H2 Teesside Project

Planning Inspectorate Reference: EN070009

Land within the boroughs of Redcar and Cleveland and Stockton-on-Tees, Teesside and within the borough of Hartlepool, County Durham

The H2 Teesside Order

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APPENDICES

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

1.1.1 This document sets out the Applicant's response to the Written Representation of Climate Emergency, Planning and Policy ('CEPP') (REP02-046 to REP02-063).

1.1.2 Given the length of CEPP's representation and the length and number of its appendices, this response is presented in narrative form, rather than tabular form, responding to the main points and themes raised.

1.1.3 The Applicant does not agree with the conceptual starting point of CEPP's Written Representation1 and does not agree with its overall content and conclusions.

1.1.4 This submission is supported by a number of reference documents. Source references have been provided for these, but to facilitate efficient Examination, the reference documents themselves are not submitted in full. If the Examining Authority wishes to see any of these reference documents, however, the Applicant would be happy to provide them.

1.1 Summary of the Applicant's Position and Key Points in Response to CEPP's Written Representation

1.1.1 CEPP's written representations are to a significant extent predicated on an express or implicit disagreement with UK policy on climate change and energy in respect of the role to be played by hydrogen with carbon capture in reaching Net Zero. As set out in the Need Statement [APP-033] and paragraphs 19.2.54-19.2.57 of the ES [APP-072], current government policy clearly identifies the necessity of producing hydrogen with carbon capture as part of the UK's trajectory to Net Zero.

1.1.2 H2Teesside is being developed to provide blue hydrogen as a direct replacement for grey hydrogen in industrial and chemical processes, as well as a fuel displacing unabated natural gas and therefore providing significant decarbonisation benefits. The Proposed Development would be one of the UK's largest blue hydrogen production facilities with a capacity of up to 1.2 gigawatts ('GW') thermal, representing more than 10% of the Government's hydrogen production target of 10 gigawatts by 2030. Further information on the need for the Project and the policy support for it are set out in the Planning Statement [APP-031 and 032] and the Need Statement [APP-033]. The Applicant also addressed the position in relation to need and policy in [PDA-020].

1.1.3 CEPP seeks to suggest that the Applicant has not complied with the requirements of the Infrastructure Planning (Environmental Impact Assessment Regulations) 2017 ("the EIA Regs"). For the reasons set out in this submission, the Applicant rejects that assertion. Chapter 19 [APP-072] of the ES sets out (at least) sufficient information to meet the requirements of the legislation and enable proper consideration by the Secretary of State of the likely significant effects of the Proposed Development.

1.1.4 The Applicant rejects the suggestion that its greenhouse gas assessment "severely" underestimates the likely GHG emissions from the Proposed Development. CEPP

[1] Set out in the first four numbers points – (i) – (iv) after the second paragraph on page 2 and further developed in section 8 of CEPP's written representation

cite three main factors which underpin its allegation of underestimation (set out at the bottom of page 2 of its written representation). The Applicant's overarching position on each of those three issues is set out immediately below. The following sections (2 onwards) set out the legal position for EIA, and further responses to CEPP's Written Representation.

<u>CEPP's first main factor – capture rate</u>

1.1.5 CEPP states that *"The project claims a 95% carbon capture rate when no similar project has achieved more than 80% carbon capture"*.

1.1.6 Achieving a 95% capture rate is a reasonable assumption upon which to base the ES. The Proposed Development is designed to achieve this carbon capture rate using proven technologies for syngas production, water gas shift, and carbon capture. The chosen technology, autothermal reforming (ATR), allows for efficient CO2 capture at high partial pressures. The CO2 capture system, based on pre-combustion amine absorption, is well-established and capable of reducing CO2 levels in the syngas stream to very low levels. The design ensures a high overall CO2 capture rate, supported by process guarantees from technology providers.

1.1.7 The Proposed Development's Environmental Permit will require a design capture rate of at least 95% in line with the Environment Agency Hydrogen Production with Carbon Capture: Emerging Techniques Guidance. This is further evidenced by the permit for Net Zero Teesside, submitted at Deadline 2 [REP2-027].

<u>CEPP's second main factor – fugitive upstream emissions and gas supply</u>

1.1.8 CEPPs second main factor is the allegation that *"Emission factors for upstream fugitive emissions from the natural gas supply are based on out-of-date data, and do not reflect the potential changes to the natural gas supply market in the UK".* The Applicant firmly rejects that allegation. The Applicant's GHG assessment has been undertaken in line with IEMA Guidance - an appropriate methodology for EIA climate assessments[2], and using emission factors from government and industry recognised datasets. The factor used for upstream emissions from the natural gas supply chain and the study underlying it explicitly included upstream emissions from venting, flaring and other fugitive emissions within the natural gas supply chain. This is the most appropriate factor to an end user – such as the Proposed Development - consuming natural gas from the UK grid, and it takes account of the varying sources of gas into the grid.

1.1.9 The LCHS will be kept under review by the government and the emissions value it requires to be used for the natural gas supply element will be updated and will reflect changes over time in the composition of UK gas grid supply. Any future contribution of LNG to the GHG intensity of the UK gas grid will be captured by the emissions factor supplied by DESNZ in the LCHS, but the Applicant will still be required. to meet an overall GHG emissions intensity of 20g CO2e/MJLHV or less for hydrogen produced, in order to comply with the LCHS and be eligible for subsidy under the terms of the LCHA.

[2] As recognised by the Courts in Boswell v Secretary of State for Transport [2024] EWCA Civ 145

<u>CEPP's third main factor – global warming potential</u>

1.1.10 The third main factor cited by CEPP is the allegation that *"The climate impact of methane is inadequately modelled for its short-term but extremely damaging effect to the atmosphere*". The Applicant does not accept this to be a valid criticism of its GHG assessment. The global warming potential of 100 years (GWP100) is the only appropriate metric for undertaking a GHG assessment in alignment with IEMA best practice and assessment against UK policy and regulations. The key approaches to assessing significance, in line with the accepted methodology for assessing GHG impacts for EIA (i.e. IEMA), are by reference to UK carbon budgets, LCHS and net zero trajectories - - these are all derived using GWP_{100}.

1.1.11 Furthermore, the two key sources of emission factors used in the GHG assessment are the: Inventory of Carbon and Energy (ICE) (Embodied Carbon – The ICE Database, ICE, 2019) and the UK government GHG conversion factors for company reporting (DESNZ, 2023c). These are both developed using GWP_{100}. It is relevant to note that in granting development consent for theNet Zero Teesside DCO (DESNZ, 2024),), the Secretary of State accepted that the use of emission factors, developed using the same derivation, was an appropriate approach for GHG assessment. Nothing has changed in the interim to justify a different approach for the purposes of assessing the impact of this proposed development.

1.1.12 The Applicant's approach therefore provides the only appropriate means by which to carry out the assessment and determine the significance of effects.

2.0 THE EIA AND LEGAL PRINCIPLES

2.1.1 The conceptual starting point of CEPP's Written Representation is set out in the first four numbered points ((i) to (iv) after the second paragraph on page 2 in its summary), which build on the content of section 8. The Applicant considers that the approach suggested by CEPP represents a fundamental mischaracterisation of the legal requirements of the EIA Regulations, as interpreted by the recent decisions in *Finch* and the *West Cumbria mine* case. In the Applicant's submission, the correct position is as follows.

2.2 Legal Principles

2.2.1 The objective of the Environmental Impact Assessment regime, given effect in the present case through the EIA Regs is to provide competent authorities with relevant information to enable them to take a decision on a specific project in full knowledge of its environment effects (R v Rochdale MBC ex parte Tew [2000] Env.L.R.1 at p.20; R (Finch) v Surrey County Council [2024] P.T.S.R. 988 at [3]; [62] and [152]).

2.2.2 That objective is achieved through a process that requires the description; consultation upon and assessment of likely significant direct and indirect effects of a project on the environment (Regulations 5 and 21 and Schedule 4 of the EIA Regs). Provided that process is undertaken, any resulting decision will be taken in "full knowledge" of the project's environmental effects.

2.2.3 The English courts ("the Courts") have stressed that it is inappropriate to apply an unduly legalistic approach to the requirements of Schedule 4 to the EIA Regs, that the requirement that an "EIA application" must be accompanied by an environmental statement is not intended to obstruct such development, and that it would be of no advantage to anyone concerned with the development process if environmental statements were to mention every possible scrap of environmental information. Such documents would be a hindrance, not an aid to sound decision-making, since they would obscure the principal issues in a welter of detail (R (Blewett) v Derbyshire County Council [2004] Env.L.R. 29 at [41] - [42]).

2.2.4 Thus the reference in authority to "full knowledge" or "full information" in respect of a project's environmental effects does not require a decision-maker to seek out every conceivable piece of environmental information about a particular project. Such an approach would be contrary to established caselaw, and would ignore the significant element of judgment involved on the part of the decision-maker in determining what information they need and what would be useful to inform their decision-making. The words "full knowledge" or "full information" do not impose some abstract state or threshold of knowledge which must be obtained, the word "full" in this context meaning sufficient to meet the requirements of the legislation and not full to capacity or exhaustive (R (Suffolk Energy Action Solutions SPV Ltd. v. Secretary of State for Energy Security and Net Zero [2023] EWHC 1796 (Admin) at [60]. This has been a clear and consistent theme in the caselaw on EIA (R v Rochdale MBC ex parte Tew [2000] Env.L.R.1 at p.29; R v Rochdale MBC ex parte Milne [2000] Env.L.R. 406 at [134]; R v Cornwall County Council ex parte Hardy [2001] Env.L.R.25 at [41]; R (Blewett) v Derbyshire County Council [2004] Env.L.R. 29 at [41]; Friends of the Earth v Secretary of State for Levelling Up, Housing and Communities [2024] EWHC 2349 (Admin) at [61]).

2.2.5 The Supreme Court decision in *Finch* does not disturb these well-established principles. The issue raised in that case was whether downstream GHG emissions arising from refinement and combustion were an indirect effect of the proposed oil extraction project. The Supreme Court found that they were, such that they should have been assessed in the EIA. Importantly, in that case it was agreed between the parties that it was inevitable that the oil produced from the well would be refined and undergo combustion; that the emissions arising from those activities would have a significant impact on the climate (i.e. the downstream emissions were both a "likely" and "significant" effect of the project); and that the likely emissions could be estimated using an established methodology such as that described in the IEMA guidance *(Finch* at [7]; [81] and [123]). On those agreed facts, the issue the Court determined related to the scope of the EIA and, in particular, whether it should include downstream emissions.

2.2.6 The majority judgment in *Finch* recognises that the EIA regime only requires an assessment of environmental effects which are both "likely" and "significant". Deciding whether an environmental effect is likely or significant are matters of judgment for the decision-maker (*Finch* at [58] and [121]; *Friends of the Earth* at [70]). It is for the decision-maker to decide whether the information contained in an environmental statement is adequate to meet the requirements of the EIA Regs. It is also for the decision-maker to decide as a matter of judgment whether the environmental information as a whole is adequate. Any such judgment is only subject to review on *Wednesbury* principles (R (Suffolk Energy Action Solutions SPV Ltd. V. Secretary of State for Energy Security and Net Zero [2023] EWHC 1796 (Admin) at [57]), and the Courts will afford an enhanced margin of appreciation to assessments of likely future effects which are made by reference to scientific or technical material as it is not the role of the Court to form its own view as between the views of different experts on technical matters (R (Friends of the Earth Limited) v Secretary of State for Transport [2021] P.T.S.R 190 at [143]; R (Blewett) v Derbyshire County Council [2004] Env.L.R. 29 at [32 – 33]; R (Spurrier) v Secretary of State for Transport [2020] P.T.S.R. 240 at [143]); R (Mott) v Environment Agency [2016] 1 WLR 4338 at [69 – 70]).

2.2.7 For the avoidance of doubt, the Courts have made it clear that the EIA process does not require that attempts be made to measure or assess putative effects which are incapable of assessment and does not impose obligations that are impossibly onerous and unworkable (*Finch* at [122] and [167]). Only effects which are likely to occur, significant and capable of meaningful assessment must be assessed (*Finch* at [167]). Conjecture and speculation have no place in the EIA process (*Friends of the Earth* at [70]).

2.3 Application of the relevant legal principles to the Proposed Development in light of CEPP's Written Representation

2.3.1 In the context of these legal principles, it is noted that the CEPP Written Representation seeks to cast doubt on the robustness of the Applicant's assessments based on the fact that there is a wide range of scientific literature (as evidenced by the number of appendices submitted) which seeks to grapple with issues related to how the assumptions which underpin the different aspects of the Applicant's assessments.

2.3.2 In light of the established legal principles, the key question is whether the Applicant's approach provides adequate and sufficient information to ascertain the likely significant effects of the Proposed Development.

2.3.3 The focus of this Response is therefore not to engage with each of the sensitivity tests presented by CEPP, but to explain why the assumptions made in the Applicant's assessment are robust in light of the Proposed Development's role in meeting the stated aims of national policy.

2.3.4 In doing so, the Applicant notes that it is clear from CEPP's Written Representation that it fundamentally disagrees with Government policy support for blue hydrogen as part of the trajectory to Net Zero. As is well established by case law, challenges to specific projects should not be used to challenge underlying Government policy (R (Spurrier) v Secretary of State for Transport [2020] P.T.S.R. 240 at paras. 92 – 110; R (oao ClientEarth) v Secretary of State for Business, Energy and Industrial Strategy [2021] P.T.S.R. 1400 at para. 101). Government policy includes not only the National Policy Statement (NPS), but also its overall approach to promoting low carbon hydrogen projects through the development of the Low Carbon Hydrogen Business Model and the LCHS.

2.3.5 Those Government policies are underpinned by a robust evidence base and assumptions derived from that evidence base, and it is upon that evidence base and assumptions that the Applicant's assessments are built. The robustness of the Applicant's approach must therefore be seen in that context, and it is important that the Examination is not used as a means effectively to seek to challenge Government policy by the 'back door'.

