Author Details	
Name	**Dr Andrew Boswell**
Position	**Independent Scientist & Consultant**
NZT Registration	**20029943**
Organisation	**Climate Emergency Policy and Planning (CEPP)**
Examination Principle Issues	• **Full lifecycle Greenhouse Gas (GHG) emissions** • **Cumulative assessment of GHG emissions** • **Scope of Development and Environmental Impact Assessment**

DEADLINE D2 SUBMISSION

I am an independent scientist and environmental consultant, working at the intersection of science, policy, and law, particularly relating to ecology and climate change. I work at a consultancy called Climate Emergency Policy and Planning (CEPP).

In so far as the facts in this statement are within my knowledge, they are true. In so far as the facts in this statement are not within my direct knowledge, they are true to the best of my knowledge and belief.

Contents

RESUME

I realised recently that my life-scientific goes back over 50 years to when aged 14 I became passionate by the mystery of quantum mechanics. As an undergraduate, I studied for BSc 1977, 1st class honours in Chemistry at Imperial College London. My doctoral work[1], at Oxford University was supervised by Professor R J P Williams, FRS, and was in structural biology, protein binding sites and dynamics (DPhil[2], 1981). I later did an MSc in the then emerging area of "Parallel Computing Systems" at the University of the West of England (1994).

Most of my career has been in scientific computation and modelling. Between 1985 and 1993, I engaged in the software engineering, and testing, of modelling and simulation systems for the high-level design and logic synthesis of Very Large Scale Integrated (VLSI) circuits. These simulation systems were state of the art UK software[3], and in the 1980s and 1990s were at the forefront of formal, mathematical based, methods in the verification of computer systems, both hardware and software, used in applications such as fly-by-wire commercial aircraft. Commercial customers of our products were running software models of microprocessors and Application Specific Integrated Circuits (ASICs), at that time[4], of up to one million transistors.

---

[1] My doctoral supervisor was the prolific, much loved and highly missed, British chemist, Napier Royal Society Research Professor R J P Williams, FRS, MBE, see [redacted]

[2] DPhil title: "Nuclear Magnetic Resonance Studies of Modified Eukaryotic Cytochrome c"

[3] See references to Electronic Logic Language (ELLA), one of the systems on which I worked, in "The development and deployment of formal methods in the UK", (2020) [redacted] Cliff Jones and Martyn Thomas, Professor at Gresham College. Professor Thomas was one of my mentors in computing and a superior colleague of mine from 1985-1992 when we both worked at Praxis Systems plc where he was a founding Director.

[4] One million was cutting edge at the time! Transistor counts now exceed two trillion on a single chip [redacted]

Between 1995 and 2006, I ran the high-performance computer service at the University of East Anglia (UEA), and I supported the university's scientific research community in running models, across a range of sciences, on a small supercomputer which I developed and manged. I have a wide understanding of the principles and practice of modelling complex systems which I bring to my current work.

I provided consultancy across the science faculties at UEA on computer modelling. This ranged from advising several generations of PhD and post-doctoral research students on modelling issues including detailed program coding issues; advising professors and research leaders on system and architectural issues of modelling, and in many cases programming solutions for them; testing and debugging extremely complex modelling systems for scientists who did not have the relevant IT skills in forensic fault finding; systems administration of servers and several iterations of high-performance computers; and running training courses of parallel computing and scientific computing languages across the campus. Supporting scientists running climate models in UEA's esteemed Environmental Science department was a significant part of my work too.

Due to the climate crisis, from 2005 I have been involved in campaigning and politics, and have also been a Green Party Councillor on Norfolk County Council for 12 years. The severity of the climate emergency is clear through science and has been for several decades, and my work through CEPP now is to promote the necessary rapid response to the Climate Emergency in mainstream institutions, such as local authorities and government, through the lenses of science, policy, and law. I am an Expert contributor to the proposed UK Climate and Ecological Emergency Bill[5], drafted by scientists, legal experts, ecological economists, and environmentalists, and designed specifically to reverse the climate and ecological breakdown that we are facing. The Bill recently had a second reading in the House of Commons.

I have been awarded a fellowship for 2022 from the Foundation for Integrated Transport[6] to study "*Exposing the flaws in carbon assessment and transport modelling for road schemes*".

5 [redacted]

[redacted]

SUMMARY

I maintain my objection (as in my relevant representation) to the Net Zero Teesside project on the basis that carbon capture and storage (CCS) technology is not the best way to decarbonise the UK energy system, and a preferrable technology is maximising the optimum balance of solar, wind and energy storage technologies. This latter technology is here, getting cheaper quickly, and can provide dispatchable energy on the same timeframe as the NZT project (ie: starting to supply power in 2027).

The applicant has failed to make quantifications and assessments of the greenhouse gas (GHG) emissions associated with the project from **a)** the full lifecycle of the gas combusted in the power station, and **b)** the cumulative effects with GHGs from other existing and/or approved projects. In particular, upstream and downstream methane emissions have not been included in the Environmental Statement. This has led to an incorrect carbon intensity being calculated and assessed for the scheme.

When methane is included, there is a range for the full life-cycle GHGs from the project, and this will vary depending upon the stability of the gas supply chain. Proper assessment of the methane leakage for the project has become very crucial, as recent policy and science are requiring deep cuts to methane emissions to help reduce the immediate impacts of global heating over this, and the next, decade. In particular, the Global Methane Pledge which the UK signed and promoted under its COP26 presidency, provides a new policy context, and an international promise and obligation on the UK Government.

The science is explained as succinctly as possible, with further material as appendices, in the Written Representation, and the following key points are presented:

- The EIA has underestimated the Climate Change impacts of the CCGT power station as no full lifecycle GHG assessment has been done.

- The cumulative effects of the project on GHGs with other existing and/or approved projects has not been assessed, breaching the EIA Regulations.

- The Environmental Statement does not follow the best practice for EIA for a cumulative assessment of greenhouse gas emissions, with local and regional and sectoral assessment of the project.

- It is premature to rely on any carbon capture rate greater than 90% being achieved.

- Assuming a stable gas supply chain which uses UK produced gas, and which reduces methane leakage to 0.2% by 2025, gives the most optimistic carbon intensity for the project. This is still **over 60% greater than** that reported by the Applicant. The applicant has, therefore, not correctly described how the project will operate.

- Should the project go ahead, early and radical methane leakage reductions are essential in the project's fuel supply chain and have the potential to contribute towards reducing global

heating over the next three decades. Although not building the project, and not extracting and burning the gas which it requires would provide a greater contribution to reducing climate change impacts.

- The Environmental Statement must be extended to include annual projections (targets) of the carbon intensities of the gas power station, based on full life-cycle analysis, in which methane leakage is rapidly curtailed in line with the methane reduction pathway implied by the International Energy Authority analysis (ie 66% reduction by 2030 from 2020).

- The DCO should be updated to include a requirement that the project can only operate when the feedstock gas is produced with a carbon intensity less than, or equal to, the IEA compliant annual projections in the Environmental Statement (previous bullet).

- The Applicant must provide information on the impact to **a)** the national target of 50GW offshore wind by 2030, and **b)** government (BEIS) and CCC trajectories for offshore wind development post-2030 to 2050 of the carbon store licences associated with the project.

1 INTRODUCTION

1.1 Deadline 2 (D2)

1 This is my submission for Deadline 2. It comprises my Written Representation, and it also responds "in passing" to REP1-045 ("Document Reference: 9.6 - Applicants' Comments on Relevant Representations").

2 When I refer to "natural gas", or "gas", I am referring to methane (CH4).

3 My WR largely relates to "Work Number ('Work No.') 1", the Combined Cycle Gas Turbine electricity generating station ("CCGT power station"). I also comment on the North Sea carbon stores.

2 ENVIRONMENTAL IMPACT ASSESSMENT: FULL LIFE-CYCLE CLIMATE CHANGE IMPACTS

2.1 The EIA has underestimated the Climate Change impacts of the CCGT power station

4 A complete assessment of the greenhouse gas (GHG) emissions associated with, and climate change impacts of, the CCGT power station requires GHGs to be assessed across the full life-cycle of the gas to be combusted. The Environmental Statement has failed to assess the full life-cycle climate change impacts of the Combined Cycle Gas Turbine (CCGT) power station because upstream and downstream emissions have not been considered. These largely relate, though not exclusively, to methane leakage emissions. In this WR, I concentrate on the methane emissions which have not been quantified or assessed.

2.2 Methane in the full life-cycle of gas combustion

5 The Applicant has only considered the carbon dioxide (CO2) generated from combusting the gas at APP-103/Table 21-12 ("Operational GHG emissions") which provides the quantification of GHGs for the EIA. However, for the gas to be combusted, it also needs to be extracted or mined, processed, and transported to the combustion site.

6 Recent scientific research shows that, in a full life-cycle analysis, methane leaks during gas production, transport, and consumption **add** significant greenhouse gas (GHG) emissions to the generation of energy in gas power stations. This is because atmospheric methane (CH4) is much more potent than CO2 as climate disrupting gas contributing to the greenhouse gas effect: methane is 86 times more potent on a 20-year timescale (referred to as Global Warming Potential, GWP20 = 86) than CO2.

7 The impacts of methane leakage are being increasingly understood, and even since the drafting of the EIA further research has emerged. For example, new techniques, in the last few years, have increased the accuracy of tracking CH4 leakage significantly, and in a recent witness statement to the Pretoria High Court[7] by Professor Robert Howarth ("the Howarth report[8]", see *Appendix A*), an expert in the field from Cornell University, states:

> *"Researchers have been able to detect emissions across the lifecycle of gas ever more accurately given new methodologies and technologies (particularly "top-down" measurements using satellite and aerial assessments); these new studies have consistently shown that emissions from gas production are higher than were previously estimated using "bottom-up" facility-based measurements. New research is also revealing higher downstream gas emissions than earlier predicted (i.e., in gas transmission, distribution, and end use)."*

8 Also there have been several papers, and briefings, on the methane issue in the gas supply chain in just the last year to which I will refer to below.

2.3 The range of the effects

9 As I stated at the ISH1 "not all gas is equal". By this, I was referring to the fact that the full climate change impacts associated with CCGT combustion for power generation depends upon the origin of the gas. That is the upstream and downstream supply chain GHG emissions, including a very wide range of methane leakage, varies significantly across different gas supply chains. As I show below, the full range of these effects generates a wide variation of possible quantifications of full life-cycle GHGs. Not only has methane leakage

---

[7] In April 2021, the South Durban Community Environmental Alliance (SDCEA) and groundWork filed review papers in the Pretoria High Court challenging the Department of Forestry, Fisheries and the Environment's authorisation of the Richards Bay 3000MW Combined Cycle Power Plant. Professor Howarth's report is attached to the May 6th 2021 "Natural Justice" website media alert "Ground-breaking litigation sees organisations challenge new power plant in Richards Bay" at [redacted]nd at *Appendix A*. The case was heard in March 2022.

[8] Whilst the South African power plant is different to the NZT one, the witness statement is provided as it is a good background to the latest science on methane leakage in the gas supply chain and quoted in this respect.

not been addressed in the environmental statement, but the range of its possible effects has not been considered by the Applicant.

10 A recent paper by Christian Bauer[9] and colleagues on "the climate impacts of blue hydrogen production" ("the Bauer paper" given at *Appendix B*) analysed the impacts of methane in the gas supply chain, and used a range of 0.2% to 8% for methane leakage in the methane gas supply chain. Whilst the Bauer paper concerned blue hydrogen, its research conclusions on methane in the gas supply chain apply to gas combustion in the NZT project.

To put the 0.2% to 8% for methane leakage in context for gas combustion, 1 kg of CH4 will produce 2.74 kg of unabated CO2 when burnt. As a rule of thumb, 32 grams of CH4 leaked to the atmosphere produces an equivalent global overheating impact over 20 years (calculation: 32 * 86 = 2740 grams equivalent of CO2 for a GWP20 potential of 86).

However, if the project is to run with 90% carbon capture, which is the way the Applicant says it will operate, then 1 kg of CH4 will produce 274 grams of CO2, with 2466 grams CO2 captured. In this case, 3.2 grams of leaked CH4, or 0.32% of the original 1 kg of CH4, would produce an equivalent 20-year global overheating impact to the combustion process with abatement.

In other words, as a rule of thumb, 0.32% CH4 leakage in the gas supply chain, which is very much towards the lower end of the range reported by Bauer, doubles the global overheating impact of the gas combustion (or the "carbon intensity" of the gas power station).

11 Table 1 below combines extracts of APP-130 Tables 21-10, 21-12 and 21-14, as shown in column A, and then generates the equivalent data when methane supply chain emissions are included at leakage rates of 0.2% (B), 0.5% (C), 1.0% (D) and 8.0% (E). The Bauer paper does a similar analysis for 0.2%, 1.5% and 8% methane leakage. However, the Bauer paper is examining the global situation, whilst for the UK situation 0.2% - 1.0% is a more useful comparison, so for this reason I have used different benchmark values, more appropriate to the NZS project, for the methane leakage (with the 8.0% case just for reference).

12 Essentially the data shown in Table 1 is generated by the same principle as the rule of thumb example given above of how 0.32% methane leakage in the gas supply chain doubles the emissions impact from burning 1kg of CH4 with 90% CO2 abatement.

[9] From the Laboratory for Energy Systems Analysis, Paul Scherrer Institute, Switzerland

From Table 21-10	A	B	C	D	E
Methane supply chain emissions %		**0.20%**	**0.50%**	**1.00%**	**8.00%**
Methane hourly equivalent GWP20 (kg CO2e)		**17,649**	**44,124**	**88,247**	**705,980**
Hourly unabated GHG emissions from power plant (kg CO2e) **– combustion CO2 only**	281,547	281,547	281,547	281,547	281,547
Hourly GHG emissions to atmosphere (kg CO2e) - **CO2 and CH4**	28,155	45,804	72,278	116,402	734,135
Annual GHG emissions	237,175	**385,855**	**608,874**	**980,572**	**6,184,350**
Carbon intensity (tonnes CO2e/GWh)	41.2	**66.97**	**105.67**	**170.18**	**1073.30**
From Table 21-12					
25 years (tCO2e)	5,929,478	9,646,364	15,221,840	24,514,301	154,608,747
TOTAL (tCO2e)	6,742,561	10,459,447	16,034,923	25,327,384	155,421,830
Annualised (tCO2e)	269,702	418,378	641,397	1,013,095	6,216,873
Percentage Contribution of Emissions / Table 21-14					
5CB	0.078%	0.121%	0.186%	0.294%	1.802%
6CB	0.140%	0.217%	0.332%	0.525%	3.221%
UK Carbon Budget (MtCO2e)					
5CB	1,725				
6CB	965				

Table 1

2.4 Discussion on Table 1 – gas supply chains are not stable

13 Whilst it is understood that current methane leakage rates in UK supply are at the low end of the range (for example, the Bauer paper says they are typically below 0.5%), it is clear that even 0.32% methane leakage will produce of the order of a doubling of the climate change impacts over that reported in the environmental statement of the NZT project. So the impacts to the NZT project from methane leakage are significant although the Applicant has ignored them.

14 Further over the lifetime for project, expected to be 2027-2052, there may be radical changes to the UK gas supply. For example, the Oxford Institute of Energy Studies (OEIS) recently

reported[10] (Appendix C) "*In 2017, the combination of UK production and pipeline imports from Norway accounted for 97 per cent of UK gas consumption. By 2021, that figure had fallen to 81 per cent, while the ongoing decline in UK gas production was offset by higher LNG imports at the UK's three main import terminals: Isle of Grain, Dragon, and South Hook*".

15 This already shows a significant UK shift to LNG. LNG may be sourced from regions with more lax regulation of methane leakage, and it requires substantial energy and emissions to cool methane to the point where it becomes a liquid (at -164°C) and compress it for shipping. Both effects adding more emissions over the UK supply case.

The Howarth report says, "*A recent study of LNG lifecycle emissions analysis found that emissions from liquefaction, tanker transport, and regasification range from about 8% to 21% of total lifecycle emissions for the LNG, depending on how large production emissions were calculated to be and how far the LNG carriers travelled, with most calculations in the upper end of this range.*"

16 It is quite possible that once built that the gas power plant would require gas supply sources including fracked and LNG gas which are both known to have higher methane leakage and full lifecycle emissions [see the Howarth report].

The applicant seems to have not precluded this possibility. No restrictions on sourcing the gas supply for the CCGT power plant appear in either the environmental statement, or the DCO.

2.5 Discussion on Table 1 – carbon capture rates

17 **It is premature to rely on any capture rate greater than 90% being achieved in operation, and therefore rates greater than 90% should not be considered for the carbon appraisal.** There is no evidence from the Applicant that the project will deliver greater than 90% capture rate, just an aspiration to do so. No weight can be given to the aspiration. Whilst the Applicant shows calculations at 90% [ie Table 21-10] and 95% [in Table 21-11] carbon capture rates, I presume that the Table 21-11 data is just for illustration. This is borne out by the Applicant only taking the 90% capture data forward into Table 21-12 for assessment.

18 Being extremely cautious about the possible delivery of a greater than 90% CO2 capture rate is consistent with the findings of a December 2020 report by the Tyndall Centre for Climate Change research at Manchester University (provided at *Appendix H*) "A Review of the Role of Fossil Fuel Based Carbon Capture and Storage in the Energy System" which stated: "*However, the lack of sufficient data on natural gas CCS power station capture rates, CCS hydrogen production operations, or any CCS energy application with >90% capture rate,*

[10] "The Potential Impact on the UK of a Disruption in Russian Gas Supplies to Europe", Jack Sharples , Katja Yafimava , Jonathan Stern , Mike Fulwood, OIES, 11th February 2022 – accessed at [redacted]/

means that it is prudent to await these results before applying high capture rates to these emissions factors."

2.6 Policy and Scientific Implications – early reduction of methane crucial

19 Although the policy paper for the North Sea Transition Deal (provided at *Appendix D*), proposes to bring methane leakage to 0.20% from a current level of 0.25%, this is for UK production in the North Sea, and is not the same as the gas supply chain for the power station, which as above may depend on future changes in supply including gas with greater methane intensity (eg: LNG and fracked gas).

20 The Howarth paper explains why it is urgent to reduce methane emissions **now**, this decade, as we are on a trajectory to heat the Earth past the 1.5ºC threshold within the next 7 years (see *Appendix A*, "Methane's role in climate change" section). The urgent need to reduce methane in the atmosphere is borne out by other recent scientific publications, including a very recent paper in a leading journal, the Proceedings of the National Academy of Sciences (PNAS), which found that making sharp cuts to methane now could contribute to keeping temperatures lower by 0.26ºC by 2050 ("the Dreyfus paper", see *Appendix F* and *Appendix G* for a useful explanatory press article).

A saving of 0.26ºC over the next three decades would be an extraordinary prize in the Climate Emergency that we are in, and it should not be looked over. **Quite the reverse, humanity should do everything it can to secure such a saving in climate disruption.**

21 This urgency was reflected, too, in the Global Methane Pledge (provided at *Appendix E*) signed by over 100 countries at the United Nations Climate Change conference in November 2021 (COP26), including the UK as COP26 host country, which stated "***Rapidly reducing methane emissions from energy****, agriculture, and waste can achieve* ***near-term gains in our efforts in this decade for decisive action*** *and is regarded as the single most effective strategy to keep the goal of limiting warming to 1.5˚C within reach while yielding co-benefits including improving public health and agricultural productivity.*" (emphasis added).

22 [Aside paragraph relating to my overall objection to the project] It is important to note that whilst reductions in methane leakage provide a relative benefit compared to not reducing methane leakage, **not** extracting and combusting gas in the first place would remove the methane emissions associated with the NZT project completely (and the abated or unabated CO2 emissions from gas combustion), provides much greater benefit and is a much more credible scientific approach. I acknowledge that UK Government policy, on which the Applicant relies, has not yet caught up with the massive technological advances and cost reductions in renewables and energy storage that provide an opportunity **now** to do much better than developing a gas power station which produces a significant net increase in GHG emissions in a climate emergency. These technologies have the potential to provide dispatchable carbon free power generation on the same timeframe as the NZT project (ie: starting to supply power in 2027).

2.7 Early and radical methane reductions for short-term gain

23 Due to the evidence above for rapid early methane reduction, I only use **only** the GWP20 metric for assessing the global warming potential of methane. This scales methane emissions to equivalent CO2 emissions over the next 20 years, as opposed to the GWP100 which scales the methane to CO2 greenhouse potential over the next century (100 years). The Dreyfus paper, the Global Methane Pledge and the science require rapid reductions in methane in this decade, and therefore GWP20 is the most appropriate scaling for methane emissions.

2.8 Implications for NZT Environmental Statement and DCO

24 The above is a very brief summary of scientific and policy issues which have come to the forefront on climate change recently, and especially in the last year, and which indicate that methane has to be treated very, very seriously when dealing with greenhouse gas emissions.

25 The EIA has failed to assess the **full** life-cycle impacts of gas, and has in particular not quantified or assessed methane from the gas supply chain. Even on the most optimistic assumptions that the NZT power station **only uses** methane supply from North Sea extraction, and the North Sea Transition Deal Methane Action Plan delivers a methane intensity of 0.2% by the CCGT power station opening in 2027, Table 1 shows that the greenhouse gas emissions associated with the scheme are at least 60% greater than that reported by the Applicant (a carbon intensity of 66.97 tCO2e/GWh compared to 41.2).

26 Put simply, the Applicant is claiming that the gas power station will operate at a carbon intensity of 41.2 tCO2e/GWh whereas the most optimistic, and possibly realistic, carbon intensity is 66.97 tCO2e/GWh.

27 The Environmental Statement has failed to comply with the Environmental Impact Assessment Regulations as it has not described all the likely significant effects on the environmental factor of greenhouse gas emissions including the "*direct effects and any indirect, secondary, cumulative, transboundary, short-term, medium-term and long-term, permanent and temporary, positive and negative effects of the development*" (EIA Regs Schedule 4 (5)). **In excluding consideration of methane, the Applicant has not described how the gas power station will actually operate, and what its environmental impacts will be.**

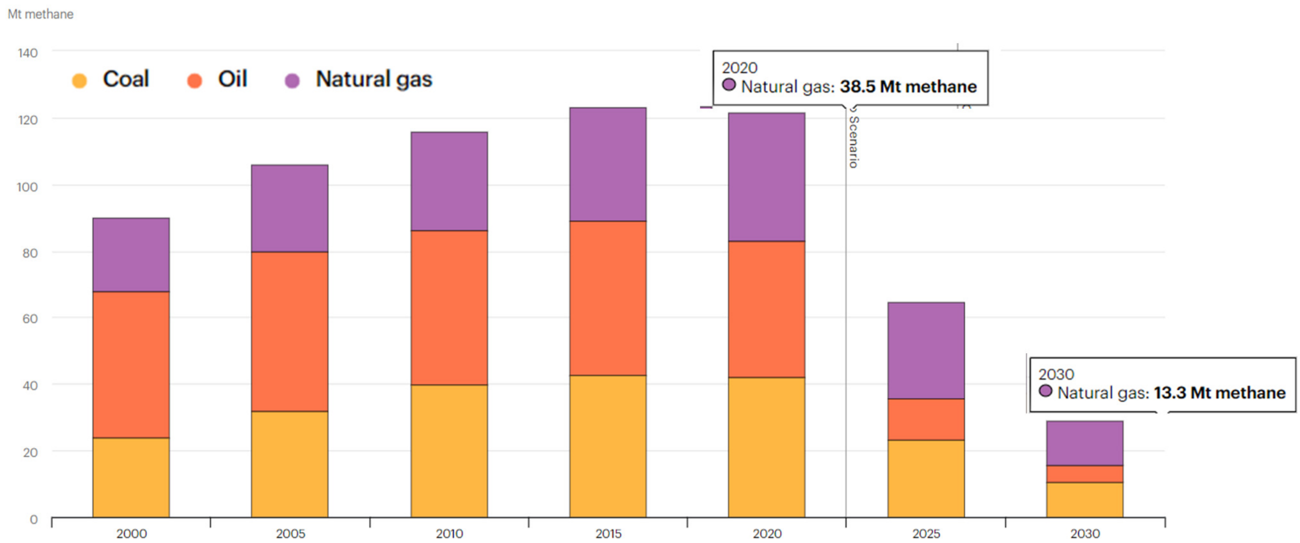
28 Further no evidence has been provided by the Applicant that the gas supply chain can be stabilised, **even at the most optimistic carbon intensity** (ie 67 tCO2e/GWh) for the duration of the project, a 25-year and possibly longer operation. As above, geopolitical pressures, lack of North Sea supply, and other events may lead to gas feedstocks being used with higher carbon intensities.

However, this should not, and cannot, be allowed to happen as increasing the carbon intensity of full life-cycle gas supply would increase greenhouse gas emissions at the point when they should be being reduced: with the IEA recommending specifically a 66% reduction for methane leakage from gas supply globally this decade (see below).

29 It should be noted that methane from oil and gas supply chains amount to around one third of annual methane emissions, and other sectors such as agriculture and waste cannot eliminate methane so quickly, so oil and gas production needs to eliminate methane more rapidly – that is, at a rate greater than the Global Methane Pledge target of 30%. The International Energy Agency (IEA) state on its "Global Methane Tracker 2022"[11] that:

> *"Fossil fuel operations account for more than one-third of human-caused methane emissions. These emissions represent one of the best near-term opportunities for climate action because the pathways for reducing them are known and understood. Achieving a 75% reduction in emissions from fossil fuel operations, as set out in the IEA's Net Zero Emissions by 2050 Scenario would take the world most of the way towards fulfilling the Global Methane Pledge."*

30 The IEA chart "Methane emissions from fossil fuels, historical and in the Net Zero Scenario, 2020-2030", reproduced below, shows methane leakage reducing from global methane production from 38.5 MtCH4 in 2020 to 13.3 MtCH4 in 2030 to meet the IEA's "Net Zero Emissions by 2050 Scenario" – a 66% reduction in ten years.



31 My RR made it clear that I oppose the project, but should it go ahead, the Applicant must be required to update the Environmental Statement and provide annual projections (targets) of the carbon intensities of the gas power station, based on full life-cycle analysis, in which methane leakage is rapidly curtailed in line with Global Methane Pledge, and the methane reduction pathway implied by the IEA analysis (ie 66% by 2030 from 2020). This is the minimum that should be required for the UK to meet our international promises and obligations under the Global Methane Pledge.

[11] This is only available as a website, and the website does not render neatly into a document (otherwise I would provide it as an Appendix) as the site is designed to be interactive. Ideally, this link should not be redacted – the IEA Global Methane Tracker 2022 is at: https://www.iea.org/reports/global-methane-tracker-2022

32 **Further this must be made a planning condition. The DCO should be updated to include a requirement that the project can only operate when the feedstock gas is produced with a carbon intensity less than, or equal to, the IEA compliant annual projections in the Environmental Statement** (as per previous bullet)**.**

2.9 Erroneous conclusions in NZT Environmental Statement

33 It should be noted that the Applicant's claim of a carbon intensity of 41.2 tCO2e/GWh instead of a realistic carbon intensity, including methane leakage, reverberates through the discussions in chapter 21 of the Environmental Statement. For example:

- Table 21.13 should list the carbon intensity as "dependent on supply-chain methane, best case 66.97 tCO2e/GWh at 0.2% leakage", and this should replace the current erroneous listings of 41.2 (ie: no methane leakage accounting at 90% carbon capture) and 20.7 (ie: no methane leakage accounting at 95% carbon capture which is an unproven capture rate).

- Similarly Diagram 21-2 should show a flat line at 66.97 tCO2e/GWh (marked "dependent on supply-chain methane, best case ") as the most optimistic grid intensity from the scheme with an explanation that this <u>assumes</u> that 0.2% methane leakage is achievable, and persistently sustained, despite geopolitical and supply chain changes, during the entire 25-year or longer operation of the power plant.

- The corresponding narrative between Environmental Statement sections 21.3.57 and 21.3.61 needs to be correspondingly changed.

2.10 Erroneous conclusions in REP1-045

34 The claim of a carbon intensity of 41.2 tCO2e/GWh also leads to an erroneous response to my relevant representation at REP1-045, bottom of page 80 where the applicant states:

> *"Table 21-14, in the Environmental Statement Climate Chapter [APP-103]) presents the impact of GHG emissions from the Proposed Development in the context of the 3rd, 4th, 5th and 6th Carbon Budgets. From the table, it can be seen that the Proposed Development is no more than 0.14% of any Carbon Budget period. GHG emissions are therefore considered as having a 'low increase' in magnitude and therefore classified as being of 'minor adverse' significance."*

35 The applicant, here, has again dispensed with any consideration of methane in the full greenhouse gas emissions life-cycle. Table 1 above adds in methane leakage to the calculation and comparison with the 5th and 6th carbon budgets, and shows that in the 6th carbon budget the GHGs associated with the scheme would be 0.22% (**<u>not</u>** 0.14%) if methane leakage was kept under 0.2% from 2033 (start of 6th carbon budget).

However, to be able to state this, the Applicant must specify that this is how it plans to run the project, and demonstrate that they will do this. This requires the planning condition by DCO requirement which restricts operation of CCGT power plant to only when its feedstock gas is produced with a carbon intensity less than, or equal to, the IEA compliant annual projections in the Environmental Statement as suggested above.

3 ENVIRONMENTAL IMPACT ASSESSMENT: CUMULATIVE EFFECTS

36 Schedule 4 (e) of the EIA Regs requires that the Environmental Statement includes a description of the likely significant effects of the project on the environment resulting from "*the cumulation of effects **with other existing and/or approved projects**, taking into account any existing environmental problems relating to areas of particular environmental importance likely to be affected or the use of natural resources*". (emphasis added)

37 The required cumulative assessment of greenhouse gas emissions has not been carried out.

3.1 "Other existing and/or approved projects"

38 What is meant by "other existing and/or approved projects" needs to be interpreted for the NZT project and in the context of the greenhouse gas emissions associated with it as an EIA environmental factor. Whilst the applicant needs to do this, and they haven't done it, there are some obvious possible ways to approach defining starting places for "other existing and/or approved projects" which I place on the record.

39 A first level would be cumulative assessment of greenhouse gases across the overarching "East Coast Cluster" (ECC) of which the NZT project is a constituent. As the applicant has explained, ECC includes the wider projects in the Teesside and Humber areas. This includes the very similar gas power station, Keadby 3, currently undergoing its own DCO examination [EN010114], and the Drax Bioenergy with Carbon Capture and Storage (BECCS) project [EN010120] due for examination starting this autumn. Such a cumulative GHG assessment across the ECC programme would be trivial as the data exists for most of the projects.

40 A second level would be a cumulative carbon assessment which includes the land based and other infrastructure projects across the Teesside and Humber area.

41 A third level could include similar CCUS clusters and blue hydrogen plants around the UK, and so would include the ECC along with the Hynet projects in the North West, the Acorn project in Scotland.

42 Each of these levels give different information, and all of them would be useful in the environmental statement. Using multiple sources of information aligns with the IEMA guidance on EIA good practice which states "*It is good practice to draw on multiple sources of evidence when evaluating the context of GHG emissions associated with a project.*" (Appendix I, page 28).

However, the problem for the applicant is that no attempt has been made to do **<u>any</u>** cross-project cumulative assessment on greenhouse gas emissions.

43 **The Environmental Statement is not compliant with the EIA regulations requirement for a cumulative assessment of carbon emissions from the project.**

4 ENVIRONMENTAL IMPACT ASSESSMENT: IEMA/EIA GUIDANCE

44 The applicant has not followed the latest EIA guidance from IEMA (the "IEMA guidance", published February 2022). This latest IEMA guidance at section 6.4 on "Contextualising project's carbon footprint" states **<u>first</u>** that assessment of a project's carbon emissions against the carbon budget for the entire UK economy **is only a starting point of limited value** in the EIA process, and **<u>second</u>** that local policies and budgets and targets should be included in EIA assessments of carbon emissions. The applicant has only assessed the project's carbon emissions against the carbon budget for the entire UK economy, at Table 21-14.

45 As well as the IEMA guidance, the EIA guidance from the European Commission[12], strongly advocates local and regional assessment of carbon emissions and has been ignored by the applicant. The EIA Regs guidance[13] (provided at <u>*Appendix J*</u>, PDF page 41) addresses how a project's impact on greenhouse gas emissions should be addressed and states:

> "*The assessment should take relevant greenhouse gas reduction targets at the national, **<u>regional, and local levels</u>** into account, where available.*" (emphasis added)

46 Whilst for cumulative effects[14] (<u>*Appendix J*</u>, PDF page 52):

> *"[They] can arise from … the interaction between all of the different Projects in the same area;"*
>
> *"… can occur at different temporal and spatial scales. The spatial scale can **<u>be local, regional or global</u>**, while the frequency or temporal scale includes past, present and future impacts on a specific environment or region.*" (emphasis added)

47 The EIA regulations were intended to require, then, that carbon assessment is done for the scheme itself and the cumulation of effects of the scheme with other existing and/or approved projects, at the local and regional scale, as well as at the national scale.

48 There are several ways in which local and regional assessment may be pursued quantitatively. These methods also allow a sector-based assessment to be made too. The **<u>first</u>** is the BEIS UK

---

[12] The EU Commission website hosts an official webpage for the EIA Directive, which lists a number of Guidance documents. The site is: https://ec.europa.eu/environment/eia/eia-support.htm.

[13] [redacted] PDF page 41

[14] [redacted] PDF page 52

local authority and regional carbon dioxide emissions national statistics[15] which are published annually. These provide the actual recorded carbon footprint, currently for each year from 2005 to 2019[16], and are broken down into sector and sub-sector, so that the energy related total may be easily calculated. The **second** is the SCATTER local authority budgets from the Tyndall Centre at the University of Manchester[17]. In each case, budgets for a benchmark area may be derived by summing the relevant, constituent local authority areas. Both these data set have been available for several years now and are well tested.

49 The Applicant should consider these for a local and regional, and sector based, assessment which complies with the above guidance, and best practice, on EIA. Table 21-14 should be extended to show local, regional and sector-based assessment, as well as whole economy national assessment.

50 Currently, the Environmental Statement does not follow the best practice for EIA, from the IEMA and EIA guidance, for a cumulative assessment of greenhouse gas emissions, with local and regional and sectoral assessment of the project.

5 COMMENTS ON ENDURANCE, AND THE ADDITIONAL 23 Mtpa CO2, STORES

51 I note that the Endurance offshore store (NSTA licence CS001) for captured CO2 overlaps with the area proposed for Hornsea Four Offshore Wind Farm [REP1-052], and also that the North Sea Transition Authority (NSTA) has recently awarded the licences to bp and Equinor (NSTA licence CS007) for a further store of approximately double the carbon storage capacity (NSTA Press Release, "BP/Equinor awarded carbon storage licences", May 12th 2022[18]).

52 The Government's Energy Security Strategy[19] recently increased the national target for offshore wind to 50GW by 2030 (up from 40GW) whilst the Committee on Climate Change (CCC) has predicted requirements of up to 125GW offshore wind by 2050[20].

53 In order for the Secretary of State to be able to make a balanced decision weighing all considerations, the Applicant must provide information to the Examination on what it considers to be the impact, if the NZT project proceeds, to **a)** the national target of 50GW offshore wind by 2030, and **b)** government (BEIS) and CCC trajectories for offshore wind development post-2030 to 2050, of:

[15] https://data.gov.uk/dataset/723c243d-2f1a-4d27-8b61-cdb93e5b10ff/uk-local-authority-and-regional-carbon-dioxide-emissions-national-statistics-2005-to-2019

[16] With 2020 data to be published in June 2022

[17] [redacted]

[18] https://www.nstauthority.co.uk/news-publications/news/2022/bpequinor-awarded-carbon-storage-licences/

[19] British energy security strategy, Policy paper, 7th April 2022, https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

[20] The Sixth Carbon Budget, Committee on Climate Change, December 2020, page 25 [redacted]

- The possible non co-existence between offshore wind developments, and carbon storage developments, in the Endurance store (licence CS001);

- Possible non co-existence between offshore wind developments, and carbon storage developments, in the additional 23 Mtpa CO2 store (licence CS007);

- Any other impacts to national offshore wind targets from licences CS001 and CS007.

6 CONCLUSIONS

54 I maintain my objection to the application on the basis that gas fired combustion, and carbon capture and storage (CCS) technology is not the best way to decarbonise the UK energy system, and it is **not** necessary for decarbonisation given the massive technological advances and cost reductions in renewables and energy storage that offer the potential for carbon free dispatchable energy on the same timescales as the NZT project (ie: starting to supply energy in 2027).

55 The key conclusions of this written representation are:

- The EIA has underestimated the Climate Change impacts of the CCGT power station as no full lifecycle GHG assessment has been done.

- The cumulative effects of the project on GHGs with other existing and/or approved projects has not been assessed, breaching the EIA Regulations.

- The Environmental Statement does not follow the best practice for EIA for a cumulative assessment of greenhouse gas emissions, with local and regional and sectoral assessment of the project.

- It is premature to rely on any carbon capture rate greater than 90% being achieved.

- Assuming a stable gas supply chain which uses UK produced gas, and which reduces methane leakage to 0.2% by 2025, gives the most optimistic carbon intensity for the project. This is still **over 60% greater than** that reported by the Applicant. The applicant has, therefore, not correctly described how the project will operate.

- Should the project go ahead, early and radical methane leakage reductions are essential in the project's fuel supply chain and have the potential to contribute towards reducing global heating over the next three decades. Although not building the project, and not extracting and burning the gas which it requires would provide a greater contribution to reducing climate change impacts.

- The Environmental Statement must be extended to include annual projections (targets) of the carbon intensities of the gas power station, based on full life-cycle analysis, in which methane leakage is rapidly curtailed in line with the methane reduction pathway implied by the International Energy Authority analysis (ie 66% reduction by 2030 from 2020).

- The DCO should be updated to include a requirement that the project can only operate when the feedstock gas is produced with a carbon intensity less than, or equal to, the IEA compliant annual projections in the Environmental Statement (previous bullet).

- The Applicant must provide information on the impact to **a)** the national target of 50GW offshore wind by 2030, and **b)** government (BEIS) and CCC trajectories for offshore wind development post-2030 to 2050 of the carbon store licences associated with the project.

[redacted]

Dr Andrew Boswell,
Climate Emergency Policy and Planning, June 9th, 2022

7 APPENDIX A: EVIDENCE TO PRETORIA HIGH COURT: PROFESSOR ROBERT HOWARTH, 2021

Supplied as separate document

8 APPENDIX B: ON THE CLIMATE IMPACTS OF BLUE HYDROGEN PRODUCTION: THE BAUER PAPER, PRE-PUBLICATION 2021

Supplied as separate document

9 APPENDIX C: OXFORD INSTITUTE OF ENERGY STUDIES (OEIS) REPORT: "THE POTENTIAL IMPACT ON THE UK OF A DISRUPTION IN RUSSIAN GAS SUPPLIES TO EUROPE", FEBRUARY 2022

Supplied as separate document

10 APPENDIX D: NORTH SEA TRANSITION DEAL, MARCH 2022

From Government website: https://www.gov.uk/government/publications/north-sea-transition-deal/north-sea-transition-deal-accessible-webpage

Supplied as separate document

11 APPENDIX E: GLOBAL METHANE PLEDGE, NOVEMBER 2021

From website:[redacted]

Supplied as separate document

12 APPENDIX F: "MITIGATING CLIMATE DISRUPTION IN TIME: A SELF-CONSISTENT APPROACH FOR AVOIDING BOTH NEAR-TERM AND LONG-TERM GLOBAL WARMING", THE DREYFUS PAPER, MAY 2022.

Supplied as separate document

13 APPENDIX G: PRESS ARTICLE ON THE DREYFUS PAPER, MAY 2022. GUARDIAN, MAY 23RD 2022

Supplied as separate document

14 APPENDIX H: "A REVIEW OF THE ROLE OF FOSSIL FUEL BASED CARBON CAPTURE AND STORAGE IN THE ENERGY SYSTEM", DECEMBER 2020, TYNDALL CENTRE FOR CLIMATE CHANGE RESEARCH AT MANCHESTER UNIVERSITY

Supplied as separate document

15 APPENDIX I: IEMA GUIDANCE, ASSESSING GREENHOUSE GAS EMISSIONS AND EVALUATING THEIR SIGNIFICANCE

Version 2, February 2022

Supplied as separate document

16 APPENDIX J: EIA GUIDANCE, "ENVIRONMENTAL IMPACT ASSESSMENT OF PROJECTS: GUIDANCE ON THE PREPARATION OF THE ENVIRONMENTAL IMPACT ASSESSMENT REPORT", EUROPEAN COMMISSION, 2017

Supplied as separate document

Appendix A

Gas Lifecycle Methane Emissions, Richards Bay Review

Robert W. Howarth, Ph.D.

The David R. Atkinson Professor of Ecology & Environmental Biology

Cornell University

Ithaca, NY 14853 USA

Synopsis

This report summarizes the latest research on the greenhouse gas emissions of "natural" gas (from here forward, "gas"). It concludes that the climate impacts of gas are greater than those of coal per unit of energy produced when evaluated in a 20-year timeframe, the period most relevant for climate change if humans are to avoid catastrophic run-away warming. The science summarized reveals the following:

- Though gas emits less carbon dioxide at combustion per unit energy than coal, its upstream greenhouse gas (GHG) emissions are more problematic for the climate, as it releases potent methane in leaks and venting throughout its lifecycle.
- Researchers have been able to detect emissions across the lifecycle of gas ever more accurately given new methodologies and technologies (particularly "top-down" measurements using satellite and aerial assessments); these new studies have consistently shown that emissions from gas production are higher than were previously estimated using "bottom-up" facility-based measurements. New research is also revealing higher downstream gas emissions than earlier predicted (i.e., in gas transmission, distribution, and end use).
- The average lifecycle emissions of gas are growing globally because
    - Shale gas is growing as a percentage of all gas, and its production likely emits more methane and other greenhouse gases than conventional gas production; and
    - Liquified Natural Gas (LNG) markets are growing, and turning gas into a liquid for shipping requires large amount of gas to be burned, greatly increasing the gas's GHG emissions.
- While it is unclear where gas will come from to feed the proposed Richards Bay 3000 MW CCPP, the environmental review materials suggest that leading candidates include shale gas from the Karoo, or LNG, potentially from shale reserves in the US or Australia, or closer African countries like Angola, Algeria, or Namibia that are increasingly looking to develop shale gas resources.
- Methane emissions from shale gas are particularly worrisome because
    - Methane (CH_4) is 86 times more potent than carbon dioxide (CO_2) on a 20-year timescale; and
    - Global methane emissions are accelerating, and appear to be rising at the rate that would be predicted to result from the shale gas boom.

The report is comprised of five sections:

I. Gas system emissions research
II. Methane's role in climate change
III. Gas lifecycle stages
IV. Emissions from stages of gas lifecycle
V. Comparison of gas and coal emissions on the climate

1 Gas system emissions research

New research methodologies and technologies have revealed that, contrary to common wisdom of twenty years ago, methane leakage from the gas system negates the climate benefits of gas at its end use over coal or heavy fuel oil.

For about two decades, many world leaders, and even environmental NGOs, assumed that "natural" gas (from here forward, "gas") would be an improvement over coal for the climate because gas produced fewer CO_2 emissions when combusted per unit energy. This enabled leaders to support domestic extraction of gas from shale using a new combination of techniques termed hydraulic fracturing, or "fracking," and the build-out of gas infrastructure to replace coal-fired power plants. Gas was described as a "bridge fuel" that allowed a continued use of fossil fuels for a few decades while phasing out coal and moving towards and eventual fossil-fuel-free future based on only renewable energy.

The new flurry of gas buildouts in the 2000s led independent researchers, particularly in the United States, to begin to examine more closely the climate impacts of gas throughout its lifecycle. It was already well-established that gas differed from coal because coal emissions are primarily comprised of those generated by end-use combustion, while gas, being comprised primarily of methane gas, is prone to leak throughout its lifecycle.[1] The extent of these leaks across the gas system was poorly understood, however, given challenges to measuring them.

Assessments of gas system emissions to date had come from "bottom-up" assessments of average leakage across a relatively small sample of the types of infrastructure used across gas lifecycles. These estimates were based on evaluating individual emission sources on the ground and summing these up to get total emissions. These figures have long been used to estimate national greenhouse gas emissions from the gas sector.

Yet new technologies have been developed over the last decade that allow researchers to assess greenhouse gas emissions from the gas lifecycle from the "top-down." These new technologies, including satellites and aerial measurements, have revealed that bottom-up estimates severely underestimate actual emissions.[2]

---

[1] c.f. P. A. Okken, *Methane leakage from natural gas*, 18 ENERGY POLICY 202–204 (1990), https://www.sciencedirect.com/science/article/pii/030142159090147V (last visited Apr 3, 2021).

[2] S. M. Miller et al., *Anthropogenic emissions of methane in the United States*, 110 PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES 20018–20022 (2013), http://www.pnas.org/cgi/doi/10.1073/pnas.1314392110 (last visited Nov 21, 2019); Robert W. Howarth, *A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas*, 2 ENERGY SCIENCE & ENGINEERING 47–60 (2014), https://onlinelibrary.wiley.com/doi/abs/10.1002/ese3.35 (last visited Apr 3, 2021); Timothy L. Vaughn et al., *Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region*, 115 PNAS 11712–11717 (2018), https://www.pnas.org/content/115/46/11712 (last visited Feb 26, 2020); Ramón A. Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, SCIENCE eaar7204 (2018), http://www.sciencemag.org/lookup/doi/10.1126/science.aar7204 (last visited Nov 20, 2019); Xinrong Ren et al., *Methane Emissions from the Marcellus Shale in Southwestern Pennsylvania and Northern West Virginia Based on Airborne Measurements*, 124 JOURNAL OF GEOPHYSICAL RESEARCH: ATMOSPHERES 1862–1878 (2019), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2018JD029690 (last visited Feb 26, 2020).

Emissions measured bottom-up have underestimated leaks in part because these bottom-up methods require permission from gas operators to access sites, likely biasing measurements toward companies and sites with more controlled methane leaks.[3] In addition, the bottom-up estimates do not include all possible individual emission sources within the gas lifecycle. For instance, to date not a single published study using bottom-up approaches to estimate methane emissions from shale gas has included the emissions during the initial well drilling phase, which can be high,[4] and the emissions from venting of tanks storing the wastewater produced in gas extraction. The snapshot bottom-up analyses may miss variation in emissions at different times of the day, such as the regular periods when liquids are unloaded as part of the production of fracked wells.[5] Bottom-up leakage estimates with smaller samples selected by the gas companies are prone to miss large emissions sources known as "super-emitters" that significantly pull up emissions averages.[6]

At the same time, sensor and infra-red camera technologies have also advanced quickly, increasing the ease with which pipeline emissions in downstream segments of the gas lifecycle can be observed and measured. Methane is invisible to the naked eye, but can be easily visualized with these new technologies. New methods for measuring atmospheric methane and parsing its source – whether from agriculture, wetlands, or fossil gas – have also increased scientific understanding of the role of gas in climate change. The results of this research, in combination with findings that climate change is accelerating faster than predicted, has, in contrast to earlier assumptions, shown continued gas expansion globally to be incompatible with a livable climate.

---

[3] Robert W Howarth, *Chapter 7: Methane and Climate Change*, *in* ENVIRONMENTAL IMPACTS FROM DEVELOPMENT OF UNCONVENTIONAL OIL AND GAS RESERVES 21 (John F. Stolz, W. Michael Griffin, & Daniel J. Bain eds., 2021).

[4] Dana R. Caulton et al., *Toward a better understanding and quantification of methane emissions from shale gas development*, 111 PNAS 6237–6242 (2014), https://www.pnas.org/content/111/17/6237 (last visited Nov 25, 2019).

[5] Stefan Schwietzke et al., *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements*, 51 Environ. Sci. Technol. 7286–7294 (2017), https://doi.org/10.1021/acs.est.7b01810 (last visited May 11, 2020).

[6] Adam R. Brandt, Garvin A. Heath & Daniel Cooley, *Methane Leaks from Natural Gas Systems Follow Extreme Distributions*, 50 ENVIRON. SCI. TECHNOL. 12512–12520 (2016), https://doi.org/10.1021/acs.est.6b04303 (last visited Nov 21, 2019); Christian Frankenberg et al., *Airborne methane remote measurements reveal heavy-tail flux distribution in Four Corners region*, 113 PNAS 9734–9739 (2016), https://www.pnas.org/content/113/35/9734 (last visited Nov 21, 2019); Daniel Zavala-Araiza et al., *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 ENVIRON. SCI. TECHNOL. 8167–8174 (2015), https://doi.org/10.1021/acs.est.5b00133 (last visited Nov 21, 2019).

2 Methane's role in climate change

Methane, the principal component in fossil gas, is a particularly potent greenhouse gas and a substantial driver of climate change, and its concentrations in the atmosphere are accelerating.

To explain why gas buildouts are incompatible with a safe climate future, it is important to review scientists' evolving view of the role of methane in climate change. Both methane and carbon dioxide are critical to global warming and climate disruption. These two carbon gases are the two most important for the rate of warming observed over the past few decades, with 25% of all warming observed to date ascribed to methane.[7] For the time both gases are in the atmosphere, methane is 105-times more potent as a greenhouse gas,[8] but methane emissions are considerably less than those for carbon dioxide. It is important to note that methane has a shorter residence time the in atmosphere as well: with a half-life of some 12 years, the influence of a pulse of methane emitted today lasts "only" for some 40 to 50 years into the future. Carbon dioxide emitted today will have an influence that will last for at least several centuries. It is for this reason that all climate scientists argue that we need to immediately and greatly reduce emissions of carbon dioxide. But it is also essential to reduce methane emissions. As shown in Figure 1 (modified from Shindell et al. 2012), we are on a trajectory to warm the Earth by 1.5^{O} C within the next 7 years, given current trajectories.[9] Note that warming since this paper was published in 2012 has risen steadily along the green-line trajectory that reflects no serious reductions in greenhouse gas emissions. The 1.5^{O} C threshold is critical: in Paris in Dec 2015 the nations of the world came together at COP21 to pledge to try to keep the planet well below 2^{O} C of warming, with the clear recognition that 1.5^{O} C of warming will be dangerous. We are already seeing significant damage globally from human-caused climate disruption, and as we reach these thresholds of warming – only 25 years from now to reach 2^{O} C of warming, we may well encounter tipping points in the Earth's climate system leading to runaway global climate disruption for the next thousand years or beyond.[10]

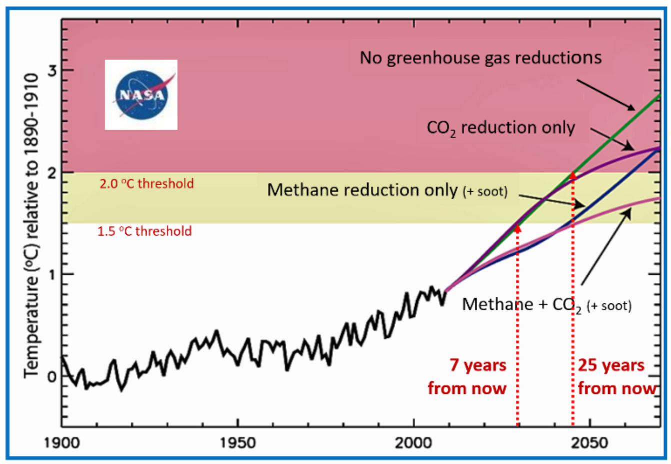


Figure 1. Observed global temperatures through 2009 and projected temperatures thereafter, relative to the 1890-1910 mean. Modified from Shindell et al. 2012

[7] IPCC, *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (2013).
[8] *Id.*
[9] Drew Shindell et al., *Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security*, 335 SCIENCE 183–189 (2012), https://science.sciencemag.org/content/335/6065/183 (last visited Apr 3, 2021).
[10] IPCC, *supra* note 7; IPCC, *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of*

The Shindell et al. 2012 study concluded that reducing methane emissions was one of the most immediate ways to slow the rate of global warming.[11] As indicated in Figure 1, had we begun to reduce methane emissions (and emissions of black carbon, or soot) as of 2011, we would already be on a better trajectory of a slower rate of global warming. To only reduce emissions of carbon dioxide without reducing methane emissions is far less effective, essentially contributing nothing over the short term; global warming only starts to slow after 30 or more years of reduced carbon dioxide emissions. Increasingly, scientists are calling for a reduction of methane emissions in the face of a possible imminent threat of runaway climate disruption.[12]

The global warming potential of methane is defined as the radiative forcing of methane compared to carbon dioxide for a specified time period into the future for a one-time pulsed release of both gases.[13] Roughly speaking, how does methane contribute to warming compared to carbon dioxide? The time frame is critical, since as noted above methane is a far more powerful greenhouse gas but it also has a far shorter lifetime in the atmosphere. Since the Kyoto Protocol was ratified in 1997, almost all greenhouse gas inventories globally have used a global warming potential for the 100-year time period, presumably based on recommendations from the IPCC. However, this greatly understates the role of methane in global warming over shorter time periods, and nor does it accurately reflect the intent of the IPCC. In 2013, the IPCC AR5 synthesis report stated: "The GWP has become the default metric for transferring emissions of different gases to a common scale; often called 'CO2 equivalent emissions' (e.g., Shine, 2009). It has usually been integrated over 20, 100 or 500 years consistent with Houghton et al. (1990). Note, however that Houghton et al. presented these time horizons as 'candidates for discussion [that] should not be considered as having any special significance'. The GWP for a time horizon of 100 years was later adopted as a metric to implement the multi-gas approach embedded in the United Nations Framework Convention on Climate Change (UNFCCC) and made operational in the 1997 Kyoto Protocol. The choice of time horizon has a strong effect on the GWP values — and thus also on the calculated contributions of CO2 equivalent emissions by component, sector or nation. There is no scientific argument for selecting 100 years compared with other choices (Fuglestvedt et al., 2003; Shine, 2009)."[14] The bottom line is that the past time choice was arbitrary, and many scientists now call for

---

strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty (2018).

[11] Shindell et al., *supra* note 9.

[12] Robert W. Howarth, Renee Santoro & Anthony Ingraffea, *Methane and the greenhouse-gas footprint of natural gas from shale formations: A letter*, 106 CLIMATIC CHANGE 679–690 (2011), http://link.springer.com/10.1007/s10584-011-0061-5 (last visited Nov 25, 2019); Shindell et al., *supra* note 9; William J. Collins et al., *Increased importance of methane reduction for a 1.5 degree target*, 13 ENVIRON. RES. LETT. 054003 (2018), https://doi.org/10.1088%2F1748-9326%2Faab89c (last visited Nov 25, 2019).

[13] IPCC, *supra* note 7.

[14] *Id.* Citing Keith P. Shine, *The global warming potential—the need for an interdisciplinary retrial: An editorial comment*, 96 Climatic Change 467–472 (2009), [redacted] J. T. Houghton, G. J. Jenkins & J. J. Ephraums, *Climate change* (1990), [redacted]; and Jan S. Fuglestvedt et al., *Metrics of Climate Change: Assessing Radiative Forcing and Emission Indices*, 58 Climatic Change 267–331 (2003), [redacted] (last visited Apr 3, 2021).

using a shorter time period such as 20 years.[15] The State of New York declared by law in the 2019 Climate Leadership and Community Protection Act that the 20-year time period be used.[16]

Unfortunately, society has not reduced emissions of either carbon dioxide or methane. Methane emissions have continued to rise, and the very latest data on the global levels of methane in the atmosphere are highly disturbing. Figure 2, released by the US National Oceanographic & Atmospheric Administration in March 2021 shows not only the increase in methane in the atmosphere since 2005, but a recent acceleration. Methane levels in 2020 are higher than at any other time in human history.

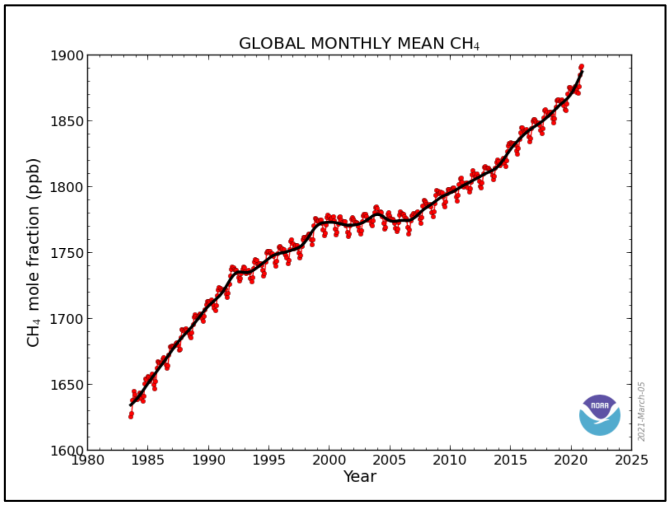


Figure 2. Mean monthly methane concentrations, 1983-2020

How do current emissions of carbon dioxide and methane compare in terms of global warming? In 2015 emissions of carbon dioxide from burning fossil fuels and producing cement were 36 billion metric tons. Emissions of methane from all human-influenced sources were approximately 0.38 billion metric tons (updated from Begon et al. 2014).[17] At the time of emission, methane is 105-times more potent as a greenhouse gas, and for an integrated 20-year period following a pulsed emission of the two gases, methane is 86-times more powerful.[18] Therefore, the methane emissions are equivalent to 39 billion metric tons of carbon dioxide emissions at first emission and to 32 billion metric tons of carbon dioxide for the average 20-year period after emission. The bottom line: over the next 20 years, methane emissions from all sources globally are contributing as much to global warming as are the total emissions of carbon dioxide globally.[19] These next 20 years are a critical time, given the very high risk of global runaway warming and climatic disruption.

---

[15] Howarth, *supra* note 2; Ilissa B. Ocko et al., *Unmask temporal trade-offs in climate policy debates*, 356 SCIENCE 492–493 (2017), https://science.sciencemag.org/content/356/6337/492 (last visited Apr 3, 2021); Lukas P. Fesenfeld, Tobias S. Schmidt & Alexander Schrode, *Climate policy for short- and long-lived pollutants*, 8 NATURE CLIMATE CHANGE 933–936 (2018), http://www.nature.com/articles/s41558-018-0328-1 (last visited Apr 3, 2021).

[16] Robert W. Howarth, *Methane emissions from fossil fuels: exploring recent changes in greenhouse-gas reporting requirements for the State of New York*, 17 JOURNAL OF INTEGRATIVE ENVIRONMENTAL SCIENCES 69–81 (2020), https://www.tandfonline.com/doi/full/10.1080/1943815X.2020.1789666 (last visited Apr 3, 2021).

[17] MICHAEL BEGON, ROBERT W. HOWARTH & COLIN R. TOWNSEND, ESSENTIALS OF ECOLOGY, 4TH EDITION (4th edition ed. 2014).

[18] IPCC, *supra* note 7.

[19] Howarth, *supra* note 3; Howarth, R.W. 2021. “Blue hydrogen” and carbon capture and storage,” briefing to US Congress, March 19, 2021.

3 Gas lifecycle stages

The full lifecycle of gas includes production, processing, transportation, and end use, and there are several forms that each of these stages might take depending on the source of the gas, the location of end use, and the end use purpose.

The gas lifecycle is comprised of various segments, from production, through to processing. Figure 3 provides an overview of these stages, and the descriptions of each stage below refer to the numbers in this figure.

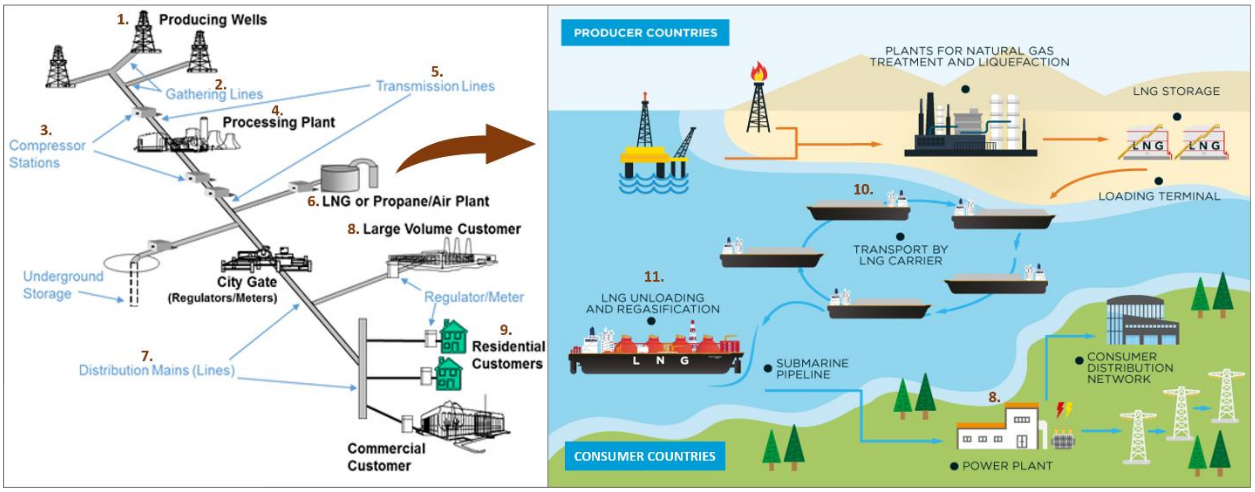


Figure 3. Gas lifecycle stages. Images adapted from American Gas Association (left) and OLT Offshore Italy (right)

3.1 Production

Methane gas may be produced (1) from several different geologic formations, with extraction techniques varying accordingly (see Figure 4).

Conventional gas refers to gas trapped in conventional reservoirs either with ("associated") or without ("nonassociated") oil. This gas has typically migrated over time from shale source rock to pockets of air created in more permeable geologic formations.

Shale gas is methane trapped in sedimentary rock formations and is considered one form of "unconventional" gas. There was virtually no commercial development of shale gas until early in the 21st Century when industry began to use two new processes to release this methane: high-precision directional drilling and high-volume hydraulic fracturing ("fracking"). Shale gas production has grown rapidly over the past 15 years, and between 2005 and 2015 two-thirds of the increase in all-natural gas production globally was from shale gas.[20]

[20] Robert W. Howarth, *Ideas and perspectives: is shale gas a major driver of recent increase in global atmospheric methane?*, 16 BIOGEOSCIENCES 3033–3046 (2019), https://www.biogeosciences.net/16/3033/2019/bg-16-3033-2019.html (last visited Jan 22, 2020).

Other forms of "*unconventional*" gas resources include coalbed methane (also known as coal seam gas), which is gas collocated with coal deposits, and "tight gas," which is gas trapped in sandstone or limestone formations. Gas can also be synthesized from coal in a process known as "coal gasification."

Coal bed methane is typically the shallowest reservoir of gas, followed by conventional deposits, while the sedimentary formations that are fracked for shale gas are often several kilometers or more below the surface.

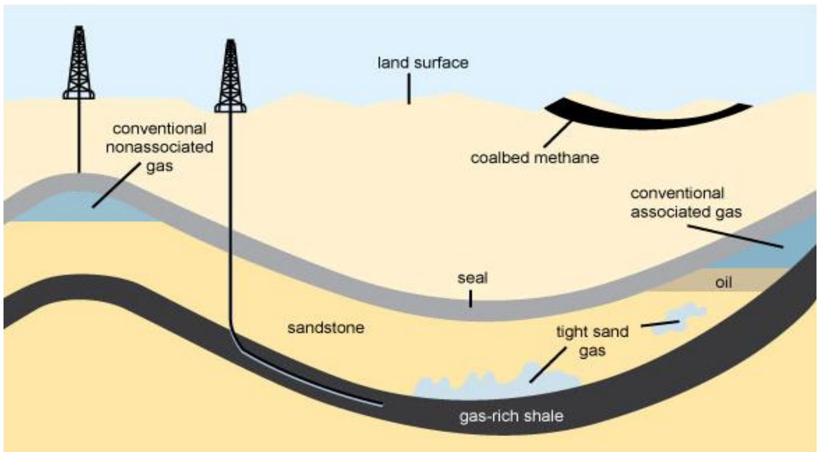


Figure 4. Gas resource schematic. Source: U.S. Energy Information Administration (EIA), Where our natural gas comes from*, U.S. ENERGY INFORMATION ADMINISTRATION (EIA) (2020), https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php.*

The steps involved in the gas production process vary based upon the kind of resource being extracted, and the emissions from these varied production steps will be detailed in Section 3.

3.2 Gathering, Processing

Gas is then collected from the various well pads on which it is being produced in a central location, via gathering lines (2). The gas is then piped to a processing plant (4) where it is cleaned of impurities and prepared for being sent through transmission pipelines.

3.3 Transportation

There are several ways of transporting gas from its production site to its end use, and pipelines (5, 7) and LNG (6) are the primary means by which gas is transported today.

3.3.1 Pipelines

Gas needs to be compressed to be sent through pipelines, and compressor stations (3) play this role along gathering lines, transmission lines, and distribution lines. These compressor stations, located at 64 to 160 km intervals on transmission pipelines, typically run on the gas passing through them. However, some compressor stations, like those moving gas directly from the wellhead, also run on diesel.

