularly projects supported by the HPBM – could be seen as at odds with the primary objective of the HPBM, which is to incentivise investment in new low carbon hydrogen production and encourage users to switch to low carbon hydrogen. For these reasons, we are considering the case for an exemption for quantities of gas shipped to CCUS-enabled hydrogen production projects that can meet the UK Low Carbon Hydrogen Standard.

Questions

As set out in the introduction and above, this consultation, and the accompanying analytical annex, provide a snapshot of the GSO costs and impacts by setting out the estimated costs and quantitative impacts for HAR1 projects only, given that these are the only projects that are in the final stages of contract signature. Costs and impacts would change with the funding of further hydrogen projects beyond HAR1, the extent of which will be subject to Government's future decisions on hydrogen production and the funding arrangements for it. Please bear this in mind when responding to the questions below - setting out, where relevant, how your response would change with higher GSO costs and impacts than those captured above and in the analytical annex and, where possible, setting out the approximate scale of costs and/or impacts in respect of which your response would change.

38. **Should gas quantities shipped to CCUS-enabled hydrogen projects capable of meeting the UK Low Carbon Hydrogen Standard be exempt from the Gas Shipper Obligation charges? Please explain your answer and provide supporting evidence.**

39. **Please provide suggestions of eligibility criteria and any data that could be used/evidence that could be required to determine whether the criteria have been met. Please explain your answer and provide evidence to support your response.**

40. **Please provide suggestions for how an exemption for CCUS-enabled hydrogen projects could be implemented.**

Other potential exemptions

We welcome views on whether any other potential exemptions from the GSO warrant consideration, such as exemptions for other gas user groups not mentioned above. As outlined above, consideration of any potential exemption will need to take into account its impact on the size of the levy base, as well as overall value for money and compliance with any relevant subsidy control requirements.

Questions

41. **Should government be considering any other potential exemptions from the GSO? If you answer yes to this question, please explain your rationale as well as suggestions of eligibility criteria and any data or evidence that could be used/required to determine whether the criteria have been met. Please provide evidence to support your response.**

42. **Is there anything else you would like to share with us on the design and operation of the Gas Shipper Obligation?**

7 Next Steps

This consultation will close on 9 April, after which responses will be analysed and it is expected that the Government response will be published in 2025.

This consultation is available from: www.gov.uk/government/consultations/funding-mechanism-for-the-hydrogen-production-business-model-proposed-design-of-the-gas-shipper-obligation

If you need a version of this document in a more accessible format, please email alt.formats@energysecurity.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.