3.0 UPSTREAM EMISSION AND METHANE EMISSION FACTORS

3.1 Upstream Emission Factors

3.1.1 The Applicant's GHG emissions assessment has been undertaken in line with the best practice guidance and policy for EIA climate assessments. Emission factors are selected in line with this practice drawn from government and industry recognised datasets, providing consistency in approach and assessments. In the case of upstream emissions from the natural gas supply chain – generally referred to as Well to Tank (WTT) emissions – the factor used in the Applicant's assessment was taken directly from the relevant year's Department of Energy Security and Net Zero (DESNZ) factors. The factor is derived from a report (Study on Actual GHG Data for Diesel, Petrol, Kerosene and Natural Gas), produced for the European Commission by Exergia et al. (2015). The study explicitly included upstream emissions from venting, flaring and other fugitive emissions within the natural gas supply chain. This is an approach that was accepted as appropriate by the Secretary of State in paragraphs 4.34 and 4.54 of the Net Zero Teesside decision letter (DESNZ, 2024).

3.1.2 The upstream emissions factor accounts for all potential emissions sources (venting, flaring and other fugitive emissions) that may occur between the point of extraction and the point of use. The factor, therefore, is relevant and most appropriate to an end user consuming natural gas from the UK grid. It takes account of the varying sources of gas into the gas grid, whether this is from domestic production on the UK continental shelf, imported from Norway via pipeline, or imported into the UK by ship in the form of liquefied natural gas (LNG).

3.1.3 In relation to Indirect/WTT Emissions from Fuels, paragraph 2.18 of the Methodology Paper that accompanies the annual dataset published by DESNZ in 2023 makes it explicit that:

"The methodology developed allows for the value calculated for gas supply in the UK to be updated annually. This allows changes in the source of imported gas, particularly LNG, to be reflected in the emissions value." (2023 Government Greenhouse Gas Conversion Factors for Company Reporting, Methodology Paper for Conversion Factors, DESNZ, 2023a)

3.1.4 This annual UK Government publication is an industry-standard dataset of emissions factors, and their continued use across multiple businesses, sectors and projects helps to ensure that operational emissions data is produced using the same overall scope, boundaries and assumptions, and is therefore comparable between different installations and operators. The guidance of this dataset states *'These factors are suitable for use by UK-based organisations of all sizes and international organisations reporting on their UK operations.'* Consistency in these matters is important, and it is neither necessary, proportionate nor desirable for individual applicants for development consent to be required to develop bespoke emission factors for use in place of those prepared and published by Government.

3.2 Low Carbon Hydrogen Agreement

3.2.1 The Low Carbon Hydrogen Agreement (the "LCHA") is the contract which underpins the hydrogen production business model. The business model will provide revenue support to hydrogen producers to overcome the operating cost gap between low carbon hydrogen and high carbon fuels. It has been designed to incentivise investment in low carbon hydrogen production and use, by making hydrogen a price-competitive decarbonisation option for existing users of unabated fossil fuels and grey hydrogen, and in doing so deliver the government's ambition of up to 10GW of low carbon hydrogen production capacity by 2030 (DESNZ Press Release for the 'standard terms and conditions' and Heads of Terms for the LCHA, (DESNZ 2023e)).

3.2.2 The business model will be delivered through a private law contract (the LCHA) between a government appointed counterparty and hydrogen producers, including the Applicant in respect of the Proposed Development. The LCHA offers a Contract for Difference-style 'variable premium', providing price certainty to producers by paying the difference between the 'Strike Price', which reflects the cost of producing hydrogen, and the 'Reference Price', reflecting the market value of hydrogen

3.2.3 The crucial point however, is that it is a requirement of the LCHA that producers can only receive these support payments for volumes of hydrogen that meet the LCHS.[3]

3.2.4 The overarching policy objective of the interaction between the LCHA and the LCHS is therefore to ensure that only genuinely low carbon hydrogen is supported by government.

3.3 The UK Low Carbon Hydrogen Standard

3.3.1 The UK's LCHS (submitted in the Examination to REP2-023), as required by the LCHA in relation to the Proposed Development (see 3.2.3 above), ensures that the emissions intensity of the hydrogen produced by a project – including upstream emissions – will be consistently and constantly measured, and will not exceed a maximum level. This therefore ensures that the hydrogen produced is 'low carbon'. The LCHS is considered in this section and is a separate mechanism to the environmental permit.

3.3.2 The LCHS sets a maximum threshold for the amount of greenhouse gas emissions allowed in the production process for hydrogen to be considered 'low carbon hydrogen'. Specifically, the LCHS requires hydrogen producers to meet a GHG emissions intensity of 20gCO2e/MJLHV of produced hydrogen or less for the hydrogen to be considered low carbon. Hydrogen producers must calculate their greenhouse gas (GHG) emissions up to the point of production.

3.3.3 Para 1.1 of the LCHS states that '*The intent of the Standard is to ensure UK hydrogen production contributes to our GHG emission reduction targets under the Climate Change Act*.' Developing the LCHS involved extensive consultation with industry, academia, consultancies and non-governmental organisations and considered specific criteria for different production pathways and conditions for compliance.

3.3.4 The current version of the LCHS (version 3) was published in December 2023. DESNZ have signalled their intent to update the LCHS at regular review points to ensure

[3] The LCHA permits limited deviations from this principle to provide reasonable protection for producers in the event of a CO2 network outage (outage not caused by the producer).

that the LCHS remains fit for purpose and reflects their growing understanding of how new technologies work in practice. Hydrogen producers will not be eligible for subsidy payments under the LCHA if they fail to meet the LCHS, which would not be possible with high upstream emissions.

3.3.5 The LCHS specifies that hydrogen producers receiving natural gas via the UK gas Transmission Network, as is the case for the Proposed Development, must use the value of $8.7gCO2e/MJ_{LHV}$ to account for emissions associated with this natural gas supply (see Table 9, LCHS Data Annex, appended to this submission). The Data Annex indicates that this value is based on data including (but not limited to) UK National Statistics (2023) Energy Trends for the mix of natural gas sources consumed in the UK and North Sea Transition Authority (2023) analysis for CO2 intensities. This value will be updated in future versions of the LCHS Data Annex, reflecting any changes over time in the composition of UK gas grid supply and individual GHG intensities of different sources of gas.

3.3.6 Accordingly, any future contribution of LNG to the GHG intensity of the UK gas grid will be captured by the emissions factor supplied by DESNZ in the LCHS Data Annex. At this point in time, however, it would be conjecture to speculate what any changes to that GHG intensity may be. Furthermore, the 20gCO2e/MJLHV figure in the LCHS which establishes what is meant by 'low carbon', and which is a key basis of the Applicant's assessment, would still need to be met.

3.4 Decarbonising Methane Supply and Falling Demand for Natural Gas

3.4.1 Further to the uncertainty around the potential supply mixes of natural gas, and a lack of projections or alternate emission factors from the government, there are a range of policies aimed at decarbonising methane supply. Policies 43 and 62-64 of the Carbon Budget Delivery Plan[4] (CBDP) (DESNZ, 2023f) specifically address reducing emissions from upstream methane supply in the UK through electrification of extraction and minimising of leakages and flaring.

3.4.2 The Applicant recognises that there will be future variation in the source of natural gas in the UK gas grid, with resulting greenhouse gas impacts on the upstream emissions factor (which could be either positive or negative). However, there are no government projections around future mixes to inform a reasonable assessment, and attempting such an assessment, would be no more than conjecture and speculation. Therefore the applicant has used the most appropriate emission factors as explained at paragraphs 3.1.1 – 3.1.4 above.

3.4.3 For example, the sensitivity test provided in table 2 of CEPP's Written Representation and in Appendix B of CEPP's Written Representation only use mixes which assume 100% LNG which the Applicant does not consider to be realistic, given the intention to obtain the gas supply through the UK Gas Supply Network (which itself is extremely unlikely to ever comprise 100% LNG). Furthermore, use of 100% LNG would likely be non-compliant with the LCHS resulting in the loss of financial support through the LCHA.

[4] Whilst the Applicant notes that the CBDP and the process for its approval was successfully challenged in the courts (Friends of the Earth, ClientEarth, Good Law Project v Secretary of State for Energy Security and Net Zero [2024] EWHC 995 (Admin)) it has not been quashed.

3.4.4 Figure 8 of Appendix B of CEPP's Written Representation [REP2-047] shows that domestic production will still be part of the mix even as it declines and states that Norwegian pipeline natural gas will decline 'more slowly'. Both CEPP's Written Representation and Appendix B, focus on additional/extra demand created by blue hydrogen, whereas Figure 8 of Appendix B clearly shows overall gas demand declining over time.

3.4.5 This is a key point that is not acknowledged or addressed in CEPP's Written Representation - the overall demand for gas in the UK is projected to fall dramatically (North Sea Transition Authority, 2024). Blue hydrogen projects are anticipated to displace existing unabated gas demand which, coupled with the rapid scale up of renewable energy, end-user electrification and energy efficiency measures and the delivery of measures anticipated in the Net Zero Strategy and the Carbon Budget Delivery Plan, is expected to lead to a significant, continuous fall in total UK gas demand between now and 2050. While proportions of imports may increase, the absolute import volumes are also projected to decline (North Sea Transition Authority, 2024).

3.4.6 The independent Climate Change Committee's Balanced Pathway in the Sixth Carbon Budget (The Sixth Carbon Budget: The UK's path to Net Zero, CCC, 2020) projects that demand for natural gas will fall by around 70% by 2050 (against 2020 levels), as natural gas use is limited to combustion with Carbon Capture & Storage ("CCS") for power generation and industrial processes, and phased out of use in buildings. Conversely, the Balanced Pathway shows demand for electricity more than doubling by 2050, compared with 2020 levels. This is driven by an increase in electricity demand from buildings, manufacturing and construction as those sectors partially electrify. Significant new sources of electricity demand arise from electrification of surface transport, and for hydrogen production using zero-carbon electricity. The Government has demonstrated the strategic importance of a decarbonised electricity grid with its Clean Power 2030 target and establishing the Mission Control for Clean Power.

3.4.7 In this context, the Applicant considers that the dataset published by the DESNZ and used in the Applicant's assessment is an appropriate and robust source of data for the following reasons:

- it is a standardised UK government emission factor for an activity that allows for practical assessment on the basis of standard, recognised factors;

3.4.8 it allows for measurement and alignment with LCHS compliance which is the basis of Government policy and essential for the Proposed Development to proceed; and

3.4.9 there are no government projections on future grid mixes or effects of national and international policy on upstream emissions.

3.4.10 The Secretary of State was satisfied with this approach in the context of the Net Zero Teesside decision, with the decision letter explaining that:

CEPP reiterated its concerns with the emissions factors used by the Applicants, questioning whether the emissions factors provided by BEIS/DESNZ are the correct ones to use and further questioned the use of the natural gas factor as the fuel supply for the Proposed Development will also include a proportion of liquefied *natural gas. The Secretary of State, taking into account information gathered through the Examination and previous consultation responses, remains satisfied with the approach taken by the Applicant,* ***notwithstanding the likelihood of variation in future emission factors***

3.4.11 Whilst CEPP seek to argue that matters have 'moved on' since the Net Zero Teesside decision, that decision specifically recognised that there may be future variations, but that following the Government approach to emissions factors, as they develop, is still the correct approach.

3.4.12 For these reasons, and having regard to the obvious importance of a consistent and coherent approach to these matters in policy-making and decision-taking, it is not considered reasonable to revisit the upstream emissions factor for natural gas in the light of CEPP's Written Representation. The overall conclusions of the GHG assessment remain valid, as does the evaluation of significance.

3.5 Global Warming Potential and Methane Emissions

3.5.1 CEPP's Written Representation allegesthat a 20-year global warming potential (GWP) emission factor should be used when assessing the impact of the Proposed Development. The Applicant does not agree. GWP_{100} is the only appropriate metric for undertaking a GHG assessment in alignment with IEMA best practice and assessment against current UK policy and regulations.

3.5.2 The difference between GWP_{100} and GWP_{20} is described in paragraph 19.5.77 of the Applicant's Climate Chapter [APP-072]. The GHG assessment was undertaken and the significance of the Proposed Development's impact on the climate was assessed in line with Institute of Environmental Management and Assessment (IEMA) guidance (Environmental Impact Assessment Guide to Assessing Greenhouse Gas Emissions and Evaluating their Significance, IEMA, 2022). Table 19-4 of the Climate Chapter [APP-072] summarises the guidance for IEMA significance consistent with the UK's trajectory towards net zero. The criteria for assessing significance include measurement of emissions against legally binding carbon budgets set by the UK government, and the LCHS, as set out in sections 19.5.20 to 19.5.28 of that document. In setting the carbon budgets, the Climate Change Committee (CCC) has used GWP_{100} as its method for recommending policies and carbon budgets (The Sixth Carbon Budget: The UK's path to Net Zero, CCC, 2020). Similarly, the emission factors prescribed to calculate alignment with the UK's LCHS use GWP_{100} as indicated in Table 1 of the data annex (Data for calculating Greenhouse Gas Emissions under the UK Low Carbon Hydrogen Standard, DESNZ, 2023b).

3.5.3 In order to assess consistency with UK's net zero trajectory and associated policies, a standard metric for global warming is necessary. The two key sources of emission factors used in the GHG assessment are the: Inventory of Carbon and Energy (ICE) (Embodied Carbon – The ICE Database, ICE, 2019) and the UK government GHG conversion factors for company reporting (DESNZ, 2023c). These are both developed using GWP_{100}.

3.5.4 For these reasons it is neither practicable nor informative to undertake the assessment using GWP_{20}, as there are limited datasets with which to undertake such an assessment, and the outputs could not be compared against national carbon budgets or LCHS to indicate consistency with UK's net zero trajectory and policies.