3.3.1.1 Transmission pipelines

Transmission pipelines carry gas from producing regions to major consumers, either entire cities of commercial, industrial, and residential use, or directly to major power plants or industrial users located outside of a city. They may also carry gas directly ports for processing into LNG for export. These pipelines, buried underground, are typically between 76 and 91 cm in diameter, but can be as big as 122 cm for particularly important gas corridors.[21]

3.3.1.2 Distribution pipelines

Distribution pipelines (7) take gas from the transmission lines into the city to consumers. They are smaller in diameter and run under city streets. The larger distribution pipelines are known as "mains."

3.3.2 Liquified Natural Gas (LNG)

Liquified Natural Gas (LNG) is gas that is liquified near a port area in a producer country (6), loaded onto LNG carrier ships to be transported to another country (10), and then re-gasified in the importer/consumer country for local use (11). The liquefaction process cools the gas to -164°C, and the methane must remain at -164°C throughout the journey so that the methane, much more compact as a liquid, is contained.

3.4 End use

After its transportation journey, gas is employed in a range of end uses, including industrial processes (8), combined cycle or open cycle power plants, and residential uses or commercial uses (9), such as space and water heating and cooking.

4 Emissions from stages of gas lifecycle

Each of these stages of the gas lifecycle releases methane, carbon dioxide, and other greenhouse gases, most of which were not accounted for in the consideration of the climate impacts of the Richards Bay 3000 MW Combined Cycle Gas to Power Plant.

4.1 Production

Methane is emitted to the atmosphere whenever natural gas is extracted, including from conventional and unconventional resources.[22] My work suggests that on average around 2.8-3.5% of conventional gas taken from the ground leaks into the atmosphere in the production stage.[23] There are indications that these emissions may be greater from shale gas, which is becoming an ever-larger share of global gas production and LNG,[24] than from conventional natural gas. For instance, in the days to weeks following high-volume hydraulic fracturing, a large portion of the injected fluids return to the surface ("flowback water") carrying large volumes of methane with them.[25] Although this methane gas can in theory be captured from the liquids, this is expensive and slows down the time necessary to bring wells to production. In the United States, the EPA has regulated these emissions since 2015, requiring that the methane from this flowback period be flared (burned) rather than released to the atmosphere as

---

[21] S.M. Folga, *Natural Gas Pipeline Technology Overview* 3 (2007), https://corridoreis.anl.gov/documents/docs/technical/APT_61034_EVS_TM_08_5.pdf (last visited Jul 19, 2020).
[22] Howarth, Santoro, and Ingraffea, *supra* note 12; Howarth, *supra* note 2; Alvarez et al. *supra* note 1.
[23] Howarth, *supra* note 20.
[24] US EIA, *Shale gas production drives world natural gas production growth*, US Environmental Information Agency Department of Energy, (2016), https://www.eia.gov/todayinenergy/detail.php?id=27512).
[25] Howarth, Santoro, and Ingraffea, *supra* note 12; Howarth, *supra* note 2; Howarth, *supra* note 3.

unburned methane, if the gas is not captured and if it is technically possible to flare the gas.[26] However, there are many loopholes in the rules; reporting is also voluntary, and enforcement of the regulation is largely lacking. In practice, venting of unburned methane due to unlit flares seems common.[27]

Another difference in emissions from shale gas compared to conventional natural gas relates to the depth of the shale gas formation and the history of earlier fossil-fuel development in many shale gas areas. Caulton et al. 2014 observed methane emissions during well drilling in the Marcellus shale region in southwestern Pennsylvania, even before the drillers reached the shale.[28] As I explain in my latest work on methane, "This area has a long history of fossil-fuel exploitation, with development of oil, conventional gas, and coal dating back to the 1800s. The emissions during shale-gas well drilling may be the result of hitting pockets of trapped methane from these earlier fossil-fuel operations, which must be drilled through to reach the shale, which is much deeper underground. In such an environment, the gas industry sometimes employs 'underbalanced' or negative-pressure drilling to reduce the chance of blowouts, and this could increase the emission of methane from any pockets that are encountered while drilling (Caulton et al. 2014)."[29] The negative-pressure drilling means that the drillers are pulling a vacuum on their rig rather than drilling under high, positive pressure. While this does reduce the chance of blowouts, it increases the sucking out of methane from underground gas pockets.

While it is presently unclear where the gas feedstock for the Richards Bay power plant would be produced and what techniques would be needed to capture it, there are indications that it could come from either shale gas fracked in South or Southern Africa, or from shale gas-heavy LNG imported from lead LNG exporters like Australia or the United States.[30]

---

[26] ENVIRONMENTAL PROTECTION AGENCY, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* (2016), https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf.

[27] Hiroko Tabuchi & Jonah M. Kessel, *It's a vast, invisible climate menace. We made it visible*, THE NEW YORK TIMES, December 12, 2019, https://www.nytimes.com/interactive/2019/12/12/climate/texas-methane-super-emitters.html (last visited Feb 9, 2020); Howarth, *supra* note 3.

[28] Caulton et al., *supra* note 4.

[29] Howarth, *supra* note 3.

[30] The project's Climate Change Impact Assessment (CCIA) asserts that, "The proposed CCPP plant will be fueled with piped natural gas or liquefied natural gas (LNG). It intends to take advantage of the large natural gas discoveries in the Rovuma Basin in Mozambique. This reserve presents a reasonably priced regional gas resource that could be transported to the Richards Bay area via pipeline or ship as LNG**."[30]** The Environmental Impact Assessment Report also notes: "The Gas Utilization Master Plan (GUMP) identifies that there are potential gas reserves in the Karoo basin, deep offshore, and at the Ibhubesi basin."[30] Currently Mozambique is not exporting LNG, construction has not begun on the pipeline described in the CCIA, and the towns and LNG infrastructure under development in the Rovuma Basin region referenced in the CCIA are under the control of an armed group known as Al-Shabab.[30] The EIA reference to the GUMP suggests that any domestic gas used in the CCPP would likely come from shale gas in the Karoo basin or offshore oil and gas production. With shale gas exploration underway in Namibia, Algeria, and Angola, it seems plausible that the gas might also come from those more local shale reserves in the future. Given the current state of gas and LNG development in all of these possible source countries, it seems likely that for the foreseeable future the gas would be sourced as LNG from Qatar, Australia, the United States, or several other leading and distant global LNG producers. Australia and United States LNG includes significant shale gas in their LNG mixtures.

I have recently reviewed all of the peer-reviewed literature on top-down estimates for methane emissions from shale gas.[31] These studies are synthesized in Table 1 and include 12 studies based on aircraft data published in 9 different papers and 3 studies based on satellite data published in 2 different papers. The estimates are for emissions that occur at the gas well sites and in the nearby area, including processing plants and some storage facilities, but generally do not include emissions from high-pressure gas transport pipelines or lower-pressure gas distribution pipelines. The studies synthesized in Table 1 show that between 0.2% and 17% of the natural gas production is emitted to the atmosphere as unburned methane, again not including the "downstream" emissions associated with transport and distribution of gas. All of the studies presented in Table 1 appear to be well conducted. The variation in emission rates probably reflects real variation in both time and space: for instance, emissions may be higher during times of greater drilling and fracking activity compared to times of low fracking. Further, some companies may follow better procedures and take greater care to reduce emissions.

Table 1. Top-down estimates for upstream emissions of methane from natural gas systems, including studies based on aircraft flyovers and satellite remote-sensing data. Studies are listed chronologically. Estimates are the percentage of the methane in natural gas that is produced*.

Aircraft data		
Peischl et al (2013)	Los Angeles Basin, CA	17%
Karion et al. (2013)	Uintah shale, UT	9.0%
Caulton et al. (2014)	Marcellus shale, PA	10%
Karion et al. (2015)	Barnett shale, TX	1.6%
Peischl et al. (2015)	Marcellus shale, PA	0.2%
Peischl et al. (2016)	Bakken shale, ND	6.3%
Barkley et al. (2017)	Marcellus shale, PA	0.4%
Peischl et al. (2018)	Bakken shale, ND	5.4%
	Eagle Ford shale, TX	3.2%
	Barnett shale, TX	1.5%
	Haynesville shale, LA	1.0%
Ren et al. (2019)	Marcellus shale, PA & WV	1.1%
Satellite data		
Schneising et al. (2014)	Eagle Ford shale, TX	9.1%*
	Bakken shale, ND	10.1%*
Zhang et al. (2020)	Permian Basin shale, NM	3.7%

*Schneising et al. (2014) estimated the percentage of methane emitted relative to the combined production of natural gas and oil; these estimates are therefore minimal estimates for the percentage of methane in natural gas that is produced.

Table 2, also from Howarth 2021, presents a detailed exploration of methane emissions and shale gas production for six shale gas fields.[32] The emission data are from Table 1, while production data are from EIA.[33] Quality data for both emissions and production in 2015 exist for only these six shale-gas fields, but these represent a total production of 325 billion cubic meters per year, or three-quarters of the total global production of shale gas that year.[34] Comparing the total mass of methane emitted (7.2 Tg per year) with the production for these six fields (325 billion cubic meters per year), the volume-weighted average rate of upstream emissions is 3.3% (Table 2). Applied to the global increase in shale gas production over the period 2005-2015, this 3.3% upstream emission rate leads to an estimated increase

[31] Howarth, *supra* note 3.
[32] *Id.*
[33] EIA, *Natural Gas: Dry Shale Gas Production Estimates by Play*, Energy Information Agency, U.S. Department of Energy (2020), https://www.eia.gov/naturalgas/data.php.
[34] Howarth, *supra* note 20.

Table 2. Shale gas production and upstream methane emissions from various major shale-gas producing fields in 2015.

	Production (billion m³/yr)	% emitted upstream (with 90% CL)	Mass emitted upstream (Tg/yr)*
Marcellus	155	2.93 % (+/- 3.4 %)	3.0
Eagle Ford	50	6.65 % (+/- 3.9 %)	2.2
Barnett	38	1.55 % (+/- 0.06 %)	0.39
Haynesville	36	1.0%	0.24
Permian	36	3.7 %	0.88
Bakken	10	7.37% (+/- 1.9 %)	0.49
Total for above fields	325		7.2
Volume-weighted average		3.3 %**	
Global total	435		9.5***

*Assumes 93% of produced gas is methane (Schneising et al. 2014).

** Calculated from total production and methane mass emission for six shale-gas fields listed.

*** Calculated from volume-weighted average percent methane emitted.

in global methane emissions of 9.5 Tg per year (Table 2), or 40% of the entire global increase in methane over that time period.[35]

One can also estimate the global emissions of methane from shale gas through observing changes in the stable isotopic composition of methane in the atmosphere. Most methane is composed of the C^{12} stable isotope, but some methane is composed on the C^{13} isotope instead. For the first many years of the 21st Century, the methane concentration in the atmosphere remained steady and the C^{13} content of that methane did not change, however, starting at the time of the shale gas revolution in 2005 or so, the concentration of methane in the atmosphere started to rise rapidly, and the C^{13} content of that methane began to fall. Some scientists concluded from this evidence that the increase in methane was due to biological sources such as animal agriculture. These scientists had assumed that the C^{13} content of methane from shale gas is identical to that of methane from conventional natural gas. However, this is not true, in fact the shale-gas methane has somewhat less C^{13}. Using this information, I reanalyzed global methane trends and demonstrated that emissions from shale gas were responsible for at least 33% of total increases in global methane emissions since 2005.[36] This indicates an emission rate of methane from shale gas of 3.5% to 4.1% of the rate of shale gas production. This is for the full lifecycle, including methane emissions at the well site as well as from transport and distribution of gas, although it may not include some of the emissions during well drilling (such as those reported by Caulton et al. 2014[37]): the methane released during drilling, although caused by the drilling, may not have originated from the shale formation and may in fact reflect methane from conventional gas sources or coal operations trapped in underground, abandoned mines and wells. This global ^{13}C approach for estimating shale-gas methane emissions is completely independent of any of the information presented in Table 1 from top-down studies. Yet the magnitude of 3.5% to 4.1% is remarkably close to the sum of 4.1% emission calculated by adding the 3.3% volume-weighted emission

---

[35] *Id.*
[36] *Id.*
[37] Caulton et al., *supra* note 4.

rate from Table 2 with an 0.8% emission from downstream transmission and distribution pipelines. This greatly increases the confidence in both the top-down and global C^{13} approaches.

Finally, it must be noted that methane emissions at all oil and gas well-heads can continue long after a well has stopped producing oil and gas for market, as even wells that are supposedly properly plugged can leak methane into the atmosphere for decades. In a study of just one state in the United States, for example, researchers found that these plugged and unplugged abandoned wells emitted between 5 and 8% of the state's total annual methane emissions.[38]

4.2 Gathering and Processing

In addition to well pad gas losses, the gathering and processing of all forms of gas before it is sent over transmission pipelines also emits significant quantities of methane. In the bottom-up measurements of Alvarez et al. 2018, for example, researchers found that around 3.32 million tons of methane were emitted from oil and gas gathering and processing alone in the US in 2015, or between a quarter and a half of the total methane emitted by cattle emissions annually across the US in that same year.[39]

4.3 Transportation

The estimate of 3.3% of shale gas production lost in methane emissions explained above also does not include the downstream emissions associated with transporting and distributing the gas through pipelines, or as LNG.

4.3.1 Pipelines

The best available data from top-down studies on downstream emissions suggest at least an additional 0.8% emission rate from the pipeline systems.[40] There has been less study of these downstream transportation and distribution emissions from pipelines than for the emissions at the gas well sites, and so this 0.8% or greater emission should be treated as uncertain. Our knowledge of these pipeline

---

[38] Mary Kang et al., *Identification and characterization of high methane-emitting abandoned oil and gas wells*, 113 PNAS 13636–13641 (2016), https://www.pnas.org/content/113/48/13636 (last visited Apr 5, 2021).

[39] Alvarez et al., *supra* note 1; Scot M. Miller et al., *Anthropogenic emissions of methane in the United States*, PNAS (2013), [redacted]; US EPA, *Chapter 5: Agriculture - Greenhouse Gas Inventory* (2017), https://www.epa.gov/sites/production/files/2017-02/documents/2017_chapter_5_agriculture.pdf.

[40] Kathryn McKain et al., *Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts*, 112 PNAS 1941–1946 (2015), https://www.pnas.org/content/112/7/1941 (last visited Apr 3, 2021); Brian K. Lamb et al., *Direct and Indirect Measurements and Modeling of Methane Emissions in Indianapolis, Indiana*, 50 ENVIRON. SCI. TECHNOL. 8910–8917 (2016), https://pubs.acs.org/doi/10.1021/acs.est.6b01198 (last visited Nov 26, 2019); Debra Wunch et al., *Quantifying the loss of processed natural gas within California's South Coast Air Basin using long-term measurements of ethane and methane*, 16 ATMOSPHERIC CHEMISTRY AND PHYSICS 14091–14105 (2016), https://acp.copernicus.org/articles/16/14091/2016/ (last visited Apr 3, 2021); Genevieve Plant et al., *Large Fugitive Methane Emissions From Urban Centers Along the U.S. East Coast*, 46 GEOPHYSICAL RESEARCH LETTERS 8500–8507 (2019), https://agupubs.onlinelibrary.wiley.com/doi/abs/10.1029/2019GL082635 (last visited Nov 21, 2019); Howarth, *supra* note 16; Howarth, *supra* note 3.

emissions should improve rapidly in the coming few years due to many more studies using satellite data.[41]

4.3.2 Liquified Natural Gas (LNG)

LNG, as mentioned above, is a likely source of gas identified in the EIA and CCIA for the Richards Bay CCPP. It takes substantial energy to cool methane to the point where it becomes a liquid (-164°C). Usually, additional natural gas is burned to provide this energy, meaning that the use of LNG has additional emissions of carbon dioxide from the burning of this natural gas as well as of methane associated with the natural gas that is burned. A recent study of LNG lifecycle emissions analysis found that emissions from liquefaction, tanker transport, and regasification range from about 8% to 21% of total lifecycle emissions for the LNG, depending on how large production emissions were calculated to be and how far the LNG carriers traveled, with most calculations in the upper end of this range.[42]

In addition, LNG methane is kept in liquefied form while it is transported and stored by allowing some of the methane to evaporate. As with sweat evaporating from one's skin on a hot day, the evaporation of methane cools the LNG to keep it in liquid form. The oil and gas industry calls this "boil off." Ideally, the evaporated methane is burned and used for energy on board tanker ships during transit and at LNG storage terminals, and the studies referenced assume this outcome. However, I am aware of no peer-reviewed objective scientific measurements regarding how much methane may be emitted to the atmosphere from boil off.

If we optimistically assume that the LNG industry does a perfect job in capturing and using methane from boil off, LNG still has the 20% penalty in greenhouse gas emissions compared to regular shale gas, due to the use of gas at the liquefaction step. This means that rather than emissions of 15 g C of carbon dioxide per MJ for shale gas or conventional natural gas,[43] LNG emissions are 18 g C of carbon dioxide per MJ. And if we accept that emissions of unburned methane from using shale gas are 3.5% of production (a low, conservative estimate as I present above), this increases to at least 4.2% for LNG. It is highly probably that some of the evaporated methane from boil off reaches the atmosphere, increasing this estimate further.

4.4 End use

Methane leakage at the end use occurs from a variety of sources, including pipelines entering the facility or within the facility, and even at the point of release of the methane. Faulty compressor stations at gas power plants can lead to tons of methane emissions going unchecked, as in the case of a massive leak at

[41] See, for instance European Space Agency, *Monitoring methane emissions from gas pipelines*, EUROPEAN SPACE AGENCY (2021), https://www.esa.int/Applications/Observing_the_Earth/Copernicus/Sentinel-5P/Monitoring_methane_emissions_from_gas_pipelines (last visited Apr 3, 2021).
[42] CHRISTINA SWANSON ET AL., *Liquefied natural gas is not an effective climate strategy* 30 (2021).
[43] Howarth, Santoro, and Ingraffea, *supra* note 12.

a 690 MW gas power plant in Los Angeles California caught in 2020.[44] Researchers have also detected significant quantities of methane being emitted from gas powerplant stacks, uncombusted.[45]

5 Comparison of gas and coal emissions on the climate

Taken in sum, the latest science on gas suggests that the greenhouse gas footprint of gas is worse than that of either coal or oil, particularly when considered in the 20-year timescale most relevant to our climate future.

In the past, conventional natural gas and shale gas were promoted as bridge fuels to an eventual fossil-free future. The argument was that for the same amount of energy produced, carbon dioxide emissions were less for gas than for oil or coal. This is certainly true.[46] However, the best available evidence shows that methane emissions are greater for shale gas and conventional natural gas than for oil products or coal, per unit of energy produced. This should not be surprising since shale gas and conventional natural gas are composed almost entirely of methane, while methane is a contaminant and small component of either coal or oil. When the methane emissions from shale gas are considered, the greenhouse gas footprint is far worse than that of either coal or oil, particularly when considered over the 20-year time period, as shown in Figure 5.[47] Here, methane emissions are compared to carbon dioxide emissions using the 20-year global warming potential from the IPCC 2013 and assuming a methane emission rate of only 3.2% of natural gas production, an extremely conservative value, as described above. If LNG transportation were included

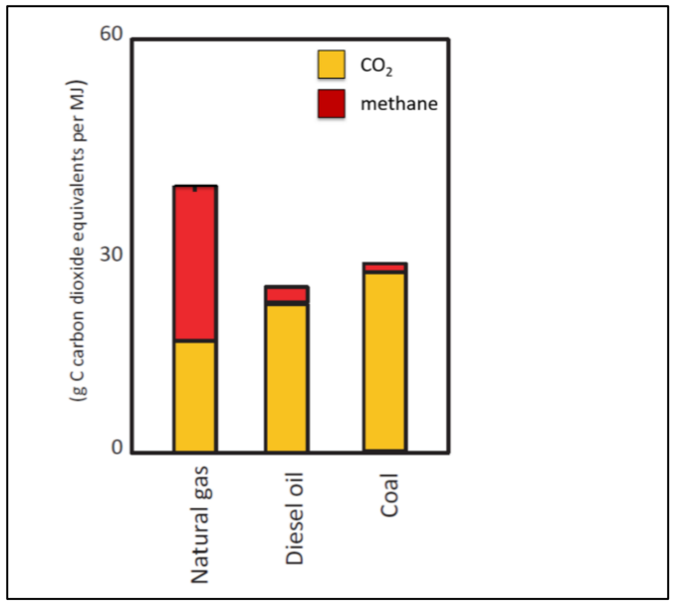


Figure 5. Greenhouse gas footprint of natural gas (including shale gas), diesel oil, and coal per unit of heat energy released as the fuels are burned. Direct emissions of carbon dioxide are shown in yellow. Methane emissions expressed as carbon dioxide equivalents are shown in red. As discussed in the text, the methane emission estimate for natural gas is very conservative and could be up to 2-times greater. Emission estimates are from Howarth 2020.

[44] Nichola Groom, *Los Angeles natural gas plant has been leaking methane for years*, REUTERS, August 26, 2020, https://www.reuters.com/article/usa-methane-california-idUKL1N2FS29W (last visited Apr 3, 2021).
[45] Tegan N. Lavoie et al., *Assessing the Methane Emissions from Natural Gas-Fired Power Plants and Oil Refineries*, 51 ENVIRON. SCI. TECHNOL. 3373–3381 (2017), https://doi.org/10.1021/acs.est.6b05531 (last visited Apr 23, 2020); Kristian D. Hajny et al., *Observations of Methane Emissions from Natural Gas-Fired Power Plants*, 53 ENVIRON. SCI. TECHNOL. 8976–8984 (2019), https://pubs.acs.org/doi/10.1021/acs.est.9b01875 (last visited Feb 25, 2020).
[46] Katharine Hayhoe et al., *Substitution of natural gas for coal: climatic effects of utility sector emissions*, 54 CLIMATIC CHANGE 107–139 (2002); Robert W. Howarth, Renee Santoro & Anthony Ingraffea, *Venting and leaking of methane from shale gas development: response to Cathles et al.*, 113 CLIMATIC CHANGE 537–549 (2012), https://doi.org/10.1007/s10584-012-0401-0 (last visited Apr 3, 2021); Howarth, *supra* note 16.
[47] Howarth, *supra* note 3; With emissions estimates from Howarth, *supra* note 16.

in this comparison, the results would be even less favorable for natural gas.

One can also view the comparison of natural gas with other fuels in the context of the technology warming potential, which specifies a level of methane emissions from the use of natural gas at which this fuel would not be desirable from a climate perspective. The original presentation of this approach by Alvarez et al. 2012 became somewhat dated quickly when the IPCC 2013 update our understanding of exactly how powerful methane is as a greenhouse gas. Updating the Alvarez et al. 2012 approach with this new information, using natural gas to generate electricity has a climate benefit relative to coal only if methane emissions from natural gas are less than 2.8% or production.[48] Shale gas is likely worse than conventional natural gas, because of increased methane emissions. And LNG is a further negative aggravation that increases emissions of both carbon dioxide and methane.

[48] Howarth, *supra* note 2.

Appendix B

pre-print, submitted for publication, 11.9.2021

On the climate impacts of blue hydrogen production

Christian Bauer[a], Karin Treyer[a], Cristina Antonini[b], Joule Bergerson[c], Matteo Gazzani[d], Emre Gencer[e], Jon Gibbins[f], Marco Mazzotti[b], Sean T. McCoy[c], Russell McKenna[g], Robert Pietzker[h], Arvind P. Ravikumar[i], Matteo C. Romano[j], Falko Ueckerdt[h], Jaap Vente[k], Mijndert van der Spek[l,†]

Natural gas based hydrogen production with carbon capture and storage is referred to as *blue hydrogen*. If substantial amounts of CO_2 from natural gas reforming are captured and permanently stored, such hydrogen could be a low-carbon energy carrier. However, recent research raises questions about the effective climate impacts of blue hydrogen from a life cycle perspective. Our analysis sheds light on the relevant issues and provides a balanced perspective on the impacts on climate change associated with blue hydrogen. We show that such impacts may indeed vary over large ranges and depend on only a few key parameters: the methane emission rate of the natural gas supply chain, the CO_2 removal rate at the hydrogen production plant, and the global warming metric applied. State-of-the-art reforming with high CO_2 capture rates combined with natural gas supply featuring low methane emissions does indeed allow for substantial reduction of greenhouse gas emissions compared to both conventional natural gas reforming and direct combustion of natural gas. Under such conditions, blue hydrogen *is* compatible with low-carbon economies and features climate change impacts in line with green hydrogen from electrolysis supplied with renewable electricity. However, neither current blue nor green hydrogen production pathways render fully "net-zero" hydrogen without additional carbon dioxide removal.

Introduction

Hydrogen is foreseen to be an important energy vector in (and after) the transition to net-zero Greenhouse Gas (GHG) emission economies.[1–5] The prerequisite is that its production results in very low GHG emissions, such that the overall process of hydrogen production and use could be made net-zero with a feasible level of carbon dioxide removal from the atmosphere. There is common agreement among Life Cycle Assessment (LCA) studies that the climate change impact of hydrogen production can be low, when produced from certain biogenic resources (some wood, agricultural residues, etc.), as well as when produced using water electrolysis powered by low-carbon electricity (e.g. from wind power).[6–15] However, there is less clarity on the climate change impact of hydrogen produced from natural gas (NG) and other fossil fuels, coupled with CO_2 capture and storage (CCS) – often colloquially called *blue hydrogen*.

Some of the authors of this contribution investigated life cycle impacts on climate change from a range of blue hydrogen production technologies for the European situation and published the results in 2020.[7] The reductions in carbon dioxide equivalent (CO_2-eq.) emissions per unit of hydrogen production were in the order of 50-85% when compared to standard NG-based hydrogen production without CCS, when calculated using 100-year global warming potentials (GWP). This result showed that at least some blue hydrogen configurations could contribute to a low-carbon future if critical issues in the corresponding production chains could be addressed. In contrast, a recent analysis suggests only very minor climate benefits of blue hydrogen and concludes that "the use of blue hydrogen appears difficult to justify on climate grounds".[16] Such contradicting results demand an in-depth analysis and a transparent scientific discussion of the underlying assumptions and approaches to come to a common understanding.

Whether, and under which conditions, blue hydrogen could represent a low-carbon energy carrier is a key question at present, as society urgently needs to make decisions about low-carbon technologies.[17] Beside requiring long-term and large investments, some of these technology choices imply systemic structural changes across the energy system, and long-lasting impacts on atmospheric concentrations of greenhouse gases and thus on climate change. Such decisions must therefore be taken based on solid scientific evidence, for which LCA – carried out in line with best practices[18–20] – seems the most appropriate

Context

Any future "net-zero" economy will rely on a broad portfolio of new and existing technologies as well as low-carbon energy carriers and feedstocks including hydrogen produced with minimal or zero greenhouse gas emissions. This is the case when water splitting via electrolysis uses low-carbon electricity from either renewables or nuclear. However, the potential growth curve in hydrogen demand is unlikely to be met by the feasible expansion in both electrolyzer and low-carbon electricity generation capacities. Natural gas based hydrogen with carbon capture and storage may allow for an additional and completely independent "low-carbon" option, thus increasing the overall implementation speed.

[a] *Laboratory for Energy Systems Analysis, Paul Scherrer Institute, Switzerland;* [redacted]
[b] *Separation Process Laboratory, ETH Zurich, Switzerland.*
[c] *Department of Chemical and Petroleum Engineering, University of Calgary, Canada.*
[d] *Copernicus Institute of Sustainable Development, Utrecht University, The Netherlands.*
[e] *MIT Energy Initiative, Massachusetts Institute of Technology, USA.*
[f] *Department of Mechanical Engineering, University of Sheffield, UK.*
[g] *School of Engineering, University of Aberdeen, UK.*
[h] *Potsdam Institute for Climate Impact Research, Germany.*
[i] *Hildebrand Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, USA.*
[j] *Department of Energy, Politecnico di Milano, Italy.*
[k] *Energy Transition, TNO, The Netherlands.*
[l] *School of Engineering & Physical Sciences, Institute of Mechanical, Process & Energy Engineering, Heriot-Watt University, UK.*
† Corresponding [redacted] k

method. Such comprehensive evidence is currently lacking: our previous analysis[7] did not explore the entire range of blue hydrogen production chains and thus did not reflect the range of potential climate change impacts. Similarly, Salkuyeh et al.[21] performed an LCA of few very specific technology options for blue hydrogen production in Canada. Finally, the more recent analysis[16] does not follow best practices in LCA as it, for example, takes into account neither GHG emissions associated with capital goods nor those originating from transportation and geological storage of CO_2; and it relies on data for natural gas supply only in the US context.

This communication seeks to contribute to closing the described evidence gap by synthesizing the results from recent peer-reviewed LCA studies of blue hydrogen production and natural gas supply chains, using broad, and realistic, ranges of key parameters, and thus providing a fact-based perspective on the potential climate benefits of blue hydrogen. In addition, it seeks to explain what causes the large differences in climate change mitigation potential of different blue hydrogen production chains. Finally, it defines essential targets for technology development and regulations. In doing so, it aims to generate enhanced understanding of the complexities of blue hydrogen, thereby providing important insights and levers to policy- and decision-makers as well as to the scientific community.

Methodological and parameter choices

The climate change impacts of hydrogen production from natural gas with CCS – quantified by means of LCA – depend on several processes within the entire value chain, and on many assumptions and methodological choices. However, as will be demonstrated below, we find that the following three aspects are particularly important: the blue hydrogen production technology; the methane emissions from natural gas supply chains; and the choice of metrics for quantifying impacts.

1) Blue hydrogen production technology with CO_2 capture

Hydrogen production from natural gas is a well-established technology that has been used for decades in industry,[22,23] e.g. for oil refining and ammonia production. Currently, the most widely used technology for production of high purity hydrogen at the scale needed in chemical plants is Steam Methane Reforming (SMR). Large-scale ammonia and methanol production use a range of reformers to produce the ideal syngas composition for the final product synthesis, e.g. SMR, air-fed Autothermal Reformers (ATR) and Gas-Heated Reformers (GHR).[24] Partial oxidation of natural gas is another commercially operating process that can be used for merchant hydrogen production. Common to all these proven processes is the production of a H_2-rich synthesis gas (syngas for short), from which H_2 and CO_2 can be easily separated with high purity.

For large-scale merchant production of hydrogen with CCS in the next decades, oxygen-based technologies with internal heating (e.g. ATR) are likely to become more commonplace due to good economies of scale, while the higher natural gas conversion may make the achievement of high CO_2 capture efficiencies more energy efficient and less costly.[25,26]

The net efficiency of converting natural gas into hydrogen is high, about 76-77% of the energy content (Lower Heating Value, LHV) of the feedstock natural gas is contained in the hydrogen, both for SMR and for ATR processes.[7] It is also notable that SMR, and to a somewhat lesser extent ATR, plants typically produce steam in excess of that needed in the reforming reaction, which can be used to generate electricity.[7,23]

CO_2 capture and geological storage is an effective means of reducing the GHG footprint of hydrogen production from fossil feedstock. In a hydrogen plant with CCS, essentially 100% of the carbon in feedstock is fully oxidized to CO_2, either through the water gas-shift reaction or combustion. It can then be readily removed by chemical solvents or physical separations. Depending on the reformer process configuration, the CO_2 will be contained in a combination of syngas and combustion exhaust streams. The CO_2 molecules can be removed from all the CO_2-containing gas streams present in the hydrogen production plant (i.e. from syngas and/or combustion flue gas), and then transported to a permanent underground storage location. The energy required to run the capture system (e.g. steam for solvent regeneration and electricity for CO_2 compression) can typically be recovered from the hydrogen production process. This means that, in contrast to CO_2 capture for electric power, relatively little, if any, additional natural gas needs to be burned to supply energy for capture and the corresponding reduction in efficiency of hydrogen production is small.[7,23] However, relative to a facility without CO_2 capture, the opportunity for electricity generation is reduced, which slightly increases the life cycle GHG emissions of the hydrogen production.

In the context of reaching net-zero GHG emissions, it is imperative and technically feasible to remove the vast majority of the CO_2 produced in the hydrogen plant. However, currently operating (first-of-a-kind) CO_2 capture plants coupled to hydrogen production capture only 50-60% of the overall (hereafter "plant-wide") CO_2 emissions produced. This is mainly because they capture only CO_2 from the syngas in SMR applications, but not the CO_2 in the combustion products. Examples include the Shell Quest project,[27] and the Port Arthur plant.[28] These examples are not representative of the hydrogen CCS plant configurations planned in Europe and the US, however, where plant-wide CO_2 removal rates higher than 90% are expected.[29–32] The relevant CO_2 capture technologies have been demonstrated in a number of commercial or demonstration scale plants over several years: commercial scale plants consistently achieve more than 92% removal of CO_2 from coal combustion gas in the commercial-scale Petra Nova facility in Texas[33] and more than 93% removal of CO_2 from synthesis gas in the Coffeyville Resources ammonia plant in Kansas.[34] More than 99% CO_2 removal from hydrogen production syngas is commonplace in ammonia plants.[35]

2) Methane emissions from natural gas supply chains

Methane emissions from the oil and gas supply chain are an important contributor to global greenhouse gas emissions.[36]

With a global warming potential around 30 and 85 times higher than that of CO_2 over 100 and 20 years, respectively, methane emissions can be an important contributor to GHG emissions associated with the natural gas supply chain.[37] Recent research has demonstrated that methane emissions occur across the entire supply chain, including production, processing, pipeline transportation, and distribution.[38–40] Furthermore, field measurements in North America have identified under-estimation in official methane emissions inventories.[41–43] The climate impacts of blue hydrogen can hinge on the sources and magnitude of these emissions, because they can make up a major fraction of the total GHG emissions when a high level of CO_2 capture (and storage) is applied within the supply chain. The higher the CO_2 capture rates, the higher the relative contributions of such methane emissions to the overall climate impact of blue hydrogen. Also, the life cycle impact of upstream methane emissions increases with application of shorter time horizons for measuring climate impacts.

Incorporating methane emissions in an LCA model of blue hydrogen in a representative and context-specific manner is non-trivial. On the one hand, the characterization of methane emissions from natural gas supply chains in commonly used life cycle inventory databases is inconsistent and outdated, and likely to underestimate these emissions.[44–46] On the other hand, reported methane emissions from natural gas supply chains based on field measurements exhibit large variability,[41,47,48] making it difficult to select a representative "average" emission value for use in LCA calculations.

Several factors contribute to real and reported variability in methane emissions from the oil and gas sector. While some of these can be addressed through appropriate methodological choices in LCA, others require further research and data collection. The key challenges – in approximate descending order of importance – to incorporating representative methane emissions in the LCA of blue hydrogen are:

1) Spatial and temporal variability
2) Lack of geographically representative field data
3) Lack of consistent reporting metrics
4) System boundaries

Recent field studies have shown significant spatial and temporal variability in methane emissions across global oil and gas basins.[39,49] These variations arise from differences in basin and resource characteristics, operational equipment, maintenance practices, and/or environmental conditions. For example, Burns and Grubert report production methane emission rates by US state varying between 0.9% and 3.6% based on a re-analysis of published literature.[48] Furthermore, methane emission rates estimated in these studies differ substantially from official inventory estimates. In a comprehensive meta-analysis of field data in the US, Alvarez et al. report a national production-averaged methane emission rate of 2.3% across the US oil and gas supply chain, 60% higher than official U.S. Environmental Protection Agency (EPA) GHG inventory estimates.[41] Similarly, a recent analysis of eight years of field observations in Western Canada by researchers at Environment and Climate Change Canada (ECCC) showed methane emissions to be 60% higher than that of official Canadian inventory estimates.[42] Estimates of methane emissions across basins are continuously being updated as a result of improved measurement approaches – e.g. a recent analysis of aerial-based methane measurements in the Permian basin in the US exhibited leakage rates over 9%.[50] Furthermore, differences in measurement platform (ground-based vs. aerial vs. satellite), time of measurement, and methodological approach renders direct comparison across studies challenging. Thus, although each of these individual studies might accurately report methane emissions in a specific time and place, the large observed variation makes simplistic country-level representation in LCA studies prone to errors.

Another major challenge for LCA studies is the lack of robust bottom-up field data on methane emissions outside North America. Over the past decade, several independent field campaigns across multiple oil and gas basins have been conducted in the US and Canada. These campaigns have significantly improved our understanding of oil and gas methane emissions, including recent breakthroughs in reconciling field measurements with inventory estimates.[43] By comparison, there have been far fewer aircraft or ground-based field studies outside North America that can shed light on global oil and gas methane emissions. Much of the available non-U.S. or Canada field data are based on satellite observations that often have low spatial resolution resulting in large uncertainties associated with source attribution.[51] An example for such satellite-based data is the methane tracker of the International Energy Agency,[52] which provides country-specific methane emissions from natural gas supply chains. This data set highlights large country-level variations, with emissions ranging from near-zero for countries like Norway and Qatar to over 6% for countries like Libya and Iraq. However, the lack of direct measurements of methane emissions often means that country-level emission estimates are uncertain due to methodological issues.

Methane emissions from natural gas supply chains are usually reported as emission rates, e.g. in terms of "gram CH_4 emitted per gram of natural gas delivered".[38] However, they can also be expressed as "mass methane emitted from natural gas production sites per mass methane withdrawn".[48] Comparing emission rates expressed in these two ways requires knowledge about natural gas compositions, which are often not explicitly provided. Similarly, if methane emission rates are based on the energy content of natural gas, it is not always clear whether net (lower) or gross (higher) calorific values are used, and the assumed value is also often unknown. Furthermore, natural gas is often produced as associated gas where it is extracted along with crude oil and other liquids, resulting in combined measurements of methane emissions associated with all products.

An LCA of blue hydrogen production requires specific emission factors for the natural gas used as feedstock. Therefore, methane emissions of combined production processes must be assigned or allocated to single products.[47,48] Sometimes, methane emissions are entirely assigned to the natural gas supply chain, which results in an overestimation. But even if the emissions of combined production are subdivided, this allocation can be based either on energy content or mass of the co-products, or on the revenue generated by selling them, which can cause substantial differences in the NG-specific methane emission rates.[53,54] Alternatively, a well-level purpose allocation can be applied,[48] assigning emissions entirely to the product representing the primary purpose of the resource extraction infrastructure.

System boundaries are relevant, because the natural gas supply chain consists of various steps from exploration to final distribution and it is sometimes unclear which of these steps are included in reported estimates.[46] In general, large-scale blue hydrogen production will be connected to the high-pressure natural gas transmission grid and therefore, methane emissions from final distribution to decentralized consumers (i.e. the low-pressure distribution network) should not be included in the quantification of climate impacts of blue hydrogen.

These challenges suggest that further research and data collection are required to develop a consistent and comprehensive inventory of our global natural gas system. In the meantime, an exploration of the variability in GHG emissions estimates is needed to understand the drivers of differences in GHG emissions from natural gas based hydrogen options.

3) Metrics for quantifying impacts on climate change

The evaluation of any methane-based mitigation option, in this case blue hydrogen, highly depends on the choice of GHG emission metric used to compare the impact of (fugitive) methane emissions to CO_2 emissions and other greenhouse gases. The most prominent metric is the Global Warming Potential (GWP) that compares the future global warming caused by an idealized pulse of emissions of a specific greenhouse gas. Importantly, the GWP is a metric that aggregates impacts over time, hence its estimation requires the specification of a time horizon over which future warming is taken into account and compared (e.g. 100 years in GWP100). Given the short atmospheric lifetime of methane of roughly twelve years,[55] the choice of time horizon has a strong impact on its GWP, and thus on the results of our analysis. This choice should be made in the context of the metric's application, and there is no general correct approach.

A key aspect in this respect is the ambition and focus of climate targets envisaged when evaluating climate mitigation options. A focus on stabilizing the climate at below 2°C warming in 2100 implies a longer time horizon such as that incorporated in the GWP100 index, which is commonly used in long-term scenario analysis and LCA. With the 2015 Paris Agreement[56] as well as increasing awareness about near-term climate damages[17] and potential tipping points[57], the scientific and political debate have shifted to limiting peak warming to close to 1.5°C.[58,59] As 1.5°C will likely be reached before 2050, this shift emphasizes the importance of avoiding warming in the next decades, which supports using shorter global warming potential time horizons such as GWP20 in addition to GWP100 and thus balancing short-term with longer-term emissions.

Discussion of implications on GHG emissions

All three elements discussed above are crucial regarding the impacts of natural gas based (blue) hydrogen production on climate change: only a low methane emission rate of the natural gas supply chain combined with a high CO_2 capture rate at the hydrogen production plant allows for substantial reductions of GHG emissions from a life cycle perspective. The methane emission rate becomes more important with a time horizon of 20 years instead of 100 years.

In Figure 1, we show life cycle GHG emissions of grey and blue hydrogen production considering the three major sources of variability. These include applying both GWP100 and GWP20, plant configurations representing high and low plant-wide CO_2 removal rates and variation of the methane emission rate of the natural gas supply chain between 0.2% and 8%. Hereby the selected CO_2 capture rate and the resulting plant-wide CO_2 removal rates do not represent absolute limits, but rather show an indicative range between low capture efficiency of the existing plants, focusing on the delivery of CO_2 as product for Enhanced Oil Recovery (EOR), and a relatively high capture efficiency that will be achieved under proper regulatory constraints or carbon taxes. The range of methane emissions represents their very large geographical variability, which reflects differences in extraction techniques and procedures, transportation of the natural gas and the related methane emissions due to flaring, venting, and leaks (see "methods" for details).

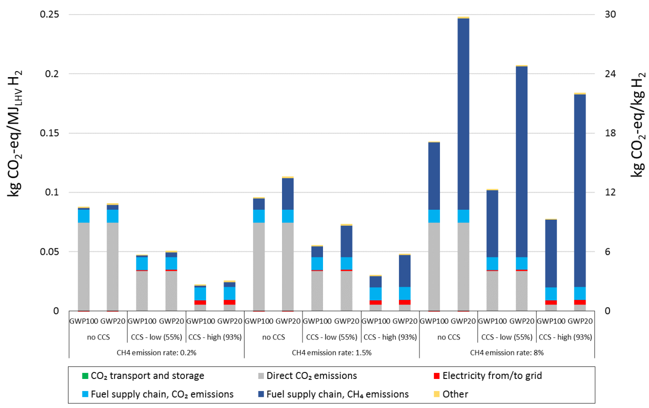


Figure 1: Impacts on climate change associated with the production of NG-based hydrogen with methane emission rates of 0.2%, 1.5%, and 8%, and two plant configurations with high and low CO_2 capture rates, applying both GWP100 and GWP20. Stacked bars show the origin of GHG emissions along the value chain. "CCS-low" and "CCS-high" indicate low and high overall plant-wide CO_2 removal rates of 55% and 93% at the hydrogen production plant, respectively (see discussion on hydrogen production technology).

The possible climate impacts of blue hydrogen vary accordingly: while the climate impact of adding CCS with the highest assumed methane emission rate (8%) – even with high capture rates – is limited to a reduction of GHG emissions by about 45% (GWP100) or 26% (GWP20), using natural gas from a supply chain with only 0.2% methane emission rate leads to a reduction of GHG emissions by about 75% (GWP100) or 72%

(GWP20) for a plant with a high CO_2 removal rate. This shows that for natural gas supply chains with low methane emissions, the choice of global warming potential time horizon makes very little difference, whereas it gains importance for higher leakage rates. Long natural gas supply chains – be it for import to Europe via pipeline from Russia or as liquefied natural gas from the US and the Middle East – generally increase GHG emissions due to methane leakage as well as CO_2 emissions associated with energy consumption along the chain. For natural gas supply chains with low methane emissions, CO_2 emissions associated with electricity supply become the main source of emissions in the high CO_2 capture cases. If low-carbon electricity were supplied, high capture cases could achieve emission reductions of up to 90% compared to hydrogen production without capture.

In Figure 2 we compare the impacts on climate change of grey and blue hydrogen with hydrogen from electrolysis, using renewable electricity or average grid electricity in Europe and the US – again for methane emission rates of natural gas supply chains up to 8% and for hydrogen plant configurations with low and high CO_2 removal rates. The figure reveals that, if methane emissions from natural gas supply are low and CO_2 capture rates high, blue hydrogen is comparable with green hydrogen in terms of impacts on climate change. There is, however, also substantial variability regarding climate impacts of green hydrogen, because GHG emissions associated with renewable power generation can vary from close to zero (run-of-river hydropower) to about 60 g CO_2-eq/kWh for solar photovoltaics (PV) at locations with rather low yields (e.g. in high northern latitudes),[60] with wind power usually at the lower end of this range. In this context, supplying electrolysis entirely with renewable wind and solar power without connection to the power grid requires installation of electricity storage (e.g. batteries) to cope with short-term intermittency of renewable generation,[61] which increases climate impacts of hydrogen from an LCA perspective. This increase has been quantified to be in the order of 10% for a given system configuration as investigated by Palmer et al.[10] However, since this is site-specific and depends on the configuration of the electrolysis system, we do not consider such aspects here.

In order to be competitive with green hydrogen in terms of climate impacts over the long-term, blue hydrogen should exhibit a life cycle GHG footprint of not more than 2-4 kg CO_2-eq/kg. This is only possible with high CO_2 removal rates and methane emission rates below about 1% (GWP100) or 0.3% (GWP20).

Life cycle GHG emissions of hydrogen from electrolysis using average grid electricity in Europe and the US are substantially higher than those of blue hydrogen up to very high methane emission rates from natural gas supply chains (in the order of 8% or above), even applying the 20 year time frame for global warming potentials. This indicates that electrolyzers that rely partially on grid electricity to increase operational hours or buffer intermittency of renewables will have a substantially higher GHG footprint of hydrogen production than off-grid systems.

Within (and beyond) the range of methane emissions from natural gas supply shown here, blue hydrogen is associated with lower GHG emissions than natural gas combustion. Relative reductions are substantial for high CO_2 capture rates, less so with low CO_2 capture rates.

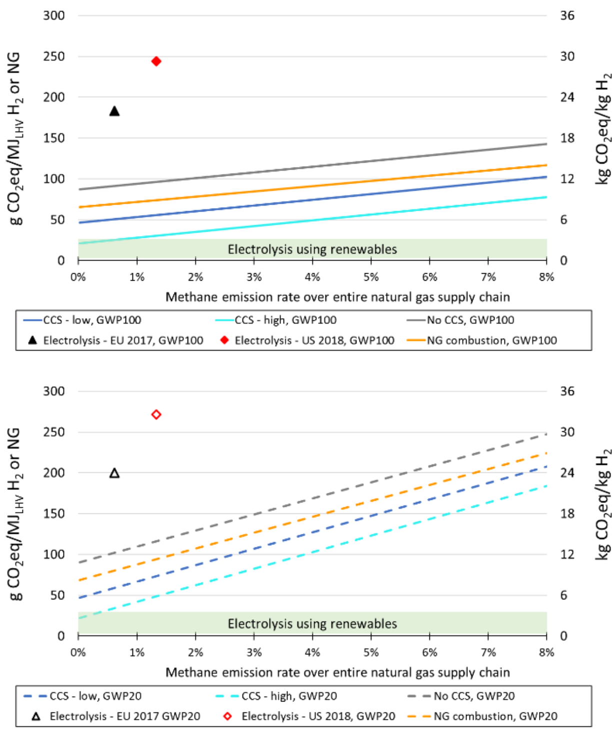


Figure 2: Impacts on climate change associated with the production of NG-based hydrogen as a function of the methane emission rate of NG supply chains for configurations with high ("CCS-high") and low ("CCS-low") CO_2 capture rates, applying both GWP100 (top) and GWP20 (lower). For comparison, the climate impacts of hydrogen produced via electrolysis using average grid electricity in Europe or the US (markers), or renewables (run-of-river hydropower, wind power or photovoltaics – green shaded area) are shown. Orange lines represent life cycle GHG emissions of NG combustion, which are also a function of NG supply chain methane emission rates.

Conclusions and recommendations

Our LCA of hydrogen production with CCS shows that the term "blue hydrogen" as such can only be taken as synonym for "low-carbon" hydrogen if two key requirements are met.

First, natural gas supply must be associated with low GHG emissions, which means that natural gas leaks and methane emissions along the entire supply chain, including extraction, storage, and transport, must be minimized. Relatively low emissions are probably already occurring in certain locations today. In the United States, emissions rates as low as 0.3-0.4% have been measured in one shale gas production region.[62] In several other countries, such as Norway, the UK and the Netherlands, natural gas supply chains have emission rates typically below 0.5%.[44,45,52] In contrast, several gas exporters like Russia, Algeria or Libya still have methane emission rates around or significantly higher than 2%[44,45,52] and will require substantial investments into their existing infrastructure and operations to reach comparably low methane emission levels. There is very large uncertainty on these emissions, which needs to be urgently addressed by improved measurement, reporting, and disclosure.

Second, reforming technology with high CO_2 capture rates must be employed. Our assessment is that CO_2 capture technology is already sufficiently mature to allow removal rates at the hydrogen production plant of above 90%. Capture rates close to 100% are technically feasible, slightly decreasing energy efficiencies and increasing costs, but have yet to be demonstrated at scale. Hydrogen production and CO_2 capture must be designed in an integrated way to minimize additional energy demand for CO_2 capture, as well as compression of hydrogen and CO_2. If this requires net electricity import, such demand should ideally be met using low-carbon electricity.

As long as the natural gas supply continues to have non-negligible methane emissions, the question whether using a global warming potential time horizon of 20 or 100 years is crucial for the evaluation of climate impacts of blue hydrogen. There is currently no conclusive answer to this question and we suggest testing the robustness of LCA results using different perspectives. However, to the extent that the focus of climate change mitigation shifts from long-term stabilization to carving the global temperature peak in the short to mid-term (e.g. around 2050), the importance of GWP20 and thus the relative impact of short-lived methane emissions increase.

Nevertheless, our main conclusion is that, if the above requirements are met, blue hydrogen can be close to green hydrogen in terms of impacts on climate change and can thus play an important and complementary role in the transformation towards net-zero economies. It is important to reiterate that no single hydrogen production technology (including electrolysis with renewables) is completely net-zero in terms of GHG emissions over its life cycle and will therefore need additional GHG removal from the atmosphere to comply with strict net-zero targets. Biomass-based hydrogen production represents an exception: adding CCS to wood gasification and reforming of biomethane can lead to net negative GHG emissions under certain circumstances.[6,7] However, sustainable biomass availability is likely to be limited.[63]

We conclude with some reflections on the main implications of this research.

First and foremost, policies and regulations applying to any type of hydrogen, such as GHG emission standards or emissions pricing, should consider the life cycle emissions of electricity for electrolysis and the natural gas supply chain for blue hydrogen. Only in this way can the whole system implications of such measures be fully understood. This means emission monitoring, verification, and reporting is required for emissions across the life cycle. A combination of public disclosure, GHG emissions pricing, public funding tied to GHG performance, and regulation would incentivise industry to produce clean hydrogen and to differentiate between natural gas suppliers. As European gas extraction has strongly declined over the last decades, with no trend reversal in sight, importing gas from countries with good monitoring practices and low methane emission rates should be prioritized from a European perspective. From a US perspective, and for other countries with primarily domestic supplies, best practices regarding minimizing methane emissions from the entire natural gas sector must be ensured.

Second, with the transformation towards highly-renewable energy systems, the direct use of renewable electricity has advantages both in terms of life cycle emissions and costs. Hydrogen most likely has an important role to play in providing a long-term, low-carbon storage vector[64] alongside decarbonising hard-to-abate sectors and applications, which can be prioritised according to climate impact, technical and economic viability.[65] For example, hydrogen as a feedstock for chemical processes certainly needs to be decarbonized through green and blue routes, whereas residential heating should preferably be electrified. In addition, a similar prioritisation applies across the spectrum of hydrogen provenance and it should be noted that natural gas with CCS may be a more sustainable route than hydrogen to decarbonize such applications as power generation.

We have demonstrated the conditions under which blue hydrogen has a comparable climate impact to green hydrogen. If these conditions are not met, then green hydrogen should be preferred. Both of these merit orders, for supply and end-use cases, require targeted policies aiming at setting efficient incentives.

Third, the temporal development of the energy system transformation needs to be borne in mind. Given the short- to medium-term scarcity of green hydrogen, blue hydrogen can play a role as a bridging technology supporting the uptake of hydrogen infrastructure and hydrogen end-use transformation. Blue hydrogen projects can be developed under the recommendations presented here without crowding out the global ramp-up of green hydrogen supply. As both blue and green hydrogen have innovation potential, policies and regulations should support both options independently until they are fairly mature and can compete (e.g. based on carbon pricing accounting for full life cycle GHG) – provided the above conditions for blue hydrogen are met and the necessary prioritization of demand areas is reflected.

Total costs of blue hydrogen are determined by the costs of achieving low leakage, high capture rates and permanent CO_2 storage, as well as natural gas prices, residual emissions and (explicit or implicit) carbon pricing. The competitiveness with green hydrogen depends on the cost reductions of electrolysis and renewable electricity, as well as green hydrogen availability compared with overall hydrogen demands. The future of blue hydrogen in a climate-neutral world therefore depends strongly on the extent to which residual emissions can be avoided or compensated for via carbon dioxide removal as well as on the availability of geological CO_2 storage sites.

Methods

We built our analysis upon the coupled process simulation and LCA model developed for our previous analysis[7] and refer to this paper for a detailed description. Some key elements of the present analysis, including updates compared to our previous work, are provided in the following.

Our reference product in the present work is "Hydrogen, gaseous, at 200 bar and with a purity of 99.9% or higher". We selected two example hydrogen production plant configurations (here called "CCS-low" and "CCS-high'') from our previous analysis,[7] they both include CO_2 capture from the synthesis gas using Methyl diethanolamine (MDEA) as absorbent. "CCS-low" represents configurations with low (i.e. ~55%) removal of plant-wide CO_2 emissions and corresponds to "SMR with CCS, HT, MDEA 90". "CCS-high" represents a configuration with high removal of plant-wide CO_2 emissions and corresponds to "ATR with CCS, HTLT, MDEA 98". The acronyms HT and LT indicate the use of high temperature water gas-shift only or the use of a low temperature and high temperature water gas-shift, the latter leading to a higher hydrogen and CO_2 content in the syngas. The numbers 90 and 98 represent the CO_2 capture rates of the capture unit that captures CO_2 from the produced synthesis gas. Plant-wide, overall CO_2 capture rates amount to 55% and 93% for the SMR and ATR configuration, respectively.[7] The lower overall capture rate of the SMR is a consequence of the fact that of the two sources of CO_2 present in an SMR, applying capture from syngas only excludes capturing the CO_2 from the natural gas (and reformer tail gas) combustion in the reformer furnace. A post-combustion unit would be needed to capture all the CO_2 in the flue gas. The ATR configuration does not include a reformer furnace as it is driven by heat produced in the reformer itself. It therefore allows recovering the majority of the direct CO_2 emissions from the syngas. The ATR does usually have a small fired heater that emits some CO_2, which is why with 98% capture from the syngas, 93% of the total plant-wide emissions are removed.[7]

Our LCA is based on detailed process modelling, which quantifies the overall energy demand of the hydrogen production plants designed to produce 9 metric tons of hydrogen per hour with and without CO_2 capture depending on the plant configuration and CO_2 capture rates. Antonini et al.[7] showed in Figure 2 that some configurations generate excess electricity, which – in line with common LCA procedures[18–20] – is assumed to substitute average grid electricity via an emission credit. Hydrogen production plant configurations that exhibit a negative electricity balance (including the compression of hydrogen to 200 bar) are supplied with average grid electricity. Our default location for hydrogen production is Europe – hence, average European electricity is used or substituted, corresponding to the "ENTSO-E" region in the ecoinvent database.[66] As the grid CO_2 intensity, e.g. in the US is higher than in Europe, electricity substitution and consumption would lead to higher CO_2 benefits and burdens, respectively.

The impacts on climate change of hydrogen from electrolysis are based on the analysis by Zhang et al.[15] Electricity demand for the PEM electrolyzer has been updated[10] and amounts to 55 kWh per kg of hydrogen (including compression from 25 bar at the electrolyzer to 200 bar). We used background LCI data from the ecoinvent database, v3.7.1, system model "allocation, cut-off by classification"[66] instead of v3.5 in the previous analysis. This includes the GHG-intensities of average grid electricity in Europe and the US, which represent technology market shares as well as imports and exports in 2017 and 2018, respectively. Europe is represented by the "ENTSO-E" supply region.[66]

The methane emission rate from the natural gas supply chain is defined as "(kg) methane emitted per (kg) natural gas delivered at high-pressure pipeline" in our analysis, i.e. the associated system boundaries include natural gas extraction from the ground (often referred to as "production"), gathering and processing, and high-pressure transmission. Hydrogen production plants are supplied by high-pressure natural gas pipelines, therefore, methane emissions from the local natural gas distribution grid are not considered.

Our quantification of life cycle GHG emissions of grey and blue hydrogen as well as natural gas combustion as a function of the methane emission rate of natural gas supply chains in Figures 1 and 2 builds upon new Life Cycle Inventory (LCI) data of natural gas extraction in countries supplying the European market[45] and associated supply chains.[44] These have been verified by the German "Institut für Energie- und Umweltforschung".[67] This average European natural gas supply exhibits a methane emission rate of about 1.3%. We modified this rate, choosing a lower bound of 0.2%, a representative mid-range value of 1.5%, and an upper bound of 8% to cover a realistic range of these emissions. We keep all other factors, such as energy demand for (re-)compression of natural gas, transport infrastructure demand and CO_2 emissions from flaring of natural gas constant, although we note that reductions in those emissions can likely be achieved as well. A methane emission rate of 0.2% corresponds to the goal of the Oil and Gas Climate Initiative[68] and emission rates below or around this target have been reported for natural gas supply from countries such as Norway, The Netherlands and the UK.[44,45] In contrast, a methane emission rate of around 8% has been reported for Libya[44,45] and some gas fields in the US,[50] which indicates high methane emissions at the gas extraction wells and/or a dysfunctional natural gas infrastructure in general. For geological storage of CO_2, it is assumed to be injected into a saline aquifer at a depth of 1000 m, which is connected to the hydrogen production plant with a 200 km pipeline. Variation of CO_2 storage depth and transport distance has shown minor impacts on LCA results for impacts on climate change.[69]

Author Contributions

Conceptualization: CB, MvdS; Formal analysis: KT; Funding acquisition: CB, EG; Investigation: CB, KT, MvdS; Methodology: KT; Software: KT; Supervision: CB, MvdS; Visualization: CB, KT; Writing – original draft: CB, FU, MvdS, RM, RP, STM; Writing – review and editing: all.

Conflicts of interest

There are no conflicts to declare.

Acknowledgements

Financial support was provided by the Kopernikus Project Ariadne (FKZ 03SFK5A) funded by the German Federal Ministry of Education and Research, the MIT Energy Initiative CCUS Low Carbon Energy Center and PSI's ESI platform. STM is supported, in part, with funding from the Canada First Research Excellence Fund.

References

1 European Commission, *A hydrogen strategy for a climate-neutral Europe*, Brussels, Belgium, 2020.

2 Bundesministerium für Wirtschaft und Energie (BMWi), *Die Nationale Wasserstoffstrategie*, Berlin, Germany, 2020.

3 USDOE, *Hydrogen Strategy - Enabling A Low-Carbon Economy*, Washington DC, 2020.

4 HM Government, *UK Hydrogen Strategy*, London, UK, 2021.

5 IEA, *Net Zero by 2050: A Roadmap for the Global Energy Sector. Revised version, July 2021*, 2021.

6 C. Antonini, K. Treyer, E. Mojoli, C. Bauer, M. Mazzotti, E. Moioli, C. Bauer, T. Schildhauer and M. Mazzotti, *Sustain. Energy Fuels*, 2021, **5**, 2602–2621.

7 C. Antonini, K. Treyer, A. Streb, M. van der Spek, C. Bauer and M. Mazzotti, *Sustain. Energy Fuels*, 2020, **4**, 2967–2986.

8 R. Bhandari, C. A. Trudewind and P. Zapp, *J. Clean. Prod.*, 2014, **85**, 151–163.

9 A. P. Borole and A. L. Greig, in *Biohydrogen*, 2019, pp. 485–512.

10 G. Palmer, A. Roberts, A. Hoadley, R. Dargaville and D. Honnery, *Energy Environ. Sci.*, 2021, **00**, 00.

11 Y. K. Salkuyeh, B. A. Saville and H. L. MacLean, *Int. J. Hydrogen Energy*, 2018, **43**, 9514–9528.

12 A. Susmozas, D. Iribarren, P. Zapp, J. Linβen and J. Dufour, *Int. J. Hydrogen Energy*, 2016, **41**, 19484–19491.

13 A. Valente, D. Iribarren and J. Dufour, *Sci. Total Environ.*, 2020, **728**, 138212.

14 X. Zhang, J. Witte, T. Schildhauer and C. Bauer, *Sustain. Energy Fuels*, 2020, **4**, 1427–1436.

15 X. Zhang, C. Bauer, C. Mutel and K. Volkart, *Appl. Energy*, 2017, **190**, 326–338.

16 R. W. Howarth and M. Z. Jacobson, *Energy Sci. Eng.*, 2021, **00**, 1–12.

17 V. Masson-Delmotte, P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P. R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J. B. R. Matthews, Y. Chen, X. Zhou, M. I. Gomis, E. Lonnoy, T. Maycock, M. Tignor and T. Waterfield, *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change,* Intergovernmental Panel on Climate Change (IPCC), 2018.

18 European Commission, *International Reference Life Cycle Data System (ILCD) Handbook - General guide for Life Cycle Assessment - Detailed guidance*, European Commission, Joint Research Centre, Institute for Environment and Sustainability, Luxembourg, 2010.

19 ISO, *ISO 14040. Environmental management - life cycle assessment - prinicples and framework*, International Organisation for Standardisation (ISO), 2006.

20 ISO, *ISO 14044. Environmental management - life cycle assessment - requirements and guidelines*, International Organisation for Standardisation (ISO), 2006.

21 Y. Khojasteh Salkuyeh, B. A. Saville and H. L. MacLean, *Int. J. Hydrogen Energy*, 2017, **42**, 18894–18909.

22 K. Liu, C. Song and V. Subramani, *Hydrogen and Syngas Production and Purification Technologies*, John Wiley & Sons, 2010.

23 IEAGHG, *Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS, 2017/02*, Cheltenham, 2017.

24 K. Aasberg-Petersen, I. Dybkjær, C. V. Ovesen, N. C. Schjødt, J. Sehested and S. G. Thomsen, *J. Nat. Gas Sci. Eng.*, 2011, **3**, 423–459.

25 Zero Emission Platform (ZEP), *Commercial Scale Feasibility of Clean Hydrogen*, 2017.

26 P. Moser, G. Wiechers, S. Schmidt, J. G. M. S. Monteiro, E. Goetheer, C. Charalambous, A. Saleh, M. van der Spek and S. Garcia, *Int. J. Greenh. Gas Control*, 2021, **109**, 103381.

27 Shell Canada Energy, *Quest Carbon Capture and Storage Project. ANNUAL SUMMARY REPORT -ALBERTA DEPARTMENT OF ENERGY: 2019*, 2020.

28 IEAGHG, *The carbon capture project at Air Product's Port Arthur hydrogen production facility - 2018/05*, 2018.

29 Progressive Energy, *BEIS Hydrogen Supply Programme - HyNet Low Carbon Hydrogen Plant Phase 1 Report for BEIS*, 2019.

30 H-vision, *Blue hydrogen as accelerator and pioneer for energy transition in the industry*, Rotterdam, 2019.

31 Air Products, Air Products Announces Multi-Billion Dollar Net-Zero Hydrogen Energy Complex in Edmonton, Alberta, Canada, https://www.airproducts.com/news-center/2021/06/0609-air-products-net-zero-hydrogen-energy-complex-in-edmonton-alberta-canada#/.

32 Suncor, Suncor and ATCO partner on a potential world-scale clean hydrogen project in Alberta, https://www.suncor.com/en-ca/newsroom/news-releases/2226977.

33 USDOE and NETL, *W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project*, 2020.

34 J. Mak, D. Heaven, D. Kubek, C. Sharp and M. Clark, *Synthesis Gas Purification in Gasification to Ammonia/Urea Complex*, 2004.

35 T. Katz, J. Nichols, V. Pattabathula and G. Colman, *Challenges in commissioning and operation of OASE® solvent systems*, 2018, vol. 59.

36 M. Saunois, A. R. Stavert, B. Poulter, P. Bousquet, J. G. Canadell, R. B. Jackson, P. A. Raymond, E. J. Dlugokencky and S. Houweling, *Earth Syst. Sci. Data*, 2020, **12**, 1561–1623.

37 IPCC, *Summary for Policymakers. In: Climate Change 2021:*

The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, 2021.
38 J. A. Littlefield, J. Marriott, G. A. Schivley and T. J. Skone, *J. Clean. Prod.*, 2017, **148**, 118–126.
39 M. Omara, N. Zimmerman, M. R. Sullivan, X. Li, A. Ellis, R. Cesa, R. Subramanian, A. A. Presto and A. L. Robinson, *Environ. Sci. Technol.*, 2018, **52**, 12915–12925.
40 D. Zimmerle, T. Vaughn, B. Luck, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, A. Marchese, L. Williams and D. Allen, *Environ. Sci. Technol.*, 2020, **54**, 7552–7561.
41 R. A. Alvarez, D. Zavala-Araiza, D. R. Lyon, D. T. Allen, Z. R. Barkley, A. R. Brandt, K. J. Davis, S. C. Herndon, D. J. Jacob, A. Karion, E. A. Kort, B. K. Lamb, T. Lauvaux, J. D. Maasakkers, A. J. Marchese, M. Omara, S. W. Pacala, J. Peischl, A. L. Robinson, P. B. Shepson, C. Sweeney, A. Townsend-Small, S. C. Wofsy and S. P. Hamburg, *Science (80-.).*, 2018, **361**, 186–188.
42 E. Chan, D. E. J. Worthy, D. Chan, M. Ishizawa, M. D. Moran, A. Delcloo and F. Vogel, *Environ. Sci. Technol.*, 2020, **54**, 14899–14909.
43 J. S. Rutherford, E. D. Sherwin, A. P. Ravikumar, G. A. Heath, J. Englander, D. Cooley, D. Lyon, M. Omara, Q. Langfitt and A. R. Brandt, *Nat. Commun.*, 2021, **12**, 1–12.
44 M. Bussa, N. Jungbluth and C. Meili, *Life cycle inventories for long-distance transport and distribution of natural gas*, Schaffhausen, Switzerland, 2021.
45 C. Meili, N. Jungbluth and M. Bussa, *Life cycle inventories of crude oil and natural gas extraction*, Schaffhausen, Switzerland, 2021.
46 E. A. Grubert and A. R. Brandt, *J. Clean. Prod.*, 2019, **222**, 760–767.
47 P. Balcombe, K. Anderson, J. Speirs, N. Brandon and A. Hawkes, *ACS Sustain. Chem. Eng.*, 2017, **5**, 3–20.
48 D. Burns and E. Grubert, *Environ. Res. Lett.*, 2021, **16**, 044059.
49 S. Schwietzke, G. Pétron, S. Conley, C. Pickering, I. Mielke-Maday, E. J. Dlugokencky, P. P. Tans, T. Vaughn, C. Bell, D. Zimmerle, S. Wolter, C. W. King, A. B. White, T. Coleman, L. Bianco and R. C. Schnell, *Environ. Sci. Technol.*, 2017, **51**, 7286–7294.
50 Y. Chen, E. D. Sherwin, E. S. F. Berman, B. B. Jones, M. P. Gordon, E. B. Wetherley, E. A. Kort and A. R. Brandt, *Submitt. to Nat. Energy*.
51 A. J. Turner, D. J. Jacob, J. Benmergui, J. Brandman, L. White and C. A. Randles, *Atmos. Chem. Phys.*, 2018, **18**, 8265–8278.
52 International Energy Agency (IEA), Methane Tracker 2021, https://www.iea.org/articles/methane-tracker-database.
53 D. Zavala-Araiza, D. T. Allen, M. Harrison, F. C. George and G. R. Jersey, *ACS Sustain. Chem. Eng.*, 2015, **3**, 492–498.
54 D. T. Allen, Q. Chen and J. B. Dunn, *Environ. Sci. Technol. Lett.*, 2021, **8**, 345–349.
55 T. F. Stocker, D. Qin, G.-K. Plattner, M. Tignor, S. K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P. M. Midgley, *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, 2013.
56 United Nations, *Paris Agreement*, 2015.
57 T. M. Lenton, J. Rockström, O. Gaffney, S. Rahmstorf, K. Richardson, W. Steffen and H. J. Schellnhuber, *Nature*, 2019, **575**, 592–595.
58 J. Rogelj, D. Huppmann, V. Krey, K. Riahi, L. Clarke, M. Gidden, Z. Nicholls and M. Meinshausen, *Nature*, 2019, **573**, 357–363.
59 J. Rogelj, P. M. Forster, E. Kriegler, C. J. Smith and R. Séférian, *Nature*, 2019, **571**, 335–342.
60 R. Frischknecht, P. Stolz, L. Krebs, M. de Wild-Scholten, P. Sinha, V. Fthenakis, H. C. Kim, M. Raugei and M. Stucki, *Life Cycle Inventories and Life Cycle Assessment of Photovoltaic Systems, International Energy Agency (IEA) PVPS Task 12, Report T12-19:2020*, 2020.
61 D. S. Mallapragada, E. Gençer, P. Insinger, D. W. Keith and F. M. O'Sullivan, *Cell Reports Phys. Sci.*, 2020, **1**, 100174.
62 Z. R. Barkley, T. Lauvaux, K. J. Davis, A. Deng, N. L. Miles, S. J. Richardson, Y. Cao, C. Sweeney, A. Karion, M. Smith, E. A. Kort, S. Schwietzke, T. Murphy, G. Cervone, D. Martins and J. D. Maasakkers, *Atmos. Chem. Phys.*, 2017, **17**, 13941–13966.
63 L. Rosa, D. L. Sanchez and M. Mazzotti, *Energy Environ. Sci.*, 2021, **14**, 3086–3097.
64 J. A. Dowling, K. Z. Rinaldi, T. H. Ruggles, S. J. Davis, M. Yuan, F. Tong, N. S. Lewis and K. Caldeira, *Joule*, 2020, **4**, 1907–1928.
65 F. Ueckerdt, C. Bauer, A. Dirnaichner, J. Everall, R. Sacchi and G. Luderer, *Nat. Clim. Chang.*, 2021, **11**, 384–393.
66 G. Wernet, C. Bauer, B. Steubing, J. Reinhard, E. Moreno-Ruiz and B. Weidema, *Int. J. Life Cycle Assess.*, 2016, **21**, 1218–1230.
67 A. Liebich, D. Münter, S. Ludmann and T. Fröhlich, *Review Statement. Validation of LCI data and reports of the project 'Update of life cycle inventory data for natural gas and crude oil supply to Switzerland and Europe with the reference year 2019'*, Heidelberg, Germany, 2021.
68 Oil and gas climate initiative, OGCI reports significant progress on aggregate upstream methane and carbon intensity targets, https://www.ogci.com/ogci-reports-significant-progress-on-aggregate-upstream-methane-and-carbon-intensity-targets/.
69 T. Terlouw, K. Treyer, C. Bauer and M. Mazzotti, *Environ. Sci. Technol.*, 2021, **55**, 11397–11411.

Appendix C

THE OXFORD INSTITUTE FOR ENERGY STUDIES

February 2022

The Potential Impact on the UK of a Disruption in Russian Gas Supplies to Europe

Introduction

The geopolitical tensions between Russia and Europe over the build-up of Russian troops on the Ukrainian border have generated concerns over the extent of Europe's reliance on Russian natural gas. There are fears that the supply of Russian gas to Europe could be disrupted, although for the reasons discussed below, we consider this eventuality unlikely. The purpose of this paper is to examine the possible consequences for the UK if such a disruption in Russian supplies to Europe were to occur.

We begin by considering the potential triggers for a disruption in Russian pipeline gas supplies to Europe, in order to highlight the different levels of disruption that could be associated with different triggers. In the second section, we examine the level of UK dependency on Russian gas, and place this dependency in the context of broader European dependence on Russian gas. In the third section, we analyse the potential impacts on the UK of such a disruption. Here we find that while the UK would be unlikely to face a physical shortage of supplies, the 'ripple effect' of price increases at hubs in continental Europe would be quickly replicated on the UK trading hub, the National Balancing Point (NBP).

In the fourth section, we consider the existing legal/regulatory frameworks for cooperation with regard to security of supply. While the position of the UK relative to neighbouring states remains uncertain with regard to post-Brexit agreements on the application of the solidarity provisions of the EU Security of Supply Regulation, pricing dynamics between the UK and neighbouring continental European markets would be sufficient to cause gas supplies to move from one market to another, albeit with the potential for some infrastructure bottlenecks. In the fifth (and final) section, we examine the potential impact of price increases on UK gas demand. This is particularly pertinent given that the large share of the domestic sector in total UK gas demand – where gas is used for space heating by 80 per cent of UK households – means that the UK is at its most vulnerable to supply shortages or price spikes during the winter. As a consequence, UK concern over the potential for an interruption to Russian gas supplies to Europe – and its impact on the UK in particular – will be especially heightened at present, and will remain so until the end of winter and the arrival of warmer weather.

What could be the triggers for disruption?

There are three potential reasons for a disruption in Russian gas supplies to Europe, each of which carries different implications for the potential extent of curtailment of Russian gas supplies to Europe. All three are predicated on Russia launching a military invasion of Ukraine.

Energy Insight: 109

Dr Jack Sharples, Dr Katja Yafimava,
Prof Jonathan Stern, and Mr Mike Fulwood, OIES

The first is the possibility of European and American sanctions against Russian gas exports (similar to those imposed on Iranian oil exports[1]). At present such sanctions against the purchase of Russian gas appear unlikely, with the sanctions currently threatened focusing on Russia's financial sector.[2] A notable exception is the Nord Stream 2 pipeline. The pipeline is now complete, with both of the parallel lines filled with technical gas by the end of December 2021, meaning that it is technically ready to flow.[3] However, the pipeline cannot begin operations until the operating company, Gas for Europe (a newly-created subsidiary of the pipeline project company, Nord Stream 2 AG), has received certification from the German regulator, the BundesNetzAgentur (BNetzA), to act as a pipeline system operator. In December 2021, the BNetzA stated that it would not make a decision on Nord Stream 2 in the first half of 2022.[4] [5] However, in late January 2022, the German Foreign Minister, Annalena Baerbock, told the German parliament that Western allies were working on a strong package of sanctions that included Nord Stream 2.[6]

A second possibility is the Russian government responding to Western sanctions by suspending the sale of Russian gas to Europe, forcing Gazprom to breach its long-term contracts with its European counterparties. Speaking anonymously to *Politico* on 31 January, one EU official stated, "as we are preparing for sanctions, we are also preparing for countersanctions, looking very closely at the energy sector".[7] This scenario also appears unlikely: while revenues from gas production and exports to Europe accounted for just over 6 per cent of Russian federal budget revenues in 2021, exports beyond the former Soviet Union accounted for 70 per cent of Gazprom's sales revenues in Q1-3 2021 (latest available data).[8] [9] [10] This would suggest an economic cost to Gazprom far beyond the economic cost to the Russian federal budget. However, if the Russian government were to suspend natural gas exports to Europe in this way, not only would its reputation as a gas supplier be in tatters, but European buyers of all Russian hydrocarbons would doubt the reliability of such supplies and begin to seek alternatives. Given the large share of Russia in European gas imports, such a displacement of Russian supplies in total European imports would take years, if it could even be achieved at all. Therefore, the impact of a major disruption in gas supplies to Europe would be to undermine the role of gas in the European energy mix in general, and potentially threaten its future even beyond the long-term decline in European gas demand forecast as part of a broader energy transition.

---

[1] Gladstone, R., 2018. Iran sanctions explained: U.S. goals, and the view from Tehran. *New York Times*, 5 November. [redacted]

[2] Strohecker, K., 2021. Explainer: How Western sanctions might target Russia. *Reuters*, 26 January. [redacted]

[3] Nord Stream 2 AG, 2021. Press Release, 29 December. h[redacted]

[4] Inverardi, M., and Steitz, C., 2021. Nord Stream 2 won't go live in first half of 2022, German regulator warns. *Reuters*, 16 December. [redacted]

[5] For detail on Nord Stream 2 certification process see Yafimava (2021) Nord Stream 2: on the verge of sending gas to Europe, OIES, November, and Yafimava and Fulwood (2021). German regulator's decision to suspend Nord Stream 2 certification: F.A.Q. OIES, November.

[6] BBC, 2022. Ukraine crisis: Nord Stream 2 pipeline could[redacted] h[redacted]

[7] Hernandez, A., 2022. 5 questions for the EU if Russia turns off the gas. *Politico*, 31 January. [redacted]

[8] Ministry of Finance of the Russian Federation, 2021. *Ежемесячная информация об исполнении федерального бюджета*. (Updated 27 December 2021). [redacted]

[9] Ministry of Finance of the Russian Federation. (2021). *Информация о дополнительных нефтегазовых доходах федерального бюджета - Сведения о формировании и использовании дополнительных нефтегазовых доходов федерального бюджета в 2018-2022 году* [updated 12 January 2022]. [redacted]

[10] Gazprom, 2021. *Annual Report 2020*[redacted] pages 121-124)

A third possibility is for the eruption of military conflict in Ukraine to cause damage to one of the gas pipelines that cross Ukraine to bring Russian gas to Europe. The two major pipelines that enter Ukraine from Russia at Sokhranovka and Sudzha are located to the north of the areas currently controlled by separatists, and so would only face possible damage if the zone of conflict expanded.

While the first scenario would suggest that all Russian gas flows to Europe remain as normal but that Nord Stream 2 is effectively cancelled, the second scenario would entail a complete cessation of Russian gas flows to Europe (both via pipelines and in the form of LNG), and the third scenario would imply localised disruption only to the flow of Russian gas via Ukraine. These scenarios, and the possible impact of a partial or complete curtailment of Russian gas supplies on the European market were analysed in the January 2022 edition of the OIES Quarterly Gas Review.11 Here it is sufficient to note that we consider it unlikely that a physical curtailment of Russian pipeline supplies to Europe would occur even in the event of a military conflict in Ukraine. At the same time, the uncertainties generated by such a conflict would have an immediate impact on European prices, due to concerns over the possible escalation of both the conflict, and the possibility that gas supplies could be affected. Indeed, we consider that uncertainties over the geopolitical situation are contributing to the current high gas prices in Europe, in addition to the fundamental physical market tightness.

How dependent are Europe and the UK on Russian gas?

In 2021, imports provided 87 per cent of the gas supply[12] to Europe (the EU plus UK), while European production only provided 13 per cent of supply. In short, Europe is heavily import-dependent. Russia was the largest external supplier, with pipeline deliveries from Russia accounting for 31 per cent of total European supply and Russian LNG deliveries accounting for a further 4 per cent.[13] [14] Therefore, natural gas produced in Russia accounted for 35 per cent of all the gas supplied to the European market in that year. Generally speaking, it is the EU member states in North-Eastern Europe, Central Europe, and South-Eastern Europe that have the greatest dependence on Russia and the EU member states furthest west that have the lowest levels of dependency on Russia to meet their gas import needs.

Between 2017 and 2021, UK gas demand[15] was generally stable at 80 bcm per year, with the exception of 2020, when demand declined to 76 bcm.[16] [17]

---

[11] Fulwood, M., Sharples, J., and Yafimava, K., 2022. *OIES Quarterly Gas Review: Impact of Conflict in Ukraine and the Short-Term Gas Markets*[redacted]

[12] Gas supply is defined as production plus pipeline and LNG imports. Storage injections and withdrawals are not included in this calculation

[13] ENTSOG, 2022. *Transparency Platform*[redacted]

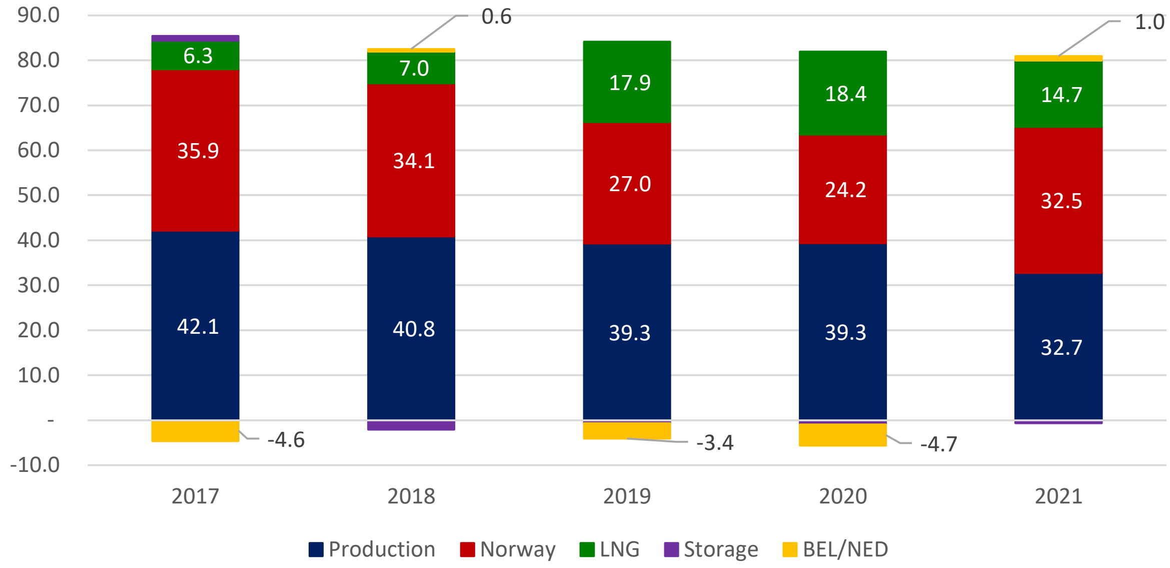
[14] Kpler, 2022. *LNG Platform*. h[redacted] [subscription required]

[15] Gross production plus net imports and stock change

[16] UK Government, 2022. *Energy trends: UK gas - Natural gas production and supply (ET 4.2 - monthly).* https://www.gov.uk/government/statistics/gas-section-4-energy-trends

[17] UK Government, 2022. *Energy trends: UK gas - Natural gas imports and exports (ET 4.3 - monthly).* https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Figure 1: UK Natural Gas Supplies by Source (billion cubic metres per year)



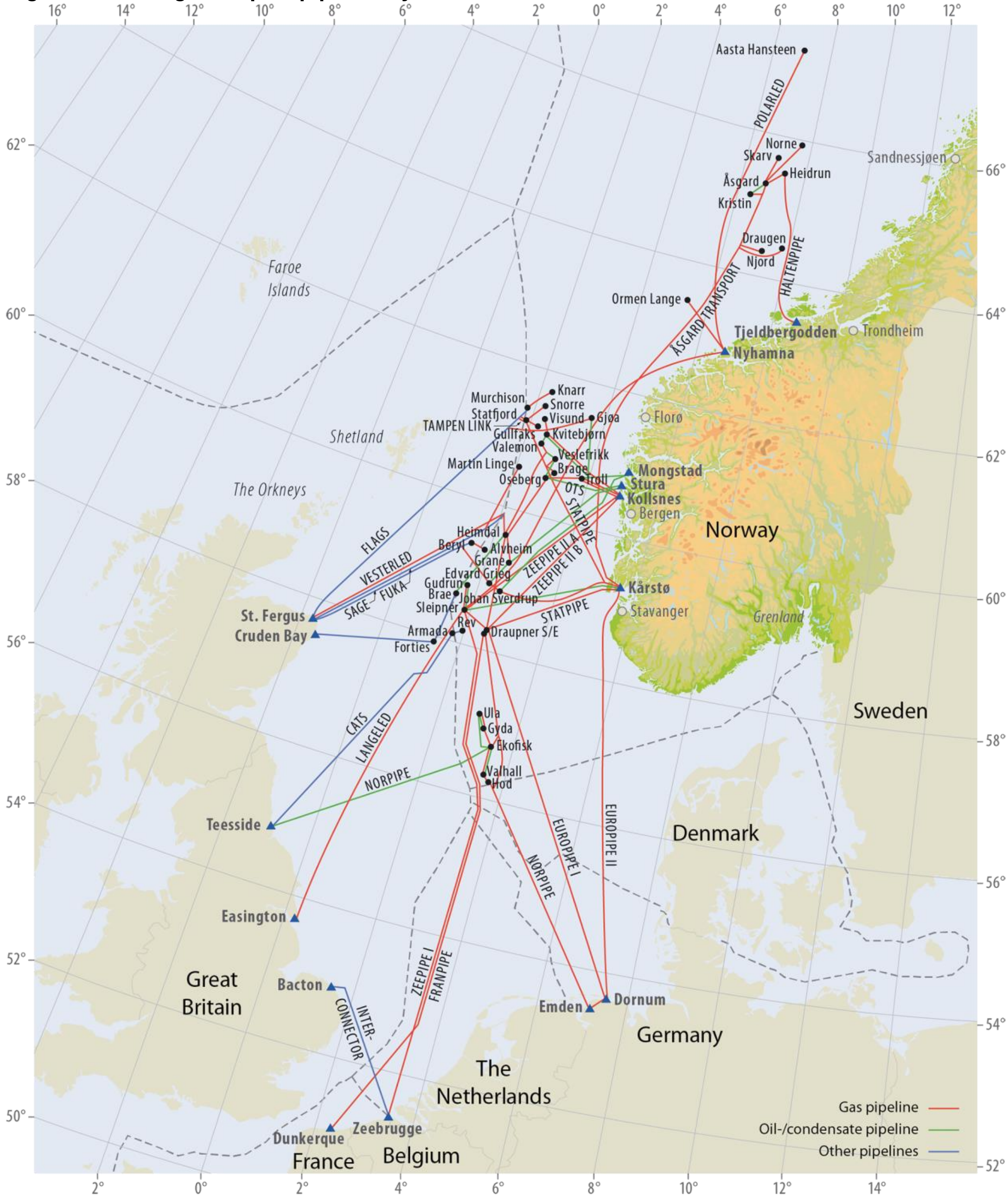
Source: Data from UK government.[18] Note that the net storage withdrawals in 2018-2021 are associated with the withdrawal of cushion gas from the Rough storage facility, which formally closed in 2017.[19] Note that BEL/NED refers to the iUK Interconnector between the UK and Belgium (BEL) and the Bacton-Balgzand Line (BBL) interconnector between the UK and the Netherlands (NEL), both of which are discussed below.

In terms of meeting that demand, the UK benefits from its own production and pipeline connections to Norway, which is the second-largest external supplier to the European market after Russia. However, as Figure 1 shows, UK gas production continues to gradually decline, and so would not be able to ramp up substantially in response to a physical shortage of import supplies to the UK. Pipeline imports from Norway are sourced via the Langeled pipeline, which makes landfall at Easington (England) and the Vesterled and FLAGS pipelines, which make landfall at St Fergus (Scotland). As illustrated in Figure 2, St Fergus also serves as a landfall point for the UK's own production in the northern part of the North Sea. The capacities of the Langeled, Vesterled, and FLAGS pipelines are given in Figure 3 (below).

The limitation on UK imports of Norwegian gas is not pipeline infrastructure, but Norwegian production and the fact that a significant proportion of that production is exported to France, Belgium, the Netherlands, and Germany via five pipelines (Franpipe, Zeepipe, Norpipe, Europipe I, and Europipe II), with the routes of those pipelines illustrated in Figure 3 (below) and the capacities of those pipelines discussed later (see Figure 6). With Norwegian production currently at maximum capacity, the UK could only receive more pipeline gas from Norway if some of those volumes were diverted away from continental Europe.

[18] UK government, 2022. *Energy Trends: UK gas*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends
[19] Argus, 2017. Centrica plans to close Rough gas storage site: Update. *Argus Media*, 20 June. https://[redacted]

Figure 2: Norwegian export pipeline system



Source: Norwegian Petroleum Directorate (NPD)20

[20] NPD, 2022. *Illustrations and quick downloads*. [redacted]

Figure 3: Daily and annual capacities of imports from Norway by pipeline and LNG by terminal

	Million cubic metres per day (mmcm/d)	Billion cubic metres per annum (bcma)
Pipelines from Norway	**151**	**55.1**
- Langeled	*72*	*26.3*
- Vesterled	*37*	*13.5*
- FLAGS	*42*	*15.3*
LNG Import Terminals	**132**	**48.1**
- Isle of Grain	*53*	*19.5*
- South Hook	*58*	*21.0*
- Dragon	*21*	*7.6*

Source: Data from ENTSOG Transparency Platform,[21] Gassco,[22] Gas Infrastructure Europe,[23] and Kpler[24]

In 2017, the combination of UK production and pipeline imports from Norway accounted for 97 per cent of UK gas consumption. By 2021, that figure had fallen to 81 per cent, while the ongoing decline in UK gas production was offset by higher LNG imports at the UK's three main import terminals: Isle of Grain, Dragon, and South Hook.[25]

The Isle of Grain terminal in South-Eastern England was launched in 2005, and is wholly-owned by the UK pipeline system operator, National Grid. It has the capacity to import up to 14.3 million tonnes per year (mtpa) of LNG, the equivalent of 19.5 billion cubic metres of natural gas (almost one quarter of UK gas demand). It also has storage tanks capable of holding 1 million cubic metres (mmcm) of LNG, the equivalent of 615 mmcm of natural gas. Since its launch, the maximum volume imported into Isle of Grain in a calendar year was 5.8 mt (2011), while imports in 2021 totalled 4.3 mt.[26] Import capacity at Isle of Grain is held under long-term capacity contracts by Centrica, TotalEnergies, Sonatrach, E.ON, and Pavilion Energy.[27]

The South Hook and Dragon LNG terminals are both located in the port of Milford Haven, in South-West Wales, and both were launched in 2009. The South Hook terminal is owned by Qatar Energy (67.5 per cent), ExxonMobil (24.15 per cent), and TotalEnergies (8.35 per cent).[28] The primary capacity at South Hook is owned by South Hook Gas Company Ltd, whose shareholders are Qatar Petroleum (70 per cent) and ExxonMobil (30 per cent).[29] The terminal has an annual import capacity of 15.4 mtpa (equivalent to 21 bcm per year of natural gas), and the capacity to store 775,000 m3 of LNG, equivalent to 476 mmcm of natural gas. The peak annual import into South Hook was achieved in 2011 (10.6 mt), while imports in 2021 totalled 5.24 mt (just over half the terminal capacity).

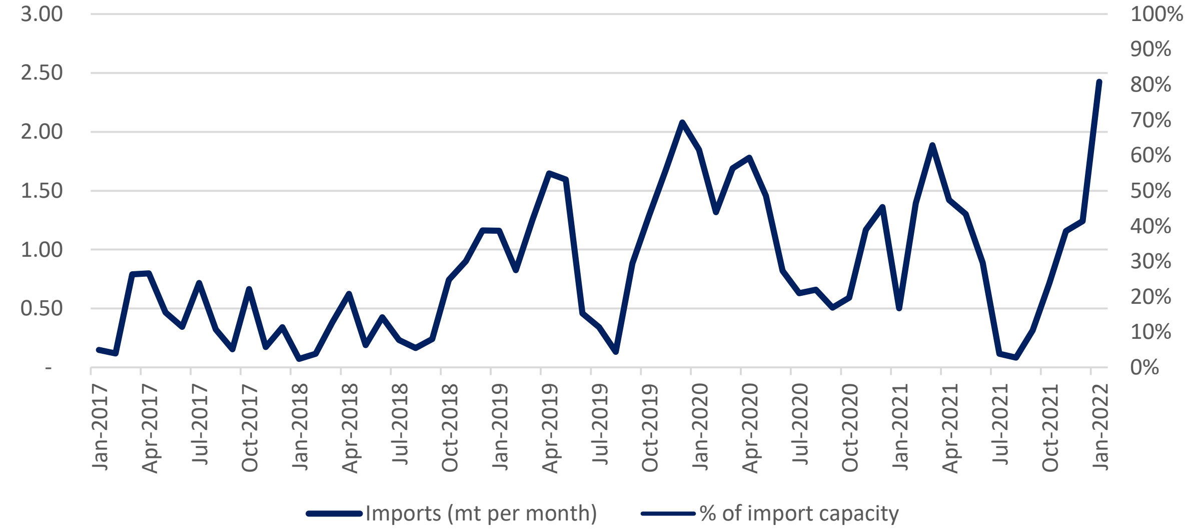
The Dragon LNG terminal is owned by Shell (50 per cent) and Ancala LNG (50 per cent), the latter being an investor focused on mid-market size infrastructure assets. The import capacity of the terminal is 5.6 mtpa, equivalent to 7.6 bcm per year of natural gas. That capacity is held by Shell (50 per cent) and Petronas (50 per cent).[30] The storage tanks at Dragon LNG can hold 320,000 m3 of LNG,

[21] ENTSOG, 2022. *Transparency Platform*. h[redacted]
[22] Gassco, 2022. *Pipelines*. https://www.gassco.no/static/transport-2.0/
[23] Gas Infrastructure Europe, 2019. *LNG Database (May 2019)*. https://www.gie.eu/transparency/databases/
[24] Kpler, 2022. *LNG Platform*.[redacted] [subscription required]
[25] Access regimes to all three UK's LNG terminals are analysed in Yafimava (2020), 'Finding a home' for global LNG in Europe: understanding the complexity of access rules for EU import terminals, OIES, January.
[26] Kpler, 2022. *LNG Platform*.[redacted] required]
[27] National Grid, 2022. *Grain LNG: Who we are*. https://www.nationalgrid.com/national-grid-ventures/grain-lng/who-we-are
[28] South Hook LNG, 2022. *Our shareholders*. h[redacted]
[29] South Hook LNG, 2022. *Terminal*[redacted]/
[30] Dragon LNG, 2022. *About us*.[redacted]

equivalent to 197 mmcm of natural gas. Peak annual imports reached 2.42 mt (in 2020), while imports in 2021 totalled 1.83 mt (around one-third of the terminal's annual capacity).

Therefore, total UK LNG import capacity on an annual basis is 35.36 mtpa, or 2.9416 mtpa per month. Between January 2017 and January 2022, total LNG imports at these three terminals exceeded 66 per cent of their monthly import capacity only twice: in December 2019 (69 per cent) and January 2022 (81 per cent).[31]

Figure 4: UK LNG imports (million tonnes) and imports as a share of nominal import capacity



Source: Data from Kpler LNG Platform

There are several reasons why the UK LNG import terminals do not regularly operate closer to full capacity on a monthly basis. Firstly, UK gas supply is predominantly based on UK production and pipeline imports from Norway, leaving LNG imports as 'third choice', and unlikely to increase in volume to displace UK and Norwegian supplies on a regular basis until those sources of supply begin to dwindle. Secondly, the UK lacks gas storage capacity relative to overall demand. Europe as a whole (EU plus UK) has roughly 105 bcm of gas storage capacity, which equates to 22 per cent of annual consumption. By contrast, the UK has just 0.9 bcm of gas storage relative to around 80 bcm of annual demand. Instead of importing substantial amounts of LNG in the summer and placing it into storage for the winter, the UK relies on swing in UK production and Norwegian pipeline supplies, 'topped up' with fluctuating monthly LNG imports. Finally, UK gas production had already peaked when these LNG terminals were launched, with the long-term view that as UK gas production declines and the UK becomes more import-dependent, LNG supplies will be needed to fill the gap. The experience of the last several years suggests that the UK would normally have substantial capacity to increase LNG imports in a time of need. However, if imports continue at the rate seen in January 2022, the spare import capacity will be relatively limited for the short-term future.

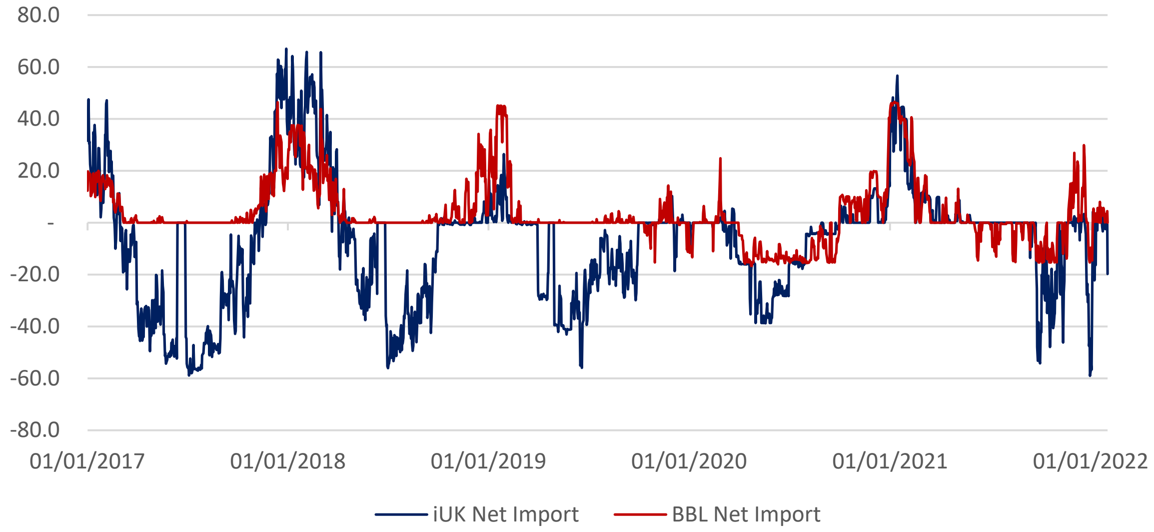
Finally, the UK is physically connected to the continental European market by two interconnector pipelines under the English Channel: The Interconnector from Bacton (UK) to Zeebrugge (Belgium), and the Bacton-Balgzand Link (BBL) from Bacton (UK) to Balgzand (Netherlands). The Interconnector between the UK and Belgium has 25.5 bcm of bi-directional technical capacity, equivalent to 70 mmcm/d.[32] Since 1 January 2017, the largest daily volume exported from the UK to Belgium was 59 mmcm, on 31 December 2021.[33] The BBL has 45 mmcm/d (16.4 bcma) of capacity from the

[31] Kpler, 2022. *LNG Platform*. [redacted] [subscription required]
[32] Reuters, 2020. Belgium-UK gas interconnector revises capacity. *Reuters*, 30 November [redacted]

Netherlands to the UK and 15 mmcm/d (5.5 bcma) of reverse flow capacity from the UK to the Netherlands.[34] The BBL most recently operated at full capacity from the UK to the Netherlands on 30 and 31 December 2021.[35] However, over the past several years the interconnections between the UK and Belgium/Netherlands have usually shipped gas from the UK to Belgium/Netherlands in the summer and to the UK in the winter. By doing so, they take advantage of the UK being supply-long in the summer due to its own production and pipeline imports from Norway, and the UK effectively making use of continental gas storage stocks in the winter, in the absence of such seasonal gas storage in the UK. This seasonality of flows on the Interconnector and BBL are illustrated in Figure 5, below. Here it should be noted that the unusual pattern of net exports from the UK to Belgium and the Netherlands is strongly influenced by the benchmark trading hub in North-Western continental Europe (the TTF) being at a premium to the UK National Balancing Point (NBP), so the additional LNG volumes imported into the UK were being shipped onwards to the continent.

As the annual figures in Figure 1 show, net annual trade between the UK and continental Europe is far below the combined annual capacity of the Interconnector and BBL. However, the value of these pipelines is in short-term and seasonal balancing with flows in both directions. For example, in 2021, the Interconnector shipped approximately 1.8 bcm from the UK to Belgium, and 1.8 bcm from Belgium to the UK, while the BBL shipped 2.4 bcm from the Netherlands to the UK and 0.9 bcm from the UK to the Netherlands.[36]

Figure 5: Flows on the Interconnector and BBL (million cubic metres per day)



Source: ENTSOG Transparency Platform. Note: Positive values indicate UK imports and negative values indicate exports from the UK to continental Europe.

Overall, UK dependence on Russian gas supplies is limited. The UK has no direct pipeline connection to Russia, and imports of LNG from Russia rose from virtually zero in 2017 to 2.4 mt (equivalent to 3.25 bcm) in 2021, meaning that Russian LNG accounted for 4 per cent of total UK gas supply in 2021.[37] However, any disruption in Russian pipeline gas deliveries to the European market would almost inevitably cause prices on European trading hubs to surge. This surge would affect the dynamics of pipeline movements both between the UK and Norway and between the UK and continental Europe, while simultaneously influencing the dynamic of LNG imports into Europe.

[34] BBL Company, 2022. *BBL Company - Transport gas in both directions between the Netherlands and the United Kingdom*. [redacted]

[35] ENTSOG, 2022. *Transparency Platform*. [redacted]]

How would the UK be impacted by a disruption in Russian gas supplies to Europe?

As we discussed in the most recent OIES Quarterly Gas Review,[38] any disruption to Russian pipeline gas supplies to Europe would almost certainly cause day-ahead and front-month hub prices in continental Europe to rise substantially. We concluded that across 2022 as a whole, pipeline imports would be lower than in 2021 (due to loss of Russian supply and the inability of other pipeline suppliers to increase their exports to Europe beyond current volumes), LNG imports would rise (with cargoes being attracted by higher prices), and storage stocks would be drawn down more rapidly in late winter and replenished to a lesser extent in summer 2022, meaning that Europe would potentially start winter 2022/23 with less gas in storage than at the start of winter 2021/22.

From a UK perspective, the first impact would be that prices on continental European hubs would rise more rapidly than those on the NBP. This would lead to traders buying gas on the NBP, exporting it from the UK to continental Europe via the Interconnector and BBL, and then re-selling those volumes on European hubs. If UK gas demand remained constant, this drawing away of supplies would tighten the UK market and cause prices on the NBP to rise, until they reached approximate parity with hub prices in continental Europe, and the commercial motivation to move gas from the UK to the European continent subsided.

At the same time, producers of gas at offshore fields in Norway that sell their gas into the spot market, and have optionality between selling to the UK and selling to continental Europe (with delivery via one of the five pipelines connecting Norway with France, Belgium, the Netherlands, and Germany noted earlier), could shift those sales to continental Europe for as long as continental European prices remained at a premium to those on the NBP.

The physical limitation to this movement of gas away from the UK to continental Europe would be the physical capacities of the Interconnector and BBL on the one hand, and the physical capacities of the pipelines bringing Norwegian gas to continental Europe on the other. As noted earlier, the Interconnector and BBL reached full capacity for the shipment of gas from the UK to Belgium/Netherlands on 31 December 2021. However, in the second half of January 2022, the movements were generally 2-5 mmcm/d of imports to the UK via the BBL and similar volumes moving between the UK and Belgium, with a change in direction every few days.

In terms of Norwegian pipeline deliveries to continental Europe, there is currently little spare capacity to increase such deliveries. The Franpipe (to France) and Zeepipe (to Belgium), have been operating at full capacity since mid-December 2021. The three pipelines (Norpipe, Europipe I, and Europipe II) that supply Germany and the Netherlands operated at almost their combined full capacity in January 2022. The capacities of these pipelines are given in the table below.

[38] Fulwood, M., Sharples, J., and Yafimava, K., 2022. *OIES Quarterly Gas Review: Impact of Conflict in Ukraine and the Short-Term Gas Markets.* [redacted]

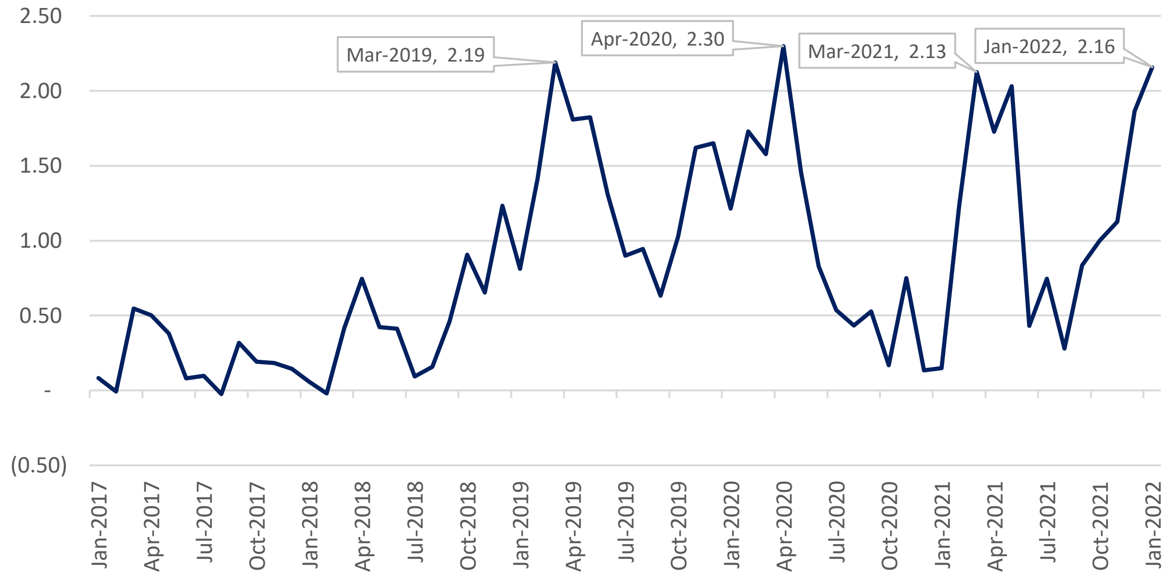
Figure 6: Capacities of pipelines bringing Norwegian gas to continental Europe

	Million cubic metres per day (mmcm/d)	Billion cubic metres per annum (bcma)
Franpipe to Dunkerque (France)	54.8	20.0
Zeepipe to Zeebrugge (Belgium)	42.2	15.4
Norpipe to Emden (Germany)	44.4	16.2
Europipe I to Dornum (Germany)	45.7	16.7
Europipe II to Dornum (Germany)	71.2	26.0
Total	**258.3**	**94.3**

Source: Gassco.[39] Note that these numbers are in standard cubic metres.

If this situation were to remain as it stands (at the beginning of February 2022), additional supplies to North-Western continental Europe would not be possible from Norway by pipeline, but only directly to the LNG terminals in France, Belgium, and the Netherlands, or to LNG terminals in the UK for regasification and re-export via the Interconnector and BBL.

Figure 7: Combined net LNG Imports to Dunkerque, Zeebrugge, and Gate Rotterdam (million tonnes per month)



Source: Data from Kpler LNG Platform

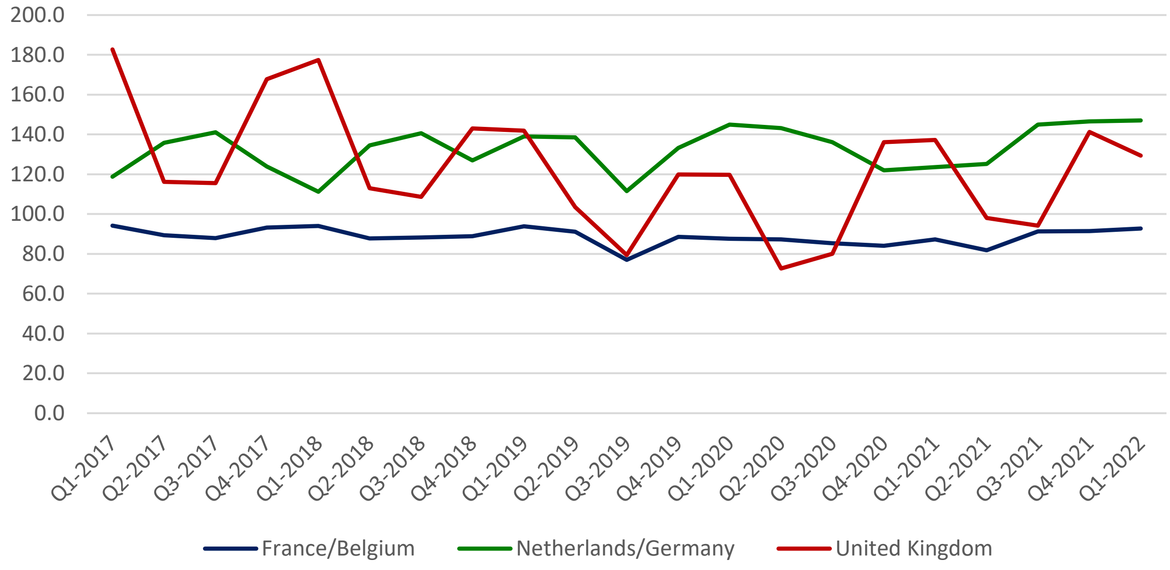
The Dunkerque LNG import terminal has an annual import capacity of 9.6 mtpa of LNG, which equates to 0.8 mt of LNG per month. The Zeebrugge LNG import terminal has an annual import capacity of 6.6 mtpa of LNG, equivalent to 0.55 mt of LNG per month. Finally, the GATE Rotterdam LNG import terminal has an annual import capacity of 8.8 mtpa of LNG, equivalent to 0.73 mt of LNG per month.[40] Together, these three import terminals have a combined nameplate import capacity of 25 mt of LNG per year, or 2.08 mt of LNG per month. In fact, the record for monthly imports into these three terminals

[39] Gassco, 2022. *Transport – pipelines*.[redacted]
[40] Kpler, 2022. *LNG Platform*.[redacted] required]

combined was 2.30 mt in April 2020 – 11 per cent above the nameplate capacity. In January 2022, combined net imports into these three terminals reached 2.16 mt, up from 1.86 mt in December 2021.[41]

Therefore, not only were Norwegian pipelines to North-Western continental Europe operating at full capacity in January 2022, but so were the LNG import terminals serving that regional market. If that were to be the situation when a disruption of Russian supplies to that market occurs, the only way to deliver more to that regional market would be to import LNG into the UK and re-export it via the Interconnector and BBL. Although the current situation represents mid-winter flows, there is generally limited spare capacity on the pipelines from Norway to continental Europe even in summer. As the graph below illustrates, the quarterly average gas flows from Norway to France and Belgium combined since January 2017 have generally stayed within a corridor of 82-94 mmcm/d, regardless of season, meaning that the flows in Q2 and Q3 and not usually substantially lower than winter flows in Q1 and Q4. There is slightly greater variation in flows to the Netherlands and Germany combined, but the variation is not overtly seasonal. It is only in flows to the UK (landing at St Fergus and Easington) that we see substantial seasonal variation that would suggest greater spare capacity during the summer months.[42] Therefore, even if a disruption in Russian supplies to North-Western Europe were to occur during the summer months, it is unlikely that there would be substantial spare capacity on the Norwegian pipelines that serve that regional market.

Figure 8: Quarterly average pipeline gas flows from Norway to different markets (mmcm per day)



Source: Data from ENTSOG Transparency Platform, graph by the author.

The limits to increased UK LNG imports for immediate re-export would be threefold. Firstly, as noted in Figure 4, earlier, UK LNG import terminals were already at 80 per cent of their nominal monthly import capacity in January 2022, while send-out from the three UK LNG import terminals to the national gas grid operated at around two-thirds of capacity, a new record. If the interruption in Russian supplies to Europe were to occur before the end of winter (i.e., before the end of March), the UK faces a slight bottleneck in its ability to receive and regasify additional LNG cargoes. In January 2022, the nominal spare import capacity amounted to 0.6 mt of LNG per month (equivalent to 816 mmcm of natural gas

[41] Kpler, 2022. *LNG* [redacted] [subscription required]

[42] Here it should be noted that the gas flows into the UK at St Fergus and Easington also include UK offshore production that is brought ashore at those terminals. The gas from UK production and imports from Norway cannot be distinguished, but an estimate based on UK government data for UK imports from Norway suggests that over 90 per cent of flows at Easington are imports from Norway via the Langeled pipeline, while flows at St Fergus are more evenly divided between UK production and imports from Norway.

per month, or just over 27 mmcm/d). The send-out of 105 mmcm/d relative to the send-out capacity of 147 mmcm/d left around 42 mmcm/d of spare send-out capacity (around 1.3 bcm per month, equivalent to 15.6 bcm per year).[43]

Secondly, the capacity to deliver that imported LNG (along with pipeline gas imported from Norway) onward to continental Europe could be constrained if the Interconnector and BBL were already operating at full capacity from the UK to Belgium and the Netherlands, as they were at the end of December 2021. As noted earlier, this was an unusual situation given that these two pipelines usually bring gas from continental Europe to the UK during the winter. The reason is market tightness in North-Western Europe, due to lower Russian flows to the region (particularly on the Yamal-Europe pipeline via Belarus and Poland). This is partly due to Gazprom not offering volumes to the European spot market and partly due to European counterparties possibly not nominating their full contractual volumes and instead seeking volumes from storage or the prompt spot market, due to a price difference between prompt hub prices and the hub-indexed prices in Gazprom's long-term contracts. As a result, the TTF day-ahead price maintained a slight premium over the NBP day-ahead price in December 2021 and January 2022. That differential was at its widest in the period 29-31 December,[44] which caused gas to flow from the UK to continental Europe via the Interconnector and BBL. This situation – of the market of North-Western continental Europe being tighter than the UK market, leading to a TTF premium over NBP – is likely to persist as long as Russian physical flows to the region remain lower than usual. In this regard, January 2022 could be seen as a small-scale example of how flows might look in the event of a curtailment in Russian physical flows to North-Western Europe, with the UK importing more LNG than it needs and then re-exporting those volumes to Belgium and the Netherlands via the Interconnector and BBL pipelines.

Finally, the increase in LNG imports into the UK – either for domestic consumption or re-export – would only be possible if there were supplies available on the global LNG market. This would be influenced by both the global supply-demand balance, and the impact of higher prices attracting cargoes from the spot market to other European import terminals. For example, if a localised disruption in Russian gas supplies to Europe via Ukraine impacted deliveries of Russian gas to northern Italy, prices on the Italian hub (*Punto di Scambio Virtuale*, or PSV) would surge to attract LNG cargoes to Italy. If the disruption was broader and affected Russian deliveries via non-Ukrainian routes as well, attempts to attract LNG cargoes to the UK for regasification and re-export to the continent would face competition from LNG terminals across Europe. More dramatically, if such a scenario was to occur during a cold spell in Asia, European LNG buyers would face stiff competition for cargoes, perhaps even leading to a bidding war. In such a dramatic context – the substantial curtailment of all Russian pipeline gas flows to Europe at the same time that strong LNG demand in North-East Asia limited the availability of LNG for Europe – the result would surely be the limitation of European gas consumption outside protected sectors (such as households and hospitals), and the sharing of gas across borders.

Existing legal/regulatory frameworks: security of supply cooperation provisions

The EU Security of Supply Regulation

When the UK was an EU Member State it was bound by the 2017 EU Security of Supply Regulation – a legal instrument aimed at safeguarding 'the security of gas supply in the Union by ensuring the proper and continuous functioning of the internal market' in natural gas, by allowing for 'exceptional measures to be implemented when the market can no longer deliver the gas supplies required, including solidarity measures of a last resort'.[45] The UK was part of the two North Sea regional groups: one, associated with a loss of Norwegian supply (which also included Belgium, Denmark, Germany, Ireland, Spain,

[43] For a more detailed discussion of LNG import capacity, please see the Appendix to this paper
[44] Pricing data from Argus (subscription required)
[45] Article 1.

France, Italy, Luxembourg, Netherlands, Portugal, and Sweden), and another, associated with a loss of UK supply (which also included Belgium, Germany, Ireland, Luxembourg, and Netherlands). These groups served as the basis for risk associated cooperation in line with preventive and emergency plans, with the latter to be activated in a crisis.

The Regulation introduced the solidarity measure under which a Member State, which is directly connected to a Member State that has requested the application of such measure, is obliged to: 'take the necessary measures to ensure that the gas supply to customers other than solidarity protected customers in its territory is reduced or does not continue to the extent necessary and for as long as the gas supply to solidarity protected customers[46] in the requesting Member State is not satisfied'.[47] In other words, the Regulation obliged a Member State to reduce supplies to its own non-household customers to enable supplies to (mostly) household customers of another Member State, which requested the solidarity measure. This suggests that the UK, being directly connected (via interconnectors) to three EU Member States – Ireland, Belgium, and the Netherlands – would be obliged to apply the solidary measure to all of them, should they request it. Conversely, all three of these countries would be obliged to provide supplies to the UK, should it make such a request (not relevant for Ireland, which receives a significant share of its gas supply from the UK both directly and via transit).

As the UK has left the EU, it is no longer bound by the Security of Supply Regulation, which means that the UK is not obliged to supply these Member States and vice versa. The Regulation stipulates that `a Member State shall also provide the solidarity measure to another Member State to which it is connected via a third country unless flows are restricted through the third country',[48] which suggests that the EU is still obliged to provide these measures to Ireland but only insofar as the UK does not restrict transit flows through its territory. There is a provision for the Gas Coordination Group (consisting of representatives of the Member States, ACER,[49] ENTSOG,[50] the industry, and customers, chaired by the European Commission) to coordinate between the EU and third countries in an emergency, but it has no binding effect on the latter.[51]

Solidarity can be requested by a Member State in a crisis, with the highest level of crisis (emergency) being defined as a situation 'where there is exceptionally high gas demand, significant disruption of gas supply or other significant deterioration of the gas supply situation and all relevant market-based measures have been implemented but the gas supply is insufficient to meet the remaining gas demand'. This suggests that the solidarity measure can only be requested in a physical gas shortage situation i.e., when supplies for protected customers are not available at any price.

UK-EU Trade and Cooperation Agreement

The post-Brexit UK position on cooperation on security of electricity and gas supply is unclear with the Trade and Cooperation Agreement stating:

> `The Parties shall cooperate with respect to the security of supply of electricity and gas... The Parties shall immediately inform each other in the event of an actual disruption or other crisis, in view of possible coordinated mitigation and restoration measures…'

'Each Party shall establish… plans', containing 'the measures needed to prepare for, and mitigate the impact of, an electricity or natural gas crisis…' Such measures must 'not significantly distort trade

[46] 'Solidarity protected customer' is a household customer who is connected to a gas distribution network but may also include (a) a district heating installation (if it is a protected customer in the relevant Member State and only in so far as it delivers heating to households or essential social services other than educational and public administration services) and (b) an essential social service if it is a protected customer in the relevant Member State (other than educational and public administration services), Article 2.6.

[47] Article 13.1.

[48] Article 13, 2.

[49] The European Union Agency for the Cooperation of Energy Regulators

[50] The European Network of Transmission System Operators for Gas

[51] Article 4, 2(g); Article 12, 3(c)

between the Parties… In the event of a crisis, the Parties shall only activate non-market-based measures as a last resort'.[52]

As the TCA refers to 'possible' coordinated mitigation and restoration measures, this suggests that both the UK and the EU have discretion as to what extent to coordinate their actions in the event of a crisis. On behalf of the EU, such coordination would be managed by the Gas Coordination Group.

Post-Brexit UK-EU cooperation on security of supply: not mandatory and subject to goodwill

From these rather general statements it might be concluded that the provisions in Security of Gas Supply Regulation are such that cooperation, even in the event of emergency when solidarity provisions would be applied across the EU, is not compulsory between the EU and the UK in either direction. The Trade and Cooperation Agreement does not bridge that gap; solidarity is for the EU Member States only. While there are no concrete commitments or obligations, all the necessary understanding is there because the UK was subject to all the requirements until recently and there were, and still are, close links between National Grid, ENTSOG, Ofgem,[53] and EU regulators, but cooperation will depend on goodwill on both sides. Given the existing LNG and pipeline gas flows around the UK – with the import of pipeline gas from Norway (not an EU Member State but bound by the *acquis*[54] through the European Economic Community) – and export and transit to Ireland (an EU Member State), it seems likely that, in the event of an emergency, cooperation would prevail. Should the UK attempt to restrict flows of available LNG to continental European EU member states this could create serious political and regulatory tensions which would be difficult to resolve. However, given the UK government's insistence on only activating non-market measures as a last resort, it would be logical to expect prices to determine flows between the UK and its neighbours, in the manner outlined earlier.

Implications of price increases for UK gas demand

If a disruption to Russian gas supplies to Europe were to occur, especially before the end of the present winter, the result would be price spikes across Europe. The UK would face price spikes similar to those in other European markets, despite the UK not being directly dependent on Russian pipeline gas supplies. A sharp increase in wholesale UK gas prices – beyond the already high level seen at present – would have dramatic implications for multiple sectors. Natural gas is widely used in the UK, for power generation (particularly to balance out variable renewable power generation), for space heating in the residential and commercial sectors, and in heavy industry.

In the event of a major price spike, industrial demand would be the first to be curtailed, as higher prices could render operations loss-making and factories could temporarily cease work. Thereafter, the UK would face a problem of demand inelasticity. Due to a lack of alternatives, gas consumers would be forced to continue using gas despite high prices. This is especially true of household gas consumers, given that four in every five UK households use gas for space heating. The retail gas prices paid by such consumers are protected from the most dramatic fluctuations in wholesale prices by a 'price cap', which regulates retail tariffs in relation to wholesale prices. In the latter part of 2021, the gap between this price cap and skyrocketing wholesale market prices led multiple retail companies to bankruptcy.

[52] ENER 17 and 18, pp.165-166. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/948119/EU-UK_Trade_and_Cooperation_Agreement_24.12.2020.pdf

[53] The Office of Gas and Electricity Markets (Ofgem) is the government regulator for the electricity and downstream natural gas markets in the United Kingdom

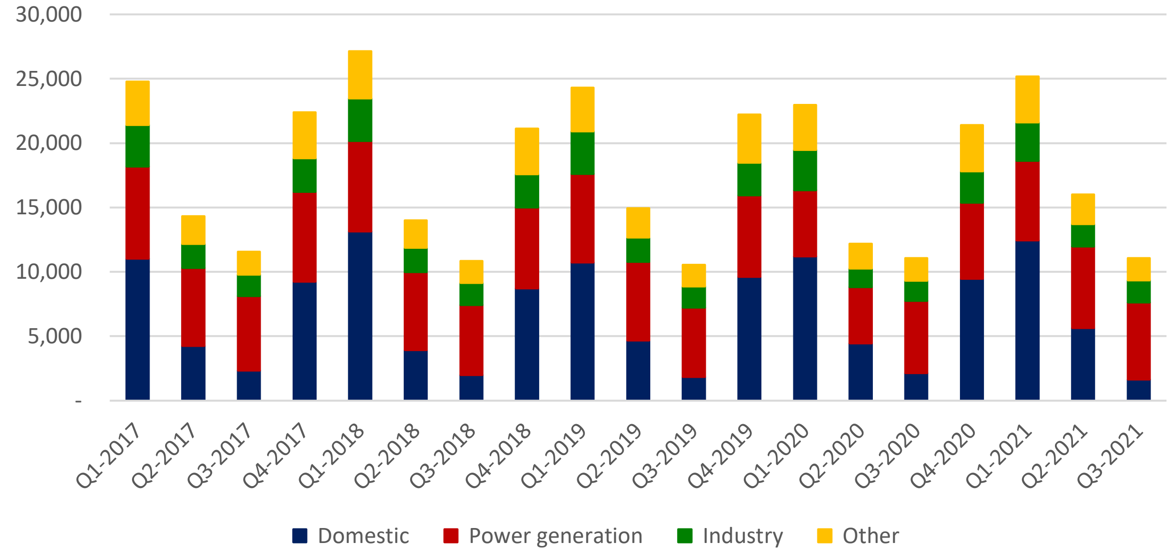
[54] "The EU's 'acquis' is the body of common rights and obligations that are binding on all EU countries, as EU Members". European Union, 2022. *EUR-Lex (Access to European Law)*. [redacted]

The UK government raised the price cap on 1 October 2021, in line with the regular revision that takes place every six months.

As of 2 February 2022, the latest rise in the energy price cap has been announced by the UK regulator, Ofgem, and it shows a rise of some 54 percent for the period 1 April to 30 September 2022, compared to the period 1 October 2021 to 31 March 2022. The rise in the wholesale gas price element of the calculation was some 115 percent, from 60 pence per therm to 130 pence per therm. The wholesale gas price element of 130 pence per therm is calculated on the forward curves for the period April 2022 to March 2023, as quoted between August 2021 to January 2022. The next price cap will be set on the forward curves for the period October 2022 to September 2023, as quoted between February 2022 and August 2022. The latest quote (2 February 2022) for that period averages some 148 pence per therm. If maintained then this would be a rise of some 14 percent, leading to a small further rise in the energy price cap from October this year. Clearly wholesale gas prices could rise further, especially with the uncertainty over a conflict in Ukraine, but equally if any conflict doesn't transpire and gas supply, especially from Russia, increases, wholesale gas prices could fall significantly.

A final point to note regarding UK gas demand is that, due to the significant share of domestic gas use (for space heating, hot water, and cooking) in total UK gas demand, such total demand is strongly seasonal. For example, between 2017 and 2021, the average share of domestic gas consumption in total UK gas demand in Q1 was 47 per cent. But for Q3, that average figure was 18 per cent. Therefore, the UK is at its most vulnerable to any physical supply shortages or price spikes during the colder winter months, and especially in Q1. For this reason, concerns over geopolitical tensions in Eastern Europe and potential impacts on Russian gas supplies to Europe, and by extension the impact on the UK, will be especially heightened from now until the end of winter, but could ease slightly from April onwards.

Figure 9: UK quarterly gas demand by sector (million cubic metres)



Source: UK Government statistics[55]

[55] UK Government, 2022. *Energy trends: UK gas - Natural gas supply and consumption (ET 4.1 - quarterly)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Conclusion

This paper began by setting out possible triggers for a disruption in Russian pipeline gas supplies to Europe, and several possible scenarios for such disruption, ranging from the effective cancellation of Nord Stream 2 through a curtailment of Russian supplies via Ukraine, to a complete cessation of Russian supplies to Europe. A key point is that the outbreak of a military conflict in Ukraine is highly likely to bring a surge in European gas prices, due to concerns over the unpredictability of a possible escalation of hostilities that could impact gas flows in Europe.

A second key point of this paper is that while the UK is seemingly removed from concerns over Russian supplies in a physical sense, with UK supply being split between domestic production, Norwegian pipeline supply, and LNG imports, any disruption to Russian supplies to the European market will generate a severe price spike that will filter through to the UK market. In physical flow terms, higher prices in continental Europe would draw gas away from the UK through the Interconnector and BBL. To the extent that LNG cargoes are available on the global market, capacity is available at UK LNG import terminals, and capacity is available on the Interconnector and BBL pipelines, the UK would become a 'land bridge' to North-Western Europe, regasifying LNG cargoes and re-exporting them. This could make the task of physical balancing on the UK transmission system more challenging, and could increase the volatility of wholesale prices on the UK market accordingly. As noted earlier, the surge in UK LNG imports and net exports to Belgium and the Netherlands (via the Interconnector and BBL pipelines) in January 2022 could serve as a foretaste of what could happen to regional flows in the event of a sustained curtailment in physical flows of Russian pipeline gas to North-Western Europe.

In terms of the movement of gas from one country to another during a supply disruption, the existing legal arrangements between the UK and its neighbours (who are EU member states) are such that, even in the event of emergency when solidarity provisions would be applied across the EU, cooperation between the EU and the UK is not compulsory for either party. Nonetheless, it seems likely that, in the event of an emergency, cooperation would prevail, and non-market measures (such as enforced restrictions on consumption in non-protected sectors to allow exports to neighbouring states in need) would only be applied as a last resort. It is highly likely that, absent government intervention to prevent the free flow of gas, pricing signals would draw gas from one market area to another.

Finally, time is of the essence. UK gas demand is strongly seasonal, yet the UK lacks seasonal storage facilities. Rather, the UK relies on swings in its own production and fluctuations in imports to meet the peaks of its winter demand. Therefore, the tightening of the market due to a disruption in Russian supplies to Europe would produce far greater challenges if it were to occur before the end of winter (late March/early April, depending on the weather). With that in mind, governments, market participants, and analysts will continue to monitor the situation on Ukraine's borders with Russia and Belarus, while the tensions generated by the threat of conflict are contributing to the current volatility and high level of European wholesale prices.

While the tight supply-demand balance since October 2021 has driven prices to high levels, the lack of 'room for manoeuvre' in such a tight market is causing increased volatility. Any indication of a shift in the supply-demand balance (such as weather reports, production outages, or geopolitical tensions) is causing a price reaction. For example, between 29 December 2021 and 12 January 2022, the TTF front-month price fell from 97 Euros per Megawatt hour (EUR/MWh) to 65 EUR/MWh, rebounded to 97 EUR/MWh and then fell back to 75 EUR/MWh. For comparison, from May 2017 to May 2021, the TTF front-month price did not surpass 30 EUR/MWh. In other words, the difference between the highest and lowest TTF front-month prices in a two-week period between the end of December 201 and mid-January 2022 was greater than the absolute highest price recorded in the four-year period between May 2017 and May 2021. If a military conflict does lead to a disruption of Russian supplies to Europe, the UK might not face a physical shortage, but the impact on wholesale (and by extension, retail) gas prices will be substantial, and due to its impact on the power generation, commercial and residential heating, and industrial sectors will contribute to inflationary pressures at a time when the UK is already facing challenging economic circumstances.

Appendix: LNG Import Capacity in the UK and North-Western Europe

The capacity of LNG import terminals depends on several elements. Firstly, the number of jetties and the size of vessels that can be accommodated at each jetty. For example, Isle of Grain and South Hook each have two jetties, while Dragon LNG has one. Isle of Grain and South Hook can accommodate vessels up to 266,000 m3 in capacity, while Dragon LNG can accommodate vessels up to 217,000 m3 in capacity. The time it takes for an LNG carrier to dock, discharge its cargo, and then leave the terminal is also a factor.

Isle of Grain reports that it offers over 200 berthing slots per year.[56] According to data from Kpler, the record number of cargoes received at the Isle of Grain in a calendar month was 15 in December 2019, followed by 11 in January 2022, and 10 in November 2019. In annual terms, 2019 saw 65 cargoes discharged, ahead of 57 in 2020 and 56 in 2021. January 2022 also saw a record number of cargoes arrive at South Hook (16), ahead of the previous record (12) that was achieved in May 2019, May 2020, and March 2021. In annual terms, South Hook received a record 79 cargoes in 2020, ahead of 2019 (74 cargoes), and 2021 (58 cargoes). January 2022 also saw a joint-record number of cargoes arrive at Dragon LNG (7), the same as in March 2020. In annual terms, Dragon LNG received 35 cargoes in 2020, higher than in 2019 (27) and 2021 (25). Overall, the three UK LNG import terminals received a combined 34 cargoes in January 2022, more than the previous record, 31 in December 2019. In annual terms, the UK received 166 LNG cargoes in 2019, 171 in 2020, and 139 in 2021.