3.5.5 While CEPP makes a number of claims to advocate for using GWP_{20} in the GHG assessment, the Applicant does not consider this would be reasonable or informative as the key approaches for assessing significance by reference to UK carbon budgets, LCHS and net zero trajectories, in line with the accepted methodology for assessing GHG impacts for EIA (i.e. IEMA) are all derived using GWP_{100}. There is therefore no support for an alternative approach within the context of the IEMA methodology. The use of GWP_{100} is an appropriate and robust basis on which to carry out the assessment and determine the significance of effects.

3.6 Implications for Assessment

3.6.1 CEPP's Written Representation claims that, based on the issues it raises, the GHG assessment does not constitute a reasonable worst-case scenario and is not in line with EIA Requirements. The Applicant refutes this.

3.6.2 As explained above, the Applicant's assessment accords with an established and widely accepted methodology for assessing GHG impacts for EIA purposes (i.e. IEMA guidance) and satisfies the requirements of EIA to assess the realistic worst-case parameters for the GHG assessment in the Climate Chapter [APP-072].

3.6.3 By contrast, a scenario which assumes 100% LNG supply, with no decarbonisation or management of leakage over the 25-year life cycle is not a realistic scenario.

3.6.4 GWP_{100} is the most robust metric available to assess the Proposed Development's consistency withthe UK's net zero trajectory and the LCHS and therefore the Applicant rejects Paragraph 70 of CEPP's Written Representation's claim that GWP_{100} does not reflect the real climate impact, and GWP_{20} does.

3.6.5 The carbon trajectories, budgets, and government emission factor databases used in the assessment all use GWP_{100} so this is the appropriate assessment metric to allow the significance of the global warming potential of the Proposed Development to be assessed. The use of the upstream methane emission factor from DESNZ is therefore appropriate to enable the Secretary of State to robustly determine the likely significant effects of the Proposed Development.

4.0 THE APPLICANT'S ASSESSMENT

4.1 Clarifying calculation methods

4.1.1 Section 6 of CEPPs Written Representations [REP 2-046] states that they were unable to reproduce the Applicant's calculations based on available data.

4.1.2 The Applicant is confident that the figures presented in Chapter 19 are correct – clarification is provided on these matters below, with the main difference from the figures noted by CEPP resulting from how the phases presented in Tables 19-8 and 19-9 of the ES [APP-072] are considered[5]. The Applicant will demonstrate how the figures match and add up to align with the total emissions over 25 years and LCHS figures with reference to tables 19-8 and 19-9 of the ES [APP-072].

4.1.3 The annual operational emissions presented in Table 19-9 (793,147 tCO_2e) represent the emissions related to the operation of Phase 1 and Phase 2 concurrently. This method of operation occurs for 23 years, prior to which Phase 1 will operate independently for two years (at 445,518 tCO_2e per year). To calculate the total operational emissions (25 years from the completion of Phase 1), the annual operational emissions from Table 19-8 must be considered for the first two years of operation, followed by 23 years of the phases operating together from Table 19-9. These are explained further in response to ExQ1.5.9 [REP2-023].

4.1.4 The difference between the average annual operational emissions of Phase 1 alone, and Phase 1 & Phase 2 together is 347,629 tCO_2e, which over two years of operation results in a difference of 695,258 tCO_2e. This is the difference identified in paragraph 57 of CEPP's WR [REP2-046]. The difference of four tCO_2e between these calculations and the total identified within CEPP's Written Representation is due to rounding and is not material.

4.1.5 For the LCHS calculations, the emissions with these operational assumptions sum up to 15,103,547tCO2e, which equates to the 16.62gCO2e/MJ carbon intensity figure presented in Paragraph 19.5.69 of the ES chapter [APP-072].

4.1.6 The differences noted in section 6.1 and 6.2 of CEPP's WR [REP2-046] are explained by this difference. 25 years of operations is broken down into 2 years of phase 1 operating independently (table 19-8) and 23 years of phase 1 and 2 in combination (table 19-9).

4.2 Contextualisation against the Carbon Budget Delivery Plan (CBDP)

4.2.1 Paragraph 130 point I of CEPP's Written Representation asks for an explanation on the methodology used to obtain the figures for the CBDP. This has been provided in the Applicant's response to ExQ1.5.9 [REP2-023]. The Applicant has addressed the limitations of the sensitivity testing methodology in approaching the CBDP in section 2 of this note, however the Applicant re-iterates that the carbon budgets were developed using GWP_{100} so it is essential to make a meaningful comparison on the same metric. The Applicant would further note that as paragraph 130 point

[5] As an aside, the Applicant would also note that as per the Proposed Change Application Report [EN070009/EXAM/7.3] the electricity consumption presented in Table 19-7 is now 40MW instead of 70MW which means the figures presented throughout the chapter are higher than what is likely for scope 2 emissions.

iii of CEPP's Written Representation mentions, many of the upstream methane emissions referred to in CEPP's Written Representation will not form part of the territorial emissions budget. This is particularly true for CEPP's proposed sensitivity test set out in the Written Representation of using 100% imported LNG, which does not constitute a reasonable or realistic worst case. As the CBDP explicitly only considers emissions that occur within the territorial boundaries of the UK, a large proportion of the upstream emissions relating to the gas supply (particularly of LNG) would not fall within the scope of the CBDP.

4.3 Significance assessment of the project

4.3.1 CEPP's Written Representation asks the Applicant to explain how it reaches the conclusion of "Minor Adverse" significance.

4.3.2 The criteria for assessing significance include comparison of emissions against legally binding carbon budgets set by the UK government and the LCHS, as set out in Paragraphs 19.5.20 to 19.5.28 of the ES [APP-072]. The UK's trajectory towards net zero includes the production of blue hydrogen that aligns with the LCHS. The Proposed Development is in line with government policy which identifies the necessity of producing hydrogen with carbon capture as part of the trajectory to Net Zero, as set out in Paragraphs 19.2.54-19.2.57 of the ES [APP-072].

4.3.3 The GHG assessment indicates that the hydrogen product will align with the LCHS in operation, as well as decarbonising in line with the legally binding carbon budgets as set out in Table 19-11 of the ES [APP-072].

4.3.4 This aligns with IEMA's guidance on determining the significance of the emissions associated with the Proposed Development where a 'Minor Adverse' project may have residual emissions, but is consistent with and contributes towards the achievement of Net Zero by 2050.

4.3.5 In the event that the plant does not comply with the LCHS then the plant will not receive any payments under the LCHA, as discussed above.

4.4 Cumulative emissions across the sector

4.4.1 CEPP's Written Representation asks the Applicant to provide a cumulative assessment across the natural gas, CCS and blue hydrogen sector. As stated in Paragraphs 19.5.3 to 19.5.6 of the ES [APP-072], a cross-sector cumulative emissions assessment is neither required to satisfy the requirements of the EIA Regulations nor in line with IEMA guidance. CEPP has not identified any other legal or policy basis that would justify its request.

4.5 The hydrogen product

4.5.1 CEPP's Written Representation challenges the method of the GHG assessment which considers the benefit of the hydrogen project against a 'without project' baseline. The Applicant considers that this approach is in line with best practice set out by IEMA and the large number of recent DCO decisions.

4.5.2 In Plate 19-2 of the ES [APP-072], the assessment compares the emissions intensity of the hydrogen produced and other fuel emission factors. This is in order to compare the Proposed Development against a 'without project' baseline of continued direct fossil fuel combustion. To make this comparison, DESNZ factors for alternative energy generation methods are used to compare the Proposed Development to the 'without project' baseline. These DESNZ factors were used in order to produce consistent and comparable results to other aspects of this Assessment, or other developments across the UK. Table 19-4 of the ES [APP-072] sets out that IEMA beneficial criteria refer to a project causing a reduction in atmospheric concentration *'whether directly or indirectly, compared to the without-project baseline.'*

4.5.3 This is an approach supported in paragraph 150 of the *Finch* judgment, in which the following statement is made: *"Just as beneficial indirect effects of a project on climate - for example, the "green" energy that would be generated by a project to develop a wind farm or solar farm - are clearly a relevant matter for the planning authority to consider, so corresponding adverse effects are also a material planning consideration."*

4.5.4 The natural gas scenario selected in Plate 19-2 of the ES [APP-072] does not represent combustion of H_2 in a Combined Cycle Gas Turbine ("CCGT") but relates to supplies for industrial processing at local off-takers. Plate 19-2 demonstrates the benefit of hydrogen under many scenarios. H2Teesside has been developed to provide blue hydrogen as a direct replacement for grey hydrogen in industrial and chemical processes as well as a fuel displacing unabated natural gas, which would provide additional substantial decarbonisation benefits.

5.0 OTHER MATTERS

5.1.1 The Applicant notes that the CEPP Written Representation raises a number of subsidiary matters to the issues discussed above. The Applicant deals with these below.

5.2 Carbon Capture Technology – DCO Drafting and 'Limitations'

5.2.1 The Applicant does not consider that any additional or different drafting or controls are required in the DCO in relation to carbon capture.

5.2.2 The Applicant considers that the CEPP Written Representation mischaracterises how Net Zero Teesside and Keadby 3 deal with the Carbon Capture rate. The Applicant would also note that this issue was considered on the Drax BECCS project (following similar submissions by CEPP) which also based its assessments on a 95% capture rate.

5.2.3 For both the Keadby 3 and Net Zero Teesside project the only reference to a capture rate within the DCO is contained with the definition of 'carbon capture and compression plant' (or 'CCP') of their DCOs:

- Keadby 3: "*the building and associated works comprised in Work No. 1C and Work No. 7 in Schedule 1 shown on the works plans and which are designed to capture, compress and export to the National Grid Carbon Gathering Network, a minimum rate of 90% of the carbon dioxide emissions of the generating station operating at full load*"; and
- Net Zero Teesside*: "the carbon capture plant, which is designed to capture a minimum rate of 90% of the carbon dioxide emissions of the generating station operating at full load"*

5.2.4 In neither DCO is there a provision requiring the capture rate to be achieved.

5.2.5 In the Drax BECCS DCO, there is no reference at all to a 90 or 95% capture rate in the DCO.

5.2.6 In all of those projects, as is the case with the Proposed Development, the mechanism for achieving the capture rate is the Environmental Permit. In considering the Environmental Permit for H2 Teesside, the EA will have regard to its February 2023 Guidance on Hydrogen Production with Carbon Capture: Emerging Techniques. That Guidance states that '*When you apply for an environmental permit for this activity, you must tell your regulator whether you are going to follow this guidance. If not, you must propose an alternative approach which will provide the same or greater level of protection for the environment'.* The Applicant's Environmental Permit application has therefore been based on meeting this Guidance.

5.2.7 Section 3.3 of the Guidance goes on to state that "*You should design plant to maximise the carbon capture efficiency. As a minimum, you should achieve an overall CO2 capture rate of at least 95%, although this may vary depending on the operation of the plant"*. The EA will therefore consider whether the Applicant has achieved this in determining the permit application. As an example of this being applied, similar guidance applies to post-combustion carbon capture plants, and the permit for Net Zero Teesside (REP2-023) sets out the mechanisms for the carbon capture rate to be achieved.

5.2.8 This context is important in light of section 4.12 of the Energy NPS, where it is stated that:

"*4.2.10: The Secretary of State should work on the assumption that the relevant pollution control regime and other environmental regulatory regimes, including those on land drainage, water abstraction and biodiversity, will be properly applied and enforced by the relevant regulator. The Secretary of State should act to complement but not seek to duplicate them.*

4.2.16: The Secretary of State should not refuse consent on the basis of pollution impacts unless there is good reason to believe that any relevant necessary operational pollution control permits or licences or other consents will not subsequently be granted.

5.2.9 The clear policy direction, therefore, is that the permitting regime will operate effectively and that the DCO should not duplicate controls that can be imposed through that alternative regime. Furthermore, it is clear that achieving a 95% capture rate is therefore a reasonable assumption upon which to base the ES.

5.2.10 The question of how this is delivered where the carbon capture is reliant upon third party infrastructure for the carbon to be transported away and stored being operational at the time of the Proposed Development commencing operations is a different matter. In such a scenario if an Environmental Permit is in place and requires a 95% carbon capture rate for compliance under normal operations, similar to the NZT Environmental Permit, the Applicant will not be able to achieve that if the transport system is not in place. No further control is therefore required. Any breach of the relevant permit would be appropriately enforced through that regulatory regime.

5.2.11 This is all important context when considering CEPP's suggestions as to the 'limitations' of carbon capture technology. The Proposed Development's Environmental Permit will ensure that the capture rate is delivered and so it is a reasonable basis of assessment for <u>this</u> development. Please also note the Applicant's response to FWQ 1.5.6.

5.2.12 CEPP's criticisms should also be seen in the context of Government policy:

- the CCC is clear that carbon capture is a necessity not an option (NPS EN-1 paragraph 3.5.2);
- NPS EN-1 (paras 3.4.22, 3.5.8 and 4.2.7) is clear that the provision of carbon capture and low carbon hydrogen infrastructure is a critical national priority; and

5.2.13 the Government's October 2024 re-statement of its commitment to carbon capture, the Proposed Development and the East Coast Cluster[6].

[6] In the Autumn Budget and in its 4 October announcement prior to the International Investment Summit

5.2.14 As such, CEPP's criticisms should be seen for what they are – a criticism of Government policy which provides consistent and emphatic support for carbon capture. In the context of the Planning Act 2008 regime and case law, criticism of Government policy is not a relevant consideration for the determination of this DCO.

5.2.15 Furthermore, the Applicant considers that it is also the case that in practical terms a 95% capture rate is a reasonable assumption upon which to base the ES assessments. Some additional technical information in this regard is set out below.

5.2.16 The Proposed Development is a new build hydrogen production plant, and its design is based on proven technologies already built at scale: syngas production, water gas shift and carbon capture, all of which have been used effectively in other industries such as methanol, gas to liquids, natural gas processing and ammonia. These technologies have been integrated in an optimised way to produce a blue hydrogen production facility with a high carbon capture rate, 95%. The technology decisions taken by the Proposed Development are also consistent with other blue hydrogen developers looking to capture high rates of CO2.

5.2.17 The Proposed Development will utilise autothermal reforming (ATR) for the syngas production, which means that all the CO2 produced in the syngas is available for capture at a high partial pressure. There is no furnace associated with an ATR, unlike Steam Methane Reformers (SMR) which are largely used to produce grey hydrogen.

5.2.18 While ATR combined with CO2 capture for blue hydrogen production may be considered a new industry, there is considerable experience in the individual components of the system.

5.2.19 Furthermore, it is noted that the proposed CO2 capture system (pre-combustion amine absorption) reduces the CO2 in the syngas stream to very low levels. The high CO2 concentration and partial pressure in the syngas make CO2 removal very efficient (Das, Peu et al, Advancements in CO2 capture by absorption and adsorption: A comprehensive review, Journal of CO2 Utilization, Volume 81, 2024). This is backed up by decades of operational experience of achieving similar levels of removal in natural gas processing using amine absorption, especially where the natural gas is to be liquefied to LNG. For those systems, it is normal to specify residual CO2 content in the natural gas stream to a value of <50 parts per million (molar) (The fundamentals of feed gas pretreatment, LNG Industry Magazine, 2019).

5.2.20 The combination of the high conversion of the carbon in the natural gas feed to CO2 in the ATR-based hydrogen production plant, followed by water gas shift and the very high removal rate of the CO2 in the CO2 capture plant means that a CO2 capture rate of 95% is eminently achievable.

5.2.21 The overall CO2 capture rate is underpinned by process guarantees from the chosen technology providers under a competitive process. The Proposed Development's design is in line with other similar types of proposed projects adopting ATR-based projects and targeting high capture rates such as low carbon ammonia plants and other blue hydrogen plants.

5.2.22 It should also be noted that comparison of the Proposed Development's design to existing projects which capture CO2 is not a direct likeness, as H2Teesside is an optimised new build with a specific high capture rate design target, whereas existing projects are generally retrofits where existing constraints may necessitate lower capture rate design targets.

5.2.23 Existing system retrofits are typically intended to partially capture the total carbon in the process. For example, the application of CO2 capture to the syngas stream of a steam methane reforming (SMR) plant does not capture the CO2 from the reformer furnace flue gas, or some gas processing processes do not need to have a high capture rate because some CO2 up to certain % levels may be acceptable in the treated gas stream.

5.2.24 Furthermore, existing system retrofits are likely based on post-combustion capture where the CO2 capture rate from the flue gas is often set at 90% due to the low partial pressure of CO2 in the flue gas. This will not be the case for the Proposed Development that is pre-combustion capture.

5.2.25 In conclusion therefore, a 95% design capture rate will be required under the Environmental Permit, is technically achievable, and carbon capture is a cornerstone of the Government's energy policy.

Teesside Flexible Regas Project and Net Zero Teesside

5.2.26 The Applicant has dealt with matters relating to LNG in section 2 above, and can confirm that it has had no discussions with the promoter of the Teesside Flexible Regas Project in relation to using any LNG transported through those proposed facilities.

5.2.27 The Teesside Flexible Regas Project is at Pre-Application stage and no information is available to inform the ES for the Proposed Development at this stage. It will be for the Teesside Flexible Regas Project to consider its wider position alongside other developments in the Teesside area as it carries out its EIA process. The introduction of a proximate LNG supply, if secured and confirmed, would not affect the intent of the Applicant to source natural gas from the grid and the obligation in the LCHS for the Applicant to use national average emission factors if natural gas is supplied from the grid.

5.2.28 In respect of Net Zero Teesside, it is noted that in line with IEMA Guidance, it is not appropriate to arbitrarily choose projects that should be considered as a 'cumulative' project when considering GHG impacts. As the IEMA Guidance states '*Effects of GHG emission from specific cumulative projects … in general should not be individually assessed as there is no basis for selecting any particular … cumulative project that has GHG emission for assessment over any other*'. This was agreed to be an acceptable approach in *Boswell v SoST* [2024] EWCA 145.

5.2.29 The Applicant's approach to assessing against carbon budgets, as explained in paragraphs 19.5.3 to 19.5.6 of Chapter 19 of the ES [APP-072], was endorsed by the Court in that case.

5.2.30 Furthermore, it is noted that the operational emissions of H2 Teesside arising from unavailability of the NEP carbon dioxide transport and storage network due to planned or unplanned outages are presented in Tables 19-8 and 19-9 of the ES [APP-

072]. Construction emissions associated with the NEP are also presented in Paragraph 19.5.78 of the ES [APP-072]. However, neither source of emissions are considered to be material to this assessment.

5.2.31 The emission figures from NZT presented in paragraph 53 of CEPP's Written Representation are predominantly operational emissions from the NZT CCGT Power Station, which the Proposed Development is not linked to. The Proposed Development does not require the NZT power station to be operating in order to use the NZT operated gas transportation network that will transport natural gas from the national transmission system to the Proposed Development, as the latter is designed to work independently of the NZT power station. The Applicant therefore does not believe these two developments need to be considered together.

5.2.32 There is therefore no need to 'extend' the Examination to consider cumulative impacts specifically with NZT (in any scenario).

6.0 CONCLUSION

6.1.1 This submission has set out why the Applicant's approach to the assessment of Greenhouse Gas emissions is robust and provides (at least) adequate and sufficient information to enable the Secretary of State to consider the likely significant environmental effects of the Proposed Development.

6.1.2 It demonstrates that the Applicant's approaches to fugitive upstream emissions, global warming potential and capture rate within its assessment are appropriate in light of Government policy, the Guidance provided by IEMA for carrying out GHG assessments and the approach supported in recent Secretary of State decision making.

6.1.3 The focus of EIA, as re-emphasised by Finch is to consider the likely significant effects of the development based on information that is reasonably available.

6.1.4 Whilst the Applicant acknowledges that there is much scientific research being undertaken on the various matters discussed in this submission, as evidenced by CEPP's Appendices, it is still evolving. It is for the decision-maker to form a judgment as to the adequacy of the environmental information to reach a judgement on the likely significant effects. This does not require the decision-maker to seek out every conceivable piece of environmental information about a particular project.

6.1.5 As set out in its submission, the Applicant's approach is based on emissions factors derived from and relied upon by Government and the application of a permitting regime that, in accordance with the NPS, must be assumed to operate effectively. It is reflective of the overall regime that the Government is creating to regulate the development of low carbon hydrogen.

6.1.6 It is not appropriate to challenge the merits of national policy through an individual development consent order (either directly or indirectly).

6.1.7 The Applicant's GHG assessment adopts an appropriate methodology in accordance with IEMA Guidance and national policy and provides a robust assessment of the Proposed Development's likely significant environmental effects, including its GHG emissions which satisfies the requirements of the EIA Regulations.

7.0 REFERENCES

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APPENDIX 1: UK LOW CARBON HYDROGEN STANDARD DATA ANNEX

Department for
Energy Security
& Net Zero

Data Annex

Data for calculating Greenhouse Gas Emissions under the UK Low Carbon Hydrogen Standard

December 2023

Any enquiries regarding this publication should be sent to us at:
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Contents

List of Tables

Introduction

DA.1. This document contains Typical Data, Default Data, and other useful conversion factors, which can be used towards determining compliance with the GHG Emission Intensity Threshold and other requirements which make up the Low Carbon Hydrogen Standard (the 'Standard'). It is intended to complement the contents of the Standard Document with supporting quantitative and qualitative data (or references to data sources) which are necessary or auxiliary to determining Standard Compliance. It will not introduce new policies, nor will it contradict the contents of the Standard Document.

DA.2. This document will be reviewed and updated on an annual basis (subject to relevant datasets being published). Updates will incorporate developments in the industry (for example, improving default efficiencies for Default Data values), changes in the referenced datasets, and/or changes to the most appropriate datasets to use. Updates to this document may happen outside of the annual cycle if required to accommodate the inclusion of a new Eligible Hydrogen Production Pathway.

DA.3. The updates in this version of the Data Annex shall be effective immediately. Future updates to the Data Annex shall be effective from a specified date in the updated Data Annex – this date will be the start of a calendar month and will be a minimum of 28 days from the date of publication of the updated Data Annex.

Global Warming Potentials (GWP)

DA.4. Table 1 shows the GWP values of CO_2, CH_4, N_2O, SF_6, NF_3, perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs) for a period of 100 years according to the 2018 Fifth Assessment Reports (AR5) of the Intergovernmental Panel on Climate Change (IPCC). These values shall be applied across all GHG emissions calculations under the Standard.

Table 1: IPCC AR5 Global Warming Potential (GWP) of GHGs without climate feedback[1]

GHG	GWP value (in gCO_2e/g)
CO_2 (fossil)	1
CO_2 (biogenic)	0
CH_4	28
N_2O	265
SF_6	23,500
NF_3	16,100
Perfluorocarbons (PFCs)	
PFC-14 (CF_4)	6,630
PFC-116 (C_2F_6)	11,100
PFC-218 (C_3F_8)	8,900
PFC-318 (c-C_4F_8)	9,540
PFC-31-10 (C_4F_{10})	9,200
PFC-41-12 (C_5F_{12})	8,550
PFC-51-14 (C_6F_{14})	7,910
PFC-91-18 ($C_{10}F_{18}$)	7,190
Trifluoromethyl sulphur pentafluoride (SF_5CF_3)	17,400
Perfluorocyclopropane (c-C_3F_6)	9,200
Hydrofluorocarbons (HFCs)	
HFC-23	12,400

[1] https://ghgprotocol.org/sites/default/files/ghgp/Global-Warming-Potential-Values%20%28Feb%2016%202016%29_1.pdf

HFC-32	677
HFC-41	116
HFC-125	3,170
HFC-134	1,120
HFC-134a	1,300
HFC-143	328
HFC-143a	4,800
HFC-152	16
HFC-152a	138
HFC-161	4
HFC-227ea	3,350
HFC-236cb	1,210
HFC-236ea	1,330
HFC-236fa	8,060
HFC-245ca	716
HFC-245fa	858
HFC-365mfc	804
HFC-43-10mee	1,650

Typical Data

DA.5. The Standard Document breaks down the Hydrogen Product GHG Emission Intensity calculation into the following Emission Categories.

Equation 1

$$E_T = E_{Feedstock\ Supply} + E_{Energy\ Supply} + E_{Input\ Materials} + E_{Process\ CO_2} + E_{Fugitive\ non\text{-}CO_2} + E_{CO_2\ Capture\ and\ Network\ Entry} - E_{CO_2\ Sequestration} + E_{Solid\ C\ Distribution} - E_{Solid\ C\ Sequestration} + E_{Compression\ and\ Purification} + E_{Fossil\ Waste/Residue\ Counterfactual}$$

Where E_T = total GHG emissions in gCO_2e over the Reporting Unit for the Discrete Consignment.

DA.6. Instructions on which emissions shall be included within the calculations for each of these Emission Categories are given in Chapter 5 of the Standard Document, whereby Activity Flow Data is combined with GHG Emission Intensities (or GWPs) for each Input and Output to the Pathway. The sections below provide the Typical Data and data sources that shall be used for these GHG Emission Intensities, along with any further guidance regarding Solid Carbon Permissible End Uses and identification of fossil Waste/Residue feedstock counterfactuals that are not given in the Standard Document.

DA.7. Guidance on whether Default Data can be used before a Hydrogen Production Facility is operational (instead of Projected Data) is given in Paragraphs DA.75-DA.87.

Feedstock Supply

DA.8. Pathways without feedstocks (e.g. electrolysis) have no emissions to report under the Feedstock Supply Emission Category. The emissions associated with any Input electricity derived from biomass or Waste Inputs shall be accounted for under the Energy Supply Emissions Category.

DA.9. Fossil gas reforming with CCS Pathways, or gas splitting with solid carbon Pathways that consume natural gas from the UK Gas Network, shall calculate the Feedstock Supply emissions for these Discrete Consignments using the natural gas GHG Emission Intensity value given in Table 9 (depending on whether withdrawing from the Transmission Network or Distribution Network), combined with the Activity Flow Data for their consumption of natural gas from the UK Gas Network.

DA.10. Pathways using biomass or Waste feedstocks shall calculate their Feedstock Supply emissions for the UK proportion of their supply chain, using the same GHG Emission Intensities for Inputs to this supply chain (such as energy and materials) as given in

Paragraphs DA.20-DA.45. For biomass and Waste feedstocks sourced from abroad, appropriate up-to-date national GHG Emission Intensities shall be sourced and evidenced for input energy and materials used within overseas segments of the supply chain.

Direct land use change (DLUC)

DA.11. For relevant biomass feedstocks, these DLUC calculations are carried out according to the methodology in Annex E of the Standard Document and included within the Feedstock Supply Emission Category result.

DA.12. Based on the location of the DLUC, climate, ecological zone and soil type can be taken from maps and data provided by the Joint Research Centre (JRC)[2].

DA.13. The Food and Agriculture Organisation of the United Nations (FAO)[3] provides similar information.

DA.14. In most cases, it is possible to find values for the different parameters required under Annex E of the Standard Document within the look-up tables in the Renewable Transport Fuel Obligation (RTFO) standard values[4].

DA.15. For C_{DOM} the value of 0 may be used, except forest land (excluding forest plantations) with more than 30% canopy cover.

DA.16. CF_B can be taken to be 0.47; CF_{DW} can be taken to be 0.5; CF_{LI} can be taken to be 0.4.