A second element is the capacity of the terminal to store LNG. At Isle of Grain, the storage capacity is 1 million cubic metres of LNG (equivalent to 615 million cubic metres of natural gas when regasified). At South Hook, the capacity is 775,000 m3 of LNG and at Dragon the capacity is 320,000 m3 of LNG. When the storage tank is full, gas must be regasified and injected into the pipeline system before more LNG import cargoes can be accommodated.

A third element is the rate at which the terminal can regasify the LNG and inject it into the national transmission system. At Isle of Grain, that rate is reported by Grain LNG as 645 GWh/d (approximately 59.5 Smmcm/d), although this is reported as 699 GWh/d (64.5 Smmcm/d) by ENTSOG and 67.1 Smmcm/d by Gas Infrastructure Europe (GIE). At South Hook, the daily send-out capacity reported by GIE is 61.8 Smmcm/d and at Dragon LNG it is reported by GIE as 28.9 Smmcm/d. That gives a combined 90.7 Smmcm/d of send-out at two terminals at the port of Milford Haven. The combined capacity of these two terminals combined is reported by ENTSOG as 949 GWh/d, or 87.4 mmcm/d. This suggests that total send-out capacity from the three terminals is 1,594 GWh/d, or 146.9 Smmcm/d, according to ENTSOG.

Finally, the nominal annual import capacity is usually lower than the annualised sum of the daily send-out capacity, even when these two values are reported by the same entity. For example, Gas Infrastructure Europe reports that Isle of Grain has a nominal import capacity of 19.5 bcm per year, and a daily send-out capacity of 2.65 mmcm per hour (63.6 mmcm/d). If that daily send-out capacity were maintained every day for 365 days, it would total 23.2 bcm – notably higher than the nominal annual import capacity. This is because LNG terminals are not expected to operate at full send-out capacity every day. LNG cargoes are offloaded from tankers, placed into storage tanks, and then withdrawn from the storage tanks and regasified for injections into the pipeline system over the course of several days.

For Figure 4 and Figure 7, and the discussion of LNG imports into the three UK LNG import terminals and the three terminals in North-Western continental Europe (Dunkerque, Zeebrugge, and Gate Rotterdam), this paper refers to the monthly LNG imports and nominal annual LNG import capacity (divided equally by 12 calendar months) reported by the Kpler LNG platform.

[56] Grain LNG, 2022. *Operational information – Capacities*[redacted]

For comparison, the nominal annual import capacity for Isle of Grain, South Hook, and Dragon LNG combined reported by Kpler equate to 139 (standard) mmcm/d. This is the same nominal import capacity reported by Gas Infrastructure Europe, which states the combined send-out capacity of the three terminals as 158 Smmcm/d. ENTSOG report the daily send-out capacity as 147.5 Smmcm/d. According to Kpler, the record daily LNG importation into the UK occurred on 19 April 2019, when 261 mmcm of natural gas equivalent was offloaded at the three LNG import terminals. However, the record for daily send-out into the National Grid transmission system occurred on 5 December 2019, when 141 mmcm was injected into the pipeline system at the three terminals.

To conclude, the capacity of an LNG import terminal is very much a 'moveable feast'. In terms of receiving cargoes, the monthly record (set in January 2022) at Isle of Grain and South Hook is a cargo every two days, and at Dragon LNG it is a cargo every four days. The LNG storage tanks at these terminals are being constantly drawn down as LNG is regasified, and topped up with fresh LNG cargoes. The monthly record send-out for the three terminals combined (also set in January 2022) saw send-out equivalent to 67 per cent of the monthly send-out capacity. While the rate of capacity utilisation (that is, volume of UK LNG imports in January 2022 relative to import capacity and, by extension, the volume of spare capacity to increase those imports from their present level) is difficult to define, it is clear that UK LNG imports in January 2022 were at a sustained high level and that the spare capacity to increase those imports further is less than is usually the case, even in mid-winter.

Appendix D

- Department for Business, Energy & Industrial Strategy (https://www.gov.uk/government/organisations/department-for-business-energy-and-industrial-strategy)

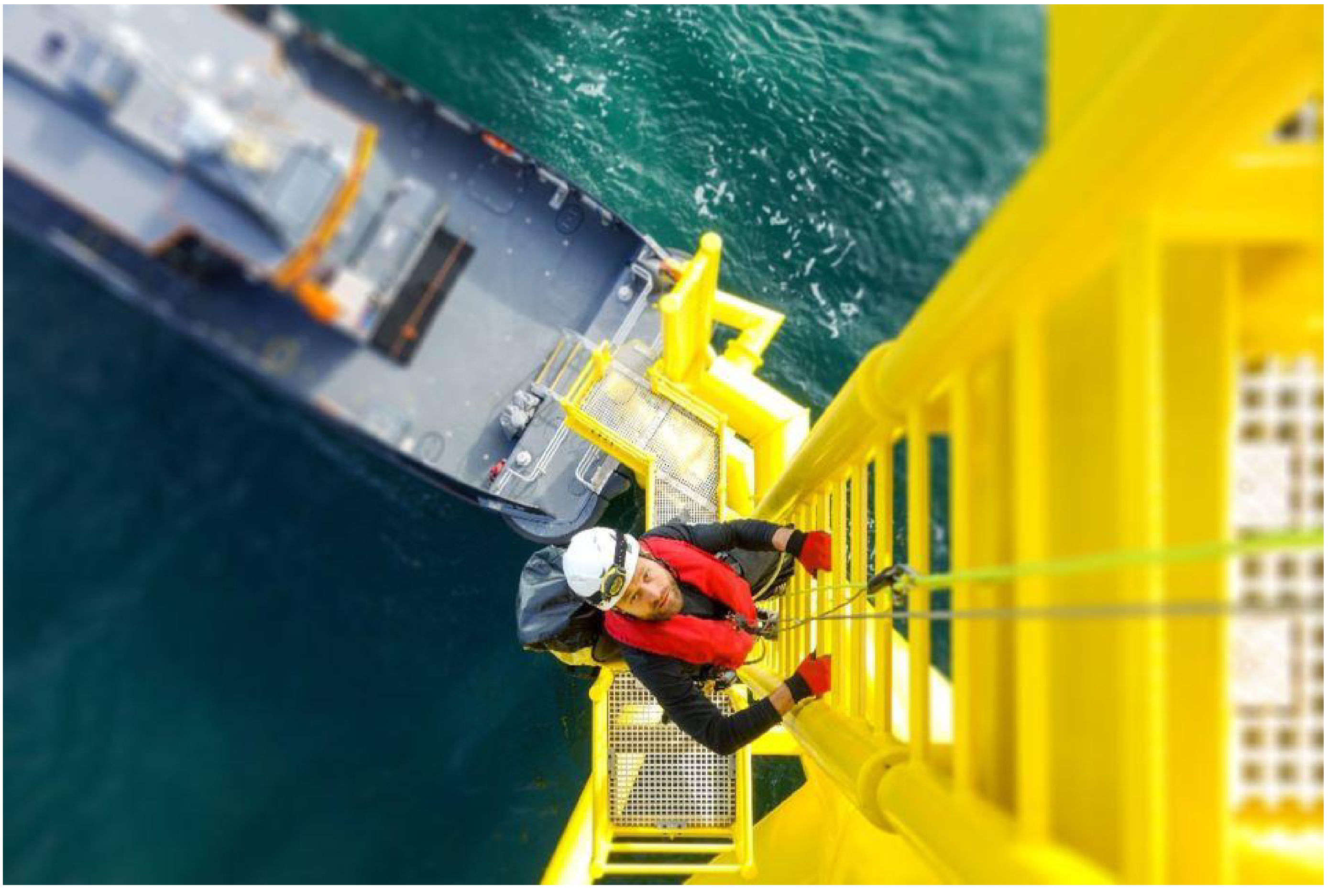
Policy paper

North Sea Transition Deal (accessible webpage)

Updated 21 March 2022

Contents

This publication is available at https://www.gov.uk/government/publications/north-sea-transition-deal/north-sea-transition-deal-accessible-webpage



Man climbing rig

Foreword

The offshore oil and gas sector is a major UK industrial success story. Since production started in 1967, the sector has produced around 45 billion barrels of oil equivalent from the UK's Continental Shelf (UKCS)[footnote 1], generating more than £350 billion in production tax revenue alone[footnote 2]. This has maintained the country's energy security, while keeping our homes warm, our country moving and creating hundreds of thousands of high-quality jobs across the UK.

However, climate change represents an existential threat to the planet. So, building back better means building back greener. The UK has set a world-leading net zero target, the first major economy to do so by statute. Last year, the Prime Minister announced a new ambitious emissions target which aims for at least 68% reduction in greenhouse gas emissions by the end of the decade, compared to 1990 levels. But simply setting the target is not enough and, as the government's Energy White Paper[footnote 3] makes clear, we need to focus all our efforts on decarbonising our economy which still relies heavily on hydrocarbons for our energy demand.

This decade will be the decade of delivery and change. Tackling climate change will require decisive global action and significant investment and innovation, creating new industries, technologies, and professions. This offers a huge opportunity for both growth and job creation.

The UK's offshore oil and gas sector recognises this fact and was amongst the first major industries to publicly back the government's net zero objectives through its Roadmap 2035[footnote 4]. The UK's demand for oil and gas, though much reduced in the future, is expected by the Climate Change Committee to continue for decades to come[footnote 5] .

This is why the government committed, in the 2019 election Manifesto[footnote 6], to deliver a transformational Sector Deal for the offshore oil and gas sector in recognition of the key role that it can play in helping the UK meet its net zero commitments.

The UKCS is a mature hydrocarbon basin with production having peaked around the turn of the century. The sector has also, in recent years, faced significant challenges with sustained low prices and the current COVID-19 pandemic. The tripartite partnership between the government, the Oil and Gas Authority and the offshore oil and gas sector has enabled the sector to remain an important part of the economy. It supports around 147,000 jobs directly and in their supply chains,[footnote 7] employing people in locations right across the country and supporting many more local jobs in sectors that rely on a vibrant oil and gas industry.

The North Sea and indigenous oil and gas supply have been at the heart of the UK's energy and industrial strategy for over fifty years. The sector has developed an international reputation for leading the world in offshore exploration and production capabilities, and the UK has developed capabilities through its supply chain services which are exported around the world.

As output from the UKCS declines, domestic demand is also projected to decline, and there is a clear need for determined action to be taken to build on the proven capabilities within the sector to support the transition to net zero. The UK already has the capability and skills within the existing sector to lead in new and emerging energy technologies such as Carbon Capture, Usage and Storage (CCUS) and the hydrogen economy as well as to support the growth of new sectors such as offshore wind.

This Deal is about harnessing the power of the oil and gas sector and anchoring it to the UK for the energy transition. It aims to reset the relationship between the government and the sector and represents a quid pro quo partnership for taking long-term action which transforms the sector and delivers the energy transition. This will reinforce the aims of the government's strategy to build back better and is closely aligned to the government's Energy White Paper and key elements of the Prime Minister's Ten Point Plan[footnote 8].

Through the Deal, the UK's oil and gas sector and the government will work together to deliver the skills, innovation and new infrastructure required to decarbonise North Sea oil and gas production as well as other carbon intensive industries. Not only will it transform the sector in preparation for a net zero future, but it will also catalyse growth throughout the UK economy. Delivering large-scale decarbonisation solutions will strengthen the position of the existing UK energy sector supply chain in a net zero world, securing new high-value jobs in the UK, supporting the development of regional economies and competing in clean energy export markets.

By creating the North Sea Transition Deal, the government and the UK's oil and gas sector are ambitiously seeking to tackle the challenges of reaching net zero, while repositioning the UK's capabilities to serve the global energy industry. The Deal will take the UKCS through to maturity and help the sector pivot towards new opportunities to keep the UK at the forefront of the changing 21st century energy landscape.

This is a Deal for the whole of the UK and, where appropriate, government will work with the governments of Scotland, Wales and Northern Ireland to take forward the aims of this Deal.

Rt Hon Kwasi Kwarteng MP
Secretary of State for Business, Energy and Industrial Strategy

Deirdre Michie OBE
Chief Executive, OGUK

Rt Hon Anne-Marie Trevelyan MP
Minister of State for Business, Energy and Clean Growth, and UK International Champion on Adaptation and Resilience for the COP26 Presidency

Executive Summary

The North Sea Transition Deal builds on the UK's global strength in offshore oil and gas production and seeks to maximise the advantages for the UK's oil and gas sector from the global shift to clean growth. It is aimed at delivering on the commitments set out in the oil and gas chapter of the government's Energy White Paper and is closely aligned to the Prime Minister's Ten Point Plan.

It will do this by:

1. The sector committing to early targets for the reduction of greenhouse gas emissions from production against a 2018 baseline and the government identifying potential funding opportunities for early offshore electrification.

2. The Deal will commit to deliver investment of up to £14-16 billion by 2030 in new energy technologies, with the government delivering a business model to enable CCUS and hydrogen at scale.

3. The sector voluntarily committing to achieve 50% local UK content across the lifecycle for all related new energy transition projects by 2030, as well as in oil and gas decommissioning. This will be supported by the appointment of an industry supply chain champion who will support the coordination of opportunities with other sectors.

4. Achieving a 60Mt reduction in greenhouse gas emissions, including 15Mt through the progressive decarbonisation of UKCS production over the period to 2030.[footnote 9]

5. Supporting up to 40,000 direct and indirect supply chain jobs in decarbonising UKCS production and the CCUS and hydrogen sectors. [footnote 10]

6. Government investment of £6.3 million in the Global Underwater Hub, and a further £2 million to develop the Deal, helping to support the sector to play a leading role in meeting the UK's net zero ambitions.[footnote 11]

7. Supporting the government's prompt payment initiative by championing the Prompt Payment Code.

Moving away from unabated greenhouse gas emissions resulting from combustion of fossil fuels will be achieved through a combination of energy efficiency, electrification, alternative decarbonised energy and the use of carbon capture technologies. The pace of this transition must be managed to balance the need to decarbonise with the need to maintain energy security and affordability. The oil and gas sector is committed to net-zero but it is a sector that is hard to abate, in view of the location and nature of the assets involved and it is exposed to international competition. It is therefore necessary to ensure that the costs of abatement are manageable and mitigate the risk of a relocation of production (and therefore carbon leakage) abroad and reduced investment in a strategic UK industry.

Oil and gas production will still be needed during the transition, but at lower levels than today. The delivery of this transformative plan, which is supported by elements of the North Sea Transition Deal, will enable the oil and gas sector to drive the energy transition by developing and deploying a range of technologies, transforming the UK supply chain, securing jobs, and protecting and building successful local communities.

It will unlock the UK's net zero ambition, delivering part of a fair and equitable energy transition by allowing the UK Continental Shelf (UKCS) to transition to a net zero basin as well as supporting decarbonisation of industries across the UK. The Deal will grow the economy, attract new investment, sustain jobs, and create new energy businesses benefiting local regions across the UK.

This Deal is built on five outcomes. Each of these is closely interlinked, meaning that the deal must be delivered as an integrated whole to achieve its full potential.

Key Outcomes

Supply decarbonisation

In 2018, upstream oil and gas activities in the UK accounted for four per cent of UK greenhouse gas emissions. The Deal will cut UK upstream oil and gas industry greenhouse gas emissions through an ambitious production emissions reduction programme. The sector has already responded to the UK's 2050 net zero targets by committing to becoming a net zero basin by 2050 and setting ambitious greenhouse gas emission reduction targets. Set against a 2018 baseline, subject to joint government and industry actions, the Deal's new early targets correspond to an absolute reduction in production emissions of 10% in 2025, 25% in 2027, and 50% in 2030 on the pathway to net-zero by 2050. This commitment focuses on actions the government and industry can take to reduce emissions from the UKCS oil and gas production, for example, electrification of offshore production installations and adherence to new standards on flaring and venting.

Carbon Capture, Usage & Storage

The Prime Minister's Ten Point Plan announced a commitment to deploy two carbon capture clusters by the mid-2020s and a further two clusters by 2030. The development of this technology will enable large parts of the UK industry and society to eliminate emissions. This commitment aims to unlock investment of £2-3 billion in CCUS Transport & Storage infrastructure from the sector, to underpin widespread capture rollout. The sector's extensive experience in implementing and operating large offshore infrastructure projects and investing in shared offshore infrastructure solutions, coupled with a deep knowledge of subsurface technologies, geoscience and reservoir management, means it is particularly suited to development of transport and storage facilities. These capabilities will enable efficiencies and cost reductions to be achieved as new CCUS projects are executed.

Hydrogen

Hydrogen is essential to meeting our net zero commitment in the UK. It could provide a clean source of energy across the economy, from industrial and domestic heat, to heavy transport, and flexible power and energy storage. The UK already has world-leading offshore wind potential and electrolyser capability, alongside unparalleled carbon capture and storage sites that the UK can maximise to scale up low carbon hydrogen production.

The hydrogen commitment in the North Sea Transition Deal focuses on creating the economic environment in which low carbon hydrogen production can flourish. This will help unlock billions of pounds of investment from the sector. The oil and gas sector is positioned to enable the production of low-carbon hydrogen at scale as part of a long-term competitive market, supporting the UK's ambition to deliver 5GW of low carbon hydrogen production capacity by 2030.

Supply chain transformation

The Deal will help develop expertise to underpin growth in the domestic energy sector and subsequently in export growth markets, creating a globally competitive energy supply chain of international repute. The supply chain commitment focuses on supporting the transformation of the oil and gas supply chain to service low-carbon energy sectors at home and abroad. The sector has built a significant supply chain across the UK to support UKCS operations with an aggregate revenue of £26.5 billion in 2018[footnote 12]. The UK's energy supply chain should be competitively positioned to seize such opportunities presented by offshore electrification, CCUS, and hydrogen both in the domestic market and internationally. As production from the UKCS declines, demand for the conventional services it provides will also fall, threatening the high-value jobs the industry creates. The sector will set its own voluntary target of 50% UK content, including capital investment, over the lifecycle of all low-carbon projects, and offshore decommissioning, as well as 30% for locally sourced technology. This will be underpinned by the appointment of a supply chain champion for the sector. The government will invest £6.3 million in the Global Underwater Hub, and a further £2 million to develop the Deal, helping to support the sector to play a leading role in meeting the UK's net zero ambitions.

People & Skills

The Deal will support up to 40,000 high-quality direct and indirect supply chain jobs in our industrial heartlands. The People & Skills commitment contains actions that will both facilitate the reskilling of existing parts of the oil and gas workforce and will ensure that everyone employed in the sector – whatever their background - can fulfil their potential.

Many of the skills present in the sector are also transferrable across the wider energy sector. Offshore renewables, as well as the future CCUS and hydrogen industries will rely heavily on many of the current skillsets in the oil and gas industry such as geologists, project managers, a wide variety of engineers, and fabricators. A carefully managed transition will help to ensure a prosperous future for the communities affected and that the UK economy retains people with these key skillsets, as demand for their current roles in the oil and gas sector wanes with production decline, so that they can help unlock these vital emerging low carbon sectors. The sector will seek to link up with initiatives on workforce transition, skills and diversity & inclusion, being undertaken through other Sector Deals (such as the Offshore Wind Sector Deal), where this will add value.

Every effort will be made by both the government and the sector to meet the commitments as set out in this document. However, whilst the commitments in this Deal are undertaken in good faith, we recognise the wide range of uncertainties that may impact on delivery.

Commitments

1. Supply Decarbonisation

Sector action to support the energy transition

Establish overarching industry targets

The sector is committed to decarbonising and, subject to making progress on the shared actions, it will take action to reduce emissions from oil and gas production by 10% by 2025, by 25% by 2027 and by 50% by 2030 (all relative to 2018 baseline), as measurable steps to a net zero basin by 2050.

Improved emissions stewardship

The sector will support the development of, and rapidly implement and follow, the OGA's Net-Zero Asset Stewardship Expectation, to encourage emissions reductions from both existing and new developments.

Streamlined emissions monitoring and reporting

The sector will work with the government, OPRED, and the OGA on consistent reporting structures and frameworks to minimise the reporting burden and enable clearer monitoring of progress.

Methane Action Plan to reduce emissions and flaring

The sector will develop and commit to a Methane Action Plan. The plan will detail commitments to improve the monitoring and reporting of emissions, whilst separately stating a separate methane target. The sector will:

- through individual assets, seek to accelerate compliance with the World Bank 'Zero Routine Flaring' Initiative ahead of 2030.
- commit to the OGCI 2025 methane intensity commitment – currently 0.25% (ambition 0.20%)

Collaborative investment in electrification of assets

The sector will invest £2-3 billion, subject to making progress on the shared actions, to allow oil and gas production to be operated using electricity supplied from the main electricity networks and/or renewable resources meet the earlier emissions targets.

Government action to support the energy transition

Streamline emissions monitoring and reporting

The OGA and OPRED will provide continued regulatory cooperation on the monitoring, reporting and management of emissions.

Early-stage funding for Offshore Electrification

The government will identify potential funding opportunities for early-stage offshore electrification studies that businesses could bid into, on a match-funded basis by the end of 2021.

Delivering support for offshore electrification

The government recognises that the sector needs to unlock investment in capital intensive offshore electrification projects and will work with the sector to identify potential decarbonisation funding solutions by late 2022.

Cost-effective offshore electricity

The government will commit to working with the sector to explore the economics of electrification and work to identify the most cost effective options to unlock investment for the electrification of its assets, addressing both the upfront capital costs and the affordability of power from electricity transmission and network charges, and exposure to other levies. The OGA will promote the adoption of cost-effective electrification opportunities via the provisions in its new Strategy.

Whole system/ offshore cooperation

The government will create and lead a senior Offshore Implementation Group addressing the regulatory and legislative barriers to electrification and other offshore energy integration matters. This will be a task and finish group, chaired by BEIS and including senior representatives from the key regulators. The first meeting will be within one month of publication of this Deal and a time-table for addressing the barriers will be established as an early action.

2. Carbon Capture Usage & Storage (CCUS)

Sector action to support the energy transition

The sector will provide long-term investment to support CCUS

To support the UK becoming a world leader in technology to capture and store harmful emissions away from the atmosphere, the sector will invest £2-3bn to build the Transport & Storage infrastructure for at least 10MT/y of carbon capture by 2030.

Develop industry standards for CCUS

The sector will develop robust industry standards to address barriers to CCUS deployment in the UK.

Coordinate approach to CCUS cost reduction

The sector will transfer learnings from international CCUS projects and previous basin cost reduction initiatives such as decommissioning practice into CCUS deployment in the UK.

Government action to support the energy transition

Deliver a business model to enable Transport and Storage at scale

In 2021, the government will bring forward details of a revenue mechanism to bring through private sector investment in industrial carbon capture and hydrogen projects, to provide the certainty investors require to deliver CCUS at pace and scale.

Develop initial Transport and Storage infrastructure in support of CCUS

The government will establish a process to sequence the deployment of CCUS clusters, with the potential for CCUS in two industrial clusters by the mid-2020s subject to value for money and affordability considerations, and aim for four clusters by 2030, capturing up to 10 million tonnes of carbon dioxide per year. The government will deliver a £1bn CCUS Infrastructure Fund to enable the deployment of transport and storage and industrial carbon capture projects.

Create a CCUS Transport & Storage asset regulatory capability

The government will establish an independent economic regulator to regulate the Transport & Storage sector, and its duties and objectives will be prescribed in legislation. The government will work with the OGA in its role as the licensing and permitting authority to steward and implement CCUS policy.

Deliver a CCUS Transport & Storage infrastructure reuse policy

The government will work with OPRED and the OGA to develop policy and regulation to support deployment of CCUS Transport & Storage in the UK seeking to optimise oil and gas asset reuse.

Coordinate offshore strategic deployment

The government will coordinate strategic deployment issues relating to carbon dioxide transport and storage, including leasing and licencing considerations and necessary liaison with relevant offshore regulatory bodies such as the Crown Estate and the OGA.

3. Hydrogen

Sector action to support the energy transition

Create low carbon hydrogen production capacity

The sector will work with the government to deliver the ambition for 5GW of low carbon hydrogen production capacity by 2030.

Support Hydrogen RD&D

The sector will invest in RD&D for hydrogen technologies that support the production, transportation, storage and consumption of hydrogen at lower cost. The sector will work with the government to align innovation objectives and maximise investments.

Support offshore green hydrogen production

The sector will support the development and deployment of offshore green hydrogen production using offshore wind to enable the technology to reach maturity.

Continue the hydrogen safety programme

The sector will support measures related to safety working with the Health and Safety Executive (HSE) and others such as the Institution of Gas Engineers and Managers (IGEM) to facilitate the effective dissemination of evolving hydrogen equipment and gas handling safety standards through the workforce.

Understand hydrogen and public opinion

The sector will measure and track public opinion on the use of hydrogen across a variety of applications, focusing on heating, to better understand the public's appetite for hydrogen. This will inform communication campaigns.

Government action to support the energy transition

Support Hydrogen RD&D

The Government will deploy funding from the £1bn Net Zero Innovation Programme for hydrogen technologies supporting the production, transportation, storage and consumption of hydrogen at lower cost. The government will work with industry to align innovation objectives and maximise investments.

Establish a revenue mechanism

In 2021, the government will bring forward detail on preferred hydrogen business models and the revenue mechanism to stimulate private investment in new low carbon hydrogen production facilities. The government will finalise business models in 2022.

Structure the market to allow hydrogen demand

The government will review the overarching market framework set out in the Gas Act 1995 to ensure the appropriate powers and responsibilities are in place to facilitate a decarbonised gas future. This will include a review of gas quality standards to enable the widest range of gasses to be used to decarbonise energy.

Accelerate the hydrogen project planning process

The government will explore ways to simplify and accelerate the planning process for hydrogen production plants.

Continue the iron mains replacement

The government will monitor the delivery of the iron mains replacement programme and support network businesses investment in net zero technology through RIIO2 price control period.

4. Supply Chain Transformation

Sector action to support the energy transition

Develop a UK low carbon supply chain of international repute

The supply chain will seek to form UK-based consortia providing targeted, innovative and broad solutions in support of the industry and the UK government's net-zero agenda. They will leverage the UK's capability and support existing delivery bodies to deliver net zero projects and secure supply chain diversification and export opportunities.

Anchor UK content in the supply chain

The sector will set a target of 50% UK content, including capital investment, over the lifecycle of all related new energy projects, as well as oil and gas decommissioning, and 30% for locally provided technology. The sector will conduct strategic mapping of energy transition requirements and revise these UK content targets as our understanding of capability and gaps develops.

Developing industrial scale capability in UK for low carbon industry

The sector will appoint an industry supply chain champion to co-ordinate business opportunities with other energy sectors. This champion will also help the supply chain to access government schemes providing funding support for low carbon energy projects, CCUS and decommissioning.

Promoting energy supply chain's net-zero capability and services to the world

The sector will develop market intelligence capability for global energy transition projects where there could be export opportunities for UK businesses. This should integrate information from other energy sectors such as renewables, focusing on alignment, collaboration, and integration opportunities. The supply chain champion will work with other sectors to raise the profile of the energy supply chain capability at home and abroad.

Attract further inward investment for net-zero

The sector will work with the government to attract and secure investment supporting individual companies and consortia to pursue opportunities to enable low carbon opportunities.

Incubate new technology development

The sector will leverage incubator funding to secure the development of new technologies, kickstarting pilot projects.

Develop the Global Underwater Hub

The sector will develop and fund the Global Underwater Hub through a subscription model, starting with the £6.3m support announced from the government. The Hub will develop and promote opportunities for our world-leading subsea engineering sector in the UK and across the world.

Prompt Payment

The sector will commit to support the government's prompt payment initiatives by championing the government's Prompt Payment Code.

Government action to support the energy transition

Develop a UK low carbon supply chain of international repute

The government will work with the sector to identify potential funding opportunities for supply chain led consortia by the end of 2021 supporting broad low carbon propositions across the UK, for the benefit of multiple users.

Anchoring UK content in the net-zero supply chain delivering first mover technology advantage

The government will support the sector's supply chain review to identify the UK's capability to deliver technology and services across both energy transition and decommissioning projects. The government will align existing mapping work in this area and support work to address gaps. The government will look to increase the visibility of the pipeline of clean growth projects to support the supply chain to assess forthcoming opportunities.

Developing industrial scale capability in UK for low carbon industry

The government will collaborate with the sector's supply chain champion in coordinating activities across sectors and between DIT, SDI, UK Export Finance and other exporting bodies to support the UK supply chain and maximise the benefit of emerging inward investment agreements.

Promoting and exporting the supply chain's net-zero services to the world

The government will use its resources and networks to promote the capabilities of the UK's energy supply chain in international markets, coupled with support for energy transition projects from UK Export Finance. This will include consideration within future trade deals.

Developing policy to attract further inward investment for net-zero

The government will develop policies to enable the net-zero supply chain to flourish, particularly in reference to the emerging CCUS and Hydrogen industrial hubs.

Simplifying funding access for new technology development

The government will simplify the various channels to access research and development and innovation funding and streamline application processes for incubator projects to bolster the UK supply chain's competitive advantage.

Support development of Global Underwater Hub

The government will support the development of the Global Underwater Hub with £5 million, subject to business case, on top of the £1.3 million committed last year. The Global Underwater Hub will work to broaden the focus of subsea engineering in the UK and will target global growth opportunities.

5. People & Skills

Sector action to support the energy transition

Energy Skills Alliance

The sector will support the work of the Energy Skills Alliance and work programme to ensure industry is prepared to meet the future demand for skills in oil and gas, and other related energy industries. This work will address:

i) Mapping of future energy skills demand

ii) Development of all-energy training & standards

iii) Implementation of all-energy apprenticeships

iv) Development of the "My Energy Future" programme

Integrated People and Skills Plan

The sector will create an integrated people and skills plan, with measurable objectives, to support its transition and diversification. Aligned with other established energy sector deals and the Energy Skills Alliance, as detailed above, and with strong commitment and support from the government, academia, trade unions and other relevant stakeholders, the plan will assess the industry's future skills, training and standards requirements, and how industry will support and enable the transition of the workforce. This action will be led by OPITO, in collaboration with other skills providers, and in a way that supports commitments to skills diversification made in other sector deals. The plan will be presented to the Government by March 2022.

Transferability of Skills

The sector will work to ensure that the workforce's skills and competencies are mutually recognised across energy sectors enabling easier job transferability. The sector will promote the uptake of relevant existing initiatives and expand these as appropriate. The sector will complete an assessment of where this is needed which will be presented as part of the People & Skills Plan. The sector will seek to link up with initiatives on workforce transition and skills being undertaken through other Sector Deals (such as the Offshore Wind Sector Deal), where this will add value.

Industry support for The Centre for Doctoral Training (CDT) in Geoscience and its role in the low carbon energy transition and challenge to meet net-zero emissions targets (GeoNetZero; GNZ)

The sector will provide continued support and previously committed matched funding for the UK Centre for Doctoral Training (CDT) in GeoNetZero (GNZ), helping create the next generation of academic expertise in the energy transition.

High employment standards

The sector will promote the UK's high employment standards to ensure the workforce is engaged in quality work.

Equality of opportunity

The sector will work to ensure that everyone employed in the sector – whatever their background - can fulfil their potential.

Government action to support the energy transition

Government support for Energy Skills Alliance

The government will continue to support the work of the Energy Skills Alliance's four workstreams

Potential government funding and support for Centre for Doctoral Training in geoscience and its role in the low carbon energy transition and challenge to meet net-zero emissions targets (GeoNetZero; GNZ)

The government will explore potential opportunities for the UK Centre for Doctoral Training (CDT) in GeoNetZero (GNZ) to ensure more students can benefit from this programme to create the next generation of academic expertise in the energy transition.

Support for the sector and workforce

The government will continue to champion the role of the sector and its workforce in the energy transition, supporting work on its People and Skills Plan. The government will continue to prioritise support for people in high carbon sectors of the economy, which need to transition, via the Green Jobs Taskforce.

Implementation Plan

Every effort will be made by both the government and sector to meet the commitments as set out in this document. However, whilst the commitments in this Deal are undertaken in good faith, we recognise the wide range of uncertainties that may impact on delivery.

1. North Sea Transition Forum – April 2021

The government to establish senior offshore implementation group to coordinate strategic development of integrated energy projects such as CCUS, hydrogen, wind and electrification of oil and gas assets – April 2021.

Deliver a business model to enable transport and storage of Carbon at scale (including legislative proposals where necessary) - in accordance with commitments in the 10 Point Plan. Strategic mapping of energy transition capabilities for domestic and external markets – start Summer 2021

2. Appointment of a Supply Chain Champion – Summer 2021

The sector to develop Business Cases for offshore electrification FEED studies and supply chain consortia funding for comprehensive spending review – Summer 2021

3. North Sea Transition Forum – October 2021

Further progress business models for carbon capture for industrial and power generation and low carbon hydrogen including legislative proposals where necessary in in accordance with commitments in the 10 Point Plan.

4. Produce an integrated people and skills plan – March 2022

5. One year on – Report on implementation – March 2022

The Offshore Oil and Gas Sector in Context

The UK's domestic oil and gas sector has had a critical role in maintaining the country's energy security for over five decades, and remains a major contributor to our economy.

The offshore oil and gas sector contributed about 0.9% to the UK's GVA in 2019[footnote 13] and has paid around £350 billion in production taxes to date[footnote 14]. The sector is a source of high-quality jobs, supporting directly or indirectly around 147,000 jobs in total across the UK in 2018. Many jobs supported by the sector are located in Scotland, particularly in Aberdeen, a global hub for the oil and gas industry. Critical supply chain clusters have grown in the North, East and South East of England. These jobs, and the estimated additional 113,000 jobs[footnote 15] induced by the sector, help support the wider UK economy.

While the Oil & Gas Authority (OGA) estimates that there are still around 10 to 20 billion barrels of oil equivalent remaining in the UKCS[footnote 16], domestic production has more than halved since 2000[footnote 17]. The Climate Change Committee (CCC) estimates that production of natural gas could drop by up to 80%[footnote 18] by 2050, compared to levels in 2017. However, the projections for demand for oil and gas, though much reduced, are forecast to continue for decades to come.

Much of the crude oil from the North Sea basin is exported, with the UK making extensive use of strong trading links to meet domestic refinery demand. Domestic production of natural gas still met 46%[footnote 19] of the country's supply of gas in 2019, with the vast majority of this supplied from North Sea offshore production.

The UK's offshore oil and gas sector has been severely affected by COVID-19. The pandemic led directly to the global collapse in demand for oil and resulted in a roughly 65% drop[footnote 20] in the price of Brent Crude between January and April 2020. OGUK has estimated that the UK sector responded by cutting expected capital expenditure by around 30 to 40% and operating expenditure by around 10 to 20% compared with anticipated expenditure at the start of the year, while maintaining production levels[footnote 21].

There is widespread recognition across the sector that it is imperative for the upstream oil and gas industry to transform itself and that 'business as usual' is no longer an option. Government support must now be within the context of delivering our net-zero target. The concerns about climate change are mirrored by the market with investors and the public more widely placing pressure on the sector to respond to the challenge. Shareholders, for example, are increasingly requiring listed companies to price carbon into their business models and demonstrate how they can reduce emissions from their operations or support the wider decarbonisation of the economy.

Many oil and gas companies are now responding to the challenge. Their investment decisions are beginning to anticipate a world without fossil fuels beyond 2050. There is great potential for the sector to play an important part in the energy transition and retain vital skills across key regional hubs around the country, supporting the CCUS and hydrogen "Super Places" clusters announced in the Prime Minister's Ten Point Plan, and helping accelerate the deployment of renewable energy generation in the North Sea.

A 2019 survey by OGUK revealed that more than half of its members had already diversified into other energy sectors, even as oil and gas remained their primary source of income. This includes many supply chain companies that are already diversifying into other energy and non-energy sectors.

Supply decarbonisation

Around 75% of the UK's primary energy needs are currently supplied by oil and gas, and production from the UKCS will continue to be a central element of the nation's energy supply as the UK transitions to net zero. The sector currently supplies over 40% of total UK primary energy demand from its operations in the UKCS. The independent Climate Change Committee's analysis underlines the ongoing need for oil and gas during the transition to net zero, albeit at significantly declining rates.

Although the UK will continue to import part of its energy needs going forward, there is no reason why the UK's indigenous industry cannot cover a sizeable part of this demand, while significantly reducing emissions associated with production.

Emissions Reductions

In 2018, upstream oil and gas activities in the UK accounted for four per cent of total UK greenhouse gas emissions. The sector has already responded to the 2050 net zero targets by committing to becoming a net zero basin by 2050 and setting ambitious greenhouse gas emission reduction targets with respect to production. Set against a 2018 baseline, the Deal's ambitious new targets correspond to an absolute reduction of 10% in 2025, 25% in 2027, and 50% in 2030 on the pathway to net-zero by 2050. This includes industry's direct greenhouse gas emissions arising from upstream exploration and production activities on the UKCS and onshore processing, including CO_2, methane and other greenhouse gas emissions.

The Deal sets out how industry, working with government, will look to achieve these targets in practice and in particular, highlights the pathway to deep decarbonisation of production activities, through the connection of oil and gas assets to low-carbon electricity production. The projects needed to achieve these targets have been identified and will need measures undertaken by both industry and government to be implemented in a timely manner if they are to proceed at the required pace.

The Deal is designed to change the nature of oil and gas production in the UK by 2030. This will be achieved through a combination of industry efforts with respect to operational practices and investment, appropriate changes to the regulatory regime, and the development of offshore infrastructure, in parallel with the major changes already needed to significantly expand offshore wind production. The outcomes expected through the Deal regarding supply decarbonisation are as follows:

1) Significant emission reduction from UKCS oil and gas production, delivered via regulatory co-operation that facilitates decarbonisation of exploration and production operations.

2) Immediate reductions in production related emissions from improved production efficiency, energy efficiency, operational processes change, consideration of fuel use and equipment upgrades.

3) Investment and deployment of new technologies that allow for a step-change in emissions reductions, in particular platform electrification or other localised solutions.

4) Phasing out of high-emission assets that are unable to economically or technically reduce emissions at prevailing carbon and commodity prices.

5) Phasing out of routine flaring and venting with a reduction of 30%, over and above natural decline, improving gas recovery and implementing new flare management plans. Individual asset owners will work to accelerate the commitment to support the World Bank Zero Routine Flaring by 2030 initiative.

6) Earlier alignment of UKCS with global methane standards through the implementation of a Methane Action Plan, incorporating enhancement quantification and measurement, followed by systematic programme of reduction of platform and fugitive emissions.

Flaring and Venting

Gas is flared at both onshore and offshore assets as part of the production process, both as routine flaring for disposal of waste gas and sometimes for safety reasons. Flaring and venting are recognised to be major sources of methane emissions which the industry has committed to reduce in line with the World Bank 'Zero Routine Flaring by 2030'.[footnote 22] A significant reduction is required to meet these 2030 targets and to achieve net zero emissions by 2050.

The sector is developing an action plan on methane which aims to promote the continuous reduction in methane emissions, establish a UKCS baseline and related methane specific emissions reduction target. The Methane Action Plan supports the World Bank Initiative and seeks to share best practice across the industry, for example: zero routine flaring in the design of newbuilds; improved gas recovery in field development plans; the development and implementation of flare management plans.

Electrification of Offshore Assets

Achieving ambitious emissions reduction targets will ultimately require a step change in emissions performance by focusing on reducing or removing the largest sources of upstream emissions. These arise from hydrocarbon fuelled electricity generation, process heat generation and direct powering of gas compression and pump systems.

Step-change abatement options under consideration include the full or partial electrification of offshore assets by connection to onshore power networks in the UK or Norway, potentially also including linking to offshore renewables and the creation of integrated energy hubs.

The electrification of offshore assets could unlock energy integration on the UKCS supporting not only oil and gas decarbonisation but also benefiting and supporting growth in other offshore sectors such as offshore wind development and green hydrogen through the energy hubs they create and the infrastructure they provide.

Significant investment will be required in technology, offshore renewable resources and infrastructure to facilitate offshore electrification of either existing or new assets. This is a major undertaking and is likely to take a decade to deploy at scale. It may be the case that some existing assets can be fully decarbonised whereas it may ultimately only be feasible to partially decarbonise others.

Unlike the other routes to emission reduction, which will be largely incentivised through higher carbon prices, electrification of existing offshore assets remains commercially challenging.

An estimated £15 billion investment is required in offshore transmission infrastructure to connect an additional 30GW of offshore wind between now and 2030. There is a high degree of alignment between future offshore wind zones and existing oil and gas infrastructure. There is an opportunity for coordination between different types of infrastructure to improve the commercial case for electrification as well as reducing the burden of any offshore transmission infrastructure on the environment and coastal communities.

The range of projects includes full or partial electrification of brownfield assets, development of fully electrified greenfield projects and integrated energy projects, with cost estimates per project ranging from £0.2 billion to £2 billion or higher for the largest projects. The expected emission reduction opportunities from these projects vary from 40,000 to 2 million tonnes of CO_2 per annum per project.

To deliver the 50% emission reduction target by 2030, it is estimated that between £2-3 billion of investment will be required to allow the completion of at least one or two of the currently identified electrification projects. Pace will be needed to deliver these projects by the required deadlines to meet the timetable of emissions reduction commitments. This will need an alignment of interests and incentives between industry and government and with other energy users of the North Sea.

The Government will work with the sector to identify potential funding sources and opportunities for early-stage offshore electrification studies (at concept and FEED stages) that businesses could bid into, on a match-funded basis. The government will commit to working with the sector to explore the economics of electrification and work to identify the most cost-efficient options for the electrification of its assets, considering the upfront capital costs and the cost of power from electricity transmission and network charges and exposure to other levies. The OGA will promote the adoption of cost-effective electrification opportunities via the provisions in its new Strategy.

The government will lead further work to explore how regulatory or legislative barriers to electrification and large-scale offshore energy integration projects can be reduced. Government will establish an Offshore Implementation Group for the energy transition, led by BEIS and including senior representation from Ofgem, the Crown Estate, OGA, OPRED, HSE, Marine Scotland and the Crown Estate Scotland. This will be a time-bound task-and-finish group which will commit to meet within the first month of publication of the Deal. The government will seek alignment of policy between the regulators in support of offshore electrification, so that barriers to platform electrification development and offshore electricity networks are identified and dealt with quickly and effectively across all regulators and policy makers.

There are increasing demands on the marine area including ambitions around climate, food security and transportation/communication. Carbon capture and storage is one of the many government ambitions for the UK's area. These ambitions include those set out in the Ten Point Plan (see Figure 1) which highlights the need to 'Advance Offshore Wind' and to protect our natural environment. Regulators will, when making decisions in the marine environment, take into consideration these ambitions as well as having regard to other directions like the Marine Policy Statement and subsequent Plans, the UK Marine Strategy (and good environmental status) and Fisheries Act.

Figure 1 - The Ten Point Plan

- Point 1: Advancing offshore wind
- Point 2: Driving the growth of low carbon hydrogen
- Point 3: Delivering new and advanced nuclear power
- Point 4: Accelerating the shift to zero emission vehicles
- Point 5: Green public transport, cycling and walking
- Point 6: Jet zero and green ships
- Point 7: Greener buildings
- Point 8: Investing in carbon capture, usage and storage
- Point 9: Protecting our natural environment
- Point 10: Green finance and innovation

Carbon Capture Utilisation & Storage (CCUS)

Investments in key technologies like hydrogen and CCUS, together with broader interventions, such as through helping people to retrain, will be crucial to enhancing local economic growth and creating jobs. The government has committed to working with local government and businesses to consider how an integrated strategic approach can most effectively be developed to enable local places to capitalise on this opportunity to build back greener. Supporting the delivery of four low-carbon clusters will enable greater decarbonisation, leading the way for a more sustainable industry.

The government has created the Carbon Capture and Storage Infrastructure Fund (CIF) to commit the investment needed to realise this opportunity. In his Budget of March 2020, the Chancellor committed at least £800 million through the Fund to support CCUS deployment. As announced in the Prime Minister’s Ten Point Plan, government is now raising our commitment to £1 billion up to 2025 to facilitate the UK’s deployment of operational CCUS in four industrial clusters by the end of the decade. This new carbon capture industry could support up to 50,000 jobs in the UK by 2030.[footnote 23] Developing carbon transport and storage infrastructure will require large upfront capital expenditure, to construct offshore and onshore pipelines and develop storage sites and wells. The government will help to put in place this critical network, as the foundation for the scaling up of CCUS across the UK.

The government will use the CCS Infrastructure Fund to facilitate the deployment of CCS in two industrial clusters by the mid-2020s, subject to value for money and affordability constraints, and a further two clusters by 2030, supporting our ambition to capture 10MtCO2 per year by the end of the decade.

For the majority of industrial sectors, CCUS is not yet a viable investment. The market currently does not provide a sufficiently robust price signal to make industrial carbon capture viable. In addition, low-carbon products do not attract a price premium, making investment harder to justify without a support mechanism. It can be hard for early investors to fully reap the benefits of learning and innovation which is generated from backing this first-of-a-kind technology. The government will therefore design and implement a business model to provide revenue support and improve companies’ confidence for investing in carbon capture solutions. The government will also aim to finalise a new commercial framework by 2022.

As part of the Deal, the oil and gas sector will help lead the development of CCUS technology by leveraging existing oil and gas infrastructure to provide transport and storage (T&S) facilities. These T&S hubs will enable CO2 to be captured at various locations, including the industrial clusters undergoing decarbonisation throughout the UK. In addition to those hubs already under development, there is significant potential for the initial locations to be expanded and other sites to be considered for development, particularly where there is the potential to build out CCUS infrastructure in line with hydrogen projects.

Where technically and economically feasible, offshore asset operators will also identify specific assets for reuse to provide these facilities and reassess asset end of life planning to deliver support for CCUS deployment. The UK’s ambitions to develop four initial CCUS industrial hubs across the UK can be enhanced by developing the right infrastructure based on the re-use of existing oil and gas pipelines, plants and assets.

The industry will also foster cross-sector cooperation to develop capture facilities for a variety of applications. These anchor projects will ensure that infrastructure is developed at an appropriate scale and improve understanding of the attainable CO2 capture rates and possible mechanisms by which they can be improved. Collaborative efforts across industry will enable the UK to accelerate CCUS development and reduce deployment cost. This cost-saving will ultimately benefit the consumers and end-users of various industries and help position the UK as a world leader in this space.

Developing suitable sites offering transportation and storage will be key to unlocking CCUS more widely across the UK including industrial capture projects. With an appropriate business model for both the capture and use as well as the transport and storage, each unit of T&S capacity delivered will help enable capture projects with a multiple of 3-4 times in terms of local economic impact. A reliable T&S network will also help the UK offer an internationally accessible carbon storage resource.

The oil and gas sector believes that a combination of the £1 billion funding and the development of the regulatory regime set out by BEIS will help address many of these challenges. If successful these actions will unlock £2 billion-£3 billion in investment that could deliver 6,600 direct and indirect jobs, across all of the clusters to be developed by 2030. The opportunity for the local supply chain is also significant given the capability overlap between the existing oil and gas industry and the future CCUS industry and could be underpinned by dynamic and voluntary industry commitments around local content as capability develops.

At least 10MtCO2 per annum of transport and storage capacity will enable the abatement of a variety of difficult to decarbonise industrial sources such as natural gas combustion for high grade heat, process emissions (e.g. steel or cement), or emissions from reforming natural gas to produce hydrogen. As described above, the clusters where this infrastructure is targeted will have sufficient capacity to grow rapidly once the market is established, and in some cases will even be able to offer the facility to import carbon dioxide from overseas.

The UK is in a strong position to become a global technology leader in CCUS. The UK has the opportunity to develop a domestic supply chain by utilising the expertise of our existing oil and gas industry. Innovative start-up companies, spun out of the UK’s world-class academic institutions, are focused on driving cost reductions and creating new UK-based innovative carbon capture technologies. With the potential to store more than 78 billion tonnes of carbon dioxide, the UK can be a global leader in carbon storage services.

Deployment of CCUS could create new markets for UK businesses, at home and abroad, as other countries look to meet their emissions reduction commitments. Action now can harness the UK’s strengths in engineering, procurement, construction, and management services, with export opportunities from CCUS estimated at £3.6 billion by 2030.

Hydrogen

The Deal will position the oil and gas sector to develop and support the deployment of hydrogen production capacity in the UK. As a gas that can be used as a fuel without emitting harmful greenhouse gasses at the point of use, hydrogen will be critical in reducing emissions from heavy industry, as well as in power, heat and transport. When heavy goods transport or a process such as steel production relies on fuel for energy, hydrogen can provide a crucial, low-carbon alternative to fossil fuels.

The Prime Minister’s Ten Point Plan and the Energy White Paper confirmed our commitment to publish the UK’s first ever Hydrogen Strategy, which the government will bring forward in the first half of this year. The Strategy will detail the key steps needed in the 2020s to deliver our 5GW ambition and set the context for further scale up on the way to net zero in 2050. This will provide a clear long-term signal that government is committed to building a world leading UK hydrogen economy, and set out the detail of how the government will work with industry – including the oil and gas sector to achieve this.

To achieve this growth in hydrogen it is expected that up to £4 billion of capital investment will need to be unlocked to develop the hydrogen production projects to deliver 5GW of clean hydrogen production capacity in 2030, equating to 42TWh/y, and supporting up to 8,000 direct jobs by 2030[footnote 24] across our industrial heartlands and beyond.

Action now to deploy hydrogen during the 2020s will stimulate domestic supply chains, enabling UK businesses to capture increasing international demand for hydrogen goods and services. Ensuring this happens will be an important part of the UK's forthcoming Hydrogen Strategy.

The exact mix of different end uses for clean hydrogen in 2050 will depend on a variety of factors including cost, availability and technical application. Action is needed now to enable hydrogen to be deployed flexibly in the future. The UK will need production at scale by 2030 to provide assurance on safety, security cost and the potential for emissions reduction, before the UK can scale up even further during the 2030s. To put the UK on this pathway, the oil and gas industry is well positioned to enable the production of low-carbon hydrogen at scale as part of a long-term competitive market. There is a growing range of initiatives and a pipeline of projects with respect to hydrogen development including those that are aligned to the main CCUS cluster locations.

The government will create a Net Zero Hydrogen Fund to support low-carbon hydrogen production, providing £240 million of co-investment out to 2024/25. The Net Zero Hydrogen Fund will deliver a major boost to production capacity, ensuring that clean hydrogen can be utilised for decarbonising industrial clusters, kick starting an expanded UK hydrogen economy that can play its role in delivering net zero. However, achieving our 2030 ambition for clean hydrogen will also require the right commercial frameworks which encourage sustained private sector investment. The government will put the necessary building blocks in place now to provide confidence that clean hydrogen can be produced reliably and cost-effective. The government will introduce a commercial framework by 2022, which enables project sponsors of all types of clean hydrogen to finance their projects. The government will consult on the preferred model in 2021.

The UK is already a world leader in investigating the use of hydrogen for heating, replacing fossil fuels like natural gas with hydrogen and hydrogen blends. The government are keen to accelerate this work by working with the oil and gas sector and others.

Both the government and the gas industry are currently running major studies and testing projects. The government will increase the funding available for testing and trialling projects, working with the industry to ensure that the overall programme of work is comprehensive and fully coordinated. A range of further research and development (R&D) and testing projects is required, including an assessment of the options for major new hydrogen infrastructure, such as gas transmission networks and inter-seasonal storage. Hydrogen will be one of the ten key priority areas in the £1billion Net Zero Innovation Portfolio.

Trials of hydrogen will also be key to evaluating the practicalities of converting existing boiler appliances and the way in which consumers experience hydrogen for heating in their own homes and workplaces. The government will support wider UK industry to begin a Hydrogen Neighbourhood trial by 2023, and a large Hydrogen Village trial by 2025. The knowledge and experience gained in delivering trials in communities, together with the results of our wider R&D and testing programme, will enable strategic decisions around the mid-2020s over the long-term role of hydrogen for heating and develop a plan for a potential Hydrogen Town before the end of the decade.

To facilitate the transition and development of the gas network, the government will continue to work with the HSE to enable up to 20% hydrogen blending on the network by 2023. This is subject to the success of testing and trials.

Supply Chain transformation

Over the last five decades as the UK has benefitted from its offshore oil and gas resources, a supply chain of world renown has developed, servicing the industry's needs both domestically and abroad. The supply chain has advanced in clusters around the main centres of offshore activity in North-East Scotland, the North of England and East Anglia, building on the UK's previous strengths in marine and maritime engineering and broader heavy industrial engineering capabilities.

The oil and gas supply chain has grown to be a valuable component of the UK economy which has gained the skills to be competitive on the world stage. It supports around 147,000 direct and indirect jobs in the UK and contributes c.£28 billion to the UK economy, including around £12.7. billion in exports 2019[footnote 25]. The oil and gas supply chain has historically been a powerhouse for innovation and employment in the UK economy. With targeted support it can pivot to bring that same innovation to meet the needs of the energy transition whilst building from its base capabilities developed by servicing the needs of the UK's domestic oil and gas sector.

Diversified Supply Chain

There are already signs of diversification with oilfield service companies generating around 27% of revenue[footnote 26] (in 2018) from non-exploration and production revenue streams. Recent OGUK member surveys indicate that as many as half of supply chain companies already provide goods and services to other sectors.

The UK oil and gas supply chain already has the necessary expertise and proven capabilities to service the needs of the energy transition both at home and abroad, putting the UK in a uniquely competitive position.

However, a new approach to transformation and capability development will be required to develop an all-energy, UK-based supply chain that can deliver decarbonisation at scale to meet the net-zero target. Current assessments show that the UK supply chain can provide some of the skills, capabilities and expertise needed to deliver the outcomes identified in the Deal – decarbonising traditional oil and gas production by offshore electrification, providing low carbon hydrogen, and safely capturing, transporting and storing carbon. Given the different nature of some of the investments required to support the Deal there is scope for contractor companies, alongside traditional investors and infrastructure businesses, taking a lead in drawing together the consortia and funding required. The sector will seek to link up with supply chain initiatives in other sectors (such as offshore wind), where this will add value.

Supply Chain Consortia

This step-change in the role of the supply chain to drive decarbonisation at scale will require support from both industry and government. Supporting UK supply chains at these early stages in the development of the energy markets and technologies of the future will be key to anchoring existing skills and high-quality jobs in the UK and will provide energy security and resilience in the face of global competition.

The supply chain will create the consortia that can lead the development of competitive low carbon solutions and deploy them at scale in the UK and internationally, making the most of the technology, innovation and expertise that has built the UK supply chain's international reputation within the oil and gas sector. These are the companies that will emerge as the low carbon supply chain of the future.

There are few energy supply chain giants in the UK and creating such supply chain led consortia with appropriate government support and funding will bring together the critical skills, technology, and capability to win business in the energy transition.

Access to government research, development and innovation funding that companies and consortia can bid into with matched funding will substantially grow the pipeline of projects reaching investment sanction both before 2030 and beyond, to the wider benefit of the UK economy. The consortia established by the oil and gas sector's supply chain should reflect the broader nature of the supply chain and provide opportunities for all sizes of businesses to work together on the emerging opportunities. These groupings will leverage the UK's capability to deliver net zero projects and secure supply chain diversification and export opportunities, and where necessary underpinned by government and industry funding to help manage investment risks.

The establishment of supply chain consortia enables balance sheets, skills, technologies, and capability to be pooled whilst business and technical risks are more effectively mitigated. Kickstarting such supply chain consortia will accelerate the movement into these new energy markets.

Net Zero Innovation Portfolio

The Prime Minister's Ten Point Plan announced a new £1 billion Net Zero Innovation Portfolio that will help bring down the cost of the net zero transition, nurture the development of better products and new business models, and influence consumer behaviour.

This fund aims to accelerate the commercialisation of innovative low-carbon technologies, systems and processes in power, buildings and industry to set the UK on the path to net zero and create world-leading industries and new jobs. The portfolio will focus on ten priority areas to decrease the costs of decarbonisation and underpin innovation across the whole energy system. Priority areas will include floating offshore wind, hydrogen and advanced CCUS.

As well as accelerating the commercialisation of novel clean energy technologies, innovation also plays an important role in driving economic growth, anchoring new technology to the UK, levelling-up opportunities across the country and reducing our significant exposure to the risks of climate change.

An ambitious and well-designed energy innovation strategy could, by 2050, annually generate £54 billion of business opportunities for the UK. The current BEIS £505 million Energy Innovation Programme is delivering some of the UK's most significant advances in low-carbon technologies, leveraging £200 million industry investment, including the UK's first CCUS plant at Tata Chemicals, Cheshire (£17 million total investment).

Prompt Payment Code

Late payment causes real hardship to smaller businesses, and the issue is more prevalent than ever due to the continued impact of the pandemic. It is important for businesses of all sizes but particularly larger businesses, to demonstrate their commitment to ending the culture of late payment and helping to increase business confidence.

In January, the government announced the reformed Prompt Payment Code. Under this Code, business signatories will, in addition to their current public commitment to pay 95% of all payments to their supply chain within 60 days, have committed to paying 95% of their small business suppliers within 30 days. The government commends all businesses to go further than this.

Under the industry's Supply Chain Principles, companies are encouraged to pay suppliers promptly for their services. These principles also recognise the flexibility that companies may choose to include in their payment terms for commercial reasons and respecting that companies should follow the terms within which they contract services. Beyond these principles OGUK will champion the adoption of the government's Prompt Payment Code within its constituent companies.

Driving UK Industrialisation

The sector will leverage supply chain capability mapping to understand where the UK supply chain can realistically deliver energy transition and decommissioning projects, considering their competitive position both in relation to the domestic market and internationally. In parallel, the government will develop its understanding of the capability required to deliver the energy transition.

The government will deliver the energy transition, including work to assess the scale of the opportunity for companies in the emerging CCUS and hydrogen sectors. In addition, the government will look to increase the visibility of the pipeline of clean growth projects in order to support the supply chain to assess forthcoming opportunities.

Based on existing knowledge, the sector will commit to voluntary targets for the proportion of UK content within an overall lifecycle of at least 50%, playing on UK strengths in project design, installation, integration and lifecycle operations. It is also proposed that a voluntary target of a minimum of 30% locally provided technology content is incorporated in all low carbon projects to reinforce the growth of domestic capabilities and the development of low carbon solutions that industry-led consortia can help foster.

Supply Chain Representation

The role of the UK energy supply chain needs more profile. Strengthening UK capability to service domestic needs as well as being positioned to compete effectively in the global market will need to be included within the considerations of future trade deals. By appointing a supply chain champion who will represent the energy supply chain, there will be a welcome focal point, enabling the coordination of activities across government, and with export focused bodies to support the UK supply chain.

Department for International Trade (DIT) strategy for the energy transition

The shifting global landscape, the increasing complexity, the deepening interrelatedness of technologies and markets have together shaped a different environment, within which DIT must deliver the government's energy trade and investment ambitions. DIT has traditionally focussed strongly on direct trade and investment support – this will continue across the government's global network - but often the 'full and long-term economic value' of that approach is not captured within the transactional, short-term nature of this focus. When considering value to the UK in the round other factors also become important including:

- Sustaining and growing key skills and capacities for the long-term
- Enhancing UK's ability to compete internationally
- Building national resilience in the face of unforeseen events
- Maintaining the security, affordability, and sustainability of energy supply
- Creating new jobs and innovation opportunities.

The energy transition has created a once-in-a-generation opportunity and DIT is ideally placed to use its international networks, corporate relationships, and market knowledge to be a major contributor to the building of a lasting and sustainable energy sector in the UK.

DIT's vision is clear: maximise the investment, growth, and export potential of the energy transition.

Government's contribution to achieve this will be to:

- Support efforts to ensure Free Trade Agreements (FTA) and other trade policy mechanisms are as supportive as possible of clean energy, with a focus on creating an exemplar 'green' FTA.
- Work directly on ambition-critical and high-profile investment and export projects resulting from our work to 'make markets'.
- Develop government to government relationships with a small number of priority markets in an effort to drive market-making activity and create pull for UK solutions.
- Informed by transition mapping and Prosperity Fund pilot projects, proactively engage with the design and delivery of relevant technical assistance programmes, supported by non-ODA resource.
- Create high-quality marketing and promotional materials to support the DIT network in messaging to buyers and suppliers.
- Work with BEIS and industry to map current and future skills needs and develop a plan to protect and grow UK energy skills, linked to the timescales and ambition for low-carbon solution deployment.
- Work with BEIS to ensure UK supply chain development is central to domestic policies supporting the deployment of low-carbon energy technologies.
- Work with domestic policy makers on sector-specific issues that impact on current and future investment and export ambitions.
- Work with suppliers in neighbouring and traditional industries and support their access to domestic clean energy projects, helping them to build competitive cost and quality propositions.
- Implement a streamlined approach to account and stakeholder management, taking a pan-energy approach wherever possible.
- Support supply chain sustainability and resilience, including a focus on the carbon intensity of these supply chains.
- Develop a new approach to working with UK Export Finance, including joint account management of key companies, a shared pipeline and upskilling of DIT staff.

People & Skills

The people and skills commitments of the Deal outlines some of the crucial steps needed to ensure that industry can retain and attract talent within the hydrocarbon industry as well as the new low carbon sectors and how it will support the workforce to transition between these. It sets out clear actions for both industry and government to work collaboratively together to achieve the commitments.

Oil and gas and heavy industry are some of the sectors most exposed to the energy transition. These industries are distributed across the UK, concentrated in regions such as North East Scotland and Aberdeen, North of England and East Anglia, and could be vulnerable to a transition of this scale.

Scotland for example is still significantly dependent on the oil and gas industry, with over 10% of workers in Aberdeen directly employed by the sector. Poorly managed, the transition may have serious impacts on the broader local economy[footnote 27] but workers in this sector have a crucial part to play in the transition, at least 68% of the UK's oil and gas workers have skills that could transition to the low carbon sector.

Green Jobs Taskforce

In 2019, the UK set a world leading target of reaching net zero emissions by 2050. This transition will transform our economy and require changes across our transport and energy systems, the way in which we construct and heat our buildings, industrial processes and our land, agriculture and food.

The Prime Minister has set out the government's determination to build back better and greener from COVID-19 and announced our Ten Point Plan to tackle climate change and drive a green industrial revolution. It will mobilise £12 billion of government investment to support up to 250,000 highly skilled green jobs in the UK, and spur over three times as much private sector investment by 2030.

The Green Jobs Taskforce forms part of the Ten Point Plan and will set the direction for the jobs market as the UK transitions to a high skill, low carbon economy. The taskforce will focus on the immediate and longer term challenges of delivering skilled workers for the UK's transition to net zero.

The Taskforce is chaired by the Minister of State for Business, Energy and Clean Growth, Anne-Marie Trevelyan, and Parliamentary Under Secretary of State for Apprenticeships and Skills, Gillian Keegan.

The priority focus areas for the Taskforce are to:

1. Support a Green Recovery and ensure the UK has the immediate skills needed.
2. Develop a long-term plan that charts the skills needed to help deliver a net zero economy focusing on the next decade.
3. Ensure green jobs are goods jobs and open to all.
4. Support workers in high carbon sectors to transition and retrain.

Oil and Gas Sector Workforce

The UK's offshore oil and gas industry is a source of significant employment, with OGUK calculating that approximately 260,000 jobs were supported in 2018, of which around 147,000 were in direct and indirect employment in the oil and gas sector[footnote 28]. As a mature hydrocarbon basin, it is forecast that production from the UKCS and investments in new developments will gradually decline over the coming decades. This will have an impact on employment in the sector, likely resulting in a corresponding decline in workforce numbers.

Based on the Roadmap 2035 production profile forecasts, OGUK estimates that over 190,000 people may still be supported by the industry in 2030 (with around 105,000 of these in direct and indirect employment). Although this is still a significant workforce, it does represent a decline compared to today's figures.

Arguably, the rate of attrition accelerated in 2020 due to the difficult business environment as the sector tackled the combined issues of COVID-19, low gas prices and low and volatile oil prices. OGUK estimated that up to 30,000 jobs could be lost by the end of 2021[footnote 29].

Many of the skills present in industry today are transferrable across the wider energy spectrum. Offshore renewables, as well as the future CCUS and hydrogen industries, will rely heavily on many of the current skillsets in the oil and gas industry such as geologists, project managers, a wide variety of engineers and craftspeople. A carefully managed transition will help to ensure that the UK retains people with these key skillsets, so that they can help unlock these vital and emerging low carbon sectors.

The Energy Transition

It is estimated that up to 40,000 direct and indirect supply chain jobs could be supported as a result of the investment outlined in the Deal. These jobs represent opportunities for the current oil and gas workforce to transition into, as demand for their current roles in the oil and gas industry wanes with production decline. It also represents opportunities for new entrants into the energy sector.

Equality of Opportunity

To attract and retain diverse talent, the sector needs to ensure it is also an inclusive and appealing place to work and therefore a sustained focus on diversity and inclusion in the workplace will be vital.