Indirect land use change (ILUC) – reporting purposes only

DA.17. The ILUC emissions values in Table 2 shall be used when reporting the estimated ILUC emissions associated with use of cereals and other starch-rich crops, sugars or oil crops. Note that the values provided are in gCO_2e/MJ_{LHV} biomass, so require conversion into gCO_2e/MJ_{LHV} Hydrogen Product values based on the usage of the biomass within the Pathway.

DA.18. ILUC emissions shall be reported as being zero for all other types of biomass.

[2] https://esdac.jrc.ec.europa.eu/projects/RenewableEnergy/
[3] https://www.fao.org/forest-resources-assessment/remote-sensing/global-ecological-zones-gez-mapping/en/
[4] https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-compliance-reporting-and-verification

Table 2: ILUC values of biomass groups

Biomass group	ILUC values (gCO_2e/MJ_{LHV} biomass)
Cereals and other starch-rich crops	12
Sugars	13
Oil crops	55

Crude oil supply

DA.19. Pathways that utilise crude oil as a feedstock may use the country-level values provided by Masnadi et al[5] as summarised in the Table 3 below to derive a weighted average GHG Emission Intensity for their crude oil mix.

Table 3: GHG Emission Intensity of crude oil imports

Country	GHG Emission Intensity (gCO_2e/MJ_{LHV})	Country	GHG Emission Intensity (gCO_2e/MJ_{LHV})
Afghanistan	8.3	Kuwait	6.9
Albania	23.7	Kyrgyzstan	9.4
Algeria	20.3	Latvia	8.9
Angola	7.5	Libya	11.0
Argentina	9.1	Lithuania	9.7
Australia	9.1	Malaysia	12.9
Austria	7.6	Mauritania	14.8
Azerbaijan	6.3	Mexico	9.9
Bahrain	5.0	Morocco	9.3
Barbados	9.3	Myanmar	20.2
Belize	8.8	Netherlands	3.9
Bolivia	9.0	New Zealand	8.2
Brazil	10.3	Niger	11.3
Brunei	5.7	Nigeria	12.6
Bulgaria	8.6	Norway	5.6

[5] https://www.science.org/doi/10.1126/science.aar6859

Cameroon	18.4	Oman	11.7
Canada	17.6	Pakistan	12.2
Chad	10.2	Papua New Guinea	8.5
Chile	11.2	Peru	10.9
China	7.0	Philippines	11.6
Colombia	8.3	Poland	8.2
Cote d'Ivoire	6.1	Qatar	6.5
Croatia	7.8	Republic of Congo	10.6
Cuba	9.0	Romania	7.4
Democratic Republic of Congo	29.2	Russian Federation	9.7
Denmark	3.3	Saudi Arabia	4.6
Ecuador	9.3	Serbia	7.7
Egypt	10.6	Spain	4.1
Equatorial Guinea	6.4	Sudan	14.9
France	7.5	Suriname	8.2
Gabon	13.2	Syria	29.8
Georgia	15.2	Tajikistan	9.4
Germany	7.7	Thailand	5.1
Ghana	5.2	Trinidad and Tobago	14.3
Greece	5.9	Tunisia	15.4
Guatemala	9.8	Turkey	8.4
Hungary	7.9	Turkmenistan	15.9
India	8.6	Ukraine	11.8
Indonesia	15.3	United Arab Emirates	7.1
Iran	17.1	United Kingdom	7.9
Iraq	14.1	United States	11.3
Italy	6.1	Uzbekistan	27.4

Japan	7.7	Venezuela	20.3
Jordan	6.3	Vietnam	8.8
Kazakhstan	9.7	Yemen	26.9

Energy Supply

DA.20. Energy Supply emissions cover the generation and supply of electricity, steam, heat, and fuels for hydrogen production.

Electricity

Electricity sourced from a specific generator via an Eligible PPA (or equivalent), or sourced from a Private Network and not linked to a specific generator, excluding grid import to the Private Network

DA.21. When calculating the emissions associated with the generation of electricity from a specific generator or from a weighted average of generators on a Private Network, the Typical Data electricity generation GHG Emission Intensity in Table 4Table 4 shall be used by the Hydrogen Production Facility (or Electricity Storage System).

DA.22. Note that values are not provided for biomass or Waste electricity generators. Given the diversity of supply chains and conversion efficiencies, the GHG Emission Intensities for biomass or Waste electricity generation shall be calculated following the methodology given in Annex G of the Standard Document. The same applies to combined heat and power generation, given the diversity of conversion efficiencies.

DA.23. If the Hydrogen Production Facility (or Electricity Storage System) is consuming electricity from an onsite or adjacent electricity generation asset, the generation GHG Emission Intensity values in Table 4 can be used directly as the delivered GHG Emission Intensity without any Transmission and Distribution Losses being applied. If the Hydrogen Production Facility (or Electricity Storage System) is sourcing electricity from the electricity generation asset via the Electricity Grid or via a Private Network, then any Transmission and Distribution Losses will need to be accounted for in the delivered GHG Emission Intensity, following Annex B of the Standard Document.

Table 4: Electricity generation GHG Emission Intensities (prior to any Transmission and Distribution Losses)

Generator	gCO_2e/kWh_e	gCO_2e/MJ_e	Sources and supporting notes
Onshore wind	0.0	0.0	JEC (2020) Well-to-tank report v5[6], WDEL1
Offshore wind	0.0	0.0	JEC (2020) Well-to-tank report v5, WDEL1
Solar	0.0	0.0	IPCC (2014) Technology-specific cost and performance parameters[7], Table A.III.2
Hydro-electric dam	0.0	0.0	IPCC (2014) Technology-specific cost and performance parameters, Table A.III.2
Run-of-river hydro	0.0	0.0	IPCC (2014) Technology-specific cost and performance parameters, Table A.III.2
Geothermal	0.0	0.0	IPCC (2014) Technology-specific cost and performance parameters, Table A.III.2, assuming geothermal power generation has not led to any increase in venting of geological CO_2. Any increase requires a GHG emissions factor to be calculated instead
Natural gas CCGT	471.6	131.0	JEC (2020) Well-to-tank report v5[8], GPEL1a
Oil	811.1	225.3	JEC (2020) Well-to-tank report v5, FOEL1
Coal	1,009.8	280.5	JEC (2020) Well-to-tank report v5, KOEL1
Nuclear	14.0	3.9	JEC (2020) Well-to-tank report v5, NUEL1

DA.24. Within the Standard Document, Annex B Paragraphs B.25-B.30 and Annex C Paragraphs C.27-C.31 require the cancellation of REGOs, which depends on the electricity generation source. The REGO Percentage of electricity generated from wind, solar, hydropower, tidal, wave, hydrothermal, aerothermal, geothermal and biogenic feedstocks will be between 100% and 0%, depending on whether the specific generator is registered with the REGO scheme and generates REGOs, and the proportion of the generation exported that generates REGOs. Any non-renewable electricity generation sources will not generate REGOs, and therefore have a REGO Percentage of 0%.

[6] https://publications.jrc.ec.europa.eu/repository/handle/JRC119036
[7] https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf
[8] https://publications.jrc.ec.europa.eu/repository/handle/JRC119036

Electricity sourced from the Electricity Grid and not linked to a specific generator

DA.25. For operational Hydrogen Production Facilities in Great Britain (GB) consuming electricity from the Electricity Grid that is not linked to a specific generator, the GHG Emission Intensity per Reporting Unit for GB from the National Grid ESO Dashboard[9] shall be used. These values already include Transmission and Distribution Losses.

DA.26. For operational Hydrogen Production Facilities in Northern Ireland (NI) consuming electricity from the Electricity Grid, 30-minute GHG Emission Intensities per Reporting Unit for NI from the EirGrid Smart Dashboard[10] shall be used. These values already include Transmission and Distribution Losses. Note that the EirGrid data gives GHG Emission Intensities every 15 minutes, therefore the 30-minute NI Electricity Grid GHG Emission Intensity shall be a simple arithmetic mean of two 15-minute periods (for example, the GHG Emission Intensity between 10:00-10:30 shall be a simple arithmetic mean of the two GHG Emission Intensities at 10:00 and 10:15 respectively).

DA.27. For Hydrogen Production Facilities, the REGO Percentage of electricity volumes from the Electricity Grid that are not linked to a specific generator shall be set as 0%.

DA.28. For pre-operational Hydrogen Production Facilities planning to consume electricity from the Electricity Grid, the Projected UK grid average electricity GHG Emission Intensity data in Table 5 shall be used. This data comes from the UK Government (2023) Green Book supplementary guidance[11]. These values already include Transmission and Distribution Losses, and so can be used directly by pre-operational Hydrogen Production Facilities in combination with their Projected grid average power consumption. Table 5 shall not be used once a Hydrogen Production Facility is operational, as grid electricity intensities that vary every 30 minutes are required to be used in emissions calculations instead.

Table 5: UK grid average electricity GHG Emission Intensity delivered to industrial consumers (after Transmission and Distribution Losses)

Year	gCO_2e/kWh_e	gCO_2e/MJ_e
2023	140.43	39.01
2024	145.96	40.55
2025	126.65	35.18
2026	94.59	26.28

[9] https://www.nationalgrideso.com/future-energy/our-progress-towards-net-zero/carbon-intensity-dashboard
[10] https://www.smartgriddashboard.com/#all/co2, selecting Northern Ireland drop-down option, selecting CO_2, selecting Month within CO_2 intensity over time, then View in Table, download .CVS
[11] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal Data Tables 1-19, Table 1, column I (for industrial consumption)

2027	70.49	19.58
2028	61.10	16.97
2029	51.62	14.34
2030	47.62	13.23
2031	40.01	11.11
2032	31.51	8.75
2033	25.01	6.95
2034	20.12	5.59
2035	19.41	5.39
2036	18.91	5.25
2037	17.67	4.91
2038	17.24	4.79
2039	16.21	4.50
2040	15.45	4.29
2041	14.72	4.09
2042	13.98	3.88
2043	8.80	2.44
2044	8.18	2.27
2045	7.60	2.11
2046	7.43	2.06
2047	5.14	1.43
2048	4.99	1.39
2049	3.17	0.88
2050	2.41	0.67

Electricity Curtailment Avoidance

DA.29. Where an operational Hydrogen Production Facility can evidence Electricity Curtailment Avoidance, the GHG Emission Intensity for this volume of electricity may use either the appropriate regional or national GHG Emission Intensity figure for the Reporting Unit. Evidence of Bid Offer Acceptances in GB is provided via Elexon's Balancing Mechanism Reporting Service[12] or National Grid Electricity System Operator's Data Hub[13], and in NI is provided by SEM-O Market Data[14].

DA.30. For Hydrogen Production Facilities in GB claiming a regional GHG Emission Intensity, the regional GHG Emission Intensity value to be used for the Reporting Unit shall be determined by the Distribution Network Operator licenced area in which the Hydrogen Production Facility BMU is located. These regional GHG Emission Intensities are only to be used for the volumes of electricity relating to Bid Offer Acceptance within the Balancing Mechanism – not any volumes involving contracted import of grid average electricity. GB regional electricity GHG Emission Intensity data is available using the National Grid approved "Carbon Intensity API"[15], and values already include Transmission and Distribution Losses. This regional 30 minute data shall be used for the relevant Reporting Unit once the Reporting Unit has passed – earlier forecast data for the Reporting Unit shall not be used (as this is updated every 30 minutes ahead of the Reporting Unit).

DA.31. For Hydrogen Production Facilities in GB claiming the national GHG Emission Intensity (instead of a regional GHG Emission Intensity), the average GHG Emission Intensity for the Reporting Unit for GB from the National Grid ESO Dashboard[16] shall be used. These values already include Transmission and Distribution Losses.

DA.32. For Hydrogen Production Facilities in NI, Northern Ireland will be treated as its own region for purposes of determining the GHG Emission Intensity of any Bid Offer Acceptance under the Balancing Market. Per Reporting Unit, 30-minute GHG Emission Intensities for NI from the Eir Grid Smart Dashboard[17] shall be used. These values already include Transmission and Distribution Losses. Note that this 30-minute GHG Emission Intensity shall be taken as a simple arithmetic mean of two 15-minute periods, for example, the GHG Emission Intensity between 10:00-10:30 is a mean of the two GHG Emission Intensities at 10:00 and 10:15 respectively.

DA.33. For Hydrogen Production Facilities in GB or NI, the REGO Percentage of any Bid Offer Acceptance electricity volumes shall be set as 0%.

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[12] https://www.bmreports.com/bmrs/?q=help/about-us
[13] https://www.nationalgrideso.com/data-portal
[14] https://www.sem-o.com/market-data/
[15] https://carbonintensity.org.uk/
[16] https://www.nationalgrideso.com/future-energy/our-progress-towards-net-zero/carbon-intensity-dashboard
[17] https://www.smartgriddashboard.com/#all/co2, selecting Northern Ireland drop-down option, selecting Month for CO2 intensity over time, then View in Table, download .CVS

Stored Electricity via an Energy Storage System

DA.34. Hydrogen Production Facilities shall either use the 30-minute Self Discharge Loss values in Table 6, or evidence the 30-minute Self Discharge Loss value for the Electricity Storage System from which they source their electricity, as per Annex C Paragraphs C.10-C.12 of the Standard Document.

Table 6: Conservative Self Discharge Loss values for Electricity Storage Systems

Electricity Storage System	Loss per 30 minutes
Lithium ion battery[18]	0.0027%
Lead acid battery[19]	0.0072%
Nickel cadmium battery[18]	0.013%
Nickel metal hydride battery[18]	0.015%
LSD-nickel metal hydride battery[18]	0.0027%
Zinc manganese battery[18]	0.00034%
Pumped storage hydroelectricity[19]	0.00042%
Compressed air energy storage[19]	0.021%
Liquid air energy storage[19]	0.021%
Flywheel[19]	7.5%
Gravity-based energy storage[20]	0%
Liquid CO_2 energy storage[21]	0.021%
Sensible heat energy storage[22]	0.021%
Latent heat energy storage[22]	0.021%
Thermochemical energy storage[22]	0.021%
Supercapacitor[22]	0.83%
Superconducting magnetic energy storage[19]	0.31%

DA.35. Hydrogen Production Facilities shall either use the Round Trip Efficiency values in Table 7, or evidence the Round Trip Efficiency of the Electricity Storage System from which they source their electricity, as per Annex C Paragraphs C.13-C.14 of the

[18] Umweltbundesamt Table 3, Page 20 https://www.umweltbundesamt.de/sites/default/files/medien/publikation/long/4414.pdf
[19] https://sei.info.yorku.ca/files/2013/03/Sauer2.pdf
[20] https://www.mdpi.com/1996-1073/16/2/825
[21] https://www.sciencedirect.com/science/article/pii/S2352152X22017704
[22] https://www.sciencedirect.com/science/article/pii/S1364032122001368

Standard Document. The Round Trip Efficiency values in Table 7 are calculated from charging and discharging losses, electrical equipment losses and from any cooling requirements.

Table 7: Conservative Round Trip Efficiencies for Electricity Storage Systems

Electricity Storage System	Round Trip Efficiency
Lithium ion battery[23, 24, 25]	70.9%
Lead acid battery[23,24,25]	44.3%
Nickel cadmium battery[23,24,25]	62.1%
Nickel metal hydride battery[23,24,25]	57.6%
Pumped storage hydroelectricity[26]	45.7%
Compressed air energy storage[26]	34.6%
Liquid air storage[26]	34.6%
Flywheel[27]	77.1%
Gravity-based storage[26]	62.8%
Liquid CO_2 storage[26]	62.8%
Sensible heat storage[22]	44.0%
Latent heat storage[26]	16.2%
Thermochemical storage[22]	25.4%
Supercapacitor[27]	81.8%
Superconducting magnet[28]	72.3%

Projected data for Transmission and Distribution Losses pre-operations

DA.36. Where pre-operational Hydrogen Production Facilities intend to claim the delivered GHG Emission Intensity of a specific generation asset (or Electricity Storage Systems) via an Eligible PPA, or where pre-operational Electricity Storage Systems intend to claim the delivered GHG Emission Intensity of an specific generation asset

[23] Heating and cooling loss of battery Figures 18 and 19 https://onlinelibrary.wiley.com/doi/epdf/10.1002/ecj.12221
[24] Cooling equipment COP efficiency Air chiller and water chiller https://www.sciencedirect.com/science/article/pii/S1876610214033372#:~:text=Under%20standard%20rating%20conditions%20at,6.39%20for%20water%2Dcooled%20chillers
[25] Battery Charging and Discharging Losses: Frontiers of Mechanical Engineering, Table 1, https://link.springer.com/article/10.1007/s11465-018-0516-8
[26] McKinsey (2023) Net-zero power: Long duration energy storage for a renewable grid, Exhibit 9, available at: https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/net%20zero%20power%20long%20duration%20energy%20storage%20for%20a%20renewable%20grid/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.pdf
[27] https://eprints.whiterose.ac.uk/154479/1/2016_05_05_MA_Modified_Manuscript_NotMarked.pdf
[28] https://www.arup.com/perspectives/publications/research/section/five-minute-guide-to-electricity-storage

via an Eligible PPA, Table 8 provides the projected Transmission and Distribution Losses that shall be used. These projected Transmission and Distribution Losses have been calculated as an average of the five National Grid Future Energy Scenarios[29], and are assumed to apply to GB and NI pre-operational facilities. These values shall not be used once Facilities or Electricity Storage Systems are operational.

Table 8: Projected Transmission and Distribution Losses for pre-operations

Year	Transmission Loss	Distribution Loss	Total T&D Loss
2023	2.3%	5.2%	7.4%
2024	2.2%	5.2%	7.3%
2025	2.2%	5.1%	7.2%
2026	2.2%	5.1%	7.2%
2027	2.1%	5.0%	7.0%
2028	2.1%	5.0%	7.0%
2029	2.1%	5.0%	7.0%
2030	2.1%	4.9%	6.9%
2031	2.1%	4.9%	6.9%
2032	2.1%	4.9%	6.9%
2033	2.1%	4.8%	6.8%
2034	2.1%	4.8%	6.8%
2035	2.1%	4.8%	6.8%
2036	2.1%	4.8%	6.8%
2037	2.1%	4.7%	6.7%
2038	2.1%	4.7%	6.7%
2039	2.1%	4.7%	6.7%
2040	2.0%	4.7%	6.6%
2041	2.0%	4.6%	6.5%
2042	2.0%	4.5%	6.4%

[29] National Grid FES 2022 Data Workbook, Tab ED1, 2023-2050 columns, using mean value of Rows 6-10 (total TWh demand), 111-115 (transmission TWh losses) and 116-120 (distribution TWh losses). https://www.nationalgrideso.com/future-energy/future-energy-scenarios/documents

2043	1.9%	4.4%	6.2%
2044	1.9%	4.3%	6.1%
2045	1.9%	4.3%	6.1%
2046	1.8%	4.2%	5.9%
2047	1.8%	4.2%	5.9%
2048	1.8%	4.1%	5.8%
2049	1.8%	4.1%	5.8%
2050	1.8%	4.0%	5.7%

Typical data for Transmission and Distribution Losses during operations

DA.37. If both the operational Hydrogen Production Facility and specific generation asset are located in GB, the Facility shall determine Transmission Loss Factors (TLFs) and Distribution Line Loss Factors (LLFs) using data from the Elexon Portal[30].

DA.38. If both the Hydrogen Production Facility and specific generation asset are based in Northern Ireland, the following sources shall be used:

- Transmission Loss Adjustment Factors (TLAFs) are available via Eir Grid[31].
- The Distribution Loss Adjustment Factors (DLAFs) are located in the NIE Networks Statement of Charges for use of the Distribution System (DuoS)[32].

Heat and steam

DA.39. Typical values for heat and steam generation GHG Emission Intensities are not provided and shall be calculated following the methodology given in Annex G of the Standard Document. This is because the input sources, conversion efficiencies and system configurations for steam and heat generation vary widely. Thermal losses during the supply of steam and/or heat from the generation asset to the Hydrogen Production Facility also need to be factored in to derive a delivered heat and/or steam GHG Emission Intensity (in gCO_2e/MJ_{th}) for use by the Hydrogen Production Facility.

DA.40. If there is Useful Heat or Useful Steam exported by generation asset for heating buildings at a temperature below 150°C (423.15 Kelvin), the Carnot Efficiency C_h used in Equation 59 of the Standard Document can be set as 0.3546. Similarly, if the Hydrogen Production Facility exports Useful Heat or Useful Steam for heating

30 https://www.elexonportal.co.uk/registration/newuser
31 https://www.eirgridgroup.com/customer-and-industry/general-customer-information/tlafs/
32 https://www.nienetworks.co.uk/about-us/regulation/network-charges

buildings at a temperature below 150°C (423.15 Kelvin), the Carnot Efficiency C_h used in Equation 59 of the Standard Document can be set as 0.3546.

Fuel

DA.41. When calculating the emissions associated with the production and supply of fuels, the following fuel GHG Emission Intensities in Table 9 shall be used in conjunction with the fuel Activity Flow Data. These GHG Emission Intensities already consider representative transport emissions associated with delivery to a Hydrogen Production Facility site, and so do not need any adjustment for transportation.

Table 9: Fuel GHG Emission Intensity (production & supply, without combustion/conversion)

Fuel	gCO_2e/MJ_{LHV}	Sources and supporting notes
Diesel	17.5	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions[33], 100% Mineral Diesel
Petrol	18.3	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions, 100% Mineral Petrol
Natural gas (Transmission Network, 7-94bar)	8.7	UK National Statistics (2023) Energy Trends[34] for the mix of natural gas sources consumed in the UK; NSTA (2023)[35] for CO_2 intensities; NSTA (2023)[36], SPGlobal (2023)[37] and ThinkStep (2017) [38] for CH_4 intensities; ~0.13% own use of gas from National Grid (2023)[39]; ~0.1% Transmission Network losses from Boothroyd et al. (2018)[40]; natural gas 92% mol methane or 86% by mass from EA (2016) [41]; natural gas combustion factor from Table 11.
Natural gas (intermediate/medium pressure Distribution	9.2	As above, but also including ~0.43% leakage, 0.006% own use and 0.01% theft, from JOGT (2023)[42]; ~0.1% leakage and all above ground installation leakage attributed to medium pressure distribution, from JOGT (2022)[43]

[33] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1083855/ghg-conversion-factors-2022-full-set.xls
[34] https://www.gov.uk/government/statistics/gas-section-4-energy-trends
[35] https://www.nstauthority.co.uk/the-move-to-net-zero/net-zero-benchmarking-and-analysis/natural-gas-carbon-footprint-analysis/
[36] https://www.nstauthority.co.uk/media/bicn5tva/nsta-emissions-monitoring-report-2023-final-accessible.pdf
[37] https://www.spglobal.com/esg/insights/featured/special-editorial/greenhouse-gas-intensity-of-the-north-sea
[38] https://globallnghub.com/wp-content/uploads/attach_380.pdf
[39] https://www.nationalgas.com/balancing/unaccounted-gas-uag
[40] https://www.sciencedirect.com/science/article/pii/S0048969718306399
[41] Table 3: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/545567/Material_comparators_for_fuels_-_natural_gas.pdf
[42] https://www.gasgovernance.co.uk/index.php/shrinkage/aa2023
[43] https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2022-03/2021-22%20Shrinkage%20and%20Leakage%20Model%20Review_FINAL%20REPORT.pdf

Network, 75mbar to 7bar)		
Natural gas (low pressure Distribution Network, up to 75mbar)	11.2	As above, but also including a further ~0.36% leakage and all interference damage attributed to low pressure distribution, a further 0.006% own use and 0.01% theft, from JOGT (2022)[44]
Marine gas oil	17.5	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Fuel oil	17.5	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Fossil methanol	28.2	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation[45]
Biomethanol	37.6	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Bioethanol	27.0	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Biodiesel FAME	13.5	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Biodiesel HVO	8.1	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions

[44] https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2022-03/2021-22%20Shrinkage%20and%20Leakage%20Model%20Review_FINAL%20REPORT.pdf
[45] https://publications.jrc.ec.europa.eu/repository/handle/JRC115952

Input Materials

DA.42. When calculating the emissions associated with the provision of Input Materials, the following GHG Emission Intensities in Table 10 shall be used in conjunction with material Activity Flow Data. These GHG Emission Intensities include manufacture of the material, and based on the references provided, are assumed to also include transport to a Hydrogen Production Facility. The exceptions are for desalinated water, oxygen and nitrogen, where the values given are for manufacture by a co-located third party directly adjacent to the Hydrogen Production Facility, so transport emissions shall be calculated and added if required for these Inputs. Future versions of the Data Annex may provide more explicit transport assumptions for all the Input materials listed.

DA.43. The Table 10 factors do not consider emissions resulting from the combustion or conversion of these Input Materials within the Hydrogen Production Facility (these combustion/conversion emissions are to be covered within the Process CO_2 and Fugitive non-CO_2 Emission Categories).

DA.44. If using a material that is not listed in Table 10, the references given in the bullets below shall be consulted to source and evidence a suitable GHG Emission Intensity, or else a robust value from peer reviewed academic literature shall be evidenced, with justification for the applicability of the value chosen.

- UK Government conversion factors for Company Reporting[46]
- RTFO guidance[47]
- RTFO Carbon Calculator[48]
- RTFO carbon intensity templates[49]
- RED II text[50]
- JEC WTT v5[51]
- JRC updated input data for biofuel GHG default values[52]
- JRC updated data for solid/gaseous biogenic GHG default values[53]
- Biograce II biomass electricity, heating, cooling calculator (RED II compliant)[54]

[46] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2023
[47] https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-compliance-reporting-and-verification
[48] https://www.gov.uk/government/publications/biofuels-carbon-calculator-rtfo
[49] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947712/carbon-intensity-data-templates-2021.ods
[50] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN
[51] https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/jec-well-tank-report-v5
[52] https://op.europa.eu/en/publication-detail/-/publication/7d6dd4ba-720a-11e9-9f05-01aa75ed71a1
[53] https://publications.jrc.ec.europa.eu/repository/handle/JRC104759
[54] https://www.biograce.net/biograce2/

- Biograce I biofuels calculator (RED I compliant)[55]
- EcoInvent database of GHG emissions[56] (old values[57])
- IEA Net Zero Emissions by 2050 scenario[58]

Table 10: Input Materials GHG Emission Intensities (manufacture & supply, no combustion/conversion)

Material	gCO_2e/kg	Sources and supporting notes
Mains water	0.18	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Desalinated water from co-located third party, using grid power	1.15	IRENA (2012)[59] mid-point efficiency (3.5-5 kWh_e/m^3) for large-scale Reverse Osmosis of sea water with UK grid electricity factor; Shahabi et al. (2014) Environmental Life Cycle Assessment of seawater reverse osmosis desalination plant powered by renewable energy[60] for emissions associated with chemicals
Oxygen (liquid) from co-located third party, using grid power	51	Linde (2009)[61] assumes 245 kWh_e/tonne power usage in cryogenic separation, and UK grid electricity factor
Oxygen from co-located third party, using wind/solar	0	Nil intensity, due to nil intensity of input power
Nitrogen (gaseous) from co-located third party, using grid power	23	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation used for inputs of assuming 0.4 MJ_e/kg and UK grid electricity factor
Nitrogen (liquid) from co-located third party, using grid power	54	Wu et al. (2020)[62] for 0.258 kWh_e/kg power usage in cryogenic separation, and UK grid electricity factor