As an industry, the oil and gas sector does have some way to go in terms of improving representation of underrepresented groups in its workforce and becoming more reflective of modern UK society.

To truly reap the benefits of a diverse workforce, it is critical to ensure that an inclusive working environment is created, enabling every individual in an organisation to participate, contribute and achieve their full potential. As well as benefitting individuals, good diversity and inclusion practice also has benefits for businesses; according to the CIPD, the three main benefits include talent retention and acquisition, market competitiveness and corporate reputation.

Recognising the need for improvements in this area, the following actions are taking place:

- Industry is currently conducting a survey to test and understand sentiment within the sector's workforce which will be used to create an Inclusion Index to identify areas for improvement.
- In 2021, industry will run an employer survey to understand the sector's current demographics and establish a baseline. The questions will seek to gain an understanding of the workforce's current makeup in terms of gender, ethnicity, age, disability, and sexuality. Key findings and a list of recommended actions to help improve diversity will be published with follow-up surveys to be run throughout the decade at agreed intervals to measure progress and change.
- The sector is committed to ensuring everyone working in the industry – whatever their background – has the opportunity to unleash their potential.
- The government will work with the oil and gas industry, alongside others, to ensure that equality of opportunity will be considered from the outset as the UK hydrogen and CCUS sectors are developed, starting with appropriate representation of groups at HMG/industry boards.

Post Graduate training

The Centre for Doctoral Training's (CDT) GeoNetZero (GNZ) programme, focuses on geoscience and its role in the low carbon energy transition and the challenge to meet net-zero emissions targets. The programme is a PhD course focused on progressing the transition to a low carbon energy economy through geology-focussed projects and theses.

Industry and academia have already pledged initial support to this newly formed scheme by contributing £7.5 million to set the programme up via £5 million towards PhD research scholarships and £2.5 million to underpin an accompanying bespoke 20-week training programme. The research funding will cover the costs for a total of 48 students who will participate and complete the programme in three annual cohorts starting in 2020-22. The first cohort, which had space for and successfully recruited 16 students, received over 260 high-quality applications; the second cohort received over 350 high-calibre applications and has led to a further 16 students being recruited in 2021. This demonstrates the huge appetite for this programme and underlines that it is at present significantly underfunded.

The government will work with the CDT to help ensure more students can benefit and, in turn, bring their expertise into the workforce to address the low carbon energy transition, extend the life of the North Sea by overseeing the re-purposing of existing infrastructure and ensure that the basin attains its net zero emission targets.

Cross Energy Skills

It is widely accepted that the oil and gas workforce possess many of the key skills and expertise that will be needed to support the CCUS and hydrogen sectors. However, a better understanding of the future skills profile is crucial to ensuring that the developing CCUS and hydrogen sectors both have access to a skilled workforce. Such profiling will increase the visibility of skills needed in all three sectors as well as highlighting potential shortages, surpluses, and opportunities for role transfer, thereby helping to ensure that demand can be met across the board.

The Energy Skills Alliance (ESA) is championing this work through its Future Energy Skills Demand workstream, which seeks to map the energy sectors' current capabilities and future requirements. This work is set to be completed in 2021, after which it will be critical for businesses, academia and governments to carefully consider how they can work collaboratively to ensure that this demand is met.

This work will be supported by a focused Integrated People & Skills Plan for the oil and gas sector. The findings of this detailed plan will be fed into the ESA's workstream.

The sector is committed to ensuring that roles within the sector, both existing and future, are of good quality and so OGUK is committed to working with its members and union representatives to ensure the UK's high employment standards are promoted across industry.

Governance of the Deal

Oversight of the implementation of the North Sea Transition Deal will be led by a delivery group, which will review progress against objectives at quarterly meetings. The delivery group will be chaired by an industry representative of the North Sea Transition Forum (NSTF) and BEIS and supported by a small Project Management Office hosted by OGUK.

The governance for the North Sea Transition Deal will build on the existing tripartite mechanism involving government, industry, OGA and the North Sea Transition Forum, which meets twice a year. The Forum, supported by its steering committee, will set the strategic direction for the sector and will also be accountable for the delivery of the Deal, including the review and approval of the work programme.

Once the Deal enters the implementation phase, representatives of the Delivery Group will report on progress bi-annually to BEIS Ministers responsible for the Deal. The Forum will be responsible for reporting to the government on delivery at regular intervals.

---

1. OGA (2020). UK Oil and Gas Reserves and Resources as at end 2019, September 2020, OGA publication. [redacted]
2. HMRC (2020). Statistics of Government revenues from UK oil and gas production, July 2020. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/902798/Statistics_of_government_rev (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/902798/Statistics_of_government_revenues_from_UK_oil_and_gas_production__July_2020_for_publication.pdf)
3. HM Government (2020). Energy White Paper – Powering our net zero future, December 2020. https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future (https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future)
4. OGUK (2019). Roadmap 2035, A blueprint for Net Zero, September 2019, OGUK.
5. CCC (2020). The Sixth Carbon Budget, The UK's path to Net zero, Climate Change Committee, December 2020. [redacted]
6. The Conservative Party Manifesto, Get Brexit Done, Unleash Britain's Potential, 2019 https://www.conservatives.com/our-plan (h[redacted]
8. HM Government (2020). The Ten Point Plan for a Green Industrial Revolution, November 2020. https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution (https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution)
9. The 60Mt also includes emissions savings from CCUS and hydrogen already set out in the PM's 10 Point Plan.
10. The CCUS and hydrogen jobs will include some of the jobs already set out in the PM's 10 Point Plan.
11. HM Government (2021) https://www.gov.uk/government/publications/budget-2021-documents (https://www.gov.uk/government/publications/budget-2021-documents)

[redacted]

13. GVA: ONS (2020). 'GDP output approach – low-level aggregates', tab CVM £million, https://www.ons.gov.uk/economy/grossdomesticproductgdp/datasets/ukgdpolowlevelaggregatesTaxes (https://www.ons.gov.uk/economy/grossdomesticproductgdp/datasets/ukgdpolowlevelaggregatesTaxes)
14. OGA (2020). Government revenues from UK oil and gas production in 2019-2020 prices h[redacted]n-[redacted]

15. OGUK (2019). Workforce Report, 2019. (Figure from 2018)[redacted]
17. OGA (2020). OGA oil and gas production projections, table 4, [redacted]
19. BEIS (2019). Energy Trends Table 4.1, https://www.gov.uk/government/statistics/gas-section-4-energy-trends (https://www.gov.uk/government/statistics/gas-section-4-energy-trends)
20. Bloomberg tracker for Brent Crude.

[redacted]

23. The estimate for CCUS jobs set out in the Ten Point Plan publication includes all parts of the CCUS sector including export opportunities and is not directly comparable with other jobs estimates in this document.
24. These estimates set out in the Ten Point Plan publication are not directly comparable with other estimates in this document.

[redacted]

27. IPPR (2020). Net Zero North Sea: A managed transition for oil and gas in Scotland and the UK after Covid-19, December 2020.

[redacted]

Appendix E

Fast action on methane to keep a 1.5°C future within reach

About the Global Methane Pledge

Methane is a powerful but short-lived climate pollutant that accounts for about half of the net rise in global average temperature since the pre-industrial era.

Rapidly reducing methane emissions from energy, agriculture, and waste can achieve near-term gains in our efforts in this decade for decisive action and is regarded as the single most effective strategy to keep the goal of limiting warming to 1.5˚C within reach while yielding co-benefits including improving public health and agricultural productivity.

President Biden and President Von der Leyen announced at the September 17 Major Economies Forum (MEF) meeting that the United States and the European Union are inviting countries to support the Global Methane Pledge to be launched at COP 26 in November 2021 in Glasgow.

Participants joining the Pledge agree to take voluntary actions to contribute to a collective effort to reduce global methane emissions at least 30 percent from 2020 levels by 2030, which could eliminate over 0.2˚C warming by 2050. This is a global, not a national reduction target. Participants also commit to moving towards using the highest tier IPCC good practice inventory methodologies, as well as working to continuously improve the accuracy, transparency, consistency, comparability, and completeness of national greenhouse gas inventory reporting under the UNFCCC and Paris Agreement, and to provide greater transparency in key sectors.

The Pledge aims to catalyze global action and strengthen support for existing international methane emission reduction initiatives to advance technical and policy work that will serve to underpin Participants' domestic actions. The Pledge also recognizes the essential roles that private sector, development banks, financial institutions and philanthropy play to support implementation of the Pledge and welcomes their efforts and engagement.

With over 100 countries on board, representing nearly 50% of global anthropogenic methane emissions and over two thirds of global GDP, we are well on our way to achieving the Pledge goal and preventing more than 8 gigatons of carbon dioxide equivalent emissions from reaching the atmosphere annually by 2030.

We will convene annual ministerial level meetings to review progress following the launch of the Global Methane Pledge in November 2021.

Read the pledge

Pledges

Participants

- Albania
- Andorra
- Argentina
- Armenia
- El Salvador
- Estonia
- Ethiopia
- European Union
- Libya
- Liechtenstein
- Luxembourg
- Malawi
- Rwanda
- Saint Kitts and Nevis

Samoa

Saudi Arabia

See all 113 participants

Supporters

[redacted]

[redacted]

[redacted]

[redacted]

GLOBAL DAIRY PLATFORM

[redacted]

Global Methane Initiative

[redacted]

GREEN CLIMATE FUND

[redacted]

iea

[redacted]

See all supporters

Media

News

NEWS

[Around 100 nations pledge to slash methane emissions on day 2 of COP26]

4 Nov: Approximately 100 countries have signed on to a global pledge to cut methane emissions by 30% by 2030, led by the United States and the European Union...

Read

NEWS

Launch by US, EU, and Partners of the Global Methane Pledge to Keep 1.5C Within Reach

2 Nov: Today, the United States, the European Union, and partners formally launched the Global Methane Pledge, an initiative...

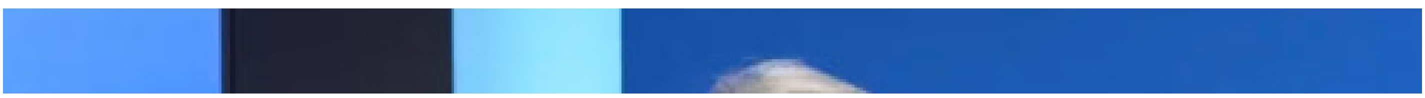
Read

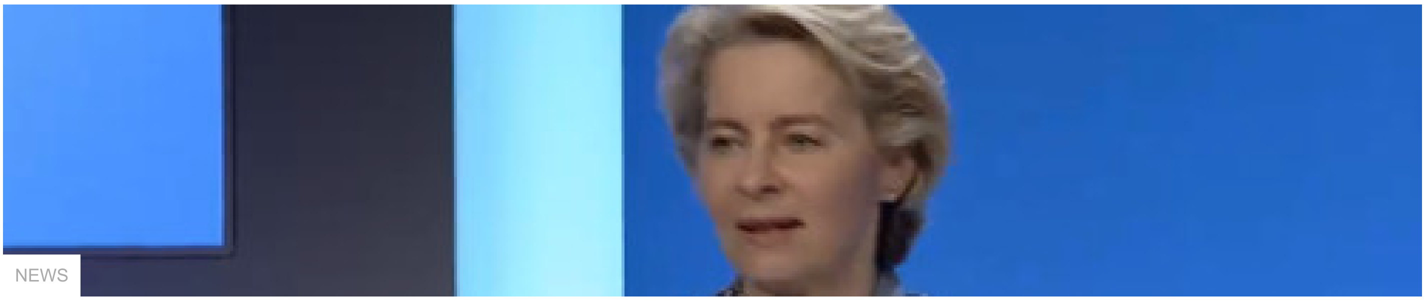
PRESS RELEASE

US, EU, and Partners Formally Launch Global Methane Pledge to Keep 1.5C Within Reach

2 Nov: A total of over 100 countries representing 70% of the global economy and nearly half of anthropogenic methane emissions have...

Read





NEWS

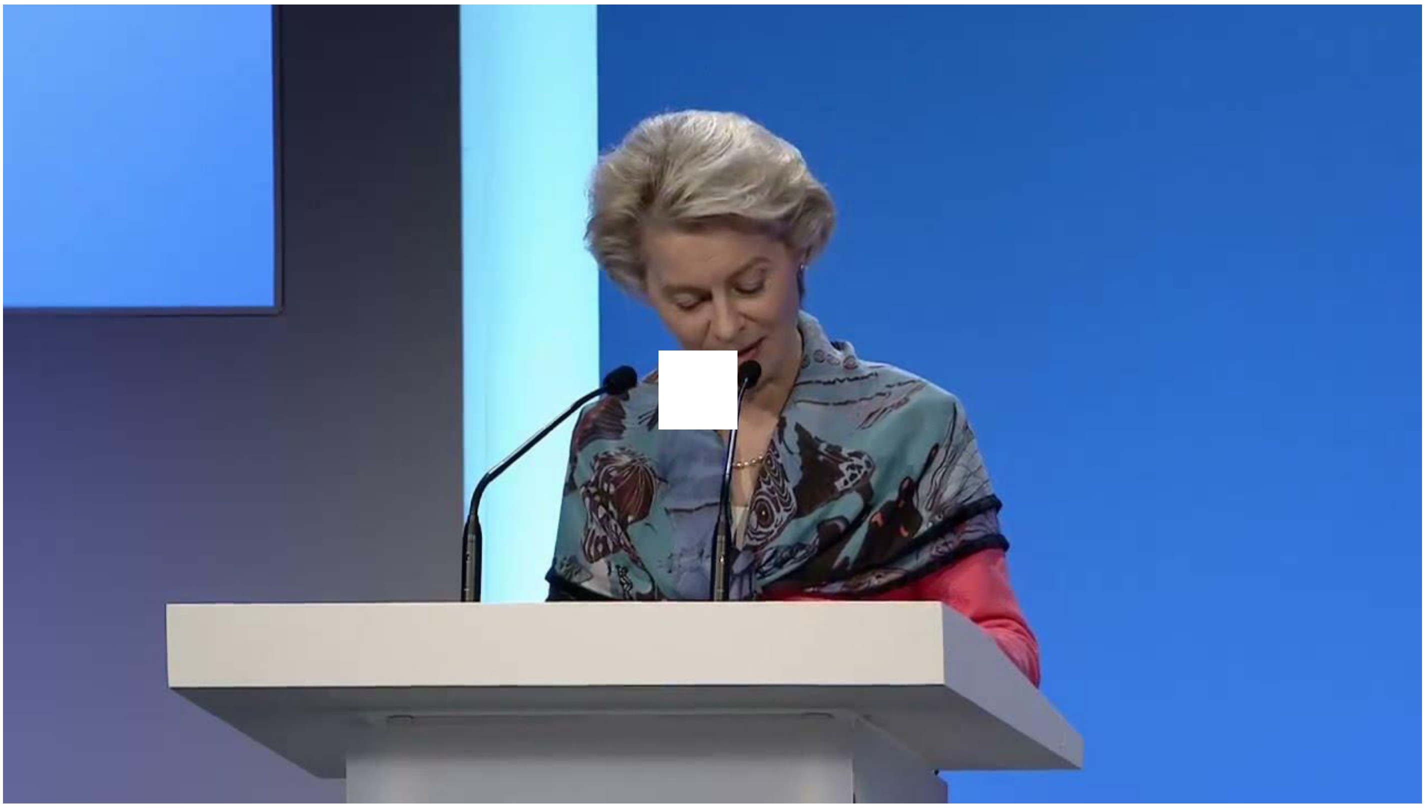
[At COP26, more than 100 countries commit to reducing methane emissions]

2 Nov: The European Union and the United States have launched a landmark pledge to slash emissions of the powerful...

Read

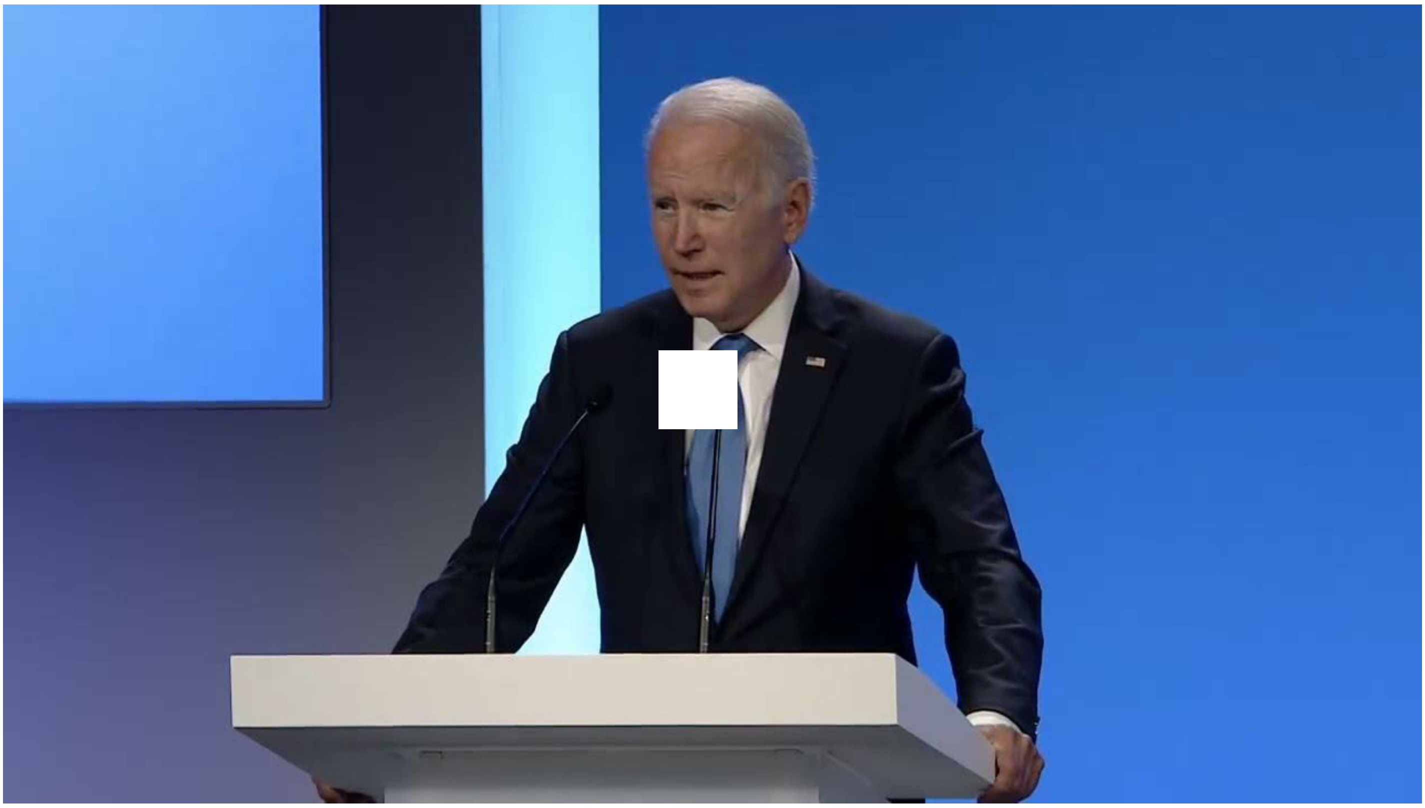
See all »

Multimedia



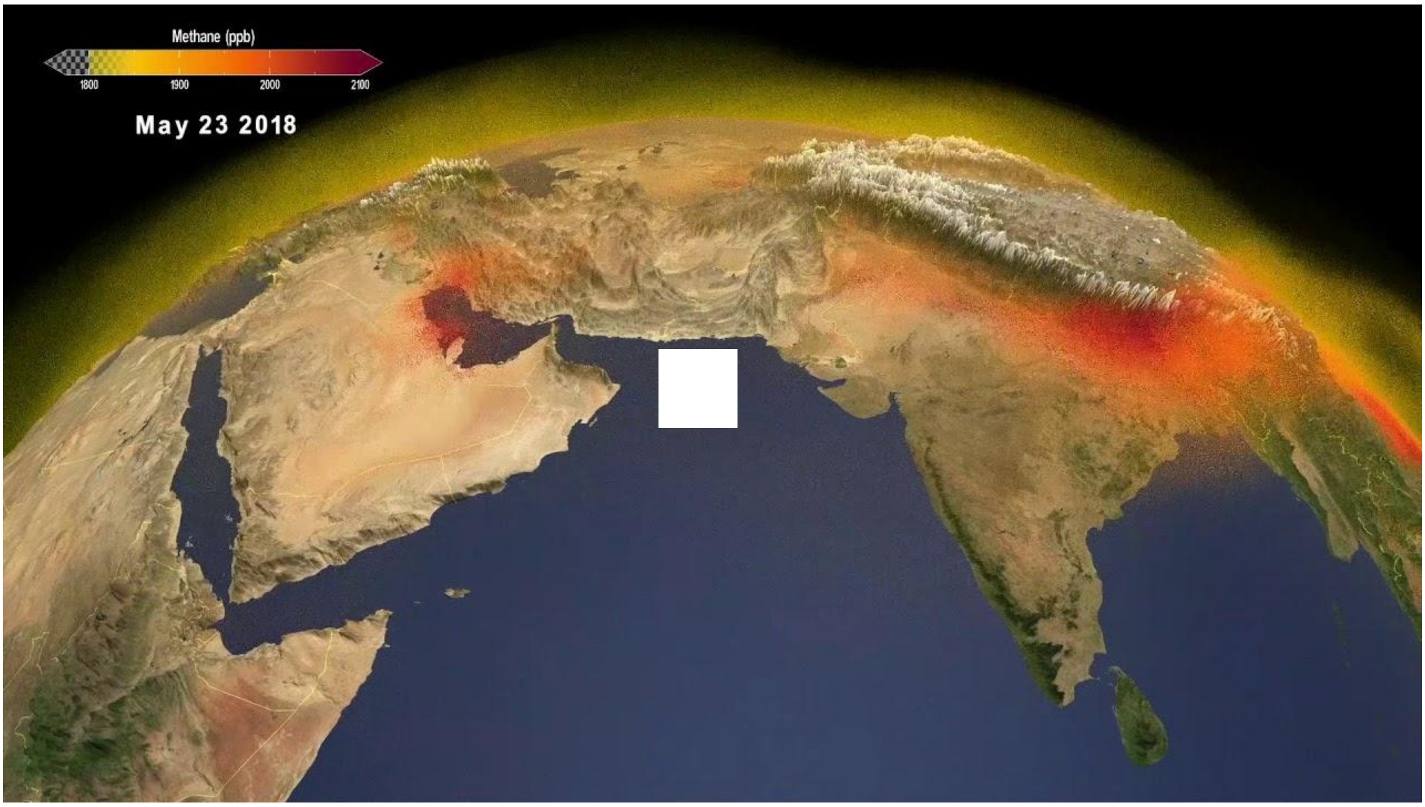
Remarks by Ursula von der Leyen

Remarks from President of the European Commission, Ursula von der Leyen, at the launch of the Global Methane Pledge at the U.N. Climate Summit (COP26), Nov. 2, 2021, in Glasgow, Scotland.



Remarks by US President Joe Biden

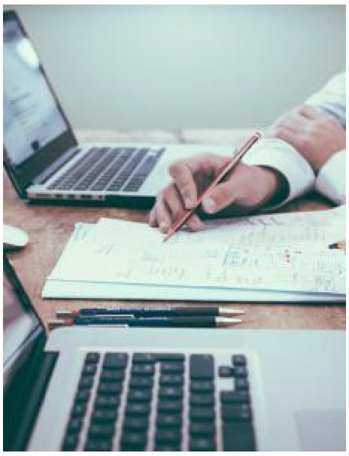
Remarks by US President Joe Biden at the launch of the Global Methane Pledge at the U.N. Climate Summit (COP26), Nov. 2, 2021, in Glasgow, Scotland.



Sources of Methane (NASA)

Visualization showing the complex patterns of methane emissions produced globally between January 2018 and November 2018 from different sources.

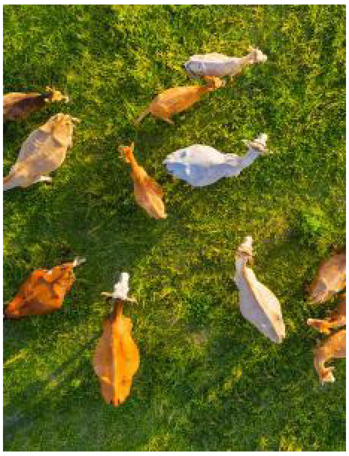
Resources



Methane technical assistance

Site providing access to methane mitigation tools, experts on methane mitigation, and national planning, policy and regulatory support.

Visit site



Briefing on the Global Methane Pledge

The Global Methane Pledge is a strong first step as the first-ever Heads-of State global commitment to cut methane emissions at a level consistent with a 1.5°C pathway. The 30% goal serves as an ambitious floor to start from. As countries get better at reducing methane and technologies improve and...

Download

Global Methane Assessment

The Global Methane Assessment shows that human-caused methane emissions can be reduced by up to 45% this decade. Such reductions would avoid nearly 0.3°C of global warming by 2045 and would be consistent with keeping the Paris Climate Agreement's goal to limit global temperature rise to 1.5˚C within...

Download

International Methane Emissions Observatory (IMEO)

The Observatory will produce a global public dataset of empirically verified methane emissions – starting with the fossil fuel sector – at an increasing level of granularity and accuracy by integrating data principally from: reporting from the Oil and Gas Methane Partnership 2.0 (OGMP 2.0), oil and...

Visit web page

Climate and Clean Air Coalition (CCAC)

The Climate and Clean Air Coalition is a voluntary partnership of governments, intergovernmental organizations, businesses, scientific institutions and civil society organizations committed to protecting the climate and improving air quality through actions to reduce short-lived climate pollutants...

Visit website

Global Methane Initiative (GMI)

The Global Methane Initiative (GMI) is an international public-private partnership focused on reducing barriers to the recovery and use of methane as a valuable energy source. GMI provides technical support to deploy methane-to-energy projects around the world that enable Partner Countries to launch...

Visit website

Contact

Use this form to request additional information or to express your interest in joining the Global Methane Pledge.

Name

Email

Title

Organization

Message

▼ CAPTCHA

This question is for testing whether or not you are a human visitor and to prevent automated spam submissions.

I'm not a robot

reCAPTCHA
Privacy - Terms

Send message

CLIMATE & CLEAN AIR COALITION TO REDUCE SHORT-LIVED CLIMATE POLLUTANTS

Appendix F

Mitigating climate disruption in time: A self-consistent approach for avoiding both near-term and long-term global warming

Gabrielle B. Dreyfus[a,b], Yangyang Xu[c,1], Drew T. Shindell[d], Durwood Zaelke[a,e], and Veerabhadran Ramanathan[f,g,1]

Contributed by Veerabhadran Ramanathan; received January 6, 2022; accepted March 22, 2022; reviewed by Valerie Masson-Delmotte and Venkatachalam Ramaswamy

The ongoing and projected impacts from human-induced climate change highlight the need for mitigation approaches to limit warming in both the near term (<2050) and the long term (>2050). We clarify the role of non-CO_2 greenhouse gases and aerosols in the context of near-term and long-term climate mitigation, as well as the net effect of decarbonization strategies targeting fossil fuel (FF) phaseout by 2050. Relying on Intergovernmental Panel on Climate Change radiative forcing, we show that the net historical (2019 to 1750) radiative forcing effect of CO_2 and non-CO_2 climate forcers emitted by FF sources plus the CO_2 emitted by land-use changes is comparable to the net from non-CO_2 climate forcers emitted by non-FF sources. We find that mitigation measures that target only decarbonization are essential for strong long-term cooling but can result in weak near-term warming (due to unmasking the cooling effect of coemitted aerosols) and lead to temperatures exceeding 2 °C before 2050. In contrast, pairing decarbonization with additional mitigation measures targeting short-lived climate pollutants and N_2O, slows the rate of warming a decade or two earlier than decarbonization alone and avoids the 2 °C threshold altogether. These non-CO_2 targeted measures when combined with decarbonization can provide net cooling by 2030 and reduce the rate of warming from 2030 to 2050 by about 50%, roughly half of which comes from methane, significantly larger than decarbonization alone over this time frame. Our analysis demonstrates the need for a comprehensive CO_2 and targeted non-CO_2 mitigation approach to address both the near-term and long-term impacts of climate disruption.

climate mitigation | short-lived climate pollutants | fossil fuel radiative forcing | near-term warming | non-CO_2 climate effects

Significance

This study clarifies the need for comprehensive CO_2 and non-CO_2 mitigation approaches to address both near-term and long-term warming. Non-CO_2 greenhouse gases (GHGs) are responsible for nearly half of all climate forcing from GHG. However, the importance of non-CO_2 pollutants, in particular short-lived climate pollutants, in climate mitigation has been underrepresented. When historical emissions are partitioned into fossil fuel (FF)- and non-FF-related sources, we find that nearly half of the positive forcing from FF and land-use change sources of CO_2 emissions has been masked by coemission of cooling aerosols. Pairing decarbonization with mitigation measures targeting non-CO_2 pollutants is essential for limiting not only the near-term (next 25 y) warming but also the 2100 warming below 2 °C.

Global warming is causing climate disruption today. At about 1.1 °C warming above preindustrial temperature (1), these impacts are being felt sooner and more intensely than previously projected (2). The frequency and intensity of climate and weather extremes have increased due to human-induced climate changes (1), and impacts such as displacements due to extremes are expected to grow with additional global warming (2).

We make a distinction between near-term warming and long-term warming: Near-term warming refers to the warming from now until 2050, while long-term refers to the period beyond 2050. This distinction omits the "mid-term (2041 to 2060)" recently introduced in the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report (AR6) (1). When the focus is on long-term, decarbonization to reach net-zero carbon dioxide emissions should be the foremost goal. However, a new set of issues has emerged because of the link between warming and extreme weather (3) and the risk of crossing uncertain tipping points that increase with additional warming (1, 4).

Every region is experiencing extreme weather impacts from climate change (2, 5). The number of potentially fatal humid heat events doubled between 1979 and 2017 (6), while heat-related mortality in people over 65 y increased 53.7% (7). Such fatal humid heat events are expected to become common in the tropics at global average temperatures above 1.5 °C (8, 9). Increases in humid heat also reduce labor productivity, with current losses of annual gross domestic product up to 6% in tropical countries (7) and nonlinear increases under warming (10). Actions that limit warming to close to 1.5 °C would "substantially reduce projected losses and damages related to climate change in human systems and ecosystems, compared to higher warming levels, but cannot eliminate them all (*very high confidence*)" (2).

The critical need to curb near-term warming and limit warming to well below 2 °C requires broadening the zero carbon dioxide emissions approach, which focuses on mitigating the long-term warming, with other approaches that can quickly reduce the near-term warming by including non-CO_2 warming pollutants as an additional major

Author contributions: G.B.D., Y.X., D.T.S., D.Z., and V.R. designed research; G.B.D. and Y.X. performed research; G.B.D., Y.X., D.T.S., and V.R. analyzed data; and G.B.D., Y.X., D.T.S., D.Z., and V.R. wrote the paper.

Reviewers: V.M.-D., Laboratoire des Sciences du Climat et de l'Environnement; and V.R., US National Oceanic and Atmospheric Administration/Geophysical Fluid Dynamics Laboratory.

The authors declare no competing interest.

[1]To whom correspondence may be addressed. Email: yangyang.xu@tamu.edu or vramanathan@ucsd.edu.

This article contains supporting information online at http://www.pnas.org/lookup/suppl/doi:10.1073/pnas.2123536119/-/DCSupplemental.

Published May 23, 2022.

focus of climate mitigation actions. The science of non-CO_2 warming pollutants dates back to 1975 with the discovery of the supergreenhouse effect of chlorofluorocarbons (CFCs) (11) followed by the addition of methane (CH_4) and nitrous oxide (N_2O) in 1976 (12). A comprehensive review of non-CO_2 warming agents by a United Nations–commissioned group in 1985 (13) concluded that non-CO_2 greenhouse gases (GHGs) were contributing as much as CO_2 to warming and projected that for the period between 1980 and 2030 non-CO_2 gases were likely to continue contributing as much as CO_2 to warming. These findings and projections have been confirmed by the most recent IPCC reports (14–17). We summarize these in the next section.

Independently, a series of studies that began in the 1970s concluded that fossil fuels (FFs), while contributing to global warming through CO_2 emissions, were also leading to global dimming and resulting cooling by increasing atmospheric aerosol particles (18, 19). While the overall aerosol effect is strongly negative due to emissions of sulfates, nitrates, and some organics that primarily reflect sunlight, there are other aerosols such as black carbon (BC) and brown carbon that absorb sunlight and thus contribute to global warming. The findings of the three decades of studies have been confirmed by the most recent IPCC report, which concludes that as of 2019 the net radiative forcing from cooling aerosols is around $-1.5\ Wm^{-2}$ (excluding about +0.38 from the aerosol-radiation forcing from BC and its effect on surface albedo). The CO_2 radiative forcing is $2.16\ Wm^{-2}$ and radiative forcing due to non-CO_2 GHGs and BC is $2.10\ Wm^{-2}$ (15).

Despite the general recognition of the role of non-CO_2 pollutants in climate mitigation, their contribution to warming as well as their potential for near-term cooling has been underappreciated in part due to inconsistencies between representation of climate forcing between IPCC Working Group I (WGI: Physical Scientific Basis), which includes all pollutants, and Working Group III (WGIII: Mitigation of Climate Change), which focuses on CO_2 and the subset of GHGs covered under the Kyoto Protocol, hence excluding halogenated gases covered by the Montreal Protocol and both warming and cooling aerosols that are primarily coemitted with CO_2 from FF usage. As we discuss in the next section, since FF combustion is the primary source of CO_2 emissions and also the source of some non-CO_2 pollutants, the extent to which decarbonization strategies to reduce FF emissions also reduce non-CO_2 emissions is ambiguous in many mitigation studies due to study design, leading some to question the benefits of early and fast targeted action in reducing non-CO_2 emissions (20).

The focus on CO_2 underpins the concept of carbon budget, which has been used to construct decarbonization pathways to meet specified long-term warming levels (21). While it has long been known that the coincidental cancelling of non-CO_2 warming and aerosol cooling was unlikely to persist due to differences in their sources and residence times (22), few carbon-budget-based studies have included the tight linkage between CO_2 mitigation and reduction in cooling aerosol emissions until recently (23).

Many publications and reports by scientific agencies (24–32) highlighted the role of non-CO_2 for rapid near-term climate mitigation, specifically short-lived climate pollutants (SLCPs)—methane (CH_4), BC, hydrofluorocarbons (HFCs), and tropospheric ozone (O_3)—but these have not captured the attention of global mitigation actions, which still focuses largely on CO_2 emissions.

There are two primary objectives of this study: first, clarifying the role of non-CO_2 GHGs (short-lived and long-lived) and aerosols (warming and cooling) in the context of the need for near-term and long-term climate mitigation, and second, clarifying the net effect of the FF phaseout in decarbonization, which involves both cooling due to cutting CO_2 emissions and warming due to unmasking of cooling aerosols coemitted by FF use. Unless otherwise stated, we rely on forcing values in the IPCC WGI reports published in 2021 and 2013.

Contributions to Radiative Forcing: CO_2 vs. Non-CO_2 GHGs (Excluding Aerosols)

Previous reports of IPCC WGI have consistently found that CO_2 and non-CO_2 GHG and GHG precursor emissions contribute close to equal shares (52 to 57% for CO_2 and 43 to 48% for non-CO_2 GHG) to climate forcing in radiative forcing terms when excluding aerosols (*SI Appendix*, Table S1). These results are reproduced in Fig. 1 *A* and *B*. In contrast, IPCC WGIII states in the Fifth Assessment Report (AR5) that "CO_2 emissions from fossil fuel combustion and industrial processes contributed about 78% of the total GHG emission increase from 1970 to 2010, with a similar percentage contribution for the period 2000–2010 … . Annually, since 1970, about 25% of anthropogenic GHG emissions have been in the form of non-CO_2 gases" (33). A similar statement was made by WGIII in the Fourth Assessment Report (AR4). However, these statements are inconsistent with WGI science and contribute to confusion for several reasons:

- First, GHG emissions considered by WGIII only include CO_2 (from FF use and forestry and other land use, [FOLU]), CH_4, N_2O, and HFCs and omit nonmethane tropospheric ozone precursors, CFCs, hydrochlorofluorocarbons (HCFCs), and other ozone-depleting substances covered by the Montreal Protocol (*SI Appendix*, Fig. S1). Taking into account these omitted non-CO_2 climate forcers using the EDGARv5.0 emissions database (34) for CO (as a proxy for nonmethane O_3 precursors) and National Oceanic and Atmospheric Administration and AGAGE (35) network data for CFC/HCFC/halon emissions, the average non-CO_2 GHGs and GHG precursors share over 1970 to 2010 is 39% (instead of the 25% quoted in WGIII reports) using the 100-y global warming potential (GWP_{100}) metric and 59% using GWP_{20}.
- Second, presenting the increase in emissions between two years (1970 and 2010) provides limited if not misleading insights into the actual forcing and climate impacts. We offer two examples, all of which adopt IPCC WGI estimates. 1) For the years 1993, 1998, 2005, 2011, and 2019, the percentage of CO_2 forcing (from all sources) compared with the total GHGs forcing ranges from 52 to 57% (*SI Appendix*, Table S1). The non-CO_2 GHGs contribute the balance of 43 to 48% (*SI Appendix*, Tables S1 and S2). 2) The contribution of the CO_2 forcing from just FFs to the total GHGs forcing is 38% for 2011 and 43% for 2019. The basic inference is that the WGIII finding of "CO_2 emissions from fossil fuel combustion and industrial processes contributed about 78% of the total GHG emission increase from 1970 to 2010" cannot be used to infer the contribution of CO_2 or FFs to either the radiative forcing or the resulting climate changes.

In short, the conclusion by WGIII that CO_2 from FF combustion contributed 78% of the total GHG emissions increase from 1970 to 2010 significantly underrepresents the nearly equal contribution of non-FFs as well as that of non-CO_2 GHGs to the total radiative forcing, which are described in the next two sections. Revisiting this historical accounting puts

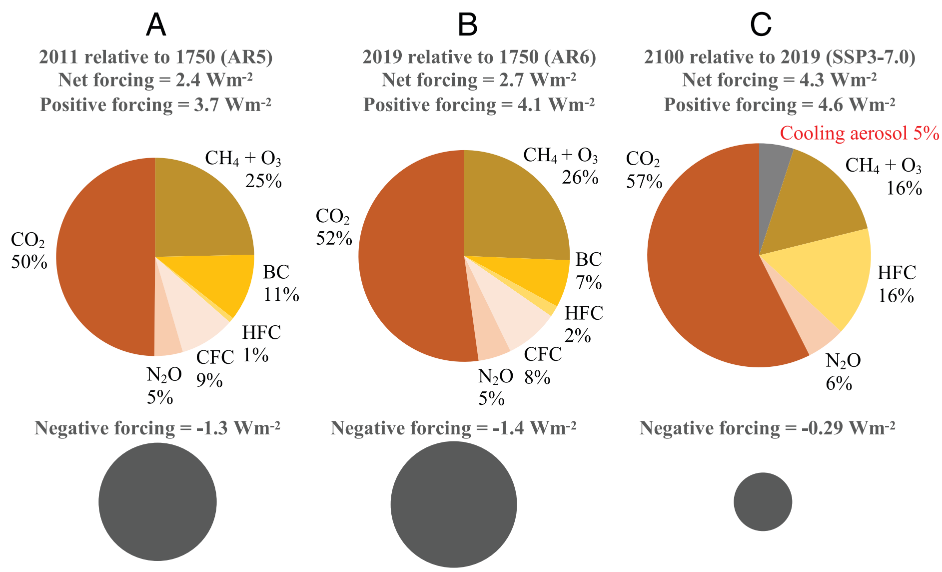


Fig. 1. Positive radiative forcing from long-lived GHGs (orange), short-lived GHGs, GHG precursors, and BC (aerosol–radiation interaction and snow albedo effects only) (yellow) and negative forcing from individual aerosol direct effects (aerosol–radiation interaction) and the total aerosol indirect effects (aerosol–cloud interaction) (separate gray pie) in (*A*) 2011 relative to 1750, from AR5 (14) and (*B*) 2019 relative to 1750, from AR6 (15). (*C*) The forcing at 2100 relative to 2019, under SSP3-7.0 emissions (49). Note the negative forcing due to assumed BC and CFC reduction and the positive forcing due to decline of cooling aerosols. Area of each pie chart is scaled to positive or negative forcing. See *SI Appendix*, Fig. S5 for bar chart version and *SI Appendix*, Table S6*A* for data.

into perspective the role of non-CO_2 emissions in the current global warming and serves as a reminder of the need to consider all sources of climate forcing when assessing mitigation strategies.

This comparison of WGI and WGIII approaches also further underscores the importance of separately accounting for short- and long-lived pollutant emissions, as discussed by Daniel et al. (36) and recently called for by Allen et al. (37). Reporting these pollutants separately allows for consideration not only of potential effects of mitigation measures by source and implications for coemissions but also an assessment of temperature impact on multiple time horizons of interest (1). With 1.5 °C expected to be crossed in the early 2030s (1, 38), Abernethy and Jackson (39) have advocated for choosing time horizons for GHG aggregation metrics consistent with temperature goals, specifically supporting the use of GWP_{20} over the GWP_{100}. A similar argument can be made in the context of the urgency to slow warming in the near term (2). In addition, common usage of aggregation metrics (e.g., GWP, GWP*, and global temperature potential) excludes very short-lived climate pollutants that are not well-mixed, such as aerosols and GHG precursors, but that can have significant implications for future warming (40, 41).

Contributions to Radiative Forcing: FFs vs. Non-FFs (Including Aerosols)

Here we clarify the historical contributions to present-day radiative forcing from FF and non-FF sources. Many heat-trapping gases and particles originate from both FF and non-FF sources, while others such as N_2O and halocarbons are primarily associated with non-FF sources. First, we calculate the relative share of emissions from FF and non-FF sources for GHGs alone, summing historical emissions pollutant by pollutant between 1850 and 2015 for each GHG based on source (42) and for future (after 2015) emissions using the FF coemission factors from Shindell and Smith (43) as described in *SI Appendix*. These shares are then applied to the total present-day radiative forcing in 2011 as in IPCC AR5 WGI (14) and 2019 as in IPCC AR6 WGI (15). Fig. 2 and *SI Appendix*, Table S2 show that for historical forcing (1750 to 2019) GHG from FF sources contributes about 53% of the total current GHG forcing, approximately the same as GHG forcing due to non-FF sources. However, if GHG emissions were to cease, residual forcing from long-lived GHG, predominantly FF CO_2, would dominate as shorter-lived pollutants would be rapidly removed.

Next, we consider warming and cooling aerosols. For forcing estimates related to aerosols, we distinguish effective radiative forcing (ERF) due to aerosol-radiation interaction (ERF_{ari}) for individual species from aerosol–cloud interaction (ERF_{aci}) considered separately as a lump-sum "indirect" forcing term associated with total aerosol emissions (*SI Appendix*). Previous studies have shown that the coemission of aerosols from FF combustion can result in warming or cooling with distinct temporal and spatial patterns (27, 44). Many studies have identified the importance of cooling aerosols—primarily sulfates (with SO_2 as the precursor), nitrates (NO, NO_2, and NH_3), and organic carbon—in masking GHG warming (1, 14). Fig. 1 shows the relative contributions of warming GHG, GHG precursors, and BC in comparison to the cooling from cooling aerosols relying on radiative forcing from historical emissions in recent IPCC reports, and how the relative contributions evolve in a reference scenario (SSP3-7.0) in 2100 relative to 2019.

The net forcings for all CO_2 and non-CO_2 FF (Fig. 2*A*) and non-FF non-CO_2 (Fig. 2*B*) sources are based on Hoesly et al. (42) for the period through 2015. For 2016 to 2019, we use the Shared Socioeconomic Pathways (SSP) scenario and adopt Shindell and Smith's (43) values for the coemission factors. We obtain similar results using radiative forcing values from AR6 WGI (*SI Appendix*, Table S3). For the radiative forcing from CO_2 emitted by FF as well as non-FF sources and non-CO_2 emitted by just FF, nearly half of the positive forcing (2.5 Wm^{-2}) in 2019 is masked by negative forcing of cooling aerosols (–1.1 Wm^{-2}), resulting in a net positive forcing of 1.4 Wm^{-2}. The forcing of cooling aerosols from non-FF non-CO_2 sources is only –0.2 Wm^{-2} compared to a positive forcing of 1.4 Wm^{-2}. Thus, the net forcing from non-FF non-CO_2 sources is 1.2 Wm^{-2} in 2019, or 45% of total net forcing when aerosols are included. The contribution to the net forcing from FFs (CO_2 and other

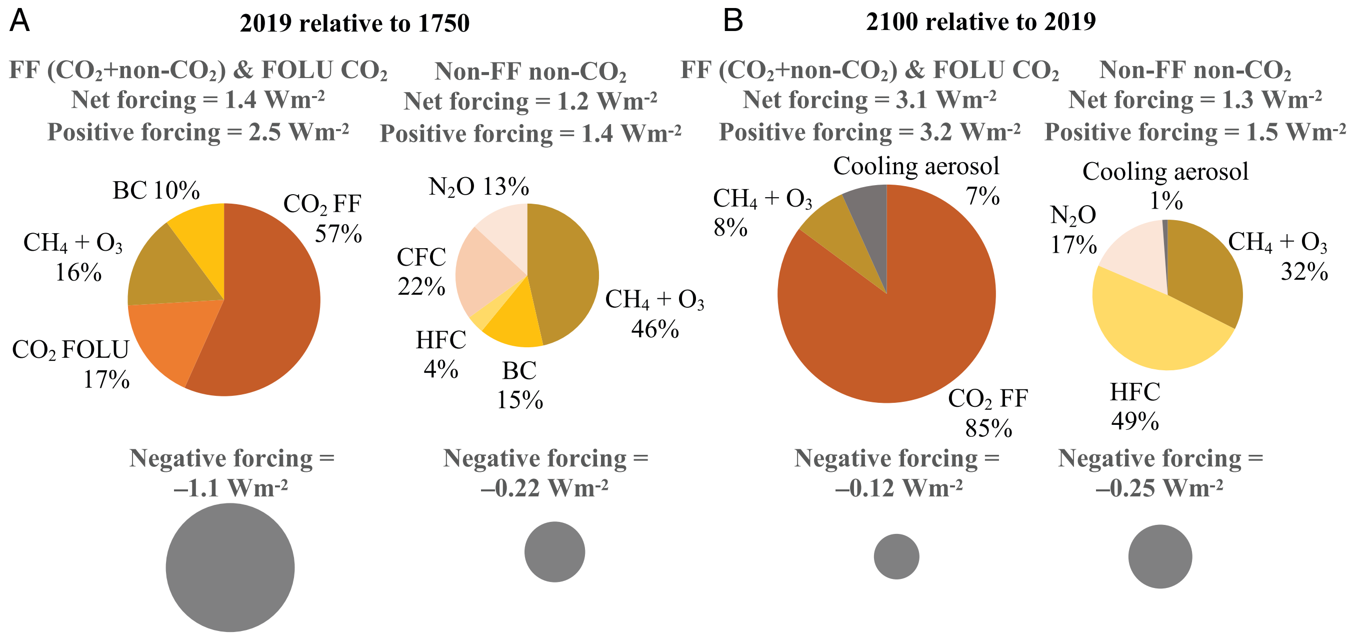


Fig. 2. (*A*) Contributions to 2019 radiative forcing from emissions by FF (CO_2+non-CO_2) sources and CO_2 from land-use changes (Forestry and Other Land Use, FOLU CO_2) compared with emissions from non-FF non-CO_2 sources based on ref. 42 and coemission factors from ref. 43 from this study, with similar results using radiative forcing values from AR6 WGI (*SI Appendix*, Table S3). (*B*) Contribution to the 2100 radiative forcing (relative to 2019) based on future emissions in SSP3-7.0 (49) partitioned by source using coemission factors from ref. 43. Area of each pie chart is scaled to positive or negative forcing. Data in *SI Appendix*, Table S6*B*.

GHGs) is 39% when aerosols are included and from non-FF sources is 61%.

The picture depicted above changes in the projection through 2100 under the limited climate policy SSP3-7.0 scenario. By 2100, around 70% of net forcing relative to 2019 is due to FF and other CO_2 emissions, emphasizing the importance of adopting decarbonization together with strategies targeting non-CO_2 to address near-term and long-term warming.

Contributions to Warming: CO_2 vs. Non-CO_2 and FFs vs. Non-FFs

The tendency to group CO_2 and non-CO_2 together irrespective of emission sources has contributed to a frequent misperception that CO_2, which comes predominantly from FF burning, is the only important contributor to observed warming. This misperception is understandable: Our model shows that out of the 1.01 °C warming simulated for 2015, CO_2 has contributed 0.98 °C (*SI Appendix*, Table S4). Thus, one can indeed claim that to the first order the observed global warming of ∼1 °C is primarily due to CO_2. However, a closer look reveals that the magnitude of warming by non-CO_2 GHGs coincidentally cancels the cooling by all (FF & non-FF sources) aerosols (45–47) (*SI Appendix*, Fig. S2). Indeed, our model shows that the combined cooling effects of aerosols including the indirect effects via enhancing cloud albedo (–1.15 °C) has masked an amount of warming that is almost equal to the total non-CO_2 warming of 1.17 °C. This leads to a facile but false assumption that most non-CO_2 forcings have canceled one another and will continue to do so in the future and obscures the significance of the residence time of the pollutants for both short- and long-term climate mitigation.

Uncovering the flaw in this reasoning requires correctly attributing the masking from cooling aerosols. Ignoring sources and aerosols, CO_2 would appear to contribute about 55% of GHG warming (*SI Appendix*, Table S4). Considering only FF sources, *SI Appendix*, Table S4 shows that the warming from FF emissions (GHGs and BC) of 1.07 °C in 2015 is mostly masked by cooling of 0.88 °C from cooling aerosols that are coemitted with FF emissions. In contrast, while the warming from non-FF emissions (GHGs and BC) is equivalent in magnitude at 1.08 °C, only 0.26 °C is masked by coemitted cooling aerosols. This analysis reveals that about 80% of warming realized in 2015 is attributable to non-FF sources due to masking by cooling aerosols coemitted from FF sources. As these aerosols fall out of the atmosphere, the future net warming contribution from FF sources under SSP3-7.0 begins to dominate by the 2060s due to the longer residence time of CO_2.

Accurately attributing past warming is key to mitigation actions going forward. As decarbonization measures reduce FF use they also reduce the coemitted cooling aerosols (primarily sulfates) and unmask the warming from accumulated GHGs in the atmosphere. In the following section we describe the implications of such unmasking for near- and long-term mitigation potential of decarbonization and clarify the essential role of strategies targeting non-CO_2 pollutants in limiting warming through 2050.

Mitigation Strategies in Time: Decarbonization and Targeted Mitigation

Reducing CO_2 emissions by shifting from FF to low-carbon energy sources is underway and needs to accelerate to achieve net-zero CO_2 emissions by midcentury or sooner consistent with the Paris temperature target (48). While getting to net-zero CO_2 emissions is critical and essential for stabilizing long-term warming, it also reduces coemitted cooling aerosols and causes weak near-term warming, which can be offset by reductions in non-FF pollutants (43). Few studies, however, have specifically quantified the contribution of measures targeting non-CO_2 independent from FF usage, such as the 16 measures in the 2011 UNEP/WMO Assessment (31).

Our analysis disentangles CO_2, SLCPs, and cooling aerosols by asking the following question: Under an aggressive climate mitigation scenario (such as the marker version of SSP1-1.9), what is the avoided warming due to decarbonization alone (i.e., reduction in FF usage) and when paired with non-decarbonization-related mitigation targeting non-CO_2 pollutants? We answer this question by explicitly accounting for the associated reductions in coemitted pollutants including cooling aerosols from each mitigation approach. As described in *SI Appendix*, we use SSP scenarios (49) and apply coemissions factors to partition emissions of individual pollutants into FF-related and non-FF-related (43). We consider three cases (Table 1): As a reference case we adopt the limited climate policy high-emission scenario SSP3-7.0, a middle case with only decarbonization-driven emissions reductions, and a "decarb+targeted" case including mitigation measures that go beyond decarbonization to target SLCPs and other non-CO_2 pollutants (based on SSP1-1.9). We construct the "decarb-only" case by partitioning the reduction in emissions in the "decarb+targeted" case relative to the baseline case into decarbonization-driven and other targeted measures. Our approach differs from ref. 43 in that we use the SSP3-7.0 scenario to quantify the nondecarbonization mitigation potential from methane and BC. This includes mitigation measures targeting the ~10% of methane emissions from abandoned coal mines and wells due to fugitive emissions that are not directly affected by decarbonization-driven reductions in FF use (*SI Appendix*).

All emission pathways including total and individual forcing were converted to temperature trajectories using the energy balance climate model RXM (*SI Appendix*), which has been validated in our earlier studies with climate models used in IPCC assessments (27, 30, 50, 51) and observed warming trends for the 20th century (*SI Appendix*, Fig. S3). Both the equilibrium and the transient climate sensitivity of the RXM model used in our study is within a few percent of the central values recommended in AR6. Our results for the avoided warming in the "decarb+targeted" case (*SI Appendix*, Table S5) are consistent with the results for methane, ozone precursor, and HFC abatement reported in AR6 WGI (52), which also used SSP3-7.0 as a reference case and SSP1-1.9 as the mitigation case, but do not account for source partitioning. With RXM we find avoided warming of 0.3 °C by 2040 from SLCP mitigation compared to 0.1 to 0.4 °C in AR6. The impact of SLCP reductions in 2100 is 0.5 to 1.3 °C in AR6, compared to 1.7 °C in our scenarios, which likely reflects the more stringent HFC and N_2O reductions in our adapted mitigation scenario. Our methane mitigation benefit of ~0.2 °C by 2050 is smaller than the ~0.3 °C in a recent assessment based on similar abatement (38), suggesting that the sensitivity of RXM to methane is lower than that in the three-dimensions composition-climate models (but well within uncertainties) (*SI Appendix*).

Aggressive decarbonization to achieve net-zero CO_2 emissions in the 2050s (as in the decarb-only scenario) results in weakly accelerated net warming compared to the reference case, with a positive warming up to 0.03 °C in the mid-2030s and no net avoided warming until the mid-2040s due to the reduction in coemitted cooling aerosols (Fig. 3*A*). By 2050, decarbonization measures result in very limited net avoided warming (0.07 °C), consistent with Shindell and Smith (43), but rise to a likely detectable 0.25 °C by 2060 and a major benefit of 1.4 °C by 2100 (*SI Appendix*, Table S5).

In contrast, pairing decarbonization with mitigation measures targeting CH_4, BC, HFC, and N_2O (not an SLCP due to its longer lifetime) independent from decarbonization are essential to slowing the rate of warming by the 2030s to under 0.3 °C per decade (Table 1 and Fig. 3*B*), similar to the 0.2 °C to 0.25 °C per decade warming prior to 2020 (38, 53). Recent studies suggest that rate of warming rather than level of warming controls likelihood of record-shattering extreme weather events (54, 55).

By 2050, the net avoided warming from the targeted non-CO_2 measures is 0.26 °C, almost four times larger than the net benefit of decarbonization alone (0.07 °C) (*SI Appendix*, Table S5). These results are calculated using an average BC forcing at present of 0.33 Wm^{-2} relative to preindustrial (direct and snow albedo; *SI Appendix*), which is consistent with the AR6 range (0.30 ± 0.2 Wm^{-2} for ERF_{ari} and 0.38 Wm^{-2} including snow albedo effects) (56). Combining all targeted non-CO_2 measures results in a net avoided warming in 2060 of 0.43 °C. Pairing decarbonization measures with targeted measures can achieve 0.25 °C in total avoided warming, a level that is likely to be detected (57) over a decade earlier (~2047) than

Table 1. Simulated warming rates and other key metrics under reference, decarbonization only, and decarb+ targeted scenarios

Scenario	Warming rate, °C/decade (2020–2040)	Year when warming rate drops below 0.25 °C/decade	Year of peak warming rate	Year when crossing 1.5 °C warming	Year when crossing 2 °C warming	Warming in 2030 relative to 1850–1900, °C	Warming in 2050 relative to 1850–1900, °C
Reference: Limited climate policy, high emission (SSP3-7.0)	0.36 (0.34–0.38)	—	—	2031–2033	2045–2046	1.5 (1.4–1.5)	2.2
Decarbonization-driven: Scenario using decreasing FF primary energy as in SSP1-1.9 and associated emission factors to calculate decline in FF-related emissions compared to reference	0.37 (0.35–0.39)	2049–2052	2030	2030–2032	2045–2046	1.5 (1.4–1.5)	2.1
Decarbonization and Targeted measures: Aggressive climate policy, low emission (based on SSP1-1.9)	0.31 (0.29–0.32)	2035–2037	2023	2030–2033	—*	1.5 (1.4–1.5)	1.85 (1.8–1.9)

The range of years reflects the uncertainty in present-day forcings of BC and cooling aerosols.
*Peak temperature of 1.9 °C in 2060s before declining to 1.7 °C in 2100.

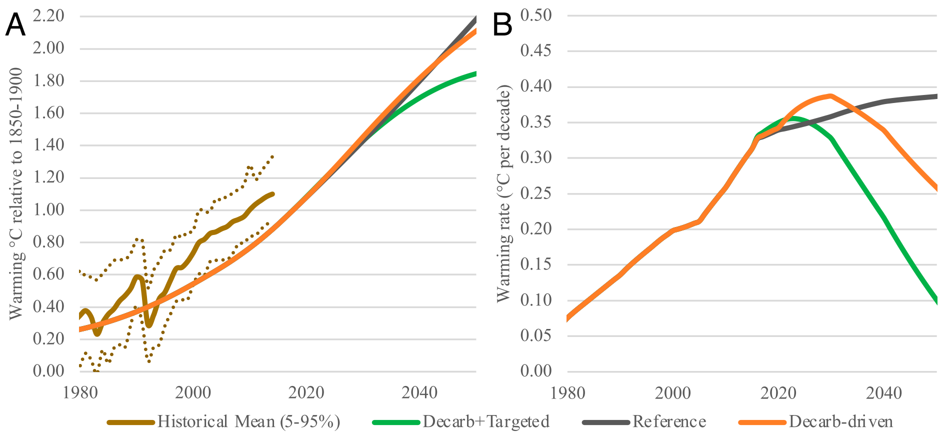


Fig. 3. (*A*) Historical and future temperature projections through 2050 calculated using the RXM energy balance model based on emissions scenarios from the SSP database (49) for reference scenario (SSP3-7.0), decarbonization-driven mitigation scenario (this study), and an "decarb+targeted" scenario including aggressive decarbonization and targeted SLCP mitigation (adapted from SSP1-1.9). Historical curve (past simulated warming) is from figure SPM8.a (47, 64). (*B*) Rate of warming (degrees Celsius per decade) in the reference SSP3, decarbonization only, and "decarb+targeted" mitigation cases.

decarbonization alone (2060; *SI Appendix*, Table S5). The avoided warming due to decarbonization begins to exceed that due to the targeted measures only after 2080 (*SI Appendix*, Fig. S4).

Only about 30% of the avoided warming from CH_4 over the period 2020 to 2040 is related to decarbonization measures (*SI Appendix*, Table S5). The larger portion of CH_4 reduction due to targeted measures may be due to a slower rate of reduction in natural gas usage in the marker SSP1-1.9 scenario (60% down in 2050 relative to 2015) compared with decrease in coal combustion (more than 90% down). Consistently, about two-thirds of non-CH_4-induced ozone mitigation is also due to non-CO_2 targeted measures rather than a direct consequence of decarbonization. These results are also consistent with UNEP/WMO (31), which found that measures to reduce methane and BC emissions cut warming in 2030 by half compared with a reference case and that aggressive CO_2 reductions, in themselves, did little to mitigate warming in the first 20 to 30 y, in part due to unmasking of coemitted cooling aerosol.

Fig. 3*A* shows that combining targeted mitigation strategies with decarbonization keeps warming below 2.0 °C, while decarbonization alone breaches 2.0 °C in 2045 in our scenario. Moreover, decarbonization alone increases the warming rate in the near term (Table 1). Notably, the warming rate in the decarbonization scenario would not drop below the current rate of warming until the 2040s (Fig. 3*B*). Pairing decarbonization with measures targeting SLCP slows the rate of warming a decade or two earlier than decarbonization alone.

Consideration of Uncertainties

The largest uncertainties in our analysis relate to the mitigation pathways chosen, both the reference limited climate policy scenario and the low-emission mitigation scenarios. While current CO_2 emissions commitments track closer to SSP2-4.5, the key insight of our study is not about additionality in terms of new policy measures. Rather, our study seeks to distinguish between mitigation policy focused on FF decarbonization alone versus decarbonization plus targeted measures. For this reason, we selected as a reference the high-emission scenario SSP3-7.0 and as a low-emission scenario SSP1-1.9, which are the same end-member scenarios as assessed in AR6 WGI (52).

The second major source of uncertainty is the nearly threefold uncertainty in climate sensitivity. All of the projected warming numbers presented here should be interpreted as median value with 50% probability. A third source of uncertainty relates to our use of constant FF coemission factors in constructing the decarbonization-driven scenario. Since this partitioning approach is most valid in the near term, we focus our analysis on the period through 2050. A fourth source of uncertainty relates to our limited understanding of the role of aerosols in climate forcing and feedbacks in future projections due to the following aspects: 1) the assumption of mixing of various aerosol species, especially the potential enhancement of BC forcing when accounting for the mixing with other reflective aerosols (58), 2) the future changes of background cloud field due to the slow feedback process to GHG warming (59, 60), and 3) the future changes of background aerosols from natural sources such as dust and sea salt due to climatic changes affecting the emission processes related to soil condition and wind stress over ocean surface and related cloud impacts (e.g., ref. 61).

Conclusions

This study clarifies as well as establishes the need for a comprehensive and inclusive CO_2 and non-CO_2 mitigation approach with distinct decarbonization and SLCP targets to address both the near-term and long-term impacts of climate disruption. A review of IPCC reports leads to the inference that non-CO_2 GHGs are responsible for nearly half of all current climate forcing from GHGs. When accounting for aerosols and coemissions by source, the inference from our analyses is that about 80% of the realized warming as of 2015 is attributable to non-FF sources due to FF GHG emissions being masked by coemission of short-lived cooling aerosols. However, the importance of non-CO_2 pollutants, in particular SLCPs, and their role in climate mitigation has been underappreciated due to misperception arising from inconsistencies between IPCC WGI and WGIII reports. The tendency to attribute impact to pollutants rather than sources and to group all non-CO_2 together regardless of emissions sources has further entrenched this misperception due to coincidental cancelling of warming and cooling pollutants and the false impression that they will continue to cancel out in the future. When historical emissions are partitioned into FF- and non-FF-related sources, we find that nearly half of the forcing from FF and other CO_2 emissions has been masked by coemission of cooling aerosols. As a result, close to half of net radiative forcing, as of now, is attributable to non-FF sources of methane, F-gases, BC, and N_2O. However, this is likely to change in the future as decarbonization policies reduce FF emissions of both warming GHGs and cooling aerosol.

By 2100, absent climate policy, FF will be the largest source (about 70%, mostly due to CO_2) for global warming and resulting impacts on planet and society. Even in the shorter term, FF emissions are the largest source of air pollution particles and ozone, which contribute to premature mortality of over 8 million people per year (45, 62). Tropospheric ozone also leads to crop losses of 100 million tons or more (63). As we have repeatedly emphasized in this study, achieving net-zero carbon dioxide emissions by 2050 is essential to limit global warming below 2 °C beyond 2050.

Pairing decarbonization with targeted SLCP mitigation measures is essential to simultaneously limit both near-term warming and long-term warming below 2 °C and thus reduce risks from crossing tipping points. Importantly, these two strategies are complementary and not interchangeable. Absent deep cuts in non-CO_2 emissions, CO_2 abatement alone is unable to keep warming below even the 2 °C threshold by 2050. Decarbonization measures alone achieve about a third of potential avoided warming from methane mitigation by 2050, less than half of SLCP mitigation potential, and none of the reductions from measures targeting N_2O. Nor can cutting methane emissions this decade replace the need for net-zero carbon dioxide by 2050 to stabilize the climate this century. Similarly, deeper CO_2 reductions this decade do not replace the need for methane and other SLCP reductions to slow warming in the near term. Aggregation metrics such as GWP and GWP* are designed in terms of warming impacts over multiple decades and are seldom used in ways that account for the important differences between strategies that can reduce warming in the near term.

Adopting a comprehensive mitigation approach that pairs rapid decarbonization with "strong, rapid and sustained reductions in CH_4 emissions" (1) as recommended in the Global Methane Assessment (32) and additional targeted SLCP mitigation responds to the call from WGII for urgent action to slow warming in the near term (2). For example, over 100 countries joined the Global Methane Pledge in November 2021, committing to a collective goal of reducing global anthropogenic methane emissions by at least 30% below 2020 levels by 2030. If achieved, this target, which is consistent with the reduction in the "decarb+targeted" scenario analyzed here, would avoid 0.2 °C by 2050 (*SI Appendix*, Table S5).

Data Availability. All study data are included in the article and/or *SI Appendix*.

ACKNOWLEDGMENTS. G.B.D. and D.Z. acknowledge support from the Sequoia Climate Foundation. V.R. acknowledges support from the Edward Frieman foundation chair funds. D.T.S. acknowledges support from the Clean Air Task Force. We thank Guus Velders for data and discussion. We thank Blake Hite, Kristin Campbell, and Trina Thorbjornsen for research assistance.

Author affiliations: [a]Institute of Governance & Sustainable Development, Washington, DC 20016; [b]Department of Physics, Georgetown University, Washington, DC 20057; [c]Department of Atmospheric Sciences, College of Geosciences, Texas A&M University, College Station, TX 77843; [d]Earth and Climate Sciences Division, Nicholas School of the Environment, Duke University, Durham, NC 27708; [e]Bren School of Environmental Science & Management, University of California, Santa Barbara, CA 93106; [f]Scripps Institution of Oceanography, University of California San Diego, La Jolla, CA 92037; and [g]College of Agriculture and Life Sciences, Cornell University, Ithaca, NY 14853

1. Intergovernmental Panel on Climate Change, *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (IPCC, 2021).
2. Intergovernmental Panel on Climate Change, *Climate Change 2022: Impacts, Adaptation and Vulnerability*, H.-O. Pörtner *et al.*, Eds. (Cambridge University Press, 2022).
3. S. C. Herring *et al.*, Explaining extreme events of 2016 from a climate perspective. *Bull. Am. Meteorol. Soc.* **99**, S1–S157 (2018).
4. T. M. Lenton *et al.*, Climate tipping points - Too risky to bet against. *Nature* **575**, 592–595 (2019).
5. J. M. Gutiérrez *et al.*, "Atlas" in *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, V. Masson-Delmotte *et al.*, Eds. (IPCC, 2021), pp. 1–196.
6. C. Raymond, T. Matthews, R. M. Horton, The emergence of heat and humidity too severe for human tolerance. *Sci. Adv.* **6**, eaaw1838, 1–8 (2020).
7. N. Watts *et al.*, The 2020 report of The Lancet Countdown on health and climate change: Responding to converging crises. *Lancet* **397**, 129–170 (2021).
8. Y. Xu *et al.*, Substantial increase in the joint occurrence and human exposure of heatwave and high-PM hazards over South Asia in the mid-21st century. *AGU Adv.* **1**, e2019AV000103 (2020).
9. Y. Zhang, I. Held, S. Fueglistaler, Projections of tropical heat stress constrained by atmospheric dynamics. *Nat. Geosci.* **14**, 133–137 (2021).
10. L. A. Parsons, D. Shindell, M. Tigchelaar, Y. Zhang, J. T. Spector, Increased labor losses and decreased adaptation potential in a warmer world. *Nat. Commun.* **12**, 7286 (2021).
11. V. Ramanathan, Greenhouse effect due to chlorofluorocarbons: Climatic implications. *Science* **190**, 50–52 (1975).
12. W. C. Wang, Y. L. Yung, A. A. Lacis, T. Mo, J. E. Hansen, Greenhouse effects due to man-mad perturbations of trace gases. *Science* **194**, 685–690 (1976).
13. V. Ramanathan *et al.*, Climate-chemical interactions and effects of changing atmospheric trace gases. *Rev. Geophys.* **25**, 1441–1482 (1987).
14. G. Myhre *et al.*, "Anthropogenic and natural radiative forcing" in *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, T. F. Stocker *et al.*, Eds. (Cambridge University Press, 2013), pp. 659–740.
15. P. Forster *et al.*, "The Earth's energy budget, climate feedbacks, and climate sensitivity" in *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, V. Masson-Delmotte *et al.*, Eds. (Cambridge University Press, 2021), chap. 7.
16. P. Forster *et al.*, "Changes in atmospheric constituents and in radiative forcing" in *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, S. Solomon *et al.*, Eds. (Cambridge University Press, 2007), chap. 2.
17. V. Ramaswamy *et al.*, "Radiative forcing of climate change" in *Climate Change 2001: The Scientific Basis. Contribution of Working Group I to the Third Assessment Report of the Intergovernmental Panel on Climate Change*, J. T. Houghton *et al.*, Eds. (Cambridge University Press, 2001), chap. 6.
18. G. G. Persad, Y. Ming, V. Ramaswamy, The role of aerosol absorption in driving clear-sky solar dimming over East Asia. *J. Geophys. Res. Atmos.* **119**, 10,410–10,424 (2014).
19. V. Ramaswamy *et al.*, Radiative forcing of climate: The historical evolution of the radiative forcing concept, the forcing agents and their quantification, and applications. *Meteorol. Monogr.* **59**, 14.1-14.101 (2018).
20. J. Rogelj *et al.*, Disentangling the effects of CO2 and short-lived climate forcer mitigation. *Proc. Natl. Acad. Sci. U.S.A.* **111**, 16325–16330 (2014).
21. J. Rogelj *et al.*, "Mitigation pathways compatible with 1.5°C in the context of sustainable development" in *Global Warming of 1.5°C. An IPCC Special Report on the Impacts of Global Warming of 1.5°C above Pre-Industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*, V. Masson-Delmotte *et al.*, Eds. (IPCC, 2018), chap. 2.
22. H. D. Matthews, S. Solomon, R. Pierrehumbert, Cumulative carbon as a policy framework for achieving climate stabilization. *Philos. Trans.- Royal Soc., Math. Phys. Eng. Sci.* **370**, 4365–4379 (2012).
23. F. Feijoo *et al.*, Climate and carbon budget implications of linked future changes in CO2 and non-CO2 forcing. *Environ. Res. Lett.* **14**, 044007 (2019).
24. J. S. Wallack, V. Ramanathan, The other climate changers. *Foreign Affairs*, September–October 2009. https://www.foreignaffairs.com/articles/2009-09-01/other-climate-changers. Accessed 3 May 2022.
25. M. Molina *et al.*, Reducing abrupt climate change risk using the Montreal protocol and other regulatory actions to complement cuts in CO2 emissions. *Proc. Natl. Acad. Sci. U.S.A.* **106**, 20616–20621 (2009).
26. S. C. Jackson, Climate change. Parallel pursuit of near-term and long-term climate mitigation. *Science* **326**, 526–527 (2009).
27. V. Ramanathan, Y. Xu, The Copenhagen Accord for limiting global warming: Criteria, constraints, and available avenues. *Proc. Natl. Acad. Sci. U.S.A.* **107**, 8055–8062 (2010).
28. J. E. Penner *et al.*, Short-lived uncertainty? *Nat. Geosci.* **3**, 587–588 (2010).
29. D. Shindell *et al.*, Simultaneously mitigating near-term climate change and improving human health and food security. *Science* **335**, 183–189 (2012).
30. Y. Xu, V. Ramanathan, Well below 2 °C: Mitigation strategies for avoiding dangerous to catastrophic climate changes. *Proc. Natl. Acad. Sci. U.S.A.* **114**, 10315–10323 (2017).
31. United Nations Environment Programme, World Meteorological Organization, "Integrated assessment of black carbon and tropospheric ozone" (United Nations Environment Programme, 2011).
32. United Nations Environment Programme, Climate and Clean Air Coalition, "Global methane assessment: Benefits and costs of mitigating methane emissions" (United Nations Environment Programme, 2021).
33. IPCC, "Summary for policymakers" in *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, O. Edenhofer *et al.*, Eds. (Cambridge University Press, 2014), pp. 1–33.
34. M. Crippa *et al.*, "Fossil CO_2 and GHG emissions of all world countries: 2019 report" (European Commission Joint Research Centre Publications Office, 2019).
35. R. G. Prinn *et al.*, History of chemically and radiatively important atmospheric gases from the advanced global atmospheric gases experiment (AGAGE). *Earth Syst. Sci. Data* **10**, 985–1018 (2018).

36. J. S. Daniel *et al.*, Limitations of single-basket trading: Lessons from the Montreal protocol for climate policy. *Clim. Change* **111**, 241–248 (2012).
37. M. R. Allen *et al.*, Indicate separate contributions of long-lived and short-lived greenhouse gases in emission targets. *NPJ Clim. Atmos. Sci.* **5**, 5 (2022).
38. Y. Xu, V. Ramanathan, D. G. Victor, Global warming will happen faster than we think. *Nature* **564**, 30–32 (2018).
39. S. Abernethy, R. B. Jackson, Global temperature goals should determine the time horizons for greenhouse gas emission metrics. *Environ. Res. Lett.* **17**, 024019 (2022).
40. M. Dvorak *et al.*, When will the world be committed to 1.5 and 2.0°C of global warming? *Research Square* [Preprint] (2021). https://doi.org/10.21203/rs.3.rs-969513/v1 (Accessed 4 January 2022).
41. V. Ramanathan, Y. Feng, On avoiding dangerous anthropogenic interference with the climate system: Formidable challenges ahead. *Proc. Natl. Acad. Sci. U.S.A.* **105**, 14245–14250 (2008).
42. R. M. Hoesly *et al.*, Historical (1750–2014) anthropogenic emissions of reactive gases and aerosols from the community emissions data system (CEDS). *Geosci. Model Dev.* **11**, 369–408 (2018).
43. D. Shindell, C. J. Smith, Climate and air-quality benefits of a realistic phase-out of fossil fuels. *Nature* **573**, 408–411 (2019).
44. D. Shindell, G. Faluvegi, Climate response to regional radiative forcing during the twentieth century. *Nat. Geosci.* **2**, 294–300 (2009).
45. J. Lelieveld *et al.*, Effects of fossil fuel and total anthropogenic emission removal on public health and climate. *Proc. Natl. Acad. Sci. U.S.A.* **116**, 7192–7197 (2019).
46. IPCC, *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press, 2013).
47. Intergovernmental Panel on Climate Change, "Summary for policymakers" in *Climate Change 2021: The Physical Science Basis, Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press, 2021), pp. 1–41.
48. IPCC, *Global Warming of 1.5°C. An IPCC Special Report on the Impacts of Global Warming of 1.5°C above Pre-Industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response To the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*, V. Masson-Delmotte *et al.*, Eds. (Cambridge University Press, 2018).
49. K. Riahi *et al.*, The shared socioeconomic pathways and their energy, land use, and greenhouse gas emissions implications: An overview. *Glob. Environ. Change* **42**, 153–168 (2017).
50. Y. Xu, D. Zaelke, G. J. M. Velders, V. Ramanathan, The role of HFCs in mitigating 21st century climate change. *Atmos. Chem. Phys.* **13**, 6083–6089 (2013).
51. R. Hanna, A. Abdulla, Y. Xu, D. G. Victor, Emergency deployment of direct air capture as a response to the climate crisis. *Nat. Commun.* **12**, 368 (2021).
52. V. Naik *et al.*, "Short-lived climate forcers" in *Climate Change 2021: The Physical Science Basis, Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press, 2021), chap. 6.
53. C. M. McKenna, A. C. Maycock, P. M. Forster, C. J. Smith, K. B. Tokarska, Stringent mitigation substantially reduces risk of unprecedented near-term warming rates. *Nat. Clim. Chang.* **11**, 126–131 (2021).
54. S. B. Power, F. P. D. Delage, Setting and smashing extreme temperature records over the coming century. *Nat. Clim. Chang.* **9**, 529–534 (2019).
55. E. M. Fischer, S. Sippel, R. Knutti, Increasing probability of record-shattering climate extremes. *Nat. Clim. Chang.* **11**, 689–695 (2021).
56. C. Smith *et al.*, "The Earth's energy budget, climate feedbacks, and climate sensitivity" in *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, V. Masson-Delmotte *et al.*, Eds. (Cambridge University Press, 2021), chap. 7.
57. B. H. Samset, J. S. Fuglestvedt, M. T. Lund, Delayed emergence of a global temperature response after emission mitigation. *Nat. Commun.* **11**, 3261 (2020).
58. H. Matsui, D. S. Hamilton, N. M. Mahowald, Black carbon radiative effects highly sensitive to emitted particle size when resolving mixing-state diversity. *Nat. Commun.* **9**, 3446 (2018).
59. M. O. Andreae, V. Ramanathan, Climate change. Climate's dark forcings. *Science* **340**, 280–281 (2013).
60. C. Heinze *et al.*, ESD Reviews: Climate feedbacks in the Earth system and prospects for their evaluation. *Earth Syst. Dyn.* **10**, 379–452 (2019).
61. K. D. Froyd *et al.*, Dominant role of mineral dust in cirrus cloud formation revealed by global-scale measurements. *Nat. Geosci.* **15**, 177–183 (2022).
62. K. Vohra *et al.*, Global mortality from outdoor fine particle pollution generated by fossil fuel combustion: Results from GEOS-Chem. *Environ. Res.* **195**, 110754 (2021).
63. D. Shindell, G. Faluvegi, P. Kasibhatla, R. Van Dingenen, Spatial patterns of crop yield change by emitted pollutant. *Earths Futur.* **7**, 101–112 (2019).
64. J. Fyfe, B. Fox-Kemper, R. Kopp, G. Garner, *Summary for Policymakers of the Working Group I Contribution to the IPCC Sixth Assessment Report - Data for Figure SPM.8 (v20210809)* (Cambridge University Press, 2021).

Appendix G

Greenhouse gas emissions

Sharp cut in methane now could help avoid worst of climate crisis

Focussing on carbon dioxide alone will not keep world within 1.5C limit of global heating, warn scientists

Fiona Harvey *Environment correspondent*

Mon 23 May 2022 20.00 BST

Cutting methane sharply now is crucial, as focusing on carbon dioxide alone will not be enough to keep rising temperatures within livable limits, scientists have warned.

CO_2 is the greenhouse gas most responsible for heating the planet, with most of it coming from the burning of fossil fuels. As a result, it has been the major focus of international efforts to prevent climate breakdown.

However, other greenhouse gases also have a sizeable warming effect, and if we ignore them we will fail to keep temperatures within globally accepted limits, according to research published on Monday.

The study found that cuts to CO_2 alone could not achieve the reductions needed to stay within 1.5C of pre-industrial temperatures.

But cutting methane and other “short-lived climate pollutants” (SLCPs) such as soot would reduce the global heating effect in the near term, thus giving the world “a fighting chance” of staving off climate catastrophe, the scientists said. Methane warming effect is as much as 80 times that of Co_2, although it quickly degrades in the atmosphere.

Prof Durwood Zaelke, the president of the Washington-based Institute for Governance and Sustainable Development (IGSD), and co-author of the paper, said cutting methane offered a quick way to reduce global heating while the world pursued longer term cuts in CO_2.

“We can’t solve the fast-moving climate problem with slow-moving solutions. Like Maverick [the Tom Cruise character in Top Gun], we’d better start feeling the need for speed,” he said.

Zaelke called on European governments to stipulate that any gas they import to replace supplies from Russia should come from sources with low rates of methane leaks. “This is the fastest and most promising way to protect the planet while we decarbonise,” he said.

Plugging the methane leaks from oil and gas operations, including shale wells, and stopping harmful practices such as venting or flaring the gas, is not only technically feasible but can also be highly profitable at today’s gas prices.

Dr Gabrielle Dreyfus, chief scientist for the IGSD, and lead author of the paper, said: “This is an optimistic message, as we have low or no-cost strategies available, with no or low-cost interventions, that can slow global warming in the critical near-term.”

Emissions of methane have been soaring in recent years, the result of leaks and venting from oil and gas exploration, and shale gas wells, and from the intensive rearing of livestock for food. Earlier this year, the International Energy Agency said many countries were drastically under-reporting their emissions of methane, and that the global problem was far worse than previously thought.

Cattle feed ration in a ranch in Brazil. Photograph: Bloomberg/Getty Images

The IGSD paper, which was published in the Proceedings of the National Academy of Sciences, showed the huge potential for "buying time" to change the world's energy systems by concentrating on cutting methane, and other SLCPs including soot, hydrofluorocarbons, ground-level ozone and nitrous oxide.

These substances contribute almost as much to global heating as CO_2, according to the study, though most of them last only a short time in the atmosphere.

Cutting CO_2 is still essential for the long term, but must be accompanied by strategies to reduce the levels of SLCPs. If not, then temperatures are likely to exceed 2C above pre-industrial levels, the upper limit set in the 2015 Paris climate agreement, even if there are stiff cuts to CO_2 emissions.

Dreyfus said sharp cuts to methane and other SLCPs could result in temperatures lower by 0.26C by 2050, which is almost four times greater than the benefit of pursuing CO_2 cuts alone, which the scientists estimated would result in temperature cuts of 0.07C by 2050.

She said: "These non-CO_2 targeted measures when combined with decarbonisation can provide net cooling by 2030, reduce the rate of warming from 2030 to 2050 by about 50%, roughly half of which comes from methane, significantly larger than decarbonisation alone over this timeframe."

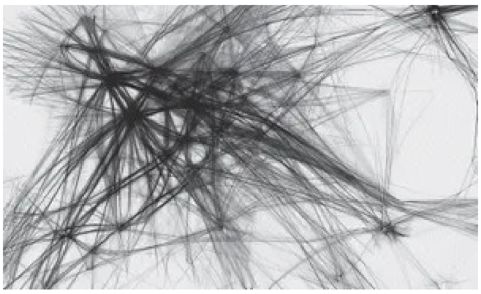
The paper found the importance of "non-carbon dioxide pollutants" had been "underappreciated by scientists and policymakers alike and largely neglected in efforts to combat climate change".

Last year, before the Cop26 climate summit, the US and the EU launched a global pledge to cut methane emissions by 30% by 2030, to which more than 100 governments responsible for more than half of those emissions are now committed. However, Russia - which has some of the world's highest methane emissions, owing to its leaky oil and gas infrastructure - is not among them.

Related stories

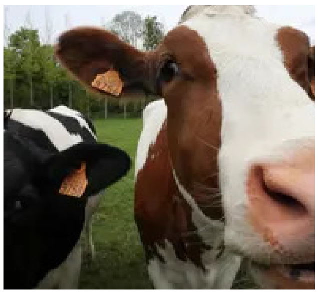
MEPs call for 20% reduction in car emissions by 2025

11 May 2022



Atlas of the Invisible: using data to map the climate crisis

1 Sep 2021



Reduce methane c climate catastropl scientists warn

6 Aug 2021

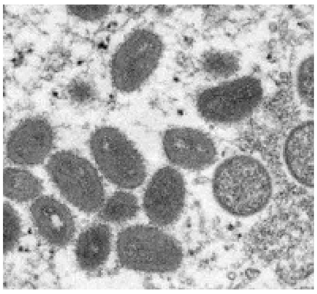
More from Headlines

Live / Russia-Ukraine war: Sievierodonetsk and Lysychansk are 'dead cities', says Zelenskiy, but says Ukraine can fight back

17m ago

Pope Francis / Pontiff's latest plans fuel rumours over resignation

3h ago



Monkeypox / UK r 77 more cases, tak to 302

2h ago

Appendix H

TyndallManchester
Climate Change Research

A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System

Client:	Friends of the Earth Scotland
Document Reference:	CCS_REV
Version:	FINAL v2
Date:	**December 2020**
Prepared by:	Dr Samira Garcia Freites & Dr Christopher Jones

NB: All views contained with this report are attributable solely to the named authors and do not necessarily reflect those of researchers within the wider Tyndall Centre for Climate Change Research.

A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System

1. Introduction

Carbon capture and storage (CCS) is a climate change mitigation system with potential applications for decarbonising industrial processes, electricity generation, hydrogen production and providing carbon dioxide removals (CDR[1]). The focus of this report is the role of CCS in the energy sector, particularly in relation to 2030 climate change targets.

While CCS for CDR[2] features in the majority of GHG emissions pathways compatible with the 1.5°C goal of the UN Paris Agreement on Climate Change [1, 2], and it is expected to have a significant role in mitigating emissions from heavy industries, its role in low carbon energy is less clear. Expectations for the role of CCS in electricity generation in international, European and UK energy pathways have decreased – which is likely due to slow deployment of coal and gas CCS, coupled with faster progress in renewables, energy storage and demand-side technologies [4]. Most (81% of global capacity) CCS deployment to date has been for enhanced oil recovery (EOR)[6]. Notionally, its use in EOR should provide expertise and bring down costs as the technology transfers into carbon mitigation, but progress on this has been slow over the past decade [4]. If CCS is to have a meaningful role in mitigation, deployment would need to accelerate markedly. Emphasis on CCS has notably shifted to industrial applications and fossil fuel-based hydrogen production.

Overall, the role fossil fuel-based CCS can and should have in energy system decarbonisation is unclear. Global carbon budgets are increasingly constrained with substantial progress in energy sector decarbonisation required by 2030 [1, 8, 9], while significant levels of CCS are not expected until 2030 at the earliest. It is still unclear what the preferred option for decarbonising heating, long-distance transport (including aviation and shipping) and feedstock hydrogen in industrial processes will be, and CCS related products are still considered as options. However, the extent to which fossil fuel-based CCS can be a part of low carbon energy systems will also depend on the level of residual emissions from hydrogen and electricity production and fuel supply [10, 11] allowable in future carbon budgets. Delays in CCS roll out also

[1] Carbon Dioxide Removal (CDR) approaches are also referred to as greenhouse gas removal (GGR) and as negative emissions technologies (NETs).
[2] For example, through bioenergy CCS (BECCS) and direct air capture (DAC) systems.

mean that developments elsewhere are salient. CCS applications for transport, power and heating services may depend upon how it performs relative to other low carbon generators (renewables and nuclear), demand management and the electrification of transport and heating. Consequently, policy makers would be expected to have low, or zero, fossil fuel CCS energy scenarios for climate change targets to reflect these uncertainties.

This report provides an overview of CCS development to date and its expected role in future decarbonisation, considering the global context but with a focus on the UK. The focus of this report is primarily on the near-term deployment of CCS in energy systems. Section 2 of the report reviews the expectations for CCS in current energy and climate scenarios. In Section 3 the progress to date is assessed, and in Section 4 key issues for future deployment of CCS are considered.

2. The Role of CCS in Scenarios and Policy

CCS features prominently in many energy and climate change scenarios and strategies for meeting climate change mitigation targets. This includes the Intergovernmental Panel on Climate Change (IPPC), European Commission, International Energy Agency (IEA) and the UK Committee on Climate Change (CCC). It is, however, apparent that the current trend of CCS deployment worldwide has yet to reach the pace of development necessary for these scenarios to be realised.

The mitigation potential of CCS for fossil fuel power generation in the energy sector features in many IPCC emissions pathways and future IEA energy scenarios. In the case of the IPCC, there are also 1.5°C pathways with no fossil fuel CCS or BECCS, which rely instead on social, business and technological innovations that lead to lower energy demand (LED - low energy demand scenarios). Under the LED scenarios, afforestation is the only CDR alternative, and nuclear is also considered [13].

For those emissions pathways with high reliance on CCS in the energy sector, however, there is inconsistency between the CCS projects currently in the pipeline and interim and these long-term expectations. Furthermore, existing CCS facilities for fossil fuel power generation are dominated by coal, despite projections for natural gas to replace coal-fired power generation in many archetypal pathways even with CCS. This section reviews the expectations for CCS in key energy and climate change scenarios and strategies. In the next section, this is then contrasted with the current status of CCS development.

IPCC - Special Report on Global Warming of 1.5°C

The ***Intergovernmental Panel on Climate Change*** (IPCC) in its special report on global warming of 1.5°C published in 2018 [14] shows that reliance on CCS to meet climate targets varies depending on the emissions pathways. Three out of four archetypal model pathways feature fossil fuel CCS. Within the CCS featured pathways there is a range between a limited role scenario (cumulative 348 $GtCO_2$ stored by 2100, of which BECCS is 151 $GtCO_2$) to a more extensive role scenario (cumulative 1,218 $GtCO_2$ stored by 2100, of which BECCS is 1,191 $GtCO_2$). Under these emissions pathways, CCS reduces CO_2 emissions from natural gas-based and, to a lesser extent, from coal-based power generation. The role of CCS combined with bioenergy production (BECCS) plays an even bigger part in most of the 1.5 °C emissions pathways with its potential to remove CO_2 from the atmosphere and thus delivering net negative emissions [1]. There are IPCC 1.5°C pathways (the LED scenarios) that do not include CCS or BECCS at all, which involve radically and immediately reducing energy demand, with CDR achieved through afforestation.

The IPCC illustrative pathways also show that the share of renewables for electricity generation in 2050 increases at different levels (63%-81%) across all the pathways. Inversely, for three out of the four IPCC model scenarios, the shares of coal, oil and gas as primary energy sources are expected to decline by 2050 relative to 2010 for all the model pathways. In relation to this, while the deployment of CCS on natural gas and coal power stations varies widely across IPCC pathways, in most cases the deployment of natural gas CCS is greater than coal CCS.

International Energy Agency Scenarios

The IEA Sustainable Development Scenario (SDS) lays out a major transformation of the global energy system it considers consistent with supporting the achievement of the Sustainable Development Goals (SDGs); affordable and clean energy access (SDG7), climate action (SDG13) and air quality (SDG3). The IEA SDS analysis includes a pathway without any CDR technology (global mean temperature rise below 1.8°C at a 66% probability), and one with CDR (consistent with a global mean temperature rise of 1.5 °C with a 50% chance - requiring around 300 Gt of CDR, which is less than the median level of CDR in the IPCC 1.5 °C scenarios) [15]. The contribution of CCS to energy-related CO_2 emissions reductions in the SDS is 9%, compared to 37% from efficiency improvements and 32% from renewables.

In the *SDS*, the role of CCS in the power sector is more limited compared to previous IEA scenarios (i.e. the *450 Scenario*[3]). The current SDS relies more on renewable energy in the power sector with 8,100 TWh of electricity generation from wind and solar PV compared to 3,900 TWh from nuclear and CCS; in contrast, the former IEA *450 Scenario* projected 3,600 TWh of electricity from wind and solar PV and 7,100 TWh from nuclear and CCUS. This reflects a change in expectations on the deployment of fossil fuel CCS power generation relative to renewables for delivering decarbonisation in IEA analysis.

[3] The 450 Scenario refers to the CO_2 concentration of 450 ppm consistent with a 50% chance of limiting global temperature rise below 2°C

In the IEA SDS, the power sector is expected to reach a decarbonisation rate of 90% by 2050. Under this scenario, CCS (and nuclear energy) supplement the role of renewable energy, increasing the share of low-carbon electricity generation to 84% by 2040. CCS combined with coal and gas power contributes to 5% of the electricity generation mix by 2040 in contrast to a 67% share from renewable sources and 11% from nuclear. In terms of energy generation, 1,909 TWh of electricity are produced from coal- (994 TWh) and natural gas- (915 TWh) based power CCS in contrast to 26,065 TWh of electricity generation from renewables in the latest IEA pathways.

European Commission: The European Green Deal

In response to the European Green Deal and the targets of the Paris Agreement, the European Union has committed to achieving climate-neutrality by 2050 and reducing emissions by 55%[4] from a 1990 baseline by 2030. The proposed transition to climate neutrality includes investments and directives on CCS, smart infrastructure and innovative technology, smart grids, hydrogen networks and energy storage. Regarding CCS, the 2009 EU CCS Directive provides a framework on the geological storage of carbon dioxide regulates mainly the CO_2 storage phase. It also includes some provisions related to the CO_2 capture and transport phases with the intention to facilitate the integration of the CCS supply.

The European Commission [16] has stated a key role of CCS deployment to meet the EU's long-term GHG emissions reduction target by 2050. The Commission expects CCS to become one of the few technology options to cut direct emissions at scale from industrial processes and serve as a low-carbon technology when combined with fossil fuel-based generation to provide flexibility to energy systems, with increasing variable renewable sources [16]. However, it also indicates that the role of CCS has diminished with the faster deployment of renewable energy and other technologies to reduce emissions from industrial processes [16]. Despite this, CCS is still considered necessary to capture and store the CO_2 from carbon-intensive industries; in the transition of fossil fuel-derived hydrogen production and for the deployment of bioenergy with CCS at scale to achieve negative emissions. The European Commission's Hydrogen Strategy as a whole however emphasises electrolysis derived hydrogen (targeting 40 GW of electrolysis capacity by 2030) [17].

The European Union via the EU Innovation Fund (circa 10 billion euros), and using revenues from around 450 allowances of the EU Emissions Trading Scheme, is financing innovation projects including renewable energies, CCS, energy storage and industrial low-carbon processes [18]

UK - Committee on Climate Change

[4] Recently voted on by the European Parliament and may increase to 60% by 2030 against 1990 baseline

The Committee on Climate Change (CCC) has advised the UK Government to reduce GHG emissions reduction to 'net-zero' by 2050 under the UK's obligations to the Paris Agreement. The CCC in their Net Zero report [19] introduced new scenarios to illustrate options on how to reduce emissions from current levels. The CCC indicates that current UK policies are insufficient to meet even the previous 80% of emissions by 2050 target and that efforts in climate policy need to ramp-up [20].

In statements made to date, the CCC considers CCS systems essential to deliver net-zero GHG emissions by contributing to the projected increase supply of low-carbon electricity, hydrogen production, and the requirement of GHG removal through BECCS systems [21]. The CCC has *Core*, *Further Ambition* and *Speculative* scenarios. The Core scenario represents findings on low-cost low-regret options, the *Further Ambition* scenario involves more challenging and costly options than those in the *Core* scenario, and the *Speculative* scenario includes options considered to be at low-level of technology readiness, higher cost and with barriers to public acceptability. The extent to which CCS contributes to the net-zero target, however, varies within the scenarios and involves an aggregate annual capture and storage between 75-175 $MtCO_2$ in 2050 and a major CO_2 transport and storage infrastructure servicing at least five clusters [19].

Under the *Further Ambition* Scenario, CCS has a larger role across industry, greenhouse gas removals (i.e. BECCS), hydrogen production and power generation, with up to 175 $MtCO_2$ captured and stored in 2050. In the power sector, CCS integration with gas-fired or biomass power plants would be required to supply some flexible electricity generation and complement the remaining 5% share needed to fully decarbonize the electricity supply in 2050. Under this scenario, 57 $MtCO_2$ /year and 46 $MtCO_2$/year would respectively be captured and stored from fossil-based electricity generation with CCS and fossil fuel-derived hydrogen production with CCS. This scenario also assumes higher CO_2 capture rates of 95% [19] than the conventional 90% capture rate usually assumed in the literature for power-CCS plants. Technology options and economic challenges of higher CO_2 capture rates are further discussed later in this report.

The CCC also finds that CCS progress has stalled in the UK due to slow movement on UK policy for CCS deployment. Although CCS has recently begun to be discussed as a priority again slow progress leaves the UK with currently no CCS facilities in operation or construction at this time [20]. In these scenarios, a minimum of two CCS clusters are expected to operate by 2030 capturing at least 10 $MtCO_2$ per year. This is on the basis of the government leading infrastructure deployment, with long-term contracts for carbon capture and encouraging investment. These scenarios also include the development of hydrogen, mainly through natural gas reforming, assumed to operate at scale by 2030 in industrial CCS clusters, as well as policy frameworks across energy generation, industry, and greenhouse gas removals. The CCC highlights in particular that the UK should take advantage of the significant potential in regional CCS storage capacity, estimated in 78 Gt and equivalent to over 150 $MtCO_2$ stored per year [19].

In an illustrative generation mix of the power system in 2050, the share of electricity generation through natural gas power stations with CCS could reach up to 23% in the mix, although this could be partially replaced by nuclear power and alternative renewable technologies. The main supply of electricity would derive from variable renewables with a minimum 59% share. Additionally, electricity from BECCS (6%), nuclear (11%) and others sources (i.e. existing bioenergy and hydropower, and hydrogen or ammonia to provide back-up) would complement the generation mix [20].

The UK Government and the Department for Business, Energy & Industrial Strategy (BEIS):

As part of the UK Government, the Department for Business and Industrial Strategy (BEIS) considers that CCS technology has a significant role to play in meeting the net-zero target. CCS is expected to contribute to the decarbonisation of the power and industry sectors, produce fossil-based hydrogen and achieve large-scale commercial greenhouse gas removal [22]. Specifically, in the power sector, CCS is expected to capture and store the 45 $MtCO_2$ emissions per year from existing natural gas CCGT[5] based electricity generation, assuming a 95% CO_2 capture rate. Emissions from these systems are currently equivalent to 12% of UK emissions [22]. In the production of fossil fuel based-hydrogen via natural gas reforming or biomass gasification CCS would capture CO_2 as a by-product.

The UK Government considers CCS infrastructure likely to be delivered for the net-zero target with a substantial CO_2 storage capacity (78 billion tonnes of CO_2) using reservoirs deep underground off the UK coastline [22]. To this end, research investment competitions for greenhouse gas removals and development plans for six industrial CCS have been supported. The Government has also invested over £130 million in R&D and innovation with the aim of reducing CCS costs. They are supporting innovative technologies such as those developed by C-Capture (i.e. pilot testing of non-amine capture technology at Drax power station); Carbon Clean Solutions on novel carbon capture solvent and the Allam cycle technology, used by NET Power, capable of 100% capture rate at costs similar to an unabated CCGT [23].

Since the Clean Growth Strategy [23], the government committed to deploy CCS at scale during the 2030s subject to costs coming down sufficiently and to invest up to £800 million in developing CCS infrastructure to support the decarbonisation of our power and industrial sectors [21].[6] Recently enhanced ambition to begin construction of two CCS hubs in the mid-2020s and a further two created by 2030 has been announced [24]. The role of CCS is, however, considered essential by BEIS to reduce the costs of meeting the 2050 target contributing to lower emissions across industry, power, heating and transport sector [23].

[5] Combined Cycle Gas Turbine
[6] See BEIS (2020) https://www.gov.uk/government/news/beis-in-the-budget

In scenarios with a significant role for CCS, deployment is required through the 2020s, with the delivery of major projects by 2030 at the latest (particularly in UK scenarios). In the case of the IEA projections for the role of CCS in the energy sector have been downgraded. In the UK changing expectations in the role of CCS in energy are manifest in the National Grid Future Energy Scenarios, wherein in 2015 CCS coal and natural gas power generation is significant in scenarios [25] but absent in the 2020 scenarios [26]. The role of CCS in National Grid scenarios 2020 is exclusively in combination with bioenergy and for hydrogen production for heat and transport [26]. This reflects a shift in the expectations for fossil fuel CCS from the power sector to hydrogen and a greater emphasis on CCS for CDR and industry. In the next section, the current status of CCS worldwide is reviewed. The delays in CCS deployment discussed may in part explain this shift. Table 1 provides a review of the role of CCS in key scenarios reviewed.

Table 1:Summary of the role of CCS on energy and climate change scenarios and strategies for the IPCC, IEA and UK Committee on Climate Change

Report	Emissions reduction by 2050	Characteristic of CCS contribution/participation
IPCC 1.5°C Global Warming report	91%-97% CO_2 emissions reduction by 2050 (relative to 2010) across the four illustrative 1.5°C model pathways. 78%-89% reduction in Kyoto GHG emissions by 2050 (relative to 2010) across the four illustrative model pathways	CCS (including BECCS) contribution to CO_2 emissions reduction leads to cumulative CO_2 stored until 2100 spanning (four illustrative model pathways) between: The lowest share, **zero GtCO2 for low-energy demand-LED scenarios** to **348 $GtCO_2$ stored in a sustainability-focused scenario** of which BECCS 151 $GtCO_2$, to **686 GtCO2 stored in a middle-of-the-road scenario** of which BECCS 414 $GtCO_2$, to the highest share **1218 $GtCO_2$** for the **resource and energy-intensive scenario** of which BECCS 1191 $GtCO_2$.
IEA - World Energy Outlook 2019	In the Sustainable Development Scenarios (SDS): The emissions trajectory of SDS decline by 730 Mt on average each year compared with a 400 Mt annual decline in the 450 Scenario.	**2776 Mt of CO_2, from the energy-related GHG emissions, are captured and stored through CCS by 2050.** CCUS contributes 9% of the energy-related CO_2 emissions reductions. Across all sectors, around 0.7 Gt of CO2 emissions are captured each year by 2030; this rises to almost 2.8 Gt in 2050 where CCS is equally split between power and industry. **Under the SDS in the power sector**, CCUS is applied to over 320 GW of coal- and gas-fired power generation capacity by 2040, with 20 GW per year from late 2020's to 2040. **1323 $MtCO_2$ are captured and stored through CCS in the power sector**
CCC – UK Net Zero Report (2019a, 2019b)	In the Further Ambition Scenario (required to get to net-zero GHG emissions): 96% reduction in all GHG emissions by 2050 compared to 1990 levels, remaining in 35 $MtCO_2e$ in 2050 CO_2 emissions slightly below net-zero Remaining emissions from agriculture and aviation.	**In the UK,** CCS captures and stores an aggregated annual 175 MtCO2 in 2050 (from zero $MtCO_2$ in 2017). CCS to integrate with hydrogen, electrification and resource efficiency, the portfolio of options for emissions reduction: **CCS in electricity generation:** 57 Mt CO_2 captured and stored through fossil power generation with CCS. Decarbonised gas via CCS and hydrogen contributes with 5% for full (100%) electricity decarbonisation in 2050 and remaining emissions are of 3 Mt CO_2e **CCS in Hydrogen production:** 46 Mt CO_2 captured and stored through fossil hydrogen production with CCS **CCS in Industry:** 24 Mt CO_2 captured and stored **BECCS:** 44 $MtCO_2$ captured and stored. Bioenergy combined with CCS to produce electricity, biofuels for aviation and in buildings off the gas grid

3. The Current Status of CCS

The CCS concept, for long-term sequestration of CO_2, has been successfully demonstrated on a technical basis since 1996, however, scaling up deployment and applications outside of the chemical sector and oil and gas processing beyond EOR as a business model has been slow. The Global CCS Institute (GCCSI) notes that in 2010 ~10 Mt of CO_2/year CCS capacity was operational, with a further 150 Mt CO_2/year in some form of development, yet by 2020 only 39 Mt CO_2/year was in operation[7], with ~75 Mt CO_2/year capacity in some form of development (see Figure 4 of GCCSI [6]). This represents a decade of very limited progress in terms of CCS project development. Projects in development fell to as low as ~30 Mt CO_2/year in 2017 [27] reflecting various cancellations in early and advanced development projects. The IEA's 2019 scenarios for meeting SDGs considers 840 Mt CO_2/year of CO_2 capture (of which 81 Mt CO_2/year is BECCS and 189 Mt CO_2/year is used rather than stored) overall by 2030 [4], implying deployment averaging 80 Mt CO_2/year capacity per year over the coming decade. This is roughly equivalent to adding 25 projects globally each year with a capacity similar to the proposed Scotland CCS cluster (3-4 Mt CO_2/year) with the additional difficulty of the long deployment timelines for CCS projects. This will require overcoming the financial and risk barriers to the technology observed so far.

Carbon capture technology for use in the energy industry (primarily oil extraction) has been in place since the 1970s, with research into applications for long term sequestration accelerating through the 1980s (e.g. with the start of the MIT Carbon Capture and Sequestration Technologies programme in 1989). The role of CCS expressly for environmental goals was demonstrated in the 1996 Sleipner gas project [28], but clearer expectations around the role of CCS in climate policy became increasingly apparent around 2008. The UK Committee on Climate Change 'Building a Low Carbon Economy' in 2008 recommended CCS as an option for power generation (with coal and gas) and likely essential for some industrial applications [29]. This informed a policy process to develop CCS, firstly for coal power stations, pursuing deployment by the early 2020s [30]. A key international indicator for CCS expectations in this period was the G8 (Group of Eight) commitment to launch 20 large scale CCS projects by 2010 with broad deployment (19 to 43 large projects) of operational CCS by 2020 [31]. The IEA's CCS Roadmap in 2009 set a goal of 100 projects globally capturing 300 Mt CO_2/year by 2020 [4]. Deployment progressed slowly in relation to this, with only five projects developed by 2012. However, by 2014 the first commercial CCS power station at Boundary Dam in Canada was completed. In the UK two R&D competitions to develop demonstration projects in the UK between 2008 and 2015 produced significant research outputs on CCS application but ultimately did not lead to a demonstration project. The failure of the UK competitions

[7] Accounting for mothballed operations at Petra Nova and Lost Cabin facilities in 2020.

was primarily attributed to uncertainty around the economic feasibility of CCS, with a £1 billion state investment into CCS ultimately not materialising at the end of the second competition process [32]. The ownership structure (i.e. responsibility for the 'full chain' of CCS processes) expected of project developers is also considered a factor [33]. Additionally, a key driver of this initial round of investment in UK CCS was to mitigate carbon from coal power generation, which is now no longer a significant part of the UK electricity mix.

To date globally, 28 CCS plants are developed to the operational stage (although 2 are currently suspended), five of them with integrated dedicated geological storage and the remaining 22 using the CO_2 captured for enhanced oil/gas recovery (EOR/EGR) applications [6].

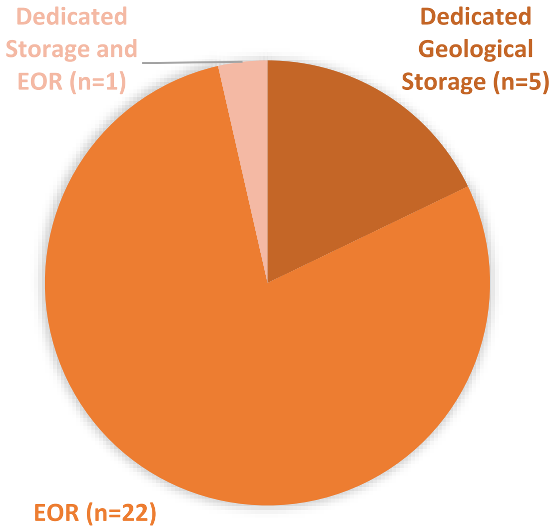


Figure 1: Operational CCS Projects by type of CO_2 storage. Based on the Global CCS Institute. The Global Status of CCS: 2020. (2020)

The CO_2-EOR process entails the injection of CO_2 in an oil reservoir, working as a solvent to swell and mobilise the oil previously trapped in rock's spaces and with the final purpose of increasing oil production in a well. The CO_2 is permanently trapped in the space that originally held the oil [27]. The global capture capacity of the operational CCS plants stands around 37 Mt CO_2/year, where approximately just 19% (~7 Mt CO_2/year) is used for the sole purpose of CO_2 emissions avoidance through dedicated CO_2 storage and the rest applied for EOR processes.

The GCCSI [6] also reports that two large-scale CCS facilities are under construction with an aggregated CO_2 capture capacity between 1.91 Mt CO_2/year and end-use applications in EOR. The expected start date of operation of these projects is in the late2020s. An additional 37 projects are in the pipeline, 13 of which are in advanced development using a dedicated front end engineering design (FEED)[8] approach and comprising a mix of dedicated storage (seven), EOR (four) and under evaluation (two). From the 21 CCS projects in early development, the majority (16) are planning to have CO_2 dedicated geological storage.

The natural gas processing industry embeds the highest number of CCS plants (11 facilities in operation) using industrial separation to capture the CO_2 and the majority with EOR application eight). These industries can capture the CO_2 at relatively low costs due to its high concentration in the gas streams [27]. Other industry sectors with projects integrating CCS, whether for emissions mitigation or as an inherent stage of the production process, are the power generation sector (one), fertiliser production (four), hydrogen production for oil refining (three), synthetic natural gas production (one), ethanol production (three) and iron and steel production (one)[6]. The emphasis on using EOR applications for existing CCS plants is because the majority of these facilities are located in the US where onshore EOR is a long-established process, with many miles of existing CO_2 pipelines. Furthermore, in the absence of strict regulations and cost on CO_2 emissions, there is little incentive to develop CCS for mitigation. Hence, EOR is so far one of the economically feasible ways to capture and store CO2 while extracting more oil. It is therefore notable that at this stage CCS planned deployment remains dominated by EOR – which has a minor role in expected CCS scenarios by 2030 (see Section 2).

CCS deployment in Europe and the UK

Among the 28 operational large-scale CCS facilities worldwide, two are located in Norway (Sleipner: 1 Mt CO_2/year and Snøhvit: 0.7 Mt CO_2/year) capturing and storing 1.7 Mt CO_2/year of CO_2 from the natural gas processing industry in dedicated storage sites [6][4]. In addition to the two operating CCS projects, the Longship CCS project in Norway is projected to commence operation by 2024 and capture up to 0.8 Mt CO_2/year of CO_2 from the Norcem's cement factory and the Fortum waste-to-energy plant facility [34]. The CO_2 transportation and off-shore storage will be managed by the Northern Lights consortium through an open-access infrastructure using existing oil and gas infrastructure. In addition to the CO_2 captured from the capture plants in Norway, Northern Lights is expected to serve as transportation and storage for other capture sites across Europe [34].

Despite a regulatory framework for CCS being in place through the 2009 CCS Directive, CCS deployment in Europe outside of Norway has not yet materialised. Compared to other regions like North America with 12 CCS large-scale facilities in operation, the integration of CCS to current power and industry sectors in Europe has been much slower.

[8] **Front End Engineering Design** is an approach used to control project expenses and thoroughly plan a project before a fix bid quote is submitted. It is conducted after completion of Conceptual Design or Feasibility Study, and before the Engineering, Procurement and Construction.

Progress on CCS deployment in Europe is however projected to accelerate in the mid and later 2020's with as many as 10 large scale CCS projects (six in the UK, two in the Netherlands, one in Norway and one in 1 Ireland) being proposed. Most of these projects are to function as part of CCS hubs and clusters in industrial installations and using shared infrastructure for the CO_2 transportation and storage network to reduce costs of the CCS supply chain. This, however, represents the current best case, with the UK Government so far only committed to 'at least two' industrial hubs by 2030.

The operation of the planned CCS facilities is expected to capture up to 26.7 Mt CO_2/year; 22.7 Mt are planned for injection in dedicated geological storage sites, with 4Mt captured from Drax (in conjunction with bioenergy) under evaluation [6]. The total CO_2 storage capacity available in Europe is estimated by the GCCSI to be 300 Gt [6].

In relation to funding and policy aspects, 10 billion euros are expected to be available for the Innovation Fund, the largest European fund financing CCS, as part of the portfolio of low-carbon technologies and processes. CCS is also part of the current European Commission strategy to achieve climate neutrality by 2050, with contributions spanning between 52 to 606 $MtCO_2$/ year in 2050 across scenarios. It is anticipated to have a more limited capacity in the power sector, instead, its proposed role is more relevant as an industrial decarbonisation alternative and for hydrogen production.

Within the UK, there are five clusters which have received funding to develop cluster plans under the first stage of the Industrial Decarbonisation Challenge Fund; bids to the second stage deployment plans have been submitted and are expected to commence early 2021. The *Net Zero Teesside* project is one of the initial CCS clusters under development estimating to capture up to 6 Mt CO_2/year of CO_2 emissions from a new commercial-scale natural gas power plant, that has completed the Stage 2 Consultation stage of the 'Development Consent Order' process, and also from other existing industrial processes. This cluster is expected to start operation by 2030. Furthermore, the Zero Carbon Humber cluster, also under development, is planned to capture CO_2 up to 10 Mt CO_2/year when fully operational from a BECCS plant (Drax biomass-power station) and from the production of hydrogen to fuel the industry sector. The Acorn Full Scale CCS project plans to function as a major fossil fuel based-hydrogen production pathway with a CCS transport and storage hub located at St Fergus in Scotland. The project was awarded the first carbon dioxide appraisal and storage licence by the Oil and Gas Authority in the UK and has stated it could commence operation in 2025. The Net Zero Teesside and Acorn projects could use the Northern Lights open-access infrastructure as an alternative CO_2 transportation and storage option. The other two clusters receiving funding from the Industrial Decarbonisation Challenge Fund (stage 1) are the HyNet North West industrial cluster for hydrogen production and the South Wales Industrial Cluster.

CCS in the power sector

The abatement of fossil CO_2 emissions through CCS deployment in the power sector remains limited, with currently two large-scale CCS facilities incorporated into coal-fired power plants, both in North America. Together, these facilities have a combined capture capacity of 2.4 Mt CO_2/year and use the CO_2 captured for EOR. This deployment is considered to be significantly off-track to meet climate change targets [4]; compared for example to the target of 310 Mt CO_2/year for power generation alone in 2030 by the IEA's Sustainable Development Scenario [15]. This would require an increase in CCS capacity in the power sector of approximately 129 times the existing capture capacity from the two existing power plants with CCS integration.

The first large-scale CCS facility in the power sector consisted of the integration of a CCS system in the Unit 3 of the *Boundary Dam* coal-fired power plant in Canada. It started operation in 2014 with a capture capacity of 1 Mt CO_2/year, resulting in a cumulative 3.4 Mt CO_2 captured up to July 2020. The capture method is the Shell Cansolv post-combustion CO_2 capture technology with a target capture rate of 90% [35]. The CO_2 is compressed and transported to Weyburn oil field for EOR and a smaller portion is stored in a dedicated saline aquifer (Aquistore project) to monitor and evaluate the safety and permanency of the deep underground CO_2 storage. The capital cost of the plant was reported to be 600 million Canadian dollars (~455 million USD) [36] and a capture cost of USD 100 per tonne CO_2.

Several conditions enabled the deployment of Boundary Dam CCS, including the opportunity to sell the CO_2 captured for EOR; grant supports, subsidy provision by government, and the prospect of low-cost CO_2 transport and storage [27]. The key driver, however, was the environmental regulation introduced by the Canadian government to meet emissions performance standards consistent with natural gas generation, therefore the only options were to retrofit (addition of a CCS unit to an existing power plant instead of adding it to a new plant) with CCS, switch to natural gas or decommission the plant [37].

Petra Nova Carbon Capture is the second commercial coal-fired power plant with CCS integration, located in Texas, USA. It started to operate in 2017 with a capture capacity of 1.4 Mt CO_2/year. It has accumulated 3.4 Mt of CO_2 captured and stored for EOR during the third phase (demonstration and monitoring) of the project between 2017-2019 [27]. The facility is however currently offline due to low oil prices [6, 38]. The capital cost of the project was USD 334 million and the levelised capture cost for this plant reduced to USD 65 per tonne CO_2, compared to Boundary Dam (although modifying existing infrastructure may have contributed to cost savings). The capture method used is an advanced amine-based CO_2 absorption technology (KM-CDR Process) [39].

The rationale behind the deployment of the plant was also different from Boundary Dam, as Petra Nova was constructed as an enhanced oil recovery project and received a significant grant (USD 190 million) from the US Government Clean Coal Power Initiative Program [36]. Furthermore, it has received emissions credits. Operation of CCS at the plant has however been reportedly affected by low oil prices [38].

As such, at this point, CCS deployment in sectors that it is primarily envisaged for (particularly in Europe) – natural gas power CCS, fossil fuel hydrogen production, industrial capture outside of oil and gas sector and carbon dioxide removals – is currently minimal or non-existent. Therefore, while technological aspects for capture technologies, transport and storage have been demonstrated, integrated systems delivering CCS services for key decarbonisation activities remain a future prospect. In the next section, the future potential for fossil fuel CCS in the energy system is reviewed. It suggests a limited role for CCS in energy system decarbonisation over the coming decade (2020-2030), but renewed policy priorities to establish CCS processes by 2030.

4. The Future Potential of CCS

Despite its representation across most model pathways for meeting climate change goals, research evidence collated in Rogelj et al [2] identifies uncertainty around the future deployment of CCS given the slow pace of deployment and lack of incentives, policies and regulation for CCS implementation compared to what is expected to be delivered by CCS infrastructure. Given the prominence of CCS in most mitigation pathways and its current limited improvement, the large-scale deployment of CCS as an option depends on the further development of the technology for permanent CO_2 (as opposed to EOR) in the near term.

This section considers some of the issues CCS faces in meeting the expectations identified in the energy and climate scenarios it features in (Section 2), specifically around emissions, technical attributes, regulation, and cost and complexity.

BOX 1: Technical Attributes of CCS

Among the stages comprising CCS, the CO_2 capture is the most energy-intensive and costly, imposing a considerable energy penalty to the process [3]. Energy penalty is a common metric applied to the power generation sector that compares the performance (efficiency) of a plant with CCS compared to a similar one without it [5]. It can be interpreted as the additional energy input (fuel) required to maintain a power's plant output at the same level, or the loss of power output for a constant energy input [7].

There are various types of CO_2 capture technology, featuring inherent advantages and limitations, and at different stages of development; post-combustion, oxyfuel combustion and pre-combustion.

In the ***post-combustion capture technology***, the CO_2 is separated and captured, from the flue gases (nitrogen, water, CO_2, and other impurities) after the fuel combustion in a power plant or industrial process. The main advantage of this technology is the feasibility for retrofits of existing industrial plants without further large equipment investments and low impact on the process operation [3].

The main energy input is required in the form of low pressure steam for the solvent regeneration process, imposing a significant efficiency penalty. Part of the steam generated to produce electricity in the power plant is diverted for the amine solvent regeneration, thus imposing an energy penalty between 15-28% for pulverised coal power plants and 15-16% for natural gas combined cycle plants with integrated post-combustion capture [5].

In ***oxyfuel combustion capture***, fuel (coal, gas, or biomass) is burned in a mixture of oxygen and recycled CO_2 (to control the temperature inside the boiler) producing a gas mainly formed of CO_2 and water vapour. The CO_2 is separated afterwards by a condensation process [3].

The major advantage of this is simple and low-cost CO_2/H_2O separation. It also has the potential of retrofitting for existing power plants. The energy penalty (around 19%) is imposed by the energy-intensive air separation process [12]. Therefore the development of more efficient air separation systems might also enhance the overall process efficiency [3].

The ***pre-combustion capture technology*** entails a reaction between coal, natural gas or biomass and air, oxygen and/or stem to produce a syngas comprised mainly by CO, H_2, CH_4 and CO_2. The syngas reacts with steam in a water-gas shift reactor to produce CO_2 and more H_2. The CO_2 is later separated using physical or chemical absorption methods, resulting in two separate gas streams: a pure CO_2 gas and hydrogen-rich fuel.

Because pre-combustion capture involves steam reforming or gasification process, this route has limitations on the operating flexibility as gasification is a more complex and novel technology than combustion. The capital costs are higher forcing full load operation to produce syngas. The operating condition of the pre-combustion technology varies to post-combustion because in pre-combustion the syngas is at higher pressures (2-7 MPa) and high CO_2 concentration content, therefore the compression and desorption requirements are not so demanding, resulting in lower efficiency penalties [3]. Energy penalties range between 5-20% for Integrated Gas Combined Cycle (IGCC) power plants combined with pre-combustion capture CCS.

Emissions

Mitigating climate change in line with the goal of staying well below 2°C of warming depends on a timely transition to low carbon energy [40]. In contexts such as the UK, legislative targets require net-zero greenhouse gas emissions by 2050, which for the energy system means almost zero CO_2 emissions [19]. It is not only what is achieved by an endpoint target (such as 2050), but the extent to which cumulative CO_2 emissions – the primary driver of long term climate change [40] – are limited over time that ultimately matters. The emissions associated with a given future technology and its contribution to mitigation at a given time are therefore of particular importance. The remaining global carbon budgets published by the IPCC imply immediate and sustained reductions in emissions, with a reduction in global CO_2 of ~45% against a 2010 baseline required by 2030 for a chance of 1.5°C [14]. The EU is considering a mitigation target of over 55% relative to 1990 by 2030 and the UK recently updated its 2030 target to 68% cut in emissions by 2030 against the 1990 baseline [41], entailing significant additional progress on heating and transport by 2025 [21]. Analysis by Anderson et al suggests that mitigation rates in countries such as the UK should be even greater (~10% per annum, up from recent historical trend of 3% per annum), decarbonising energy systems by 2035 to 2040 [8]. By all measures, significant progress in energy system decarbonisation is required over the coming decade particularly in developed nations such as within Europe.

Within many of the pathways proposed for reaching these targets, CCS has various roles in industrial decarbonisation, power sector decarbonisation and CDR (see Section 2). CCS offers a means of capturing ongoing emissions of CO_2 from existing industrial processes such as iron & steel and cement, providing an option to decarbonise these typically hard to abate emissions. Hydrogen via electrolysis also offers an alternative to CCS based decarbonisation of steel production. The IEA World Energy Outlook 2019 reports that CCS together with energy and material efficiency supports the decarbonisation of heavy industries, such as cement, iron and steel production, and the refining sub-sector of oil and gas extraction [15]. In the IEA SDS, CCS contributes to 21% of savings in energy-related CO_2 emissions in industry [15]. They also note that the current pipeline of projects, however, is far short of what is required under this scenario to abate emissions from key industrial sectors of the economy [15]. Carbon dioxide removal with CCS is central to national net-zero targets in the UK [19]. In the case of energy provision through fossil fuel CCS, however, there are apparent limitations to the role that it may be able to play within highly constrained future carbon budgets.

In the case of natural gas CCS power stations, there are residual emissions that would contribute to direct territorial CO_2 emissions of at least 39 $kgCO_2e/MWh$ (assuming a 90% CO_2 capture rate) [42]. Upstream emissions of greenhouse gases (notably methane) associated with extraction, processing and transport increase with CCS application due to increased energy use for capture and reduced efficiency meaning life cycle emissions of at least 123 $kgCO_2/MWh$ [10].[9]

Steam methane reforming (SMR) and autothermal reforming (ATR) processes of transforming natural gas feedstock into hydrogen also entail greenhouse gas emissions in production and across the supply chain. The UK CCC estimates emissions savings on a whole life basis of 65% to 85% when switching from natural gas to hydrogen from fossil fuel CCS for home heating [11]. Producing fossil fuel-based hydrogen with CCS is estimated to produce 50 gCO_2/kWh to 188 gCO_2/kWh (process and supply emissions) [11]. Similarly, a report by Navigant reports a range of 51 gCO_2/kWh to 63 gCO_2/kWh for producing CCS derived hydrogen [43]. As such whether fossil fuel-based hydrogen is sufficiently low carbon – from UK Net Zero and relative to global remaining carbon budgets – to have a major role in energy provision is an important consideration.

With these considerations in mind, the IEAGHG note that scenarios for a constrained global carbon budget, especially for 1.5°C and high probability well below 2 °C cumulative budgets, have limited fossil fuel CCS energy production [42]. The UK CCC similarly concludes that hydrogen utilisation should be prioritised for niche functions and where derived from fossil fuel conversion would not have a widespread role in low carbon scenarios [11].

These emissions considerations assume a 90% to 95% CO_2 capture rate, which as discussed below, could in principle be increased (however with increased upstream emissions through increased fuel use). There may also be wider environmental impacts (as is the case with any scale-up of a technology) not captured in a global warming potential (CO_2e) focused assessment. However, the lack of sufficient data on natural gas CCS power station capture rates, CCS hydrogen production operations, or any CCS energy application with >90% capture rate, means that it is prudent to await these results before applying high capture rates to these emissions factors.

Potential higher capture rates (99%)

In power generation plants with CCS, the CO_2 capture rate has been historically fixed at 85% - 90% due to associated captures costs of flue gas streams with low CO_2 concentration (below mol-20%). The two large-scale power plants with CCS retrofit used this capture rate as target (*Boundary Dam* and *Petra Nova*) and IAMs used a 90% capture rate in their assessments, assuming 10% of residual emissions.

Recent studies by the IEAGHG [10] looking at the feasibility of reaching near zero emissions in fossil-CCS concluded that in theory there are no technical barriers to

[9] The data presented in table 9 of IEAGHG (2019) 'Towards zero emissions CCS in power plants using higher capture rates or biomass' provides this breakdown based on the best performing emissions data for natural gas fired turbines.

increasing the capture rate across the three main capture technologies. However, trade-offs should be considered as costs (total plant cost and levelised costs of electricity) are expected to increase, in some cases modestly, depending on the capture technology. Additionally, the plant's performance is expected to decline (i.e. higher energy penalties) and the indirect emissions from fossil fuel use increase. Alternatives to increasing the CO_2 capture rate above 90% and the implications of higher capture rates on costs and plant's performance are presented in more detail below for each of the three main carbon capture technologies. While optimisation for CO_2 capture at a CCS facility presents opportunities to mitigate direct emissions, it also has implications for indirect emissions and validation against actual performance is still required [10].

For ***post-combustion capture***, pathways for reaching higher CO_2 capture rates are through increasing the effectiveness of the CO_2 separation process or co-firing with biomass, which could result in relatively lower costs depending on the biomass type. The increase in costs will also depend on the type of power plant. In ultra-supercritical coal (USC) power-CCS plant with 99.7% CO_2 capture, the levelised cost of electricity (LCOE) can increase by 8% and the CO_2 avoided cost (CAC) by 6%. Further, co-firing with 10% of biomass in the same plant could increase, instead, the LCOE by just 2% and the CAC by 1.4%. In a CCGT-CCS plant, a 99% of CO_2 capture increases the LCOE by 6.6% and CAC by 7.8% [10]. Concerning the net plant efficiency, a 99% capture rate decreases the net plant efficiency by 5% in a USC power plant configuration and by 4.5% in a CCGT plant. The cofiring of biomass (10%) would avoid a further reduction in the plant's efficiency for a USC coal-CCS plant and a neutral CO_2 emission intensity with a 90% capture rate.

Pathways to increase the CO_2 capture rate in ***oxy-combustion capture process*** are achieved via a reduction in the inert gases of the CO_2 stream by using oxygen with higher purity and/or reducing the air leakage to the boiler [10]. CO_2 can also be recovered by passing the vent gases from CO_2 purification to a membrane separation unit [44]. From a performance and costs perspective, increasing the capture rate from 90% to 98% could reduce the plant's net electrical efficiency by -1% and increase the total plant costs (TPC) by 2% and the LCOE by 3%, while reducing the cost of CO_2 avoidance by -4%.

For **pre-combustion capture**, increasing the capture rate to 98.6% in a coal-based Integrated Gasification Combined Cycle power plant leads to a 2% reduction in the plant's electrical efficiency, and higher total plant costs by 4% and LCOE by 4.2%. These figures almost doubled the efficiency penalty and costs increase, compared to oxy-combustion capture, however, the CO_2 avoidance costs also decrease by around 3.6% [44]. Reducing the CO_2-slip emissions in the flue gas could be attained by improving the carbon conversion (water-gas shift reaction conditions) and the CO_2 separation process. As in other processes that increase the gross fuel input into the power plant to account for energy penalties of the capture stage, doing so has consequences for environmental and human health impacts through the coal supply chain.

Table 2 collates performance data reported by the IEAGHG [10, 44]on the implication of higher CO_2 capture rates and/or biomass cofiring to reach near 100% CO_2 direct emissions reduction in comparison to standard CCS integration with 90% capture rate:

Table 2. Implications of higher CO_2 capture rates on plant net efficiency, LCOE and CAC

Capture technology	Characteristics	Change in plant efficiency	Change in TPC	Change in LCOE	Change in CAC
Post-combustion capture [10]	USC-power plant (99% capture rate)	↓ 5%	↑ 6.6%	↑ 8%	↑ 6%
	10% biomass cofiring (90% capture rate)	0%	↑ 1.9%	↑ 2%	↑ 1.4%
	NGCC power plant (99% capture rate)	↓ 4.5%	↑ 6.5%	↑ 6.6%	↑ 8%
Oxy-combustion capture [44]	SC-power plant (98% capture rate)	↓ 1.1%	↑ 2.2%	↑ 3%	↓ 4%
Pre-combustion capture [44]	Coal-IGCC plant (98.6% capture rate)	↓ 2.4%	↑ 4.1%	↑ 4.2%	↓ 3.6%

Overall, increasing the capture rate in oxy-fuel combustion and pre-combustion CCS would marginally increase costs and reduce the plant's efficiency, also the CO_2 abatement costs could decrease for both capture technologies. More detrimental results are observed for post-combustion capture plants using coal or natural gas and better results for biomass cofiring keeping the same 90% capture rate. Numbers are more favourable for oxy-combustion capture because of a relatively simpler and low-cost CO_2 separation process. IEGHG [10] also highlight that these findings need validation through demonstration in real-life operation across the different CO_2 capture routes and, that indirect emissions from the coal and/or natural gas power–CCS plant supply chains should be minimised in parallel to direct emissions in order to decrease total lifecycle emissions.

Global CO_2 storage capacity

CO_2 storage starts with the injection of the captured CO_2 into deep underground geological reservoirs, such as deep saline formations and depleted oil and gas reservoirs, for permanent storage. The porous rock layer is overlaid by an impermeable layer of rocks that seals the reservoir and prevents the upward migration of CO_2 and escape into the atmosphere.

The estimations of global CO_2 storage capacity vary hugely and have many uncertainties. These estimates indicate that capacity is potentially sufficiently large to meet the global demand for CO_2 storage [4, 5] [45]. Global estimates of storage capacity sit between 8,000 Gt and 55,000 Gt CO_2 [4] whereas 600-2,000 Gt of cumulative CO_2 are expected to be stored by 2100 to keep CO_2 concentrations between 400-500 ppm [4] for global climate targets. A larger storage potential capacity exists for onshore reservoirs (6,000 Gt to 42,000 Gt) compared to offshore (2,000 Gt to 13,000 Gt) and the regions with largest capacities are in Eurasia, North America and Africa [4]. For context, annual global emissions of CO_2 for energy were at around 35 $GtCO_2$ in 2019 [46].