55 http://www.biograce.net/home
56 https://ecoinvent.org/the-ecoinvent-database/use-of-the-ecoinvent-database/
57 https://web.archive.org/web/20190605065129/http://www.arb.ca.gov/fuels/lcfs/workgroups/lcfssustain/ISCC_EU_205_GHG_Calculation_and_GHG_Audit_2.3_eng.pdf
58 https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf
59 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2012/IRENA-ETSAP-Tech-Brief-I12-Water-Desalination.pdf
60 https://www.sciencedirect.com/science/article/abs/pii/S0960148113006289
61 https://ieaghg.org/docs/oxyfuel/OCC1/Plenary%201/Beysel_ASU_1stOxyfuel%20Cottbus.pdf
62 https://www.sciencedirect.com/science/article/abs/pii/S0959652620330729

Nitrogen from co-located third party, using wind/solar	0	Nil intensity, due to nil intensity of input power
Sodium hydroxide (NaOH) solution	530	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Potassium hydroxide (KOH) solution	419	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Calcium oxide (CaO, pure)	1,193	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Calcium carbonate ($CaCO_3$, pure)	440	GHG Protocol (2005) Calculation Tools for Estimating GHG emissions from pulp and paper mills[63]
Sodium carbonate (Na_2CO_3, pure)	1,245	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Sodium hypochlorite (NaClO)	920	Winnipeg (2012)[64]
Sodium methoxide ($NaCH_3O$)	2,426	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Sodium bisulphite ($NaHSO_3$)	440	Winnipeg (2012)
Salt (NaCl)	8.3	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation used for inputs of power, diesel, natural gas heating and explosives. Input intensities for UK grid electricity, UK diesel, UK natural gas heating using 90% efficient boiler, ANFO emissions factor[65]
Hydrochloric acid (HCl) solution	1,061	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Sulphuric acid (H_2SO_4)	218	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Phosphoric acid (H_3PO_4)	3,125	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Boric acid (H_3BO_3)	720	Winnipeg (2012)

[63] https://ghgprotocol.org/sites/default/files/2023-03/Pulp_and_Paper_Guidance.pdf
[64] https://www.winnipeg.ca/finance/findata/matmgt/documents/2012/682-2012/682-2012_Appendix_H-WSTP_South_End_Plant_Process_Selection_Report/Appendix%207.pdf
[65] https://iaac-aeic.gc.ca/050/documents/p62225/104540E.pdf

Lubrication oils	947	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Cyclohexane	723	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Monoethanolamine (MEA)	3,400	Cuellar-Franca et al. (2016) A novel methodology for assessing the environmental sustainability of ionic liquids used for CO2 Capture[66]
Ammonia (NH_3) from unabated natural gas	2,288	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation used for inputs of power and natural gas. Input intensities for UK grid electricity factor, UK natural gas
Urea (CH_4N_2O) from unabated natural gas	1,640	JRC (2019) Definition of input data to assess GHG default emissions from biofuels in EU legislation
Activated carbon	5,270	Winnipeg (2012), using Mineral sources

Process CO_2 emissions

DA.45. To calculate the amount of CO_2 generated from the conversion/combustion of feedstock, or feedstock material also used as a fuel, Hydrogen Production Facilities shall use the methodology set out in Annex H of the Standard Document. The values in Table 11 shall not be used to calculate the amount of CO_2 generated from the conversion of feedstocks.

DA.46. When calculating the amount of CO_2 generated from the combustion of any non-feedstock fuels (prior to any CO_2 Capture), the following CO_2 Emission Intensities in Table 11 shall be used in conjunction with the fuel Activity Flow Data. Note that these factors do not include the input production and supply of these fuels to the hydrogen production site, which are considered in the Fuel Supply Emission Category.

DA.47. If using a fuel or material that is not listed in Table 11, the same references as in Paragraph DA.44 shall be consulted to evidence a suitable CO_2 Emission Intensity, or else a robust value from peer reviewed academic literature shall be evidenced, with justification for the applicability of the value chosen.

[66] https://pubs.rsc.org/en/content/articlepdf/2016/fd/c6fd00054a

Table 11: Fuel combustion CO_2 Emission Intensity (no production or supply emissions included)

Source	gCO_2/MJ_{LHV}	gC_{fossil}/kg	Sources and supporting notes
Diesel	74.4	864	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions, 100% Mineral Diesel
Petrol	70.7	856	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions, 100% Mineral Petrol
Natural Gas	56.7	703	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions, 100% Mineral Blend
Marine gas oil	75.0	875	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Fuel oil	77.8	881	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Fossil methanol	68.9	374	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions, using biomethanol Outside of Scopes
Biomethanol	0	0	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Bioethanol	0	0	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Biodiesel FAME	0	0	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions
Biodiesel HVO	0	0	UK government (2023) conversion factors for company reporting of Greenhouse Gas emissions

Fugitive non-CO_2 emissions

DA.48. No Typical Data is provided for this Emissions Category.

CO_2 Capture and Network Entry

DA.49. Pathways where the Inputs of energy and materials to operate CO_2 Capture and Sequestration equipment are not included in the above Emission Categories, and/or those Pathways where CO_2 is transported, purified, and/or compressed offsite prior to the CO_2 T&S Network Delivery Point shall calculate their emissions under this category using the same Typical GHG Emission Intensities given in Paragraphs DA.20-DA.45 used to calculate the emissions for Energy Supply and Input Materials Emission Categories.

CO_2 Sequestration

DA.50. All CO_2 sources (e.g. fossil, biogenic) are treated equally under this Emission Category, with 1 tonne of CO_2 meeting the requirements of Paragraph 5.49 of the Standard Document being given a credit of 1 tonne of CO_2 for this Emission Category.

Solid Carbon Distribution

DA.51. Pathways where solid carbon is collected, transported, stored, purified or densified offsite prior to its final use shall calculate their emissions under this Emission Category using the same Typical GHG Emission Intensities for Energy Supply and Input Materials as given in Paragraphs DA.20-DA.45.

DA.52. This term only applies to solid carbon generated from gas splitting Pathways and does not apply to other Pathways.

Solid Carbon Sequestration

DA.53. This Emission Category only currently applies to solid carbon generated from gas splitting Pathways and does not apply to other Pathways.

DA.54. For a gas splitting Pathway to be eligible under the Standard, all of the solid carbon generated shall be used in one of the following Solid Carbon Permissible End Uses:

- incorporated into concrete or cement for construction; or

- kept in inert underground storage (e.g. disused mines and bunkers, inert landfill, spent oil and gas wells).

DESNZ may consider adding further Solid Carbon Permissible End Uses in the future, based on any evidence submitted following Paragraphs 4.4-4.7 of the Standard Document.

DA.55. Solid Carbon arising from fossil Inputs meeting the requirements of Paragraph 5.57 of the Standard Document shall be assigned a nil sequestration credit for this Emission Category. Solid Carbon arising from biogenic Inputs meeting the requirements of Paragraph 5.57 of the Standard Document shall be assigned a sequestration credit of 3.664 gCO_2e/gC for this Emission Category (using the elemental carbon within the Solid Carbon, see Equation 64 of the Standard Document.

Compression and Purification of hydrogen

Compression of hydrogen

DA.56. DESNZ may update the theoretical compression method outlined in this section in the future in line with industry developments, along with more regularly updating the relevant GHG Emission Intensities.

DA.57. **If using Projected or Measured Data for Energy Supply, and H_2 Output pressure is below 3MPa.** Paragraph DA.61 below shall be used to calculate the additional theoretical GHG Emission Intensity required to achieve an outlet pressure of p_1 = 3MPa, to add to the GHG Emission Intensity result.

DA.58. **If using Default Data for Energy Supply and H_2 Output pressure is below 3MPa**. The emissions associated with hydrogen compression to 3MPa have already been accounted for within the Energy Supply Default Data, so Paragraph DA.61 below shall not be used.

DA.59. **If using Projected or Measured Data for Energy Supply and H_2 Output pressure is above 3MPa.** The total emissions associated with compression to the outlet pressure shall be accounted for within the Energy Supply Emission Category, and Paragraph DA.61 below shall not be used.

DA.60. **If using Default Data for Energy Supply and H_2 Output pressure is above 3MPa.** If a pre-operational Hydrogen Production Facility is using Default Data for the Energy Supply Emission Category, they shall use Paragraph DA.61 below to calculate the theoretical additional GHG emissions associated with raising the hydrogen pressure p_0 from the 3 MPa already included within the Default Data to their expected outlet pressure p_1.

DA.61. The GHG emissions from energy use for (theoretical) compression shall be calculated as follows:

Equation 2

$$EI_{compression} = A \times B \times \frac{1kg}{120\ MJ_{LHV}}$$

Where:

- $EI_{compression}$ = Hydrogen Product added GHG Emission Intensity from electricity use for theoretical compression, in gCO_2e/MJ_{LHV} H_2.
- A = Electricity required to compress hydrogen (with losses), in kWh_e/kg H_2.
- B = Delivered electricity GHG Emission Intensity, in gCO_2e/kWh_e, adjusting for any Transmission and Distribution Losses. B shall be at least as large as the annual weighted average GHG Emission Intensity of the electricity sources consumed by the Hydrogen Production Facility (e.g. a nil GHG Emission Intensity cannot be assumed for B if the Facility only consumes grid average electricity). If grid average electricity is used as part of the annual weighted average mix of electricity sources being claimed under B, use Table 5 for the grid imported electricity volumes Table 5if the Hydrogen Production Facility is pre-operational, or if operational, use the annual average data from the latest Government conversion factors for company reporting[67] (30 minute grid GHG Emission Intensity data is not required for theoretical compression calculations).

Compression energy, A, is calculated as follows:

Equation 3

$$\mathrm{A} = \frac{\mathrm{W}}{3.6 \times \eta}$$

Where W is defined as the specific compression power, and η is the adiabatic efficiency, which can be taken from Table 12.

Equation 4

$$W = \left[\frac{n}{n-1}\right] \times p_0 \times V_0 \times \left[\left(\frac{p_1}{p_0}\right)^{\frac{(n-1)}{n}} - 1\right]$$

Where n is the adiabatic coefficient, p_o and p_1 are the respective inlet and outlet pressures, as defined in Table 12. V_0 is the input specific volume (of hydrogen), as defined below.

Equation 5Table

[67] Government conversion factors for company reporting of Greenhouse Gas emissions, Full set workbook, summing factors for UK electricity generation and Transmission & Distribution, https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

$$V_0 = k \times p_0{}^{\alpha}$$

Where α is the power law exponent and k is a constant. The values of α and k shall be taken from Table 13 (derived using a line of best fit derived from hydrogen density data[68]), using the temperature closest to the compressor inlet temperature. For example, a hydrogen production outlet temperature of 40°C shall use the α and k values for 50°C.

Table 12: Terms and units for Compression and Purification calculations

Term	Provided value	Units	Definition
A	Equation 3	kWh_e/kg	Compression energy
W	Equation 4	MJ/kg	Specific compression power
p_o	Operator	MPa	Input pressure
p_1	Operator	MPa	Output pressure
V_0	Equation 5	m^3/kg	Input specific volume
n	1.41	-	Adiabatic coefficient
η	60%	%	Adiabatic efficiency
α	Table 13	-	Power law exponent
k	Table 13	-	Constant
P_C	0.0013	kWh_e/kgH_2	Purity correction factor (assuming starting pressure ≥ 3MPa)

Table 13: Line of best fit parameters for Equation 5 at specific temperatures

Temperature (°C)	k	α
0	1.1651	-0.935
25	1.2691	-0.939
50	1.373	-0.943
75	1.4767	-0.946
100	1.5804	-0.949
125	1.6839	-0.952

[68] https://h2tools.org/hyarc/hydrogen-data/hydrogen-density-different-temperatures-and-pressures, data source NIST Reference Fluid Thermodynamic and Transport Properties Database (REFPROP): Version 8.0

Purification of hydrogen

DA.62. DESNZ may update the theoretical purification method outlined in this section in the future in line with industry developments, along with more regularly updating the relevant GHG Emission Intensities.

DA.63. Hydrogen producers with Measured hydrogen purity of less than 99.9% by volume shall calculate the theoretical emissions associated with theoretical purification up to 99.9% by volume. The following theoretical purification Equation 6 shall be used, and assumes a minimum starting pressure of 3MPa is input into pressure swing absorption equipment.

DA.64. To utilise Equation 6, the GHG emissions associated with compression to a minimum of 3MPa must have already been accounted for either in the Energy Supply Emission Category, or theoretically using Paragraphs DA.56 – DA.61.

DA.65. If Energy Supply Default Data is being used for a pre-operational Hydrogen Production Facility, the GHG emissions associated with purification to 99.9% (or higher) by volume have already been accounted for, and Equation 6 shall not be used.

Equation 6

$$EI_{purification} = P_c \times B \times \frac{1kg}{120\ MJ_{LHV}}$$

Where:

- $EI_{purification}$ = Hydrogen Product added GHG Emission Intensity from electricity use for theoretical purification, in gCO_2e/MJ_{LHV} H_2.
- P_C = Electricity required to purify hydrogen of 3MPa or higher to a purity of 99.9% (with losses), in kWh_e/kg H_2, as found in Table 12.
- B = as defined above in Paragraph DA.61.

Fossil Waste/Residue Counterfactual

Fossil fraction of RDF counterfactual

DA.66. DESNZ may update the counterfactual outlined in this section in the future based on the development of the UK Waste industry and other relevant UK policies.

DA.67. The current counterfactual for the fossil fraction of Refuse Derived Fuel (RDF) shall be an energy from waste (EfW) plant that produces only electricity at 22% net electrical Lower Heating Value (LHV) efficiency, without Useful Heat sales and without any CCS. The current counterfactual is focused only on the fossil Waste/Residue feedstock CO_2 emissions emitted (and displaced utility), but not any non-CO_2 emissions arising from conversion of the fossil Waste/Residue feedstock in the counterfactual, nor any change in other inputs used in the counterfactual (for example, fossil heating oil use for plant start-up), nor any change in the supply chain for fossil Waste/Residue feedstocks.