Emissions pathways consistent with 1.5 °C (with no or limited overshoot) indicate that CCS could produce up to 1,200 $GtCO_2$ for storage. On the other hand, IPCC 2005 estimates a technical potential of at least about 2,000 $GtCO_2$ of storage capacity in geological formations [47]. In general, the storage capacity of all these global estimates is larger than the cumulative CO_2 stored via CCS in 1.5°C pathways over this century.

This storage capacity varies within regions, with USA, China and West Europe accounting for almost half of the global CO_2 storage capacity under 1.5°C and 2°C scenarios. For the top five regions that include USA, China, Western Europe, India and Russia, the storage demand fits within the regional storage capacity except for Russia, where the CO_2 storage required for this region exceeds the estimated capacity for a 2°C scenario with 66% probability [45].

Overall, there is broad agreement on the match, at a global level, between the demand of CO_2 storage and the technical potential capacity of CO_2 storage in geological formations, at least for CO_2 storage operation until the year 2050 (IPCC[14] and GCCSI [6]). Under the IEA Sustainable Development Scenario, the demand of CO_2 storage required (220 Gt CO_2) between 2020-2070 could be met by the lower end of the estimated CO_2 storage capacity (8,000 Gt).

To attain a large annual CO_2 storage rate, the IEAGHG estimates that approximately 30-60 storage sites need to be characterised and deployed annually until 2050, with these numbers expected by the GCCSI to double when including negative emissions storage [27].

For certain regions, such as, in China, Japan and South Korea, the source-sink matching is more uncertain and could be potentially limited, compared to other regions where regional storage supply is more developed, i.e. North America, Europe and Brazil [5]. Furthermore, by 2100, there is more uncertainty on the real CO_2 storage capacity for different regions.

Detailed assessment and careful selection of the storage sites is considered essential to guarantee the safety and permanency of the CO_2 stored and to reduce risks of potential CO_2 leakage to the atmosphere or groundwater [4].

The costs associated with CO_2 storage are lower compared to the capture process, however, is considered an essential factor to CCS deployment in the coming decades [4]. CO_2 storage costs range between negative costs (approximately -30 USD/t CO_2) for EOR applications, to costs ranging between 10 USD/t CO_2 with60% of the onshore storage capacity, to even higher costs for offshore storage, 60% of offshore capacity is available at costs below 60 USD/t CO_2. The cheapest options among the different reservoirs are the depleted oil and gas sites [4].

The development of CCS industrial clusters that pools the transport and storage demands to share the infrastructure is expected to contribute to reducing transport and storage costs [4].

Risks over CO_2 leakage and long-term geological stability

The leakage of CO_2 refers to the unintended escape of the fluid from the storage site.

One of the barriers identified to large-scale CCS deployment has been the risk associated with the safety of the CCS infrastructure, particularly during CO_2 transportation and storage[5, 48]. For instance, CO_2 leakage and over-pressurisation are common concerns underscored in public acceptance analysis [49].

Practical experience gained through the operation of many industrial-scale CCS projects in the oil and gas industry; in addition to pilot-scale research projects have provided further knowledge on the physical and chemical phenomena affecting the stability of a storage site. Advanced monitoring tools and modelling capability is also available to assess with more precision the behaviour of the CO_2 plume in the storage site [28]. These advances have provided a better understanding and common agreement on the safety of long-term storage and the low probability of CO_2 leakage if the storage sites are characterised, monitored and managed in an adequate manner [48].

On the other hand, the stability of a geological storage site can be managed through its local pressurisation, limiting the CO_2 injection into the well to prevent wellbore fracturing. Additionally, to oversee regional pressurisation of the storage sites, management strategies for pressure and waste brine disposal should be considered [5]. The absence of these strategies to control the reservoir pressurisation imposes limits to the CO_2 storage capacity, as pressures in the reservoirs need to maintained under certain values to avoid induce fractures or reactivate faults in the sealing caprock [5].

With regard to storage integrity, the IPCC SRCCS considered that "for well-selected, designed geological storage sites the vast majority of the injected CO_2 will gradually be immobilised by various trapping mechanisms and in that case be retained for millions of years. Because of the trapping mechanisms identified storage would become more successful over longer time frames" [47]. This body of research concluded that CO_2 storage is by and large a safe operation if storage sites are properly selected, characterised and managed, thus reinforcing the message in the IPCC SRCCS [47, 48].

Regulatory frameworks to monitor and oversee the safety of CCS infrastructure

A robust legal and regulatory framework is important to ensure appropriate site selection and safe operation of geological CO_2 storage sites. This already exists in many countries, with the UK having launched a licencing process.[10] Project developers and public authorities have to address public concerns through effective stakeholder engagement [4].

To address and minimise the risks associated to CO_2 leakage during long-term storage, as well as the geological stability of the storage site, it is important that liabilities are allocated and managed among the stakeholders of the CCS supply chain.

Risks should be distinguished depending on their potential impacts, whether it is a local environmental and safety issue or a global "climate-related leakage risks [28]. Policymakers and project developers have agreed that practical, well-defined legislation and a strong global regulatory framework are necessary for CCS to reach its potential.

Programmes of Monitoring, Measurement, and Verification (MMV) are considered essential to ensure that CO_2 storage meets operational, regulatory and community expectations, using the experience of the oil, gas, and groundwater industries [5, 27].

Cost and Complexity

The financing of CCS projects has been an ongoing issue causing delays to project development. Most carbon capture projects developed to date have revenue from the utilisation of CO_2 in EOR, particularly in North America. For example, the Petra Nova CCS project's reliance on revenue from EOR is highlighted by its recent mothballing since the fall in oil prices in 2020 [38]. The development of Sleipner CCS projects in 1996 and Boundary Dam to CCS in 2014 can be attributed to tax and regulatory regimes in Norway and Canada [37] respectively that made CCS economically beneficial for the ongoing operation of the facility.

This is in part a reflection of the scale, complexity, and consolidated nature of CCS projects, which face similar challenges to nuclear in terms of deployment. For example, the capture, transport and storage aspects of CCS have been described as quite distinct, but co-reliant businesses which multiply the risks to a potentially unmanageable degree if a single developer responsible for the whole 'chain' is not in place to handle this [33, 50]. This has been an observed problem in the UK where the attribution of long term CO_2 storage liabilities to the private sector and ownership of the full-chain of CCS processes are seen as a barrier to development [33]. Research by Wilson et al [51] suggests that these 'lumpy' characteristics of technologies such as CCS can in part explain why more modular technologies such as solar photovoltaics, wind energy and battery storage have deployed at a faster rate. De-risking CCS sufficiently to facilitate the required capital investment into CCS infrastructure appears to be a core challenge that requires long term state intervention in some form (if EOR is not part of the business model). This seems particularly acute for 'transport and

[10] See https://www.ogauthority.co.uk/licensing-consents/carbon-storage/

storage' (T&S) operators for whom there are high up front capital costs with expected multi-decadal operating lifetimes [50, 52].

In relation to costs, the UK CCC estimated that in 2050 using CCS combined to mid-merit electricity generation would have CO_2 abatement costs ranging between 115-120 £/tCO_2 and generation costs around 108 £/MWh. However, if CCS would have to be part of firm low carbon power in gas-fired power plants abatement, costs would be lower 48 £/tCO_2 and generation costs around 70-80 £/MWh [19]. Although costs are expected to be higher for CCS as a mid-merit generation technology, this is considered to be the preferred alternative so renewables have higher priority over CCS and power-CCS would precede over unabated fossil-based power generation.

Support for new CCS will likely need to subsidise ongoing revenue for CCS enabled products (electricity, hydrogen, or carbon removal) or offer long term avoided costs (e.g. a carbon tax) to make industrial process capture attractive. The current Contracts for Difference (CfD) mechanism (essentially a guaranteed minimum price for electricity sold over a period of time), capacity and/or flexibility payments for electricity grid services (e.g. frequency response, black start, and inertia). CCS power generation in the UK is now not expected until 2030 and the form and scale of public subsidy is not clear. In the meantime, costs associated with technologies such as offshore wind have seen their levels of required support (as viewed through UK CfD payments) fall from over £100/MWh to less than £40/MWh. While capacity factors for offshore wind have improved, they do not provide dispatchable power equivalent to existing power stations. Capacity or other grid service payments may be needed to compete with low marginal costs per unit of electricity from renewables while valuing potential dispatch, inertia, and flexibility benefits of CCS power stations relative to renewables. Here too CCS may face increasing competition from energy storage and demand response offerings over the coming decade. The European Zero Emissions Platform review for the industry identified a likely need for state support for transportation and storage aspects of the CCS industry akin to electricity and water network investments [52]. This is a key issue as new CCS projects in the UK for long term geological storage are unlikely to progress until the policy and investment for T&S are agreed. A delay in agreeing to this will postpone the deployment of CCS further.

5. Summary

Highly constrained global carbon budgets for meeting the goals of the Paris Agreement require significant progress in energy sector decarbonisation by 2030, particularly in developed economies [8]. This is increasingly being reflected in national policies to increase the rate of decarbonisation in relation to 2030 as well as setting longer term targets. While the longer-term application of CCS in industrial processes and for carbon dioxide removal retains a significant role in climate scenarios, this is not necessarily the case for fossil fuel-based CCS in the energy sector (see Section 2). CCS deployment in the energy system for power, heat and transport decarbonisation has to-date been largely non-existent, with significant deployment now not expected until 2030. As such the role of natural gas- and coal-based CCS for power generation has been downgraded in future energy pathway scenarios. In contexts such as Europe, with supra-national and national targets to cut emissions by over 50% against 1990 levels by 2030 – through which the energy sector would change significantly - CCS deployment is likely now too slow (see Section 3). Focus recently has in part shifted to the role of CCS with fossil fuel-based hydrogen as an alternative vector. There are at present disparities in the extent to which CCS is featured in future hydrogen pathways, relative to electrolysis based hydrogen and electricification alternatives. The European Commission [17] assume limited if any role for CCS in hydrogen provision, while in the UK its application varies across scenarios considerably [19, 26]. This reflects concern about residual emissions from capture and fuel supply stages of the CCS hydrogen life cycle in the context of constrained carbon budgets, and that commercial applications of this technology are still forthcoming (see Section 4). The technical feasibility of higher CO_2 capture rates (>95%) and application of capture throughout the fuel supply chain may address these issues, but until this can be demonstrated and costs are clarified it is prudent to have energy pathways without fossil fuel CCS in policy scenarios for meeting climate change goals.

Acknowledgements:
The authors would like to thank Dr Sarah Mander and Dr Clair Gough for their insight and comments in developing this report. We would also like to thank the anonomous peer reviewer for their helpful comments and challenges which have improved this work.

6. References

1. Masson-Delmotte, V., et al., *Global warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change,*. 2018, IPCC: [redacted]
2. Rogelj, J., et al. *Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development*. in *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change*. 2018.
3. Florin, N. and P. Fennel, *Carbon capture technology: future fossil fuel use and mitigating climate change*, in *Grantham Institute for Climate Change Briefing paper*. 2010: [redacted]

[redacted] *and Storage; CCUS in clean energy transitions*. 2020, International Energy Agency: [redacted]

5. Budinis, S., et al., *An assessment of CCS costs, barriers and potential.* Energy Strategy Reviews, 2018. **22**: p. 61-81.
6. Global CCS Institute, *Global Status of CCS 2020*. 2020: [redacted]
7. House, K., Z.,, , et al., *The energy penalty of post-combustion CO2 capture & storage and its implications for retrofitting the U.S. installed base.* Energy & Environmental Science, 2009. **2**(2).
8. Anderson K., J.F. Broderick, and I. Stoddard, *A factor of two: how the mitigation plans of "climate progressive" nations fall far short of Paris-compliant pathways.* Climate Policy, 2020. **(In Press)**.
9. Prognos, Ö.-I., Wuppertal-Institut,, *Towards a Climate-Neutral Germany. Executive Summary conducted for Agora Energiewende*. 2020, Agora Verkehrswende and Stiftung Klimaneutralität.: [redacted].
10. IEAGHG. *Towards zero emissions CCS in power plants using higher capture rates or biomass*. 2019. Cheltehnham.
11. Committee on Climate Change, *Hydrogen in a Low Carbon Economy*. 2018: [redacted]
12. Cremer, C., *Carbon capture and storage.* The Hydrogen Economy: Opportunities and Challenges, 2009. **9780521882**: p. 168-198.
13. Grubler, A., et al., *A low energy demand scenario for meeting the 1.5 °C target and sustainable development goals without negative emission technologies.* Nature Energy, 2018. **3**(6): p. 515-527.
14. IPCC, *Summary for Policymakers*, in *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change,*, P.Z. V. Masson-Delmotte, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, T. Waterfield, Editor. 2018. p. 24 p.
15. IEA. *World Energy Outlook-2019*. in *World Energy Outlook 2019*. 2019.

16. Commission, E., *The European Green Deal*, in *COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE EUROPEAN COUNCIL, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS*. 2019: Brussels. p. 24.
17. European Commission, *COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS*. 2020: [redacted]
18. Delbeke, J. and P. Vis, *Towards a climate-neutral Europe : curbing the trend*. 2019, [redacted] Routledge.
19. Committee on Climate Change, *Net Zero: The UK's contribution to stopping global warming*. 2019, Committee on Climate Change: [redacted]
20. Committee on Climate Change, *Reducing UK emissions 2019 Progress Report to Parliament* 2019: [redacted]
21. Committee on Climate Change, *Reducing UK emissions - 2020 Progress Report to Parliament.* Reducing UK emissions: 2019 Progress Report to Parliament, 2020: p. 1-93.
22. BEIS, *`CARBON CAPTURE , USAGE AND STORAGE: A Government Response on potential business models for CCUS*. 2020, Department of Business Energy and Industrial Strategy: [redacted]
[redacted] [redacted]. 2017: https://www.gov.uk/government/publications/clean-growth-strategy.
24. HM Treasury, *National Infrastructure Strategy*. 2020: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/938539/NIS_Report_Web_Accessible.pdf.
25. National Grid, *Future Energy Scenarios 2015*. 2015: [redacted]
26. National Grid, *Future Energy Scenarios 2020*. 2020: [redacted]
27. Global CCS Institute. *The Global Status of CCS: 2019*. 2019. Australia.
28. IEA. *20 Years of Carbon Capture and Storage - Accelerating Future Deployment*. 2016. Paris.
29. Change, C.o.C., *Building a low-carbon economy – the UK ' s contribution to tackling climate change.* Global Environmental Change, 2008. **8**: p. 201-208.
30. DECC, *Government Response to the House of Commons Environmental Audit Committee Report: Carbon Capture and Storage (CCS)*. 2009, Department for Energy and Climate Change: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/238627/7605.pdf.
31. IEA, *Carbon Capture and Storage Progress and Next Steps*. 2010, International Energy Agency: [redacted]
32. National Audit Office, *Carbon Capture and Storage: the second competition for government support.* 2017: p. 50.
33. Oxbrugh, *LOWEST COST DECARBONISATION FOR THE UK: THE CRITICAL ROLE OF CCS*, in *Report to the Secretary of State for Business, Energy and Industrial Strategy from the Parliamentary Advisory Group on Carbon Capture and Storage (CCS)*. 2016.
34. CCS Norway. *Longship CCS*. 2020; Available from: [redacted].

35. Stéphenne, K., *Start-up of world's first commercial post-combustion coal fired ccs project: Contribution of shell cansolv to saskpower boundary dam iccs project.* Energy Procedia, 2014. **63**: p. 6106-6110.
36. World Coal Association. *Driving ccus deployment the pathway to zero emissions from coal*. 2018. UK.
37. Herzog, H., *Financing CCS demonstration projects: Lessons learned from two decades of experience.* Energy Procedia, 2017. **114**: p. 5691-5700.
38. Schlissel, D., *Dennis Wamsted, Analyst/Editor Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign Red Flags for Investors on Coal-Fired CCS Projects; Shutdown Lays Bare the Risks Around Proposals That Include Enchant Energy's in N.* 2020: p. 1-9.
39. NETL, D.-. *Final Scientific/Technical Report - Petra Nova*. 2020.
40. IPCC, *Summary for Policymakers; Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* J.S. P.R. Shukla, E. Calvo Buendia, V. Masson-Delmotte, H.- O. Pörtner, D. C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, Editor. 2019: [redacted]
41. Committee on Climate Change, *Letter to the Secretary of State Department for Business, Energy & Industrial Strategy; Advice on the UK's 2030 NDC*. 2020: [redacted]
42. IEAGHG, *CCS in Energy and Climate Scenarios*. 2019: [redacted]
43. Navigant, *Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain*. 2019: [redacted]
44. IEAGHG. *CO2 Capture at Coal Based Power and Hydrogen Plants*. 2014. Cheltehnham.
45. Vaughan, N.E., et al., *Evaluating the use of biomass energy with carbon capture and storage in low emission scenarios.* Environmental Research Letters, 2018. **13**(4): p. 044014.
46. Global Carbon Project. *Global Carbon Budget 2019*. 2020; Available from: [redacted]
47. IPCC, *Carbon Dioxide Capture and Storage (SRCCS)* O.D. Bert Metz, Heleen de Coninck, Manuela Loos and Leo Meyer, Editor. 2005: [redacted]
48. Gale, J., et al., *Special Issue commemorating the 10th year anniversary of the publication of the Intergovernmental Panel on Climate Change Special Report on CO2 Capture and Storage.* International Journal of Greenhouse Gas Control, 2015. **40**: p. 1-5.
49. L'Orange Seigo, S., S. Dohle, and M. Siegrist, *Public perception of carbon capture and storage (CCS): A review.* Renewable and Sustainable Energy Reviews, 2014. **38**: p. 848-863.
50. Poyry, *A STRATEGIC APPROACH FOR DEVELOPING CCS IN THE UK*. 2016: [redacted]
51. Wilson, C., et al., *Granular technologies to accelerate decarbonization.* Science, 2020. **368**(6486): p. 36.
52. Zero Emissions Platform, *Business models for commercial CO2 transport and storage*. 2014: [redacted]

Appendix I

IEMA Transforming the world to sustainability

Institute of Environmental Management & Assessment (IEMA) Guide:

Assessing Greenhouse Gas Emissions and Evaluating their Significance

2nd Edition

February 2022

Contents

Acknowledgements

Working group

This practitioner's guide has been developed by IEMA and EIA professionals working for organisations registered to the EIA Quality Mark (www.iema.net/qmark).

The project was co-authored by the GHG Working Group, coordinated by Arup along with the assistance of Rufus Howard and Nick Blyth of IEMA.

The Working group is composed of:

James Blake (Turley)

Tom Dearing (RPS)

Caroline Dinnage (Stantec)

Roz Griffiths (Arup)

Kirsten Leggatt (Sweco / Arup)

Emma Marsland (Arup)

Michael Pantling-Skeet (Ramboll)

Joe Parsons (RHDHV)

Tom Peacock (Buro Happold)

James Peet (WSP)

Andrew Tasker (RPS)

George Vergoulas (Arup)

Joanna Wright (LUC)

About IEMA

The Institute of Environmental Management & Assessment (IEMA) is the professional home of over 18,000 environment and sustainability professionals from around the globe. We support individuals and organisations to set, recognise and achieve global sustainability standards and practice. We are independent and international, enabling us to deliver evidence to governments, information to business, inspiration to employers and great stories to the media that demonstrate how to transform the world to sustainability.

Join us at www.iema.net

List of Abbreviations / Glossary

BaU – Business as Usual

BIM – Building Information Modelling

BREEAM – Building Research Establishment Environmental Assessment Method

CEEQUAL – Civil Engineering Environmental Quality assessment scheme

CEMP – Construction Environmental Management Plan

CEN – European Committee for Standardization

Climate change – changes in general weather conditions over 30 years (seasonal averages and extremes)

Climate Change Adaptation – the process that a receptor or project must go through to ensure it maintains its resilience to climate change

Climate Change Resilience – a measure of ability to respond to changes in climate. If a receptor or project has a good climate change resilience, it is able to respond to the changes in climate in a way that ensures it retains much of its original function and norm

CCC – Climate Change Committee

DBEIS – Department for Business, Energy & Industrial Strategy

DEFRA – Department for Environment, Food & Rural Affairs

DfT – Department for Transport

EIA – Environmental Impact Assessment

EMP – Environmental Management Plan

EPD – Environmental Product Declaration

ES – Environmental Statement

F-gases – a group of greenhouse gases called fluorinated gases, consisting of HFCs, PFCs and SF6

GHG – Greenhouse Gases

GHG practitioner – an environmental consultant with specific experience and knowledge pertaining to GHG modelling and reporting; not to be confused with EIA practitioners who typical have a wider EIA delivery role overseeing the coordination of all environmental topics in an ES

IA – Impact Assessment

IEMA – the Institute of Environmental Management and Assessment

IPCC – Intergovernmental Panel on Climate Change

kWh – kilowatt-hour

LCA – Life Cycle Assessment is a cradle-to-grave or cradle-to-cradle analysis technique to assess environmental impacts associated with all the stages of a product's life, which is from raw material extraction through materials processing, manufacture, distribution, and use.

LICR – Large Infrastructure Carbon Rating

LPA – Local Planning Authority

LULUCF – Land Use, Land-Use Change and Forestry

TCFD – Task Force on Climate-related Financial Disclosures

tCO_2e – tonnes of carbon dioxide equivalent

UK – United Kingdom

UNFCCC – United Nations Framework Convention on Climate Change

WBCSD – World Business Council for Sustainable Development

WRI – World Resource Institute

I – Introduction

1.1 The aim of this guidance

The aim of this guidance is to assist greenhouse gas (GHG) practitioners (hereinafter referred to as 'practitioners') with addressing GHG emissions assessment, mitigation and reporting[1] in statutory and non-statutory Environmental Impact Assessment (EIA). It is a revision of the 2017 IEMA guidance on Assessing Greenhouse Gas Emissions and Evaluating their Significance[2] (Box 1 lists the key updates from the 2017 version of the guidance). It complements IEMA's latest guide on Climate Change Resilience and Adaptation[3] published in 2020 and builds on the Climate Change Mitigation and EIA overarching principles (as in the previous version of the GHG Guidance). The requirement to consider this topic has resulted from the 2014 amendment to the EIA Directive (2014/52/EU), the Town and Country Planning (Environmental Impact Assessment) Regulations 2017[4] and the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017[5], hereafter referred to as the 'EIA Regulations'.

A lot has changed since 2017. Climate change has moved up the national and international agenda with local authorities across the UK declaring a climate change emergency. The UK's legally binding Climate Change Act 2008[6] was amended in 2019[7] in response to the Paris Agreement, setting a new and challenging target to reduce UK GHG emissions to net zero by 2050, accounting for residual emissions which are offset. Devolved administrations in Scotland and Wales have also set net zero targets. In December 2020, the UK Government's independent advisors, the Climate Change Committee (CCC), set the sixth[8] carbon budget at 965 million tCO_2e from 2033 to 2037, which has since been enshrined in to law. There is a distinct requirement for deeper cuts in emissions across all sectors of the economy to meet the net zero target according to the CCC.

1 Note: Statutory EIA reports are called 'Environmental Statements' in England, Wales and Northern Ireland and 'Environmental Reports' in Scotland.

2 IEMA (2017) Environmental Impact Assessment Guide to: Assessing Greenhouse Gas Emissions and Evaluating their Significance. Available at: https://www.iema.net/preview-document/assessing-greenhouse-gas-emissions-and-evaluating-their-significance

3 IEMA (2020) Climate Change Resilience and Adaptation. Available at: https://www.iema.net/resources/reading-room/2020/06/26/iema-eia-guide-to-climate-change-resilience-and-adaptation-2020

4 UK Legislation (2017) The Town and Country Planning (Environmental Impact Assessment) Regulations 2017. Available at: https://www.legislation.gov.uk/uksi/2017/571/contents/made

5 UK Legislation (2017) The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017. Available at: https://www.legislation.gov.uk/uksi/2017/572/contents/made

6 UK Legislation (2008) Climate Change Act 2008. Available at: https://www.legislation.gov.uk/ukpga/2008/27/contents

7 UK Legislation (2019) The Climate Change Act 2008 (2050 Target Amendment) Order 2019. Available at: https://www.legislation.gov.uk/ukdsi/2019/9780111187654

8 UK Legislation (2021) The Carbon Budget Order 2021. Available at: https://www.legislation.gov.uk/uksi/2021/750/contents/made

Box 1: Key updates to the 2017 guidance

Mitigation has taken a much more prominent role within the EIA. It is no longer an element to be considered towards the later stages of the EIA process (after scoping, emissions assessment and significance determination). Instead, mitigation should be considered from the outset and throughout the project's lifetime, whilst also helping to deliver proportionate EIAs. Mitigation is addressed first in the guidance (Section II) but also as part of the GHG Assessment Methodology (Section V).

The guidance presents more nuanced levels of significance. The 2017 guidance stated that "…in the absence of any significance criteria or defined threshold, it might be considered that all GHG emissions are significant…". This update of the guidance does not change IEMA's position (or the science) that all emissions contribute to climate change, however specifically in the EIA context it now provides relative significance descriptions to assist assessments. Section VI describes five distinct levels of significance which are not solely based on whether a project emits GHG emissions alone, but how the project makes a relative contribution towards achieving a science-based 1.5°C aligned transition towards net zero.

In November 2021 Glasgow hosted COP26 – widely regarded as the most important climate summit since the 2015 Paris Agreement and acknowledging the urgency (as evidenced by latest IPCC reports), the Glasgow Climate Pact was agreed. This set the agenda on climate change for the next decade. Pledges made to further cut emissions, and a plan set to reduce the use of coal and phase-out fossil fuel subsidies are some of the commitments made at COP26. The nations present at COP26 collectively agreed to work to reduce the 'emissions gap' and to ensure that the world continues to advance during the present decade, so that the rise in the average temperature is limited to 1.5°C.

With climate change taking centre stage, projects are increasingly scrutinised and challenged for not mitigating GHG emissions in line with the net zero ambition and the associated required pace of reductions[9]. This critical change is known as the transition imperative. EIA Climate chapters are receiving a lot more attention with clients, project developers and stakeholders often asking: '*what do we need to do and how can we be net zero?*'. Addressing significance and contextualising projects' emissions is an increasingly challenging exercise, especially under a tapestry of national and sectoral carbon targets and budgets, regional and local plans and sectors all on different pathways. This guide aims to provide practitioners with the best advice on how to tackle these questions.

Through a working group facilitated by Arup on behalf of IEMA, this guidance helps practitioners take an informed approach to the treatment of GHG emissions within an EIA. It sets out areas for consideration at all stages of the assessment and offers methodological options that can be explored. It highlights some of the challenges to the assessment, such as establishing study boundaries and what constitutes significance. However, this guidance is not a prescriptive 'how to' guide and will be updated as the process of incorporating GHG assessment in EIA continues to mature.

1.2 EIA and project linkage

EIAs can often be undertaken in silo, separate from the full design process, resulting in an accounting exercise rather than realising the full potential of the GHG emissions reduction opportunity. This can be addressed by delivering the EIA in close cooperation with the project design team.

9 The pace of reduction should align with a credible 1.5°C transition scenario (for example Science Based Targets Initiative Net Zero or Tyndall Centre aligned carbon budget)

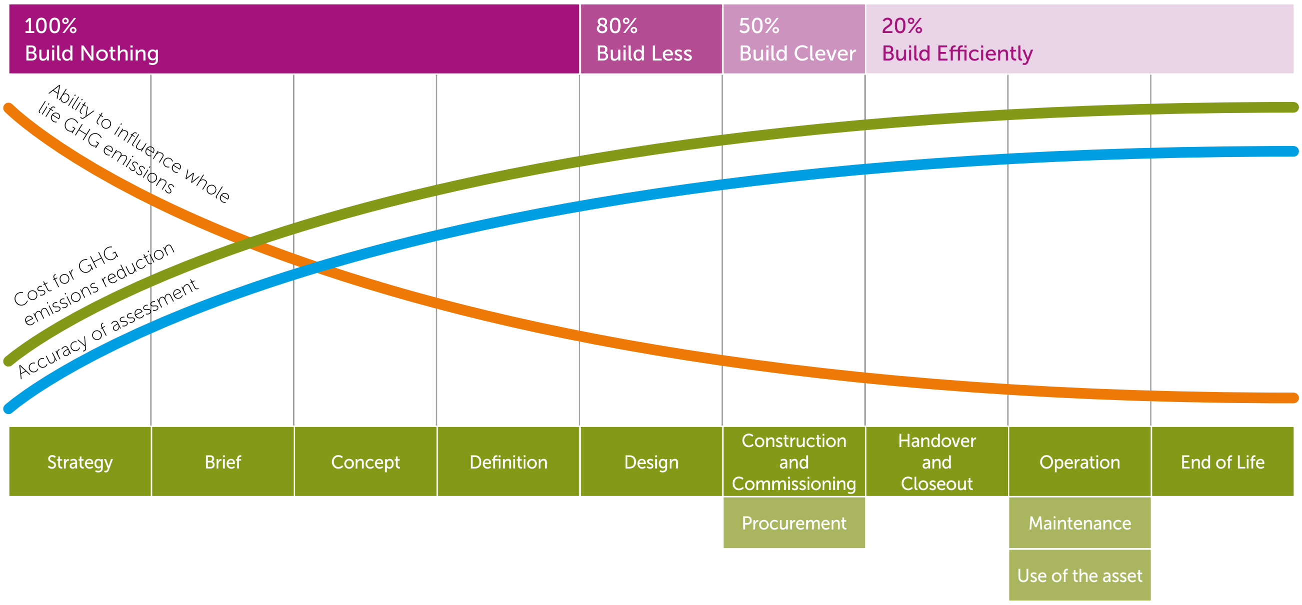


Figure 1: The ability to effect change to achieve GHG emissions reduction for the project reduces over time. This makes it important that the emissions reduction is considered from the outset or at the earliest practical point. (Source: Infrastructure Carbon Review & PAS 2080).

Early stakeholder engagement is fundamental to maximising GHG emissions savings. GHG reductions are likely to be greater if mitigation is considered at project inception and throughout all subsequent work phases: planning, construction and operation stages – enabling mitigation measures to be identified and implemented throughout the life cycle of the proposed project. Examples of stakeholders can be found in Appendix A. Figure 1 illustrates how the potential to achieve GHG emissions reduction declines with time over a project life cycle.

The interaction between the design process and EIA process is underpinned by four key principles:

1. Early, effective and ongoing interaction
2. Appropriate stakeholder engagement
3. Managing consenting risk
4. A clear narrative

For further detail on these principles and ensuring that GHG mitigation measures are built in rather than bolted on at a later stage, refer to IEMA's EIA guide on Shaping Quality Development[10].

The need to ensure that GHG mitigation measures are implemented does not end at the pre-application EIA stage, but extends after consent has been granted to the proposed project. To ensure that GHG mitigation measures are carried forward, the development of Environmental Management Plans (EMP) and Construction Environmental Management Plans (CEMP) are the primary mechanisms. For further information refer to IEMA's EIA guide to Delivering Quality Development[11].

The scope of this document is presented in Figure 2.

10 IEMA (2015) Environmental Impact Assessment Guide to Shaping Quality Development. Available at: https://www.iema.net/download-document/7018

11 IEMA (2016) Environmental Impact Assessment Guide to Delivering Quality Development. Available at: https://www.iema.net/download-document/7014

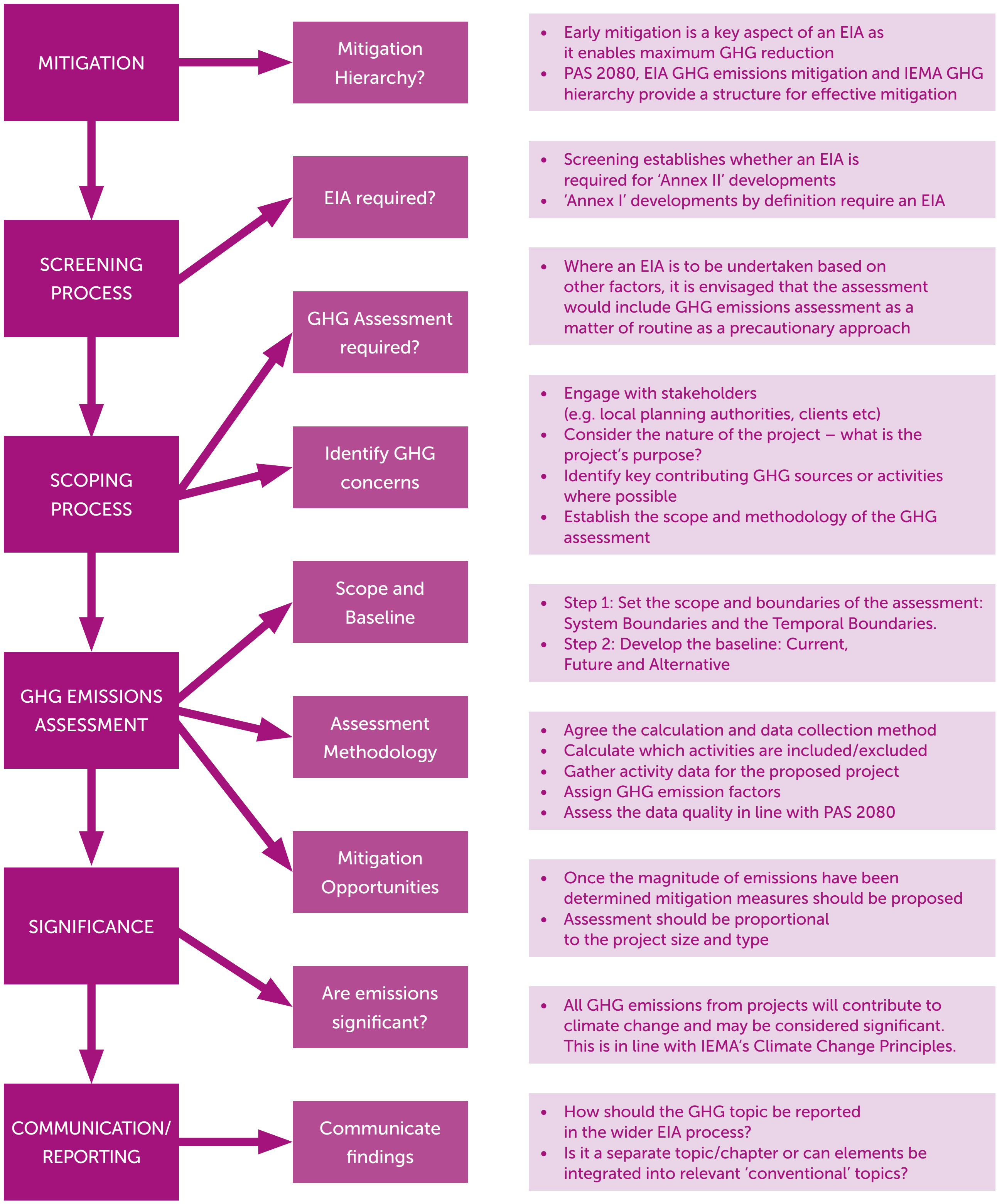


Figure 2: Scope of this guide

II – Mitigation

2.1 Early design mitigation

It is important that project designers incorporate measures to reduce GHG emissions at an early stage. This means evaluating what GHG emissions reduction measures may be appropriate to include in the design. Mitigation should be considered at all stages of design development – from optioneering through to detailed design, not just as a part of the EIA process (see Figure 1). To successfully address GHG emissions at an early stage, it is good practice to ensure there is a 'carbon coordinator' within the design team, who focuses on promoting GHG saving opportunities and ensures GHG reduction is a focus of the design team.

GHG mitigation is best achieved by taking a planned and focused approach following the IEMA GHG management hierarchy principles[12]. There are many different variations on the use of hierarchies in environmental management and assessment, with the commonality that they set out a graded structure of interventions with generally more favourable options presented over others. Such structures typically start with first avoiding or reducing harm, before suggesting compensations. Depending on the proposed project and contextual setting, the practical outcomes of this can be many and diverse. In addition to mitigations listed in IEMA's GHG Management Hierarchy, BS EN ISO 14064-1: 2019[13] on GHG quantification and reporting provides an example list of GHG mitigation interventions such as:

- Energy demand and use management
- Energy efficiency
- Technology or process improvements
- GHG capture and storage in, typically, a GHG reservoir
- Management of transport and travel demands
- Fuel switching or substitution
- Afforestation
- Waste minimisation
- Alternative fuels and raw materials (AFR) use to avoid landfilling or incinerating the wastes
- Refrigerant management

2.2 Mitigation hierarchy

For EIA GHG emissions mitigation, PAS 2080 also provides a useful structure for working through and identifying potential opportunities and interventions. The IEMA GHG Management Hierarchy[14] (see Figure 3) provides a similar structure set out as **eliminate**, **reduce**, **substitute** and **compensate**. A variation of these steps is set out below and can be followed by practitioners in the EIA to identify opportunities that direct GHG mitigation action for a project:

- **Do not build:** evaluate the basic need for the proposed project and explore alternative approaches to achieve the desired outcome/s
- **Build less:** realise potential for re-using and/or refurbishing existing assets to reduce the extent of new construction required
- **Design clever:** apply low carbon solutions (including technologies, materials and products) to minimise resource consumption and embodied carbon during the construction, operation, user's use of the project, and at end-of-life
- **Construct efficiently:** use techniques (e.g. during construction and operation) that reduce resource consumption and associated GHG emissions over the life cycle of the project

12 IEMA (2020) Pathways to Net Zero: Using the IEMA GHG Management Hierarchy. https://www.iema.net/document-download/51806

13 BS EN ISO 14064-1: 2019 Greenhouse gases – Part 1: specification with guidance at the organizational level for quantification and reporting of greenhouse gas emissions and removals.

14 IEMA (2014) Position Statement on Climate Change and Energy. Available at: https://www.iema.net/climate-emergency/position-statement

IEMA Greenhouse Gas Management Hierarchy (updated 2020)

Eliminate
- Influence business decisions/use to prevent GHG emissions across the lifecycle
- Potential exists when organisations change, expand, rationalise or move business
- Transition to new business model, alternative operation or new product/service

Reduce
- Real and relative (per unit) reductions in carbon and energy
- Efficiency in operations, processes, fleet and energy management
- Optimise approaches (eg technology) and digital as enablers

Substitute
- Adopt renewables/low-carbon technologies (on site, transport etc)
- Reduce carbon (GHG) intensity of energy use and of energy purchased
- Purchase inputs and services with lower embodied/embedded emissions

Compensate
- Compensate 'unavoidable' residual emissions (removals, offsets etc)
- Investigate land management, value chain, asset sharing, carbon credits
- Support climate action and developing markets (beyond carbon neutral)

Updated from original IEMA GHG Management Hierarchy, first published in 2009

Figure 3: IEMA GHG Management Hierarchy

- **Offset and remove emissions:** as a complementary strategy to the above, adopt off-site or on-site means to offset and/or sequester GHG emissions to compensate for GHG emissions arising from the project

2.3 Offsetting residual emissions

Multiple terms are used to describe how offsets are used to mitigate residual emissions, and projects may sometimes be promoted as 'carbon neutral' or 'net zero'. It is important that the EIA is clear in defining any terms used. Figure 3 above sets out the position of carbon offsets (referred to as 'Compensate' in Figure 3) in the mitigation hierarchy. There is a distinction between carbon offsets that provide a financial payment to avoid emissions and offsets that remove and sequester atmospheric GHG emissions, and this should be communicated transparently where offsetting is assessed in an ES chapter.

The October 2021 IEMA's Net Zero Explained report[15] summarises the concept of net zero, its origin and science behind the definition. The report also links to alternative sites providing some clarity behind evolving definitions, such as net zero, carbon neutral and zero carbon. The UNFCCC's Race to Zero Lexicon[16] provides the following definitions:

- Net Zero: "*When anthropogenic emissions of greenhouse gases to the atmosphere are balanced by anthropogenic removals over a specified period.*" Net zero is achieved where emissions are first reduced in line with a 'science-based' trajectory with any residual emissions neutralised through offsets.
- Carbon Neutral: "*When anthropogenic emissions of greenhouse gases to the atmosphere are balanced by anthropogenic removals over a specified period… irrespective of the time period or magnitude of offsets required.*"

15 IEMA (2021) Net Zero explained. Available at: https://s3.eu-west-2.amazonaws.com/iema.net/documents/knowledge/policy/climate-change-energy/Net-Zero-Explained-Oct-2021-4.pdf

16 UNFCCC (2021) Race to Zero Lexicon. Available at: https://racetozero.unfccc.int/wp-content/uploads/2021/04/Race-to-Zero-Lexicon.pdf

- Absolute Zero or Zero Carbon: *"When no GHG emissions are attributed"* to an activity or project without the need for offsets.

After following the mitigation hierarchy, projects can seek to compensate residual emissions by the use of either carbon credits (purchased from credible eligible schemes) or by removals within the organisation or entity itself (e.g. nature based solutions on owned land or land with partners). In order to avoid significant adverse effects, mitigation and compensation (if required) would need to be implemented at a magnitude and in a timescale that is consistent with measures required to achieve a 1.5°C compatible trajectories, as discussed in Section VI on determining significance of effects.

III – Screening

The purpose of screening is to establish whether or not an EIA is required for 'Schedule 2' developments (Schedule 1 developments by definition require an EIA). The EIA Regulations require specific information at the screening stage. This includes the consideration of likely significant effects of the proposed project on the environment, taking into account the following:

- The magnitude and spatial extent of the impact (e.g. the geographical area and size of the population likely to be affected)
- The nature of the impact
- The transboundary nature of the impact
- The intensity and complexity of the impact
- The probability of the impact
- The expected onset, duration, frequency and reversibility of the impact
- The cumulation of the impact with the impact of other existing and/or approved projects
- The possibility of effectively reducing the impact

Applying screening criteria (Schedule 3) will allow a judgement to be made on whether there is potential for likely significant environmental effects to arise which may trigger the need for an EIA. Occasionally, this may apply to only a very limited number of topics, for example in a sensitive location for a relatively small-scale project. Generally, however, where an EIA is required, it is common for there to be several topics that require assessment. As the assessment of most topic areas is well established (e.g. ecology, water, heritage), it is usually clear cut which topics trigger the need for EIA.

Sensitivity of receptor(s)

GHG emissions are not geographically limited. They have a global effect rather than directly affecting any specific local receptor to which a level of sensitivity can be assigned. The receptor for GHG emissions is the global atmosphere. The receptor has a high sensitivity, given the severe consequences of global climate change and the cumulative contributions of all GHG emission sources.

It is always good practice to consider whether the effects associated with GHG emissions are likely to be significant enough to trigger an EIA. At the screening stage, proposed mitigation measures that the developer has committed to which aim to avoid or prevent significant adverse effects, may be taken into account when determining whether significant effects are likely to occur.

It should be noted that, as with most environmental topics, there are likely to be only limited cases in which GHG emissions alone are the decisive factor in whether an EIA is needed for a particular project, but in almost all cases GHG emissions are likely to be a relevant factor at the screening stage.

For proposed projects where the need for an EIA has been screened out, it is still important that its GHG emissions are minimised wherever possible, as emissions of any scale contribute cumulatively to global climate change. Undertaking a proportionate assessment of GHG emissions on non-EIA projects is therefore good practice to support decisions that reduce GHG emissions.

IV – Scoping

4.1 Introduction

The scoping process should be used to determine the approach to considering GHGs within the ES. The approach should be proportionate[17] to the proposed project and may, in some cases, not require an ES chapter where it can be justified that GHGs can be addressed within upfront sections of the ES (see further detail in Section V: Methodology, Section VI: Significance and Section VII: Communication/ Reporting). Additionally, ES chapters may differ in scope or assessment detail on a project-by-project basis. The scoping process should therefore consider both the scope of the EIA and the scope of the GHG assessment.

The scoping process should provide an explanation of the likely significant effects of a proposed project. Section VI: Significance sets out the principles in determining likely significant GHG effects which should be reviewed at the scoping stage.

The following should be considered when determining a proportionate approach:

- The type, size, location and temporal scale of the proposed project
- Whether other assessment work has already considered life cycle GHG emissions
- Whether mitigation has already been agreed with the design team, particularly if this is beyond minimum policy requirements
- Whether the proposed project has specific goals or aspirations (e.g. achieving BREEAM certification)

In selecting or developing an approach for an EIA GHG emissions assessment, the aim should be to deliver a robust, proportionate, appropriate and consistent assessment.

During scoping, it is also important to set out in principle the methodological approach that will be taken to assessing project GHG emissions. This means documenting in outline aspects such as baseline setting, assessment approach, how significance will be determined and strategies for mitigation. These are commonly recorded in a project scoping report, and this can form a useful first record of the approach to delivering the GHG emissions assessment. Each of these steps for the EIA are addressed in the following sections, which should be consulted for further detail.

4.2 Stakeholder engagement

Stakeholder engagement is an important part of undertaking an EIA, especially during the scoping stage. It will provide useful information and support the goals of the GHG emissions assessment.

Stakeholder engagement will provide the practitioner better contextual understanding of the project including on key issues, opportunities, constraints and information pertinent to the assessment. Stakeholders will include clients, project developers and statutory consultees who all have an interest and influence on the project.

Depending on the nature of the proposed project, GHG emissions can be discussed during public consultation. Initial consultation with the project team and wider EIA topic specialists may also reveal parallel activities where input from the GHG assessment would be beneficial. For example, clients may wish to report on the sustainability performance of their projects using assessment schemes such as PAS 2080, CEEQUAL and BREEAM. Being able to report on the proposed project's GHG performance will help with such assessments. It may be sensible that a single GHG assessment is carried out which provides evidence for the EIA's GHG scope as well as CEEQUAL or BREEAM assessment requirements. Depending on contractual agreements there are efficiencies to be gained in minimising effort and avoiding duplication of work.

17 IEMA (2017) Delivering Proportional EIA. Available at: https://www.iema.net/resources/reading-room/2017/07/18/delivering-proportionate-eia

Other project management decisions may include the desire to manage the project in an integrated manner, combining 3D models with performance data (including environmental data) such as BIM (Building Information Modelling).

4.3 Benefits and challenges of raising GHG emissions as part of project scoping

By going through the scoping process, the practitioner gains an early and informed understanding of the project's impact and potential sources of GHG emissions. This provides an opportunity to influence and even mitigate GHG emissions early in the design process as well as consider emissions from alternative options.

The challenge at the scoping stage is that there is often limited project information available from the design team at this early stage, resulting in a qualitative-based decision and professional judgement from the practitioner. Nevertheless, by engaging with key stakeholders, the practitioner should be able to define the boundaries of the GHG assessment (see Section 5.3), as well as start to form a view of where the majority of emissions are likely to arise from and appropriate mitigation strategies.

Where the competent authority (e.g. LPA) provides a scoping opinion, the subsequent ES must be 'based on' the expectations set out in the opinion, including any reference to GHG assessment. This underlines the importance of the scoping stage; however, case law has established that the ES can also adapt to development design evolution that occurs post-scoping.

V – GHG emissions assessment methodology

5.1 Introduction

There are many different assessment methods available for measuring and quantifying GHG emissions associated with the built and natural environment. These range from general guidance to formal standards, and many will be appropriate for use in EIA depending on the goals and scope of the assessment required. There is ample GHG quantification guidance in the public domain. However, undertaking an EIA is different to other GHG assessments as the total net impact of the proposed project must be quantified. Therefore, any assessment should follow the principles set out below (see Section 5.2). A list of relevant methods can be found in Appendix B.

Given the wide variation of working situations and the particular aims and objectives of the EIA process, this guidance does not recommend a particular approach. Rather, it sets out advice for the key common components necessary for undertaking a GHG emissions assessment. This guidance does, however, outline a framework of six steps that an assessment should incorporate, which are set out in Section 5.3.

5.2 GHG quantification principles

- GHG quantification within EIA should follow the principles outlined in key documents such as the GHG Protocol Corporate Standard, BS EN ISO 14064-2 or PAS 2080 (see Appendix B) – Relevance, Completeness, Consistency, Transparency and Accuracy
- The assessment should seek to quantify the difference in GHG emissions between the proposed project and the baseline scenario (the alternative project/solution in place of the proposed project). Assessment results should reflect the difference in whole life net GHG emissions between the two options
- The assessment must include all material emissions (defined by magnitude, see Section 5.3, Step 3 *for the exclusion threshold*), direct or indirect (based on the point above), during the whole life of the proposed project. The boundary of the assessment should be clearly defined, in alignment with best practice
- The assessment should seek to present a reasonable worst case
- Any exclusions, limitations, assumptions and uncertainties should be justified and reported where appropriate

5.3 Six Steps of GHG emissions assessment

In developing the approach, the aim should be to deliver a robust, proportionate, appropriate and consistent assessment. The following six steps outline the framework a GHG emissions assessment should incorporate:

1. Set the scope and boundaries of the GHG assessment
2. Develop the baseline
3. Decide upon the emissions calculation methodologies
4. Data collection
5. Calculate/determine the GHG emissions inventory
6. Consider mitigation opportunities and repeat steps 4 & 5

The following sections explore these aspects in more detail. The contextualisation of emissions and determination of significance is addressed in Section VI: Significance.

Step 1: Set the scope and boundaries of the GHG assessment

In the first instance the assessment should set out the rationale for the assessment and its scope, as well as provide background and context. This will normally incorporate a description of the proposed project, its purpose and activities, the system boundary to apply and life cycle stages scoped in and out (including justification) of the assessment.

System boundaries

All material existing sources and removals of GHG emissions prior to project construction and operation (i.e. without the project) should be identified and clearly described.

EIAs should use data that is consistent with and report using the modular approach (Figure 4). A detailed and complete GHG emissions assessment typically covers all life cycle modules.

As projects vary in size, so does the scale of GHG assessments in the spirit of delivering proportionate EIAs. Certain life cycle modules (or stages) can be excluded if these exclusions are clearly highlighted and justified by the practitioner using professional judgement and in accordance with the materiality and cut-off guidance.

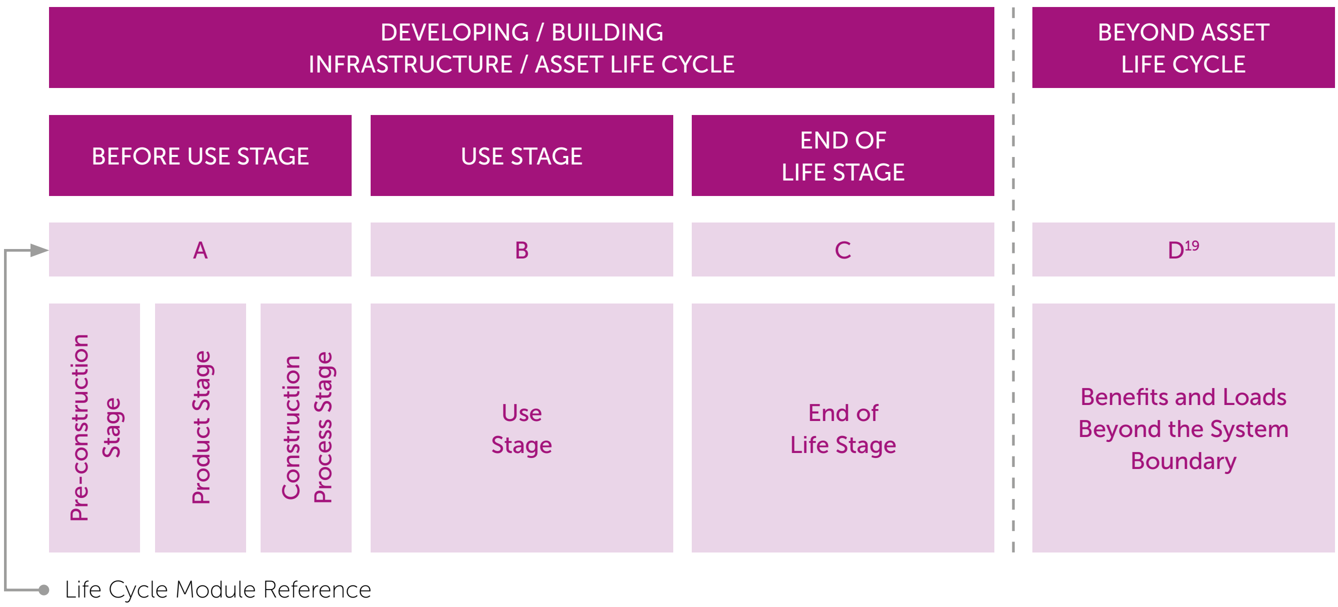


Figure 4: Modular approach of life cycle stages and modules for EIA GHG emissions assessment; the module references are widely used in construction GHG emissions assessment and reduction activities. The figure provides a simplified presentation of the modular approach that can be used for boundary definition and the gathering and reporting of information associated with the assessment. A more detailed presentation of this structure can be found in PAS 2080 and BS EN 15978[20].

18 'For clarity, Module D in Figure 4 (Benefits and Loads Beyond the System Boundary) refers to wider impacts that may not be appropriate to attribute (in part or whole) to the project when calculating net impacts within the study boundary but are nevertheless relevant context to consider. Examples include the benefits of a project sending waste materials for recycling rather than disposal (which is properly attributed to the user of recycled products, but still relevant to acknowledge) or where a major project such as an airport or rail line might affect regional or national travel patterns and emissions (properly attributable to a wider group of transport users, but relevant to acknowledge in the project context).'

19 BS EN 15978:2011 Sustainability of construction works, Assessment of environmental performance of buildings, Calculation method

Temporal boundaries

A reference study period shall be chosen as the basis for the GHG emissions assessment, and this should be based on the expected service life of the construction asset. Additional assistance is available in ISO 15686-1[20], RICS Whole life Carbon Assessment[21] and TAG GHG Assessment guidance[22].

Step 2: Develop the baseline

A baseline is a reference point against which the impact of a new project can be compared against; sometimes referred to as 'business as usual' (BaU) where assumptions are made on current or future GHG emissions. Baseline can take the form of:

A. GHG emissions within the boundary of the GHG quantification but without the proposed project; or

B. GHG emissions arising from an alternative project design and/or BaU for a project of this type.

The ultimate goal of establishing a baseline is being able to assess and report the net GHG impact of the proposed project.

Current baseline

The current baseline represents existing GHG emissions from the assessment prior to construction and operation of the project under consideration. This may include emissions from existing projects (e.g. energy consumption from a building which is scheduled for refurbishment, demolition or replacement) and infrastructure (e.g. current operational and end-user emissions of a road due to be upgraded).

Depending on the nature of the project, in addition to the project baseline, it may also be necessary to establish a sectoral baseline. For example, baseline emissions from BaU power generation would also be important to consider due to the interconnected nature of the electricity grid. This will equally apply to other project types that have wider interlinkages beyond a site level, e.g. many transport, industrial and waste projects.

It may not always be possible to report on current baseline emissions, particularly with projects situated in areas with no physical development or activity. In this instance there would be zero GHG emissions to report at a site level, although particular attention should be paid where changes in land use are expected. For example, land use and land-use change such as woodland creation can sequester carbon over their lifetime and therefore contribute to climate change mitigation. Their disturbance or removal through construction will release previously sequestered GHG emissions.

20 ISO 15686-1:2011Buildings and constructed assets — Service life planning — Part 1: General principles and framework

21 RICS (2021) Whole Life Carbon Assessment for the Built Environment, 1st edition. Available at: https://www.rics.org/uk/upholding-professional-standards/sector-standards/building-surveying/whole-life-carbon-assessment-for-the-built-environment

22 Department for Transport (2021) TAG unit A3 environmental impact appraisal.
Available at: https://www.gov.uk/government/publications/tag-unit-a3-environmental-impact-appraisal

Future baseline

Future baseline should capture both operational[23] and user[24] GHG emissions irrespective of their source (i.e. direct and indirect emissions). The distinction between operational and user GHG emissions is important. For example, an existing motorway will have operational emissions (i.e. lighting, maintenance, upgrades) as well as user emissions associated with vehicles travelling along the route. Current baseline travel patterns should be assessed as projected change (e.g. changes in mode share, increased efficiency in vehicles and trip numbers). With regards to energy supply and demand (e.g. electricity use in a commercial building), future baseline should report on operational GHG emissions and how these may change over time (e.g. based on occupancy changes, UK grid decarbonisation projection scenarios or the adoption of renewables).

Box 2 lists potential sources of information which can be considered when establishing future baseline emissions.

Box 2: Potential sources of information on GHG and energy projections (see Appendix A for further details)

- Modelled or projected future scenarios and pathways to net zero published by authoritative bodies such as the CCC[25]
- The Department for Business, Energy & Industrial Strategy (previously DECC)[26]
- The Department for Transport (DfT) TAG (the Transport Analysis Guidance) – Data Book[27]
- BEIS Electricity emissions to 2100 factor projections[28]
- GHG emissions from the operation of existing buildings can be estimated using published benchmarks (e.g. CIBSE Guide F – Energy Efficiency in Buildings (2012) or BSRIA Rules of Thumb Guidelines for Building Services (5th Edition, 2011)) where primary data such as annual metered energy consumption is not available
- GHG emissions associated with other sources or activities such as playing fields may be harder to estimate. It may be appropriate to assume zero baseline GHG emissions in such cases to ensure a reasonable worse-case approach to establishing the net GHG effect of the project. It could in such cases be important to also quantify (estimate) emissions release from the land used change and soil disturbance

23 PAS 2080:2016 Carbon Management in Infrastructure defines operational carbon as GHG emissions associated with the operation of infrastructure required to enable it to operate and deliver its service

24 PAS 2080:2016 Carbon Management in Infrastructure defines user carbon as GHG emissions associated with Users' utilisation of infrastructure and the service it provides during operation

25 Climate Change Committee (2020) The Sixth Carbon Budget. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget

26 The Department for Business, Energy & Industrial Strategy. Available at: https://www.gov.uk/government/organisations/department-for-business-energy-and-industrial-strategy

27 The Department for Transport (2021) Transport Analysis Guidance (TAG). Available at: https://www.gov.uk/guidance/transport-analysis-guidance-tag

28 The Department for Business, Energy & Industrial Strategy (2021) Energy and emissions projections – Net Zero Strategy Baseline. Available at: https://www.gov.uk/government/collections/energy-and-emissions-projections

Alternative baselines

Alternative baselines can be used to supplement the analysis and address uncertainty. For example, it may be unclear what baseline to adopt and compare a proposed project against if the site is 'empty' (i.e. the project is not replacing an existing development). For example: different locations, designs or layouts for building developments; or alternative energy generation options in the instance of a wind or solar farm proposal. However, a realistic worse-case baseline should still be used for assigning significance.

In many instances, alternatives may not have been considered by the developer. Ideally, alternatives would have been considered earlier in the project life cycle, and the EIA is viewed as the platform for improving the preferred design. Nevertheless, where alternative baselines were considered, even a qualitative assessment of their GHG impact would be acceptable as part of the overall assessment.

Step 3: Assessment methodology

Once the scope and baseline is set, the calculation method can be agreed along with data collection. The methodology should result in a relevant, complete, consistent, transparent and accurate assessment of the reasonable worst case. In most cases, the assessment should use activity data and emissions factors. However, where possible, it may be preferable to generate bespoke emissions factors (e.g. through mass balance calculations) or use actual monitored data. The methodology chosen should follow best practice guidance, such as the GHG protocol, and it is not the aim of this guidance to provide this.

Inclusions & exclusions

The project boundary should include its spatial extent and life cycle stages relevant to the scope of the assessment.

Activities that do not significantly change the result of the assessment can be excluded where expected emissions are less than 1% of total emissions, and where all such exclusions total a maximum of 5% of total emissions; all exclusions should be clearly stated.

Step 4: Data collection

Project activity data

To calculate GHG emissions of a proposed project it is necessary to gather data on the activities occurring and associated GHG emissions factors. It is important that data for both these aspects, and particularly the activity data, is specific to the proposed project.

Activity data consists of information that defines and describes the size, magnitude and physical nature of the proposed project. It will take many different forms, including material specifications and quantity, energy and water demand, waste generation, transportation distances and modes, and works techniques/ technologies.

GHG emission factors

GHG emission factors are a value for 'GHG emissions per unit of activity'. Examples of this are:

- HGV: kg CO_2e / tonne.km
- UK electricity grid: kg CO_2e / kWh
- Concrete: kg CO_2e / tonne

GHG emission factors vary in their scope and coverage and will be representative of a single process/activity or multiple of these, sometimes incorporating multiple life cycle stages. Care should be taken to select and reference the right factors for the proposed project.

When undertaking a study, it is often necessary to apply multiple GHG factors for the same activity or material particularly when the assessment is studying a life cycle with a long time period. This may be appropriate when future GHG emissions for that activity are expected to change; this might occur, for example, when accounting for reduced GHG emissions associated with a national electricity grid and the benefit this brings to demand side GHG emissions of using electric trains.

For examples of sources of GHG factors refer to Appendix A.

Data quality

The following aspects, in line with PAS 2080[29], should be considered when collecting assessment data:

- Primary (measured), secondary (estimated) or benchmarks
- Age (age of data, and the period over which they have been collected)
- Geography (the region or country from where the data have originated)
- Technology (whether the data are specific to a particular technology or mix of many)
- Methodology (the approach applied to gather or calculate the data)
- Competency (proficiency of entity that developed the data)

Baseline GHG emissions from the operation of existing buildings can be estimated using published benchmarks (e.g. CIBSE Guide F – Energy Efficiency in Buildings (2012) or BSRIA Rules of Thumb Guidelines for Building Services (5th Edition, 2011)) where primary data (e.g. annual metered energy consumption) is not available.

Baseline GHG emissions associated with other sources or activities such as agricultural fields may be harder to estimate. It may be appropriate to assume zero baseline GHG emissions in such cases to ensure a reasonable worse-case approach to establishing the net GHG effect of project proposals.

Types of data

The type of data used by the practitioner will vary depending on how detailed the project design is. Most assessments are based on design-stage information, hence activity data specific to the project should in theory be available from the engineering and design teams. If this is not the case, an alternative approach would be to fall back on generic or publicly available information that best represents the project and its activities.

Studies undertaken as part of the planning application for the proposed project outside of EIA process can provide a useful source of information for GHG assessments, for example:

- BREEAM Pre-assessment (especially RIBA 2 evidence for Mat 01 Construction Materials LCA)
- Energy Statement
- Whole Life Carbon Assessment (e.g. London Plan)
- Circular Economy Statement (e.g. London Plan)
- Sustainability Statement

Step 5: Calculate GHG emissions inventory

GHG emissions calculation method

Quantification of the GHG emissions for an EIA may be associated with either a measured or calculated approach or a combination of both for the emissions associated with the project. It is expected that in almost all cases a calculated approach for quantifying GHG emissions will be taken because an EIA is completed in advance of supply chain mobilisation and associated construction works.

29 PAS 2080:2016 Carbon Management in Infrastructure.

When undertaking a quantification calculation the formula for determining a GHG emission (or removal value), associated with the construction works, should have the following structure:

GHG emission factor × Activity data = GHG emission or removal

Calculations may be taken at different scales reflecting specific activities, components or elements of construction. Therefore, individual calculations should be summed to form a GHG emissions inventory for the quantification as a whole.

Study uncertainty

Uncertainty can arise from quality of data, study boundaries and period of assessment, and can never be eliminated from a study. Uncertainty should be considered and if it significantly affects the outcome of the study, additional steps should be taken to reduce it and provide confidence in results. As a reminder, a relevant, complete, consistent, transparent and accurate assessment of the reasonable worst case must be undertaken despite uncertainties.

Uncertainty can be considered by:

- Testing upper and lower limits
- Testing for different inclusions and exclusions
- Modifying study period
- RAG (red, amber, green) rating input data based on data quality criteria presented above
- If the scale of uncertainty provides findings that are likely to change any decision based on the data, then it should be appropriately reduced.

Cumulative GHG emissions

The atmospheric concentration of GHGs and resulting effect on climate change is affected by all sources and sinks globally, anthropogenic and otherwise. As GHG emission impacts and resulting effects are global rather than affecting one localised area, the approach to cumulative effects assessment for GHGs differs from that for many EIA topics where only projects within a geographically bounded study area of, for example, 10km would be included.

For example, air pollutant emissions are dispersed and diluted after emission and only the cumulative contributions of other relatively nearby sources contribute materially to the pollutant concentration, and hence effect, at a particular sensitive receptor in the study area. Due to the persistence of GHGs in the atmosphere, that same dispersion effect contributes to the global atmospheric GHG emissions balance. There is no greater local climate change effect from a localised impact of GHG emission sources (or vice versa).

All global cumulative GHG sources are relevant to the effect on climate change, and this should be taken into account in defining the receptor (the atmospheric concentration of GHGs) as being of 'high' sensitivity to further emissions.

Effects of GHG emissions from specific cumulative projects therefore in general should not be individually assessed, as there is no basis for selecting any particular (or more than one) cumulative project that has GHG emissions for assessment over any other.

The contextualisation of GHG emissions, as discussed in Section 6.4, should incorporate by its nature the cumulative contributions of other GHG sources which make up that context. Where the contextualisation is geographically – or sector-bounded (e.g. involves contextualising emissions within a local authority scale carbon budget, or a sector level net zero carbon roadmap), then the consideration of cumulative contributions to that context will be within that boundary.