DA.68. The displaced electricity is assumed to be supplied by UK grid average electricity, with the annual average GHG Emission Intensity data from the latest Government conversion factors for company reporting[69] if the Hydrogen Production Facility has started operations, or from Table 5 for the relevant future year of operations if the Hydrogen Production Facility is yet to start operations. Note that 30 minute UK grid electricity intensity data is not required for counterfactual emissions calculations – only annual average data is required.

DA.69. If hydrogen is generated via electrolysis using electricity generated in a specific EfW plant, then instead of the generic EfW counterfactual assumption above, the counterfactual shall instead be taken as the specific EfW plant. This means the Hydrogen Production Facility shall use the electricity and heat efficiencies from the specific EfW plant to calculate the displaced electricity (and any heat), along with the GHG Emission Intensity of the grid electricity (and any replacement natural gas for heating) in the relevant year of operations. In this particular case, any CCS at the specific EfW plant will not impact the overall hydrogen GHG Emission Intensity, as CCS is used regardless of the destination of the diverted electricity.

Refinery Off-Gases (Residue) counterfactual

DA.70. DESNZ may update the counterfactual outlined in this section in the future based on the development of the UK refining industry, CO_2 T&S Networks and other relevant UK policies.

DA.71. If ROG is classified as a Residue with a counterfactual, the counterfactual for ROG shall be the unabated use of fossil natural gas. It is assumed that ROG and fossil natural gas would have the same LHV energy efficiency when converted in onsite furnaces to heat or in onsite boilers to steam regardless of where ROG-derived hydrogen is used. The natural gas supply GHG Emission Intensity in Table 9 (for Transmission Network withdrawals) shall be added to the natural gas CO_2 Emission Intensity in Table 11, and this combined intensity result (in gCO_2e/MJ_{LHV} natural gas) shall be assigned to the ROG at the start of the Pathway GHG Emission Intensity calculations (the same value in gCO_2e/MJ_{LHV} ROG). After conversion efficiency

[69] Government conversion factors for company reporting of Greenhouse Gas emissions, Full set workbook, summing factors for UK electricity generation and Transmission & Distribution, https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

impacts, these high counterfactual GHG emissions will be largely, but likely not entirely, cancelled out by the CO_2 Sequestration Emission Category credit for reforming with CCS Pathways.

DA.72. If ROG is classified as a Co-Product, no counterfactual applies.

Default Data

Use of Default Data

DA.73. Prior to Hydrogen Production Facility operations commencing, if Projected Data is not available, Default Data can be used instead of Projected Data for a few of the Emission Categories. Default Data is only provided for the Feedstock Supply, Energy Supply and Input Materials Emission Categories, and is only provided for the following Pathways:

- Steam methane reformation (SMR) using UK natural gas with CCS
- Auto thermal reformation (ATR) using UK natural gas with CCS
- Food waste biomethane directly connected to autothermal reformation (ATR) with CCS (if CCS not implemented, the default values provided for the Pathway with CCS can still be used)
- Forestry residue gasification with CCS (if CCS is not implemented, the default values provided for the Pathway with CCS can still be used)
- Biogenic and fossil fractions of mixed refuse derived fuel (RDF) gasification with CCS (if CCS is not implemented, the default values provided for the Pathway with CCS can still be used)
- Electrolysis using grid average electricity
- Electrolysis using wind/solar electricity
- Electrolysis using nuclear electricity

DA.74. If pre-operational electrolysis Hydrogen Production Facilities plan to use different electricity sources to the list above, they may still use the Default Data for the Input Materials Emission Category (but not the Energy Supply Emission Category). If pre-operational fossil gas reforming with CCS Hydrogen Production Facilities plan to use different gas feedstocks to the list above, they may still use Default Data for the Energy Supply and Input Materials Emission Categories (but not the Feedstock Supply Emission Category). Pre-operational gasification Hydrogen Production Facilities using different biomass or Waste feedstocks to the list above shall not use Default Data, due to potentially significant changes in their Inputs. Prior to operations, any Pathway not listed above shall use Projected Data in their hydrogen GHG Emission Intensity calculations. A summary of which Default Data values can currently be applied across which pre-operational Pathway Emission Categories is given below in Table 14.

Table 14: Ability to use default factors for pre-operational Pathway Emission Categories

Production pathway	Feedstock Supply	Energy Supply	Input Materials
UK grid natural gas to SMR with CCS	Yes	Yes	Yes
Other fossil natural gas to SMR with CCS	No		
Biomethane to SMR with/without CCS	No		
UK grid natural gas to ATR with CCS	Yes	Yes	Yes
Other fossil natural gas to ATR with CCS	No		
Food Waste biomethane to ATR with/without CCS	Yes	Yes	Yes
Other biomethane to ATR with/without CCS	No		
Forestry Residue gasification with/without CCS	Yes	Yes	Yes
Other biomass gasification with/without CCS	No	No	No
Biogenic fraction of mixed RDF Waste gasification with/without CCS	Yes	Yes	Yes
Fossil fraction of mixed RDF Waste gasification with/without CCS	Yes	Yes	Yes
Other Waste gasification with/without CCS	No	No	No
Electrolysis using grid average electricity	NA	No, divide grid electricity GHG Emission Intensity by default electrolysis LHV efficiency (0.586 MJ_{LHV} H_2/MJ_e)	Yes
Electrolysis using wind/solar electricity		Yes	
Electrolysis using nuclear electricity		Yes	
Electrolysis using other electricity sources		No	
Other Pathways not listed above	No	No	No

DA.75. Default Data is not provided for the Process CO_2 emissions, CO_2 Capture and Network Entry, CO_2 Sequestration, Solid Carbon Distribution, Solid Carbon Sequestration, Fugitive non-CO_2 emissions and Fossil Waste/Residue

Counterfactual Emission Categories. These Emission Categories will always have to be projected by pre-operational Hydrogen Production Facilities, and once operational shall use Measured Data.

DA.76. For the Compression and Purification category, the Energy Supply Default Data provided already accounts for the emissions that will be required to reach the theoretical minimum pressure and purity under the Standard (3 MPa and 99.9 vol% purity). However, if non-Default Data is being used for the Energy Supply category, and the hydrogen Output pressure or purity is planned to be below the theoretical minimum, the data and methodology provided in Paragraphs DA.56 – DA.61 shall be used to calculate the theoretical additional emissions. Similarly, if Default Data for the Energy Supply category is being used, but the hydrogen Output pressure or purity is planned to be above the theoretical minimum, the data and methodology provided in Paragraphs DA.56 – DA.61 shall be used to calculate the additional emissions.

DA.77. The Standard Document and Data Annex have been developed into a Hydrogen Emissions Calculator (HEC) to support pre-operational Hydrogen Production Facilities in checking their likely compliance against the Standard. The Default Data provided below, and the theoretical compression and purification calculations, are already built into the HEC.

DA.78. To ensure that the Default Data provided is conservative, the central scenario values taken from DESNZ modelling have each been multiplied by a factor of 1.4 to derive the default values presented in this Annex. The exceptions are Feedstock Supply emissions for natural gas taken from the UK Gas Network, and Energy Supply emissions for grid average electrolysis, neither of which were multiplied by the conservative factor.

DA.79. All Default Data for electricity inputs to Pathways have been derived assuming an Estimated 2025 UK grid electricity GHG Emission Intensity of 35.2 gCO_2e/MJ_e. The exception is electrolysis using grid average electricity, where the projected grid average GHG Emission Intensity in the relevant future year (from Table 5) shall be divided by a default electrolysis LHV efficiency of 58.6%, without any conservative factor applied.

Default Data tables

DA.80. DESNZ will update the following Default Data values over time to respond to industry developments and changes in the relevant input GHG Emission Intensities that were used to derive these Default Data values.

Feedstock Supply

DA.81. Feedstock Supply emissions cover the GHG emissions arising from feedstock cultivation, harvesting, collection, pre-processing, storage, and transportation. Depending on the Pathway, this term could include fossil natural gas, uranium, biomethane, solid biomass feedstocks and Waste feedstocks.

DA.82. Note that Feedstock Supply for the food waste biomethane Pathway includes the emissions from food waste collection through to anaerobic digestion biogas production up to the point of biomethane delivery to the reformer plant via direct pipeline connection.

DA.83. Counterfactual emissions for Waste/Residue fossil feedstocks are considered separately to this Emissions Category.

Table 15: Default Data for Feedstock Supply

Production pathway	GHG Emission Intensity (gCO_2e/MJ_{LHV} Hydrogen Product)
UK grid natural gas to SMR	11.16
UK grid natural gas to ATR	11.45
Food Waste biomethane to ATR	5.16
Forest Residue gasification	7.94
Biogenic fraction of mixed RDF Waste gasification	3.92
Fossil fraction of mixed RDF Waste gasification	3.92
Electrolysis	NA

Energy Supply

DA.84. Energy Supply emissions are the GHG emissions associated with the supply of electricity, steam, heat, and fuels for hydrogen production (but excluding emissions associated with directly converting feedstock to hydrogen which are separately considered under the Process CO_2 Emissions Category).

Table 16: Default Data for Energy Supply

Production pathway	GHG Emission Intensity (gCO_2e/MJ_{LHV} Hydrogen Product)
SMR	0.74
ATR	4.16
Forestry residue gasification	0.00
Biogenic fraction of mixed RDF Waste gasification	8.63
Fossil fraction of mixed RDF Waste gasification	8.63
Electrolysis using grid average electricity	Use the UK grid factor in the relevant year from Table 5 divided by 58.6% LHV efficiency
Electrolysis using wind/solar electricity	0.00
Electrolysis using nuclear electricity	9.58

Input Materials

DA.85. Input Materials emissions refers to GHG emissions associated with the production and supply of any Input Materials (except those covered in Feedstock Supply and Energy Supply Emission Categories) to a system. This could include Inputs such as oxygen, water, salts, catalysts, solvents, acids, alkali solutions.

Table 17: Default Data for Input Materials

Production pathway	GHG Emission Intensity (gCO_2e/MJ_{LHV} Hydrogen Product)
SMR	0.38
ATR	0.39
Forestry residue gasification	1.56
Biogenic fraction of mixed RDF Waste gasification	3.37
Fossil fraction of mixed RDF Waste gasification	3.37
Electrolysis	0.11

Sustainability Criteria

DA.86. Voluntary schemes[70] that may be used to provide evidence of compliance with the relevant Sustainability Criteria are listed below. Note that the coverage of each is different, and one scheme may not cover all the Sustainability Criteria that a given Input is required to meet.

- Biomass Biofuels voluntary scheme (2BSvs)
- Bonsucro EU (formerly Better Sugar Cane Initiative (BSI)
- International Sustainability and Carbon Certification (ISCC)
- KZR INiG System
- Better biomass (formerly NTA 8080)
- Red tractor farm assurance combinable crops and sugar beet scheme (Red tractor)
- REDcert
- Roundtable on Sustainable Biomaterials EU RED (RSB EU RED)
- Scottish Quality farm assured combinable Crops (SQC)
- Trade Assurance Scheme for Combinable Crops (TASCC)
- Universal Feed Assurance Scheme (UFAS)

[70] These are the voluntary schemes that are recognised under the RTFO. Further information on the schemes can be found here: https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-voluntary-schemes/rtfo-list-of-recognised-voluntary-schemes

Useful References

Sources of data for Lower Heating Values

DA.87. The following references provide useful data on the Lower Heating Values (MJ/kg_{dry}) of various Inputs and Outputs, that for consistency purposes should be used within Activity Flow Data calculations for pre-operational Hydrogen Production Facilities, or if composition data for the Input or Output is not measured as per Annex H for operational Hydrogen Production Facilities:

- Renewable Transport Fuel Obligation (RTFO): compliance, reporting and verification[71]
- Greenhouse gas reporting: Conversion factors 2023[72]

Where LHV data for a particular Input or Output is not available in these references, the other references given in Paragraph DA.45 or peer reviewed academic literature may be consulted, with justification given for the applicability of the value chosen.

Unit conversions for pure hydrogen

DA.88. LHV to Higher Heating Value (HHV): To convert an LHV energy content of pure hydrogen into an HHV energy content of pure hydrogen, multiply the LHV amount of energy by 1.182 to obtain the HHV amount of energy.

DA.89. /MJ to /kWh: To convert from a per MJ H_2 measure to a per kWh H_2 measure, multiply the per MJ H_2 measure by 3.6.

DA.90. /MJ to /kg: To convert from a per MJ_{LHV} pure H_2 measure to a per kg pure H_2 measure, multiply the per MJ_{LHV} pure H_2 measure by 120.0 $MJ_{LHV}/kg\ H_2$. To convert from a per MJ_{HHV} pure H_2 measure to a per kg pure H_2 measure, multiply the per pure MJ_{LHV} H_2 measure by 141.8 MJ_{HHV}/kg pure H_2. Note that these values for MJ_{LHV} and MJ_{HHV} are for a pure hydrogen stream, while the Hydrogen Product will contain impurities.

[71] RTFO standard data, ODS file: https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-compliance-reporting-and-verification

[72] Conversion factors 2023: Full set (for advanced users) – updated 28 June 2023, Excel workbook: https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2023

Table 18: Example conversion factors from 1.0 gCO_2e/MJ_{LHV} pure H_2

1.0 gCO_2e/MJ_{LHV} pure H_2 is equal to:
0.846 gCO_2e/MJ_{HHV} pure H_2
3.6 gCO_2e/kWh_{LHV} pure H_2
3,047 gCO_2e/MWh_{HHV} pure H_2
0.12 $kgCO_2e/kg$ pure H_2
0.12 $tCO_2e/tonne$ pure H_2