Step 6: Mitigation opportunities

Once the magnitude of emissions has been determined (as discussed in Section 5.3, Step 4), mitigation measures (as discussed in Section 2) should be proposed. Any mitigation measures that are committed to need to be included within the assessment. This means recollecting new activity data where this has changed due to mitigation measures, and new emissions calculations need to be undertaken. Steps 4 & 5 should be repeated as necessary.

5.4 GHG assessment and proportionality

GHG emissions should be assessed and reported as part of a good practice approach to EIA.

Projects will vary by type and size, and so will GHG emissions. An effective scoping exercise ensures that a balance is struck between the amount of GHG emissions emitted or saved by the project and the effort committed to the actual GHG assessment. For example, if most impacts occur during a project's construction phase and operational impacts are negligible, then the GHG assessment can reflect this. A high-level or qualitative GHG assessment for certain project elements or activities can be carried out as long as it is justified and agreed during the scoping stage with stakeholders. This will help contribute towards delivering a proportionate assessment.

It should also be recognised that qualitative assessments are acceptable, for example: where data is unavailable or where mitigation measures are agreed early in the design phase with design and engineering teams.

VI – Significance

6.1 Introduction

IEMA's 2010 principles on climate change mitigation and EIA identify climate change as one of the defining environmental policy drivers and that action to reduce GHG emissions is essential. Specifically, three overarching principles are particularly relevant in considering the aspect of significance[30]:

1. The GHG emissions from all projects will contribute to climate change, the largest interrelated cumulative environmental effect
2. The consequences of a changing climate have the potential to lead to significant environmental effects on all topics in the EIA Directive (e.g. human health, biodiversity, water, land use, air quality)
3. GHG emissions have a combined environmental effect that is approaching a scientifically defined environmental limit[31]; as such any GHG emissions or reductions from a project might be considered to be significant[32]

This document builds on those principles as follows:

- When evaluating significance, all new GHG emissions contribute to a negative environmental impact; however, some projects will replace existing development or baseline activity that has a higher GHG profile. The significance of a project's emissions should therefore be based on its net impact over its life time, which may be positive, negative or negligible
- Where GHG emissions cannot be avoided, the goal of the EIA process should be to reduce the project's residual emissions at all stages
- Where GHG emissions remain significant, but cannot be further reduced, approaches to compensate the project's remaining emissions should be considered

The guidance in this document provides further detail of how those principles can be applied, particularly how the net effect of a project and its beneficial or adverse effects can be evaluated in the context of emission reductions on a trajectory towards net zero.

6.2 Background to significance

The goal of the Paris Agreement is to limit global temperature rise to well below 2°C, aiming for 1.5°C, compared with pre-industrial levels, in order to stand a greater chance of avoiding severe adverse effects from climate change.

The UK has set a legally binding GHG reduction target for 2050 with interim five-yearly carbon budgets which define a trajectory towards net zero. The 2050 target (and interim budgets set to date) are, according to the CCC, compatible with the required magnitude and rate of GHG emissions reductions required in the UK to meet the goals of the Paris Agreement, thereby limiting severe adverse effects. Further budgets are set by the devolved administrations in Wales and Scotland, which are also in line with advice from the CCC. Carbon budgets allow for continuing economic activity, including projects in the built environment, in a controlled manner.

To meet the 2050 target and interim budgets, action is required to reduce GHG emissions from all sectors, including projects in the built and natural environment. EIA for any proposed project must therefore give proportionate consideration to whether and how that project will contribute to or jeopardise the achievement of these targets.

30 IEMA (2010) Climate Change Mitigation & EIA. Available at: https://www.iema.net/document-download/33006

31 There is a global GHG emission budget that defines a level of dangerous climate change, and any GHG emission that contributes to exceedance of that budget or threatens efforts to stay within it can be considered as significant.

32 The third principle is related to the IPCC carbon budget definition. The IPCC's Sixth Assessment Report (WG1: The Physical Science Basis, Table SPM.2) indicates that the remaining global carbon budget from 2020 that provides a two-thirds likelihood of not exceeding 1.5°C heating is 400 $GtCO_2$; for an 87% likelihood it is 300 $GtCO_2$.

However, it is important to note that:

(a) The UK's and devolved administrations' GHG targets incorporate a staged set of reductions between the present day and 2045 or 2050, defined by five-yearly carbon budgets. A continuing, but, over time, reduced level of GHG emissions is compatible with national and international climate change commitments. Going above and beyond these commitments and achieving net zero at an earlier date is strongly desirable and a high priority.

(b) The necessary level and rate of GHG emission reductions will be unevenly distributed across different economic sectors, activities and types of projects. Net zero for the UK in 2050 (and in the interim) will include some activities with net negative emissions and some with residual emissions greater than zero.

A key goal of EIA is to inform the decision maker about the relative severity of environmental effects such that they can be weighed in a planning balance. Therefore, it is essential to provide context for the magnitude of GHG emissions reported in the EIA in a way that aids evaluation of these effects by the decision maker.

The crux of significance therefore is not whether a project emits GHG emissions, nor even the magnitude of GHG emissions alone, but whether it contributes to reducing GHG emissions relative to a comparable baseline consistent with a trajectory towards net zero by 2050[33].

Often a project will cause a change in GHG emissions compared to the baseline which should be assessed, as discussed in Sections 5.3. When setting this impact into context to determine significance, it is important to consider the net zero trajectory in line with the Paris Agreement's 1.5°C pathway[34].

The timing of reductions is critical due to the cumulative effect of GHG emissions in the atmosphere. Achieving net zero or very low emissions by 2025 instead of 2040 would avoid 15 years of cumulative heating.

The specific context for an individual project and the contribution it makes must be established through the professional judgement of an appropriately qualified practitioner, drawing on the available guidance, policy and scientific evidence[35].

The following principles are a guide to determining significance.

6.3 Significance principles and criteria

Figure 5 illustrates how to determine significance depending on the project's whole life GHG emissions and how these align with the UK's net zero compatible trajectory. The following section provides further explanation on the different levels of significance and should be read in conjunction with Figure 5.

33 (or other date as defined in targets for devolved administrations or as may be defined for the UK or specific economic sectors in future).

34 IEMA (2021) Net Zero explained. Available at: https://s3.eu-west-2.amazonaws.com/iema.net/documents/knowledge/policy/climate-change-energy/Net-Zero-Explained-Oct-2021-4.pdf

35 At the time of publication, the applicable evidence is that provided by the IPCC and UNFCCC, supporting the commitments defined in the Paris Agreement, and in the UK that provided by the CCC with regard to GHG budgets and policies that are compatible with the UK's Paris Agreement commitments. Evidence will continue to be developed, for example, through the IPCC's Sixth Assessment Report, future international treaty negotiations and further advice of the CCC or other expert bodies, and the practitioner must evaluate the prevailing evidence at the time.

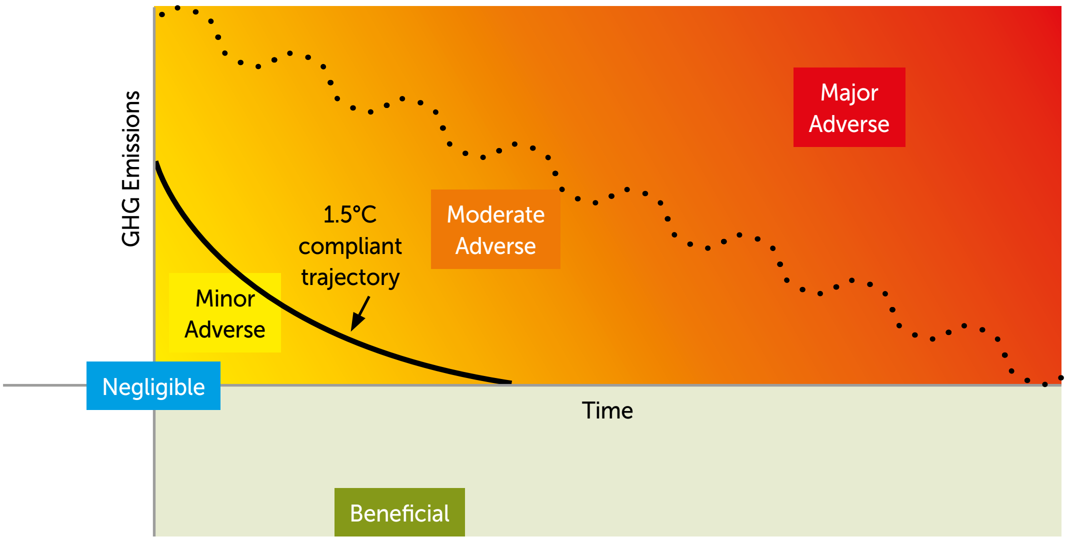


Figure 5: Different levels of significance plotted against the UK's net zero compatible trajectory[36]

A project that follows a 'business-as-usual' or 'do minimum' approach and is not compatible with the UK's net zero trajectory, or accepted aligned practice or area-based transition targets, results in a **significant adverse** effect. It is down to the practitioner to differentiate between the 'level' of significant adverse effects e.g. '**moderate**' or '**major**' adverse effects (see Box 3 for an example of such a differentiation).

A project that is compatible with the budgeted, science-based 1.5°C trajectory (in terms of rate of emissions reduction) and which complies with up-to-date policy and 'good practice' reduction measures to achieve that has a **minor adverse** effect that is **not significant**. It may have residual emissions but is doing enough to align with and contribute to the relevant transition scenario, keeping the UK on track towards net zero by 2050 with at least a 78% reduction by 2035[37] and thereby potentially avoiding significant adverse effects.

A project that achieves emissions mitigation that goes substantially beyond the reduction trajectory, or substantially beyond existing and emerging policy compatible with that trajectory, and has minimal residual emissions, is assessed as having a **negligible** effect that is **not significant**. This project is playing a part in achieving the rate of transition required by nationally set policy commitments.

A project that causes GHG emissions to be avoided or removed from the atmosphere has a **beneficial** effect that is **significant**. Only projects that actively reverse (rather than only reduce) the risk of severe climate change can be judged as having a beneficial effect.

36 Ideally, the curve will be quantitative, derived from a set of carbon budgets that show the rate of reduction to be achieved; but where this is not available, it will need to be evaluated qualitatively based on policy goals and advice of expert guidance bodies on the actions needed to achieve the necessary rate of reductions.

37 or other science-based 1.5°C compatible trajectory as may be defined for a specific sector or local area, as applicable

For the avoidance of doubt, a 'minor adverse' or 'negligible' non-significant effect conclusion does not necessarily refer to the *magnitude* of GHG emissions being carbon neutral (i.e. zero on balance) but refers to the likelihood of avoiding severe climate change, aligning project emissions with a science-based 1.5°C compatible trajectory, and achieving net zero by 2050[38]. A project's impact can shift from significant adverse to non-significant effects by incorporating mitigation measures that substantially improve on business-as-usual and meet or exceed the science-based emissions trajectory of ongoing but declining emissions towards net zero.

A 'minor adverse' effect or better is therefore a high bar and indicates exemplary performance where a project meets or exceeds measures to achieve net zero earlier than 2050. However, in the context of the severe threat of climate change, such an effect cannot be judged as significant beneficial – this category is reserved for projects with effects that directly or indirectly remove or avoid GHG emissions in the without-project baseline.

An example of how these principles may be applied in practice is given in Box 3.

Box 3: Examples of significance criteria

For the avoidance of doubt IEMA's position that all emissions contribute to climate change has not changed. This Box 3 provides practitioners with examples of how to distinguish different levels of significance. Major or moderate adverse effects and beneficial effects are **considered to be significant**. Minor adverse and negligible effects are **not considered to be significant.**

Major adverse: the project's GHG impacts are not mitigated or are only compliant with do-minimum standards set through regulation, and do not provide further reductions required by existing local and national policy for projects of this type. A project with major adverse effects is locking in emissions and does not make a meaningful contribution to the UK's trajectory towards net zero.

Moderate adverse: the project's GHG impacts are partially mitigated and may partially meet the applicable existing and emerging policy requirements but would not fully contribute to decarbonisation in line with local and national policy goals for projects of this type. A project with moderate adverse effects falls short of fully contributing to the UK's trajectory towards net zero.

Minor adverse: the project's GHG impacts would be fully consistent with applicable existing and emerging policy requirements and good practice design standards for projects of this type. A project with minor adverse effects is fully in line with measures necessary to achieve the UK's trajectory towards net zero.

Negligible: the project's GHG impacts would be reduced through measures that go well beyond existing and emerging policy and design standards for projects of this type, such that radical decarbonisation or net zero is achieved well before 2050. A project with negligible effects provides GHG performance that is well 'ahead of the curve' for the trajectory towards net zero and has minimal residual emissions.

Beneficial: the project's net GHG impacts are below zero and it causes a reduction in atmospheric GHG concentration, whether directly or indirectly, compared to the without-project baseline. A project with beneficial effects substantially exceeds net zero requirements with a positive climate impact.

38 or other date as defined in targets for devolved administrations or as may be defined for the UK or specific economic sectors in future.

A modification to this approach is required for the very largest-scale developments, those that in themselves have magnitudes of GHG emissions that materially affect the UK's or a devolved administration's total carbon budget. An indicative threshold of 5% of the UK or devolved administration carbon budget in the applicable time period is proposed, at which the magnitude of GHG emissions irrespective of any reductions is likely to be significant. A project that meets this threshold can in itself materially affect achievement of the carbon budget.

Practitioners should note that existing policy and regulation may in some cases lag behind the necessary levels of GHG emission reductions (or types of actions to achieve those) that are compatible with the UK's or devolved administrations' targets and with a science-based 1.5°C compatible trajectory towards net zero. Meeting the minimum standards set through existing policy or regulation cannot necessarily be taken as evidence of avoiding a significant adverse effect, and it is recommended that practitioners consider and have reference also to emerging policy/standards and the guidance of expert bodies such as the CCC on necessary policy developments, particularly for multi-phased projects with long timescales. This must be evaluated by the practitioner as part of the evidence base used in the assessment of effects. References to 'existing' and 'emerging' policy in the principles of significance and example criteria above must be interpreted with this in mind.

In following this guidance, the practitioner is contextualising the project to understand whether committed mitigation represents best endeavours, to avoid significant adverse effects in line with the principles and example criteria defined above.

The assessment process for GHG emissions will therefore require a review of the current and emerging policy/regulatory position together with a review of expert scientific advice from bodies such as the CCC or IPCC about where existing policy or regulation is insufficient or not, relative to the science.

It bears reiterating that an ES should inform decision makers about both adverse and beneficial effects, so that all significant effects can be weighed in decisions. Where the fundamental reason for a proposed project is to combat climate change (e.g. a wind farm or carbon capture and storage project) and this beneficial effect drives the project need, then it is likely to be significant.

6.4 Contextualising a project's carbon footprint

The context of a project's carbon footprint determines whether it supports or undermines a trajectory towards net zero. Determining that trajectory and the position of a project within it, however, is the challenge for practitioners.

It is down to the practitioner's professional judgement on how best to contextualise a project's GHG impact.

The UK has a defined national carbon budget and budgets set by devolved administrations which have been determined as being compatible with net zero and international climate commitments. The starting point for context is therefore the percentage contribution to the national or devolved administration carbon budget as advised by the CCC. However, the contribution of most indivdual projects to national-level budgets will be small and so this context will have limited value.

The available contextual information base is rapidly developing and will continue to grow in the coming years as developments such as sector initiatives, locally set carbon budgets and the Task Force on Climate-Related Financial Disclosures (TCFD) and transition risk scenario analysis progress.

Existing government policy will in many cases define goals and necessary action for GHG emissions reduction that is compatible with national climate commitments. However, it is also essential to evaluate this in the context of expert advice/commentary on policy gaps and emerging policy recommendations.

Industry bodies for many sectors crucial to reducing GHG emissions have published analyses, strategies and net zero compatible reduction trajectories for their sectors. This can provide useful and highly specific evidence of what constitutes the necessary type and rate of GHG reduction actions for a particular project type.

For example, the Green Construction Board[39] has calculated carbon budgets for each of the UK built environment sectors. Similarly, the CCC[40] has determined a UK wide carbon budget broken down into the following key sectors: surface transport, buildings, manufacturing and construction, electricity generation, fuel supply, agriculture and land use, land-use change and forestry (LULUCF), aviation, shipping, waste, F-gases, and greenhouse gas removals. Researchers at the Tyndall Centre at the University of Manchester have proposed local authority scale carbon budgets that are compatible with the UK's commitments under the Paris Agreement[41]. Further examples of sectoral strategies and budgets are given in Figure 6 below.

The good practice approach included in Figure 6 below provides an example of how to contextualise your project's carbon footprint against pre-determined carbon budgets or against emerging policy and performance standards where a budget is not available.

Where quantified carbon budgets or a net zero trajectory is lacking, a more qualitative or policy-based approach to contextualising emissions to evaluate significance may be necessary. In these instances, uncertainty and the likelihood of effect should be discussed.

It is good practice to draw on multiple sources of evidence when evaluating the context of GHG emissions associated with a project. The practitioner should be aware that sources of evidence are still emerging, subject to revision as understanding develops and innovation occurs, and in some cases will be contested and conflicted. Professional judgement will therefore be vital in integrating these sources of evidence and evaluating them. Table 1 sets out further sources of contextual information against which the GHG emissions and reduction actions of project can be evaluated.

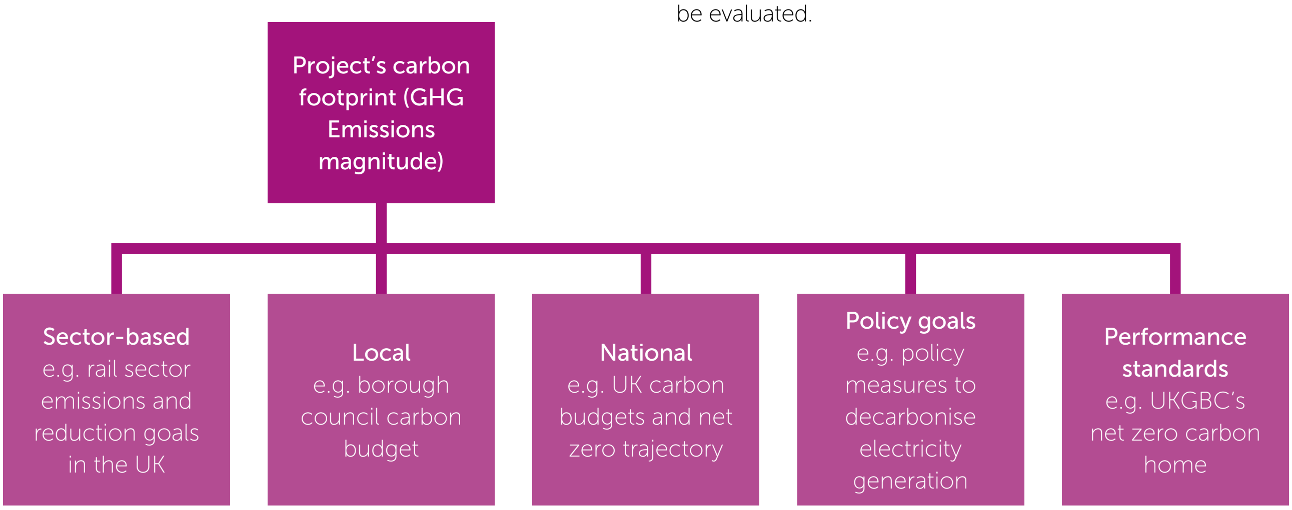


Figure 6: Good practice approaches for contextualising a project's GHG emissions

39 The Green Construction Board (2015) Green Construction Board Low Carbon Routemap for the Built Environment. Available at: http://www.hwa.uk.com/site/wp-content/uploads/2020/10/CD-17.13-Low-Carbon-Routemap-for-the-Built-Environment-Technical-Report-Green-Construction-Board-2015.pdf

40 Climate Change Committee (2020) The Sixth Carbon Budget: The UK's path to Net Zero. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget

41 Tyndall Centre for Climate Change Research (2022) Quantifying the implications of the United Nations Paris Agreement for local areas. Available at https://carbonbudget.manchester.ac.uk

Table 1: Sources of contextual information against which projects can be evaluated.

Context	Advantages	Limitations
National or devolved administration carbon budget and NDC	• Clearly defined and based on robust scientific evidence	• Too high level for most individual projects
Local or regional carbon budgets developed by local authorities and researchers (e.g. the Tyndall Centre at the University of Manchester[42])	• A more pertinent scale for individual projects and local decision-making • Will reflect regional factors such as concentration of industry	• Effects of GHG emissions are not geographically circumscribed, so a geographic budget (below a national budget defined based on negotiated NDCs to commitments to a global budget agreed through the UNFCCC) is not very meaningful • Displacing GHG emissions from one local authority or region to another within the UK has no benefit • It's unclear whether emerging local authority or regional budgets will add up coherently to the UK budget
Sectoral budgets or reduction strategies	• These are available for many crucial sectors (e.g. the Energy Transitions Commission[43] presents net zero strategies for a wide range of sectors) • They often contain detailed, staged measures (and several scenarios) for GHG reductions with interim targets, providing a clearly defined trajectory	• There is a risk that some sectoral strategies represent a lobbying position rather than science-based target setting
Current and future GHG emissions intensity of an activity	• This provides useful context in cases where a project is meeting an established demand, such as for electricity generation, and may have a GHG benefit by displacing a legacy source (e.g. renewable generators displacing gas-fired baseload)	• This would not be applicable context for absolute emissions changes, (e.g. construction emissions or land-use change at a site level), so would need to be combined with other sources of information
Existing and emerging national and local policy or regulation	• This is extensive, providing context for all development types • It will often provide relatively detailed and specific goals and implementation measures • Policy should be compatible with the UK's national GHG commitments and actions to achieve those	• There can be significant policy gaps or policy lag • It will not always be clear that compliance with policy measures, or a subset of them, amounts to a net zero carbon compatible trajectory
Expert advice of guidance bodies Voluntary performance standards (e.g. the UK Green Building Council's 'Net Zero Carbon Building' framework[44])	• Extensive publications and strategies are available, providing context for all development types • Considerable reliance can be placed on the advice of the CCC, which has the statutory duty of advising the government on policy that is necessary to achieve national climate commitments • Expert advice of guidance bodies can identify existing policy/regulatory gaps • Expert advice of guidance bodies can be used as a source to define what constitutes achievable best practice for many development types • Voluntary performance standards provide a framework for evaluating what constitutes best practice for emissions performance, and the means to predict and then monitor this	• Guidance and advice may be contested or conflicting • There is a risk that some guidance represents a lobbying position rather than science-based GHG reductions
Company-specific TCFD reporting, transition risk assessments or Science-Based Targets	• This can provide context that is highly specific to the project in question, where the developer has already set science-based targets and/or undertaken climate risk assessments with scenario analysis that includes a best practice measures / minimum climate risk scenario	• This may not be available for the majority of projects

42 Tyndall Centre for Climate Change Research (2022) Quantifying the implications of the United Nations Paris Agreement for local areas. Available at: https://carbonbudget.manchester.ac.uk

43 Energy Transitions Commission (2022) A global coalition of leaders from across the energy landscape committed to achieving net zero emissions by mid-century. Available at: https://www.energy-transitions.org

44 UKGBC (2019) Net Zero Carbon Buildings: A Framework Definition. Available at: https://ukgbc.s3.eu-west-2.amazonaws.com/wp-content/uploads/2019/04/05150856/Net-Zero-Carbon-Buildings-A-framework-definition.pdf

6.5 Embedded or committed mitigation

When determining significance, any embedded/committed mitigation measures that form part of the design should be considered.

It is valuable and strongly encouraged for GHG emissions mitigation to be considered and embedded at the earliest stages of design, where the greatest influence can be achieved, as discussed in Section II and in IEMA's 'Pathways to Net Zero: GHG Management Hierarchy' guidance[45].

Where embedded/committed mitigation is relied upon in the assessment of effects, the practitioner must form a clear judgement that this mitigation is:

1. Evidenced in the design for the project
2. A committed goal that is secured, e.g. forming part of the description of development, a specific planning condition/requirement, or a legal agreement
3. Realistic and achievable to deliver

In some cases, mitigation commitments (especially in the form of targets or commitments to actions at a later design stage) may not offer sufficient certainty at the time of undertaking the assessment that the practitioner can rely upon in judging the significance of effects.

In this case, the significance of effects should initially be stated without this mitigation, and it should then fall into the assessment of additional mitigation and residual effects.

6.6 Additional mitigation and residual effects

Where the initial assessment identifies significant adverse effects, additional mitigation should be considered to reduce these effects to an acceptable and non-significant level where feasible.

As a matter of good practice, available mitigation to reduce non-significant effects or further enhance beneficial effects should also be considered where possible.

As noted above, where there is embedded mitigation in the form of project commitments to GHG emission reductions but the details of this are not secured within the project design at the time of assessment, further detail of the potential mitigation measures to achieve that commitment can also be considered within the additional mitigation section and assessment of residual effects.

The assessment of potential residual effects, with incorporation of additional mitigation, must be expressed in conditional terms. The residual effects would depend on the additional mitigation recommendations being accepted, secured and delivered in practice. An example of appropriate wording would be:

"Residual effects: with the implementation of [the additional mitigation measures as set out above] and the achievement of [measurable GHG emissions goal] the residual effect could be [reduced to not significant / negligible / beneficial]".

45 IEMA (2020) Pathways to Net Zero: Using the IEMA GHG Management Hierarchy November 2020. Available at: https://www.iema.net/resources/reading-room/2020/11/26/pathways-to-net-zero-using-the-iema-ghg-management-hierarchy-november-2020

VII – Communication / Reporting

When reporting on GHG emissions assessment in EIA, the text should conform to Schedule 4: Information for inclusion in environmental statements, of the EIA Regulations document.

7.1 Where should GHG emissions be reported within an ES chapter?

There are three main ways in which GHG emissions can be reported on within an ES chapter. These are as follows:

- Within a GHG emissions ES chapter that focuses on the effects of the proposed project on climate change only
- Within an integrated climate change ES chapter that focuses on both the effects of the proposed development on climate change and of the effects of climate change on the proposed development (i.e. climate change resilience and adaptation)
- It may be proportionate for a section in the project description or an appendix to provide information on GHG emissions to support a conclusion about whether these are significant, without a full ES chapter

Regardless of where GHG emissions are reported within the ES chapter, it is crucial that the assessment is transparent and a conclusion on the significance of effects is reached and clearly stated.

7.2 How does reporting on GHG emissions fit with related EIA topics?

The effects of potential future climate change based on the net GHG impact from a project are likely to be interrelated with other key EIA topics. To ensure consistency is provided throughout the ES, the GHG team will need to liaise with other key EIA topics including (but not limited to):

- Logistics/Transport (Transport Assessment)
- Resources and waste management (construction and demolition)
- Noise/vibration and air quality (construction activities, hours of work, fuel uses, list of plant and energy use)
- Ecology, landscaping and Sustainable Urban Drainage Systems (green infrastructure and land-use change)

7.3 What should be included when reporting on GHG emissions within an ES chapter?

Consistent reporting of GHG emissions in EIA will highlight the importance of accounting for GHG emissions from project inception. It will encourage clients, project developers and engineering design teams to consider the impacts of GHG emissions during early design stages. It is suggested that a brief introduction to climate change and the role of GHG emissions as a contributing factor is included where the effects of GHG emissions are reported within the ES chapter. This will help explain the interrelationship between GHG emissions and climate change with other relevant topics to the readers. This may further be supported with relevant links to documents and information on the topic.

When reporting on GHG emissions and mitigation in EIA, the following steps should be presented where available:

- Baseline emissions: the existing and future emissions within the assessment boundary without construction and operation of the project
- Net emissions (Year 1 and lifetime): the direct and indirect emissions of the project during the first year of operation and for the full lifetime of the project expressed as a change compared to the current and/or future baseline
- Significance: a significance value should be assigned to effects based on the criteria set out
- Further mitigation: the GHG reductions that could be achieved through the application of further mitigation (this will be expressed conditionally and may be quantitative or qualitative)
- Residual effects: a new significance value is assigned to effects taking account the further mitigation measures that have been outlined

7.4 What are the challenges associated with reporting on GHG emissions in EIA?

There are a number of challenges, difficulties and opportunities associated with integrating GHG assessment into EIA practice. These challenges and ways to overcome them are presented below:

- The possible effects identified from a GHG emissions assessment can be interlinked with other EIA topic chapters. Therefore, it is important to liaise with other EIA topic specialists where necessary (e.g. transport, waste management, air quality) – and indeed with practitioners providing assessments such as energy modelling and BREEAM/CEEQUAL. This also needs to be considered when reporting on significant effects within the ES.
- GHG emissions associated with a proposed project are often reported as a whole life figure that takes account of both construction and operation. This whole life approach is often at odds with the sub-headings set out in ES chapter templates provided by EIA co-ordinators. However, due to the nature of GHG emissions, it is good practice to include a section that reports on the whole life GHG emissions associated with the proposed project, alongside the sections that assess construction and operation effects in isolation. Additionally, if there is other data or information that needs to be included that doesn't fit into the provided ES chapter template, then additional sub-sections should be added in order to present all the data from the GHG emissions assessment; to inform the EIA and account for the possible effects on future climate change.
- It is challenging to identify fixed numerical thresholds against which to identify the significance of a proposed project regarding the net change in GHG emissions. The GHG assessment should therefore present context for the GHG emissions as discussed in Section VI: Significance.
- Where GHG assessment is used to inform early design stages, it is vital to get stakeholders to understand the importance of minimising the GHG contribution of a project and designing a project that will limit the net change in future GHG emissions.

Appendix A – Potential Stakeholders and Sources of GHG Information

A1 Potential stakeholders, sources of environmental information and carbon tools

Source	Description
Climate Change Committee (CCC) – The Sixth Carbon Budget[46]	The CCC reports on UK carbon budgets, by sector, and reductions that need to be achieved if the UK is to achieve its carbon reduction target of net zero by 2050. This includes reports for GHG emissions by UK industrial sector: surface transport, buildings, manufacturing and construction, agriculture & LULUCF, aviation, shipping, waste, F-gases and GHG removals. Reports for the UK's electricity and fuel supply are also reported.
The Department for Business, Energy & Industrial Strategy (previously DECC)[47]	The UK Government regularly reports on UK energy and emissions projections by source: agriculture, business, energy supply, industrial processes, land-use change, public, residential, transport and waste management. Currently, GHG emissions reach back to 1990 and project into the future up until 2035 and 2040 (for the 2019 projections).
The Department for Business, Energy & Industrial Strategy (previously DECC)[48] UK greenhouse gas emissions statistics	The UK Government also reports on GHG emissions from a geographical perspective, by UK local authority. Current and historical emissions are available which may be used to establish current baseline emissions.
The Department for Transport (DfT) TAG (the Transport Analysis Guidance) – Data Book[49]	TAG provides UK transport modelling values and information including projections on how the UK's modal mix (diesel, petrol, electric) is expected for change over time, current and future fuel efficiency projections (litres or kWh per kilometre travelled) up to 2050. Also reported are carbon dioxide emissions per litre of fuel burnt or kWh used for: petrol, diesel, gas oil and electricity used on road and rail travel.

46 Climate Change Committee (2020) Sixth Carbon Budget. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget

47 Department for Business, Energy & Industrial Strategy (2021) Energy and emissions projections. Available at: https://www.gov.uk/government/collections/energy-and-emissions-projections

48 Department for Business, Energy & Industrial Strategy (2018) UK greenhouse gas emissions statistics. Available at: https://www.gov.uk/government/collections/uk-greenhouse-gas-emissions-statistics

49 Department for Transport (2021) TAG data book. Available at: https://www.gov.uk/government/publications/tag-data-book

Source	Description
The Green Construction Board – Infrastructure Carbon Review, Technical Report[50]	The GCB has developed a tool that allows stakeholders to model policy changes associated with the built environment and visualise what this means in terms of GHG emissions. Also available is the Low Carbon Routemap report[51] which explores various GHG emissions projections for both building and infrastructure at the UK level.
Inventory of Carbon and Energy (ICE) – University of Bath: Sustainable Energy Research Team[52]	The Inventory of Carbon and Energy (ICE) database is a leading embodied energy and carbon database for building materials.
The Department for Business, Energy & Industrial Strategy (previously DECC)[53] – Government emission conversion factors for greenhouse gas company reporting	The Government conversion factors for greenhouse gas reporting are suitable for use by UK based organisations of all sizes, and for international organisations reporting on UK operations.
Examples of publicly available carbon assessment tools. The list of carbon tools is non – exhaustive and constantly changing. It is up to the practitioner's professional judgement to decide which tool is most appropriate for the project at hand. It is perfectly appropriate to develop bespoke assessment sheets which may provide more flexibility and transparency.	• Scottish Government Windfarm Carbon Assessment tool[54] • Environment Agency Carbon Planning Tool[55] • RSSB Carbon Tool[56] • National Highways Carbon Tool[57] • MacKay Carbon Calculator[58] • Transport Scotland: Carbon Management System (CMS)

50 The Green Construction Board (2013) Infrastructure Carbon Review Technical Report. Available at: https://www.constructionleadershipcouncil.co.uk/wp-content/uploads/2019/06/Infrastructure-Carbon-Review-Technical-Report-25-11-13.pdf

51 Institution of Civil Engineers (nd.) Low Carbon Concrete Routemap. Available at: https://www.ice.org.uk/getattachment/knowledge-and-resources/briefing-sheet/low-carbon-concrete-routemap/low-carbon-concrete-roadmap.pdf.aspx

52 Circular Ecology (2019) Embodied Carbon – The ICE Database. Available at: https://circularecology.com/embodied-carbon-footprint-database.html#.WMO7PYXXLD4

53 Department for Business, Energy & Industrial Strategy (2021) Government conversion factors for company reporting of greenhouse gas emissions. Available at: https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

54 Scottish Government (2018) Carbon calculator for wind farms on Scottish peatlands: factsheet. Available at: https://www.gov.scot/publications/carbon-calculator-for-wind-farms-on-scottish-peatlands-factsheet

55 Environment Agency (2016) Carbon planning tool. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/571707/LIT_7067.pdf

56 RSSB (2021) Rail Carbon Tool. Available at: https://www.rssb.co.uk/sustainability/Rail-Carbon-Tool

57 National Highways (2021) Carbon emissions calculation tool. Available at: https://nationalhighways.co.uk/industry/carbon-emissions-calculation-tool

58 Department for Business, Energy & Industrial Strategy (2020) Carbon calculator. Available at: https://www.gov.uk/guidance/carbon-calculator

Appendix B – List of Standards*

- BRE IMPACT LCA standard – allows the embodied carbon, life cycle environmental (LCA) and life cycle cost (LCC) performance of buildings to be measured and compared in a standardised way.
- BS EN 15686-1:2011 – Buildings and construction assets – service life planning, general principles and framework.
- BS EN 15804:2012 – Sustainability of construction works. Environmental product declarations. Core rules for the product category of construction products.
- BS EN 15978:2011 – Sustainability of construction works, Assessment of environmental performance of buildings, Calculation method.
- BS EN ISO 14021:2016 – Environmental labels and declarations. Self-declared environmental claims (Type II environmental labelling).
- BS EN ISO 14025:2006 – Environmental Labels and Declarations. Quantified environmental performance declarations (Type III Environmental Labelling) – guiding principles and procedures.
- BS EN ISO 14044:2006 – Environmental Management. Life cycle assessment. Requirements and guidelines.
- BS EN ISO 14064-1:2018 – guidance on reporting GHG emissions at an organisational level.
- BS EN ISO 14065:2020 – guidance on principles and requirements for bodies performing validation and verification of environmental information statements.
- BS EN ISO 14604-2:2018 – guidance on reporting GHG emissions at the project level.
- ENCORD: the European Network for Construction Companies for Research and Development – a network for active members from the construction industry who have published a 'Construction CO_2e Measurement Protocol'.
- Greater London Authority – draft Whole Life-Cycle Carbon Assessments Guidance.
- PAS 2050:2011 – Specification for the assessment of the life cycle greenhouse gas emissions of goods and services.
- PAS 2070:2013 – Specification for the assessment of greenhouse gas emissions of a city.
- PAS 2080:2016 – Carbon Management in Infrastructure – the world's first standard for managing infrastructure GHG emissions.
- PD CEN ISO/TS 14067:2018 – Greenhouse gases. Carbon footprint of products. Requirements and guidelines for quantification and communication.
- RICS (2021) Whole Life Carbon Assessment for the Built Environment, 1st edition.
- UK Green Building Council – Net Zero Carbon Buildings: A Framework Definition.
- WRI GHG Protocol – the World Resource Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) partnered to develop internationally recognised guidance and standards on GHG accounting and reporting, and includes advice on:
  - Corporate Standards;
  - Corporate Value Chain (Scope 3);
  - Product Life Cycle assessments;
  - Project Protocol (The GHG Protocol for Project Accounting);
  - GHG Protocol for Cities; and
  - Agricultural Guidance.

*Please note this list is not exhaustive, and subject to updates

IEMA Transforming the world to sustainability

About IEMA

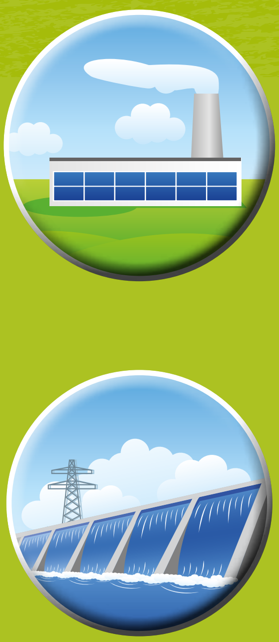
IEMA is the professional body for everyone working in environment and sustainability. We're committed to supporting, encouraging and improving the confidence and performance, profile and recognition of all these professionals. We do this by providing resources and tools, research and knowledge sharing along with high-quality formal training and qualifications to meet the real world needs of members from their first steps on the career ladder, right to the very top. We believe that, together, we can change perceptions and attitudes about the relevance and vital importance of sustainability as a progressive force for good. Together, we're transforming the world to sustainability.

Join us at iema.net

IEMA +44 (0)1522 540069 | info@iema.net | iema.net

Appendix J

European Commission



Environmental Impact Assessment of Projects

Guidance on the preparation of the Environmental Impact Assessment Report

(Directive 2011/92/EU as amended by 2014/52/EU)

Environment

Printed in Luxembourg

Paper	ISBN 978-92-7974373-3	KH-04-17-939-EN-C	doi:10.2779/8247
PDF	ISBN 978-92-7974374-0	KH-04-17-939-EN-N	doi:10.2779/41362

Cover:
©iStockphoto/Si-Gal
©iStockphoto/Juffin

This document benefited from Specific Contract No 070201/2016/729522/SER/ENV.D.1 under Framework Contract No ENV.F.1/FRA/2014/0063, implemented for the European Commission by COWI A/S and Milieu Ltd.
The main authors were: Adrien Lantieri, Zuzana Lukacova, Jennifer McGuinn, and Alicia McNeill from Milieu Ltd

Guidance on the preparation of the EIA Report (Directive 2011/92/EU as amended by 2014/52/EU)

TABLE OF CONTENTS

GLOSSARY OF TERMS

Key terms used in the guidance documents are explained in the Glossary below.

Term	Explanation
2012 IA Study	Impact Assessment Accompanying the document Proposal for a Directive of the European Parliament and the Council amending Directive 2011/92/EU on the assessment of the effects of certain public and private Projects on the environment, SWD/2012/0355 final
Alternatives	Different ways of carrying out the Project in order to meet the agreed objective. Alternatives can take diverse forms and may range from minor adjustments to the Project, to a complete reimagining of the Project.
Baseline scenario	Description of the current status of the environment in and around the area in which the Project will be located. It forms the foundation upon which the assessment will rest.
Candidate Countries	Countries which are seeking to become Members States of the European Union.
Competent Authority (CA)	The authority which the Member States designate as responsible for performing the duties arising from the Directive.
Cumulative effects	Changes to the environment that are caused by activities/projects in combination with other activities/projects.
Developer	The applicant for a Development Consent on a private Project or the public authority which initiates a Project.
Development Consent	The decision of the Competent Authority or Authorities which entitles the Developer to proceed with the Project.
EIA Directive	European Union Directive 2011/92/EU, as amended by Directive 2014/52/EU on assessment of the effects of certain public and private Projects on the environment
EIA process (or EIA)	The process of carrying out an Environmental Impact Assessment as required by Directive 2011/92/EU, as amended by Directive 2014/52/EU on assessment of the effects of certain public and private Projects on the environment. The EIA process is composed of different steps: preparation of the EIA Report, publicity and consultation and decision-making.
EIA Report	The Environmental Impact Assessment Report is the document prepared by the Developer that presents the output of the assessment. It contains information regarding the Project, the likely significant effect of the Project, the Baseline scenario, the proposed Alternatives, the features and Measures to mitigate adverse significant effects as well as a Non-Technical Summary and any additional information specified in Annex IV of the EIA Directive.
Measures to mitigate (Mitigation Measures)	Measures envisaged to avoid, prevent or reduce any identified significant adverse effects on the environment
Measures to monitor (Monitoring Measures)	Procedures to keep under systematic review the significant adverse effects on the environment resulting from the construction and operation of a Project, and to identify unforeseen significant adverse effects, in order to be able to undertake appropriate remedial action.
Member States (MS)	Countries which are members of the European Union
Measures to compensate / offset (Compensation Measures)	Measures envisaged to offset any identified significant adverse effects on the environment.
Non-Technical Summary	An easy-to-follow and understandable summary of the information included in the EIA Report addressed to a non-technical audience.
Project	The execution of construction works or of other installations or schemes, and/or other interventions in the natural surroundings and landscape including those involving the extraction of mineral resources.
Reasoned Conclusion	The explanatory statement made by the Competent Authority on the significant effects of the Project on the environment, based on the examination of the EIA Report and, where appropriate, on the results of its own supplementary

	examination.
Screening	The process of determining whether a Project listed in Annex II of the EIA Directive is likely to have significant environmental effects.
Screening Decision	Decision taken by the Competent Authority on whether a Project listed in Annex II will be made subject to the EIA procedure.
Scoping	The process of identifying the content and extent of the information to be submitted to the Competent Authority under the EIA process.
Scoping Opinion	The Competent Authority's decision on the Scoping process.

LIST OF ABBREVIATIONS

Key abbreviations used in the guidance documents are detailed in the list below.

Abbreviation	Full name
AA	Appropriate Assessment
Aarhus Convention	Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters
BISE	Biodiversity Information System for Europe
CDCIR	Community Documentation Centre on Industrial Risk
CJEU	Court of Justice of the European Union
CLIMATE-ADAPT	European Climate Adaptation Platform
EIB	European Investment Bank
EIONET	European Environment Information and Observation Network
EMIS	Environmental Marine Information System
EMODNET	European Marine Observation and Data Network
ePRTR	European Pollutant Release and Transfer Register
ESPOO Convention	Convention on Environmental Impact Assessment in a transboundary context
GBIF	Global Biodiversity Information Facility
GEO BON	Group on Earth Observations Biodiversity Observation Network
GMEP	Global Marine Environment Protection
IED	Industrial Emissions Directive
INSPIRE	Infrastructure for Spatial Information in the European Community
IPCC	Intergovernmental Panel on Climate Change
JRC	Joint Research Centre
LCA	Life Cycle Assessment
LEAC	Land and Ecosystem Accounting
LIFE +	The EU's Financial Instrument for the Environment
MSFD	Marine Strategy Framework Directive
PCI	Project of common interest
REACH	Registration, Evaluation, Authorisation and Restriction of Chemicals
RBMP	River Basin Management Plans
SEA	Strategic Environmental Assessment
TEN-E	Trans-European Networks for Energy
TEN-T	Trans-European Networks - Transport
UNFCCC	United Nations Framework Convention on Climate Change
WFD	Water Framework Directive
WISE	Water Information System for Europe

PREFACE

In 2001, the European Commission published three EIA Guidance Documents concerning specific stages in the EIA process: Screening, Scoping, and Environmental Impact Statement Review. These documents have been updated and revised to reflect both the legislative changes brought about since the publication of the original guidance documents and the current state of good practice.

These three updated documents concern the following three specific stages of the EIA process:

- EIA Guidance Document on Screening;
- EIA Guidance Document on Scoping;
- EIA Guidance Document on the preparation of the EIA Report.

What is the aim of the Guidance Documents?

The aim of the Guidance Documents is to provide practical insight to those who are involved during these stages in the EIA process, drawing upon experiences in Europe and worldwide.

The Screening and Scoping EIA guidance documents aim to improve the decisions taken on the need for an EIA and the terms of reference on which the assessment is made. These two documents focus on getting the EIA process started well.

The preparation of the EIA Report guidance aims to help Developers and consultants alike prepare good quality Environmental Impact Assessment Reports and to guide competent authorities and other interested parties as they review the Reports. It focuses on ensuring that the best possible information is made available during decision-making.

Who can use the Guidance Documents?

The three EIA Guidance Documents are designed for use by competent authorities, Developers, and EIA practitioners in the European Union Member States and, where applicable, by Candidate Countries. It is hoped that they will also be of interest to academics and other organisations who participate in EIA training and education, to practitioners from around the world, as well as to members of the public.

Who prepared the Guidance Documents?

The original 2001 EIA Guidance Documents were prepared by Environmental Resources Management (ERM) under a research contract with the Directorate General for Environment of the European Commission. The revised 2017 EIA Guidance Documents have been prepared by Milieu Ltd and COWI A/S under a service contract specific contract number 070201/2016/729522/SER/ENV.D.1. to framework contract ENV.F.1/FRA/2014/0063 with the Directorate General for Environment of the European Commission.

How can I get a copy of the Guidance Documents?

Copies of the Guidance Documents can be downloaded from the website of the Directorate General Environment of the European Commission at http://ec.europa.eu/environment/eia/eia-support.htm.

EIA: concept and stages

The Environmental Impact Assessment (EIA) of Projects is a key instrument of European Union environmental policy. It is currently governed by the terms of European Union Directive 2011/92/EU, as amended by Directive 2014/52/EU on the assessment of the effects of certain public and private Projects on the environment (EIA Directive).

Since the adoption of the first EIA Directive in 1985 (Directive 85/337/EEC), both the law and EIA practices have evolved. The EIA Directive was amended by Directives 97/11/EC, 2003/35/EC, and 2009/31/EC. The Directive and its three amendments were codified in 2011 by Directive 2011/92/EU. The codified Directive was subsequently amended by Directive 2014/52/EU. This guidance document focuses on the modifications made to the EIA Directive since 2001, with a particular emphasis on the key changes brought about by the most recent 2014 amendment to the Directive, which Member States have to transpose into their national legal systems by 16 May 2017.

The EIA Directive requires that public and private Projects that are likely to have significant effects on the environment be made subject to an assessment prior to Development Consent being given. Development Consent means the decision by the Competent Authority or authorities that entitles the Developer to proceed with the Project. Before Development Consent can be granted, an EIA is required if a Project is likely to impact significantly upon the environment. Article 2(1) of the EIA Directive (see box below) sets out the Directive's overarching requirement.

Box 1: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 2(1)

Member States shall adopt all measures necessary to ensure that, before development consent is given, projects likely to have significant effects on the environment by virtue, inter alia, of their nature, size or location are made subject to a requirement for development consent and an assessment with regard to their effects on the environment.

The guidance documents in this series cover three stages involved in EIA: Screening, Scoping, and the Preparation of the EIA Report.

The 'Screening stage' ascertains whether the Project's effects on the environment are expected to be significant, i.e. the Project is 'Screened' to determine whether an EIA is necessary. Projects listed in Annex I to the Directive are automatically subjected to an EIA because their environmental effects are presumed to be significant. Projects listed in Annex II to the Directive require a determination to be made about their likely significant environmental effects. The Member State's Competent Authority make that determination through either a (i) case-by-case examination or (ii) set thresholds or criteria.

The 'Scoping stage' provides the opportunity for Developers to ask Competent Authorities about the extent of the information required to make an informed decision about the Project and its effects. This step involves the assessment and determination, or 'scoping', of the amount of information and analysis that authorities will need.

The information relating to a Project's significant effects on the environment is gathered during the third stage: the preparation of the EIA Report.

These three stages are complemented by specific steps in the EIA process. This is defined in Article 1(2)(g) (see box below) which provides a definition of the Environmental Impact Assessment by describing the EIA process.

Box 2: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 1(2)(g)

For the purposes of this Directive, the following definitions shall apply:

[…]

(g) 'environmental impact assessment' means a process consisting of:

(i) the preparation of an environmental impact assessment report by the developer, as referred to in Article 5(1) and (2);

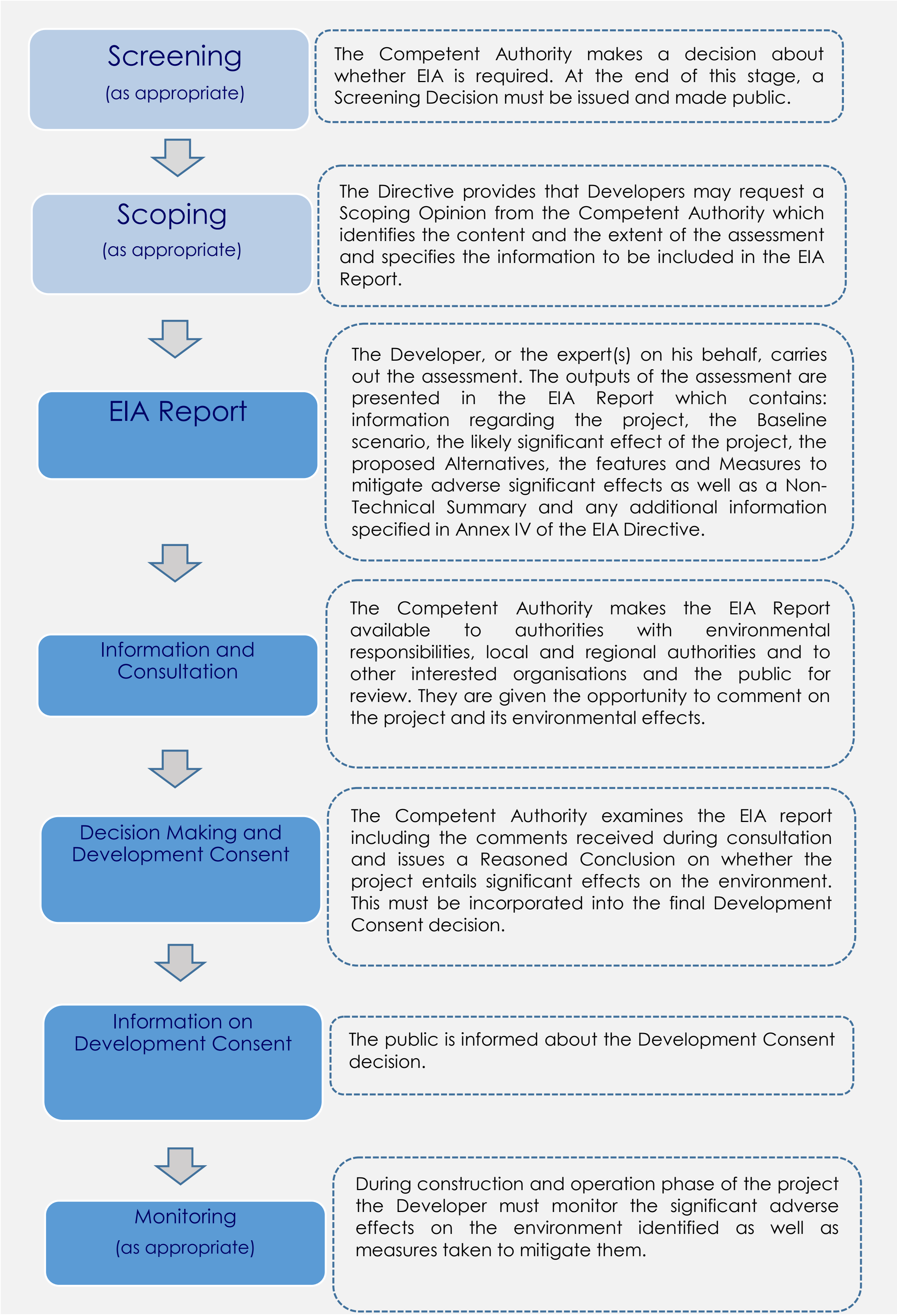
(ii) the carrying out of consultations as referred to in Article 6 and, where relevant, Article 7;

(iii) the examination by the competent authority of the information presented in the environmental impact assessment report and any supplementary information provided, where necessary, by the developer in accordance with Article 5(3), and any relevant information received through the consultations under Articles 6 and 7;

(iv) the reasoned conclusion by the competent authority on the significant effects of the project on the environment, taking into account the results of the examination referred to in point (iii) and, where appropriate, its own supplementary examination; and

(v) the integration of the competent authority's reasoned conclusion into any of the decisions referred to in Article 8a.

The figure below sets out an overview of the stages and steps usually taken when completing an EIA. As mentioned above, implementation arrangements for these stages may vary slightly between Member States, so care should be taken in this regard. The steps defined under Article 1(2)(g) are mandatory when undertaking an EIA. By comparison, undertaking the Screening and Scoping stages may not be required, depending on the nature of a Project or other circumstances: e.g. Screening is not necessary for Projects listed under Annex I to the Directive, and the Directive only foresees Scoping to be mandatory when it is requested by the Developer to the Competent Authority.


Screening
(as appropriate)
The Competent Authority makes a decision about whether EIA is required. At the end of this stage, a Screening Decision must be issued and made public.
Scoping
(as appropriate)
The Directive provides that Developers may request a Scoping Opinion from the Competent Authority which identifies the content and the extent of the assessment and specifies the information to be included in the EIA Report.
EIA Report
The Developer, or the expert(s) on his behalf, carries out the assessment. The outputs of the assessment are presented in the EIA Report which contains: information regarding the project, the Baseline scenario, the likely significant effect of the project, the proposed Alternatives, the features and Measures to mitigate adverse significant effects as well as a Non-Technical Summary and any additional information specified in Annex IV of the EIA Directive.
Information and Consultation
The Competent Authority makes the EIA Report available to authorities with environmental responsibilities, local and regional authorities and to other interested organisations and the public for review. They are given the opportunity to comment on the project and its environmental effects.
Decision Making and Development Consent
The Competent Authority examines the EIA report including the comments received during consultation and issues a Reasoned Conclusion on whether the project entails significant effects on the environment. This must be incorporated into the final Development Consent decision.
Information on Development Consent
The public is informed about the Development Consent decision.
Monitoring
(as appropriate)
During construction and operation phase of the project the Developer must monitor the significant adverse effects on the environment identified as well as measures taken to mitigate them.

GUIDANCE ON THE PREPARATION OF THE ENVIRONMENTAL IMPACT ASSESSMENT REPORT

HOW TO USE THIS GUIDANCE DOCUMENT

This Guidance Document is one in a series of three Guidance Documents on EIA that has been published by the European Commission. This Guidance Document is about the preparation of the EIA Report. The other two guidance documents are concerned with Screening and Scoping.

This Guidance Document has been designed to be used throughout the European Union (EU) and cannot, therefore, reflect all of the specific legal requirements and practices of EIA in the different EU Member States. As such, any existing national, regional or local guidance on EIAs should always be taken into consideration alongside this document. Furthermore, the Guidance Documents should always be read in conjunction with the Directive and with national or local EIA legislation. Interpretation of the Directive remains the prerogative of the Court of Justice of the European Union (CJEU) solely and, therefore, case-law from the CJEU should also be considered.

The guidance is designed for use by various participants in the EIA process.

- **Project Developers and EIA practitioners:** Project Developers are ultimately responsible for preparing a submitting to the Competent Authorities an EIA Report that meets the requirements of the Directive as transposed to national legislation. They frequently hire specialist experts or consultants ('EIA Practitioners') to support them in the preparation of the EIA Report. Part B Section 1 of this Guidance Document reviews the requirements of the EIA Report in detail, and provides practical tips. Part B sections 2 and 3 on quality of the report and the review procedure can also be useful for Developers and practitioners, who will need to follow the decision-making process and provide additional information if requested. Part C is a checklist that can be used during the process of preparing the report to check that it is in line with requirements.

- **Competent Authorities:** Competent Authorities will need to review the EIA Report and use the information for decision-making. They need to ensure that they have the necessary expertise to carry out this role, either through in-house or external resources. Where appropriate, the Competent Authority may request further information to be submitted by the Developer in order to reach a credible, reasoned conclusion about the impacts of the proposed Project or development on the environment. Part B sections 2 and 3 explain the requirements of the Directive in this regard and provide some practical information on how Competent Authorities can best carry out this role. Authorities can use the checklist in Part C when reviewing the report to ensure that it meets the requirements of the Directive.

- **Review Bodies:** In some EIA regimes, bodies have been set up to review environmental information submitted under EIA procedures and to advise Competent Authorities on the adequacy of the information before it is used for decision-making. As noted above research institutes and professional bodies may also be asked to undertake reviews by Competent Authorities.

- **Consultees – the public and stakeholders:** Some consultees who have significant interests in particular Projects may also undertake reviews of an EIA Report on their own behalf to ensure themselves that their interests have been adequately addressed and that it forms a sound basis for decision-making.

The guidance is comprised of three main sections:

- **Part A – Overview of legislative requirements for the EIA Report.** This section introduces the concept of the EIA Report and the relevant provisions of the EIA Directive that govern its preparation and use. It serves as a reference point for guidance users to check which sections of the legislation they need to refer to, and for understanding the main changes to the legislation in 2014.

- **Part B – Practical guidance on the preparation of the EIA Report.** The practical guidance is more hands-on and detailed, aimed at providing an in-depth understanding of the specific, current legislative requirements regarding the preparation and use of the EIA Report. It also provides information on how to carry out the required steps, based on practice from around the EU.

- **Part C – The EIA Report checklist.** The EIA Report checklist allows users to determine if they have fulfilled all the relevant information requirements for different parts of the EIA Report. It follows the structure of the practical guidance in Part B and is designed to be used by practitioners and Developers during the process of preparing the EIA Report and by Competent Authorities when reviewing the report for completeness and quality.

PART A – OVERVIEW OF THE LEGISLATIVE REQUIREMENTS FOR THE PREPARATION OF THE EIA REPORT

1 LEGISLATIVE REQUIREMENTS FOR THE PREPARATION OF THE EIA REPORT

As part of the Environmental Impact Assessment, the Developer must prepare and submit an Environmental Impact Assessment Report (hereafter referred to as the EIA Report). This is the first step of the EIA process, as mentioned in Article 1(2)(g), that defines the EIA process (see box 2 in the Preface). This Guidance Document is designed to support users to prepare and complete the EIA Report to the high standard envisioned by the Directive. This report must include the necessary information for the Competent Authority to reach the Reasoned Conclusion and should be of a sufficient quality to enable this judgement. Many of the EIA Directive's requirements and provisions aim to ensure that the EIA Report is of a sufficient quality to effectively serve this purpose.

Article 5 of the EIA Directive sets out what must be included in the EIA Report, and how to ensure that it is both of a sufficient high quality and complete. Extracts from the text of the Article can be found in the box below.

Box 3: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1)

1. Where an environmental impact assessment is required, the developer shall prepare and submit an environmental impact assessment report. The information to be provided by the developer shall include at least:

- (a) a description of the project comprising information on the site, design, size and other relevant
- features of the project;
- (b) a description of the likely significant effects of the project on the environment;
- (c) a description of the features of the project and/or measures envisaged in order to avoid, prevent or
- reduce and, if possible, offset likely significant adverse effects on the environment;
- (d) a description of the reasonable alternatives studied by the developer, which are relevant to the project and its specific characteristics, and an indication of the main reasons for the option chosen, taking into account the effects of the project on the environment;
- (e) a non-technical summary of the information referred to in points (a) to (d); and
- (f) any additional information specified in Annex IV relevant to the specific characteristics of a particular project or type of project and to the environmental features likely to be affected.

[…] the environmental impact assessment report […] include the information that may reasonably be required for reaching a reasoned conclusion on the significant effects of the project on the environment, taking into account current knowledge and methods of assessment. The developer shall, with a view to avoiding duplication of assessments, take into account the available results of other relevant assessments under Union or national legislation, in preparing the environmental impact assessment report.

Article 5(3)

3. In order to ensure the completeness and quality of the environmental impact assessment report:

- (a) the developer shall ensure that the environmental impact assessment report is prepared by competent experts;
- (b) the competent authority shall ensure that it has, or has access as necessary to, sufficient expertise to examine the environmental impact assessment report; and
- (c) where necessary, the competent authority shall seek supplementary information from the developer, in accordance with Annex IV, which is directly relevant to reaching the reasoned conclusion on the project's significant effects on the environment.

[…]

Article 5(1) sets out what Developers must include as a minimum in the EIA Report. Annex IV, referenced in Article 5(1)(f), expands on these requirements. In short, this includes the following:

- **A description of the Project:** this is an introduction to the Project, and includes a description of the location of the Project, the characteristics of the construction, and the operational phases of the Project, as well as estimates of the expected residues, emissions, and waste produced during the construction and operation phases (Article 5(1)(a) and Annex IV point 1);

- **Baseline scenario**: a description of the current state of the environment, and the likely evolution thereof without the implementation of the Project. This sets the stage for the subsequent EIA, and Member States shall ensure information for the Baseline scenario held by any authorities is available to the Developer (Annex IV.3);
- **Environmental factors affected:** a description of the environmental factors impacted by the Project, with specific emphasis being placed on climate change, biodiversity, natural resources, and accidents and disasters (Article 3, Annex IV points 4 and 8).
- **Effects on the environment**: this section addresses the concept of 'significant effects'[1] and the importance of cumulative effects (Article 5(1)(b), Annex IV point 5);
- **Assessment of Alternatives**: Alternatives to the Project must be described and compared, with an indication of the main reasons for the selection of the option chosen being provided (Article 5(1)(d) and Annex IV point 2);
- **Mitigation or Compensation Measures**, i.e. features or measures to avoid, prevent or reduce, and offset adverse effects should also be considered (Article 5(1)(c) and Annex IV.7);
- **Monitoring**: Monitoring Measures proposed should be included in the EIA Report, where significant adverse effects have been identified. This monitoring should be carried out during the construction and operation of a project(Annex IV.7);
- **Non-Technical Summary**, i.e. an easily accessible summary of the content of the EIA Report presented without technical jargon, hence understandable to anybody without a background in the environment or the Project (Article 5(1)(e) and Annex IV.9);
- **Quality of the EIA Report**: as well as presenting the Report well, complete with the Non-Technical Summary, experts preparing the EIA Report should be competent, and the Competent Authority reviewing the EIA Report should have access to sufficient expertise to examine it. Failure to include all necessary information can result in the Competent Authority requesting supplementary information (Article 5(3)).

Article 5 also refers to the scope and level of detail that are to be included in the EIA Report:
- This should match the scope and level of detail requested by the Competent Authority in the Scoping Opinion, where one exists, and should be sufficient to allow for a Reasoned Conclusion on the significant effects of the Project on the environment to be arrived at (Article 5(1) last paragraph).
- The Developer shall, with a view to avoiding duplication of assessments, take the available results of other relevant assessments under Union or national legislation, into account when preparing the Environmental Impact Assessment report (Article 5(4)).

The EIA Directive also contains provisions on how the EIA Report, once it has been drafted by the Developer, should be used in practice. The EIA Report serves as a tool to 1) communicate the results of the assessment of significant effects of a proposed Project on the environment; and 2) enable the Competent Authority to reach a Reasoned Conclusion regarding the impact of the proposed Project on the environment and whether and how the Project should be granted consent to be implemented. These provisions are laid out in Articles 6, 7, and 8 of the EIA Directive.

These and other requirements and provisions regarding the preparation of the EIA Report are covered in greater detail in Part B of this Guidance Document.

[1] More details on how to understand the concept of significant effects have been provided in the EIA Guidance document on Scoping.

2 LEGISLATIVE CHANGES FOR THE PREPARATION OF THE EIA REPORT

A key objective of the 2014 amendments to the EIA Directive has been to improve the quality of EIA, including with respect to the collection and assessment of environmental information and to the EIA Report's content. Briefly, the key changes include:

- The coverage of environmental issues required in the EIA Report is extended as new requirements related to climate change, biodiversity, risk of major accidents and/or disasters are introduced (Article 3.1 and Annex IV.4, IV.5 and IV.8 – this is described in detail in Part B section 1.4 below). Moreover, the EIA Report will have to cover transboundary effects, and the requirements for the assessment of cumulative effects are provided in further detail.
- The assessment of reasonable Alternatives is broadened: Alternatives studied by the Developer e.g. Alternatives to Project design, technologies, location, size, and scale, must be described in the EIA Report and an indication of the main reasons for the option chosen must be given (Article 5.1(d) and Annex IV, paragraph 2 – this is described in detail in Part B section 1.5 below);
- Provisions related to the completeness and quality of EIA Reports have been introduced (Article 5.3 – this is described in detail in Part B section 2 below);
- Monitoring requirements to be carried for Projects with significant adverse effects (Article 8a, paragraph 4 – this is described in detail in Part B section 1.6 below);
- The Competent Authority's Development Consent decision needs to be justified (Article 8a, paragraph 1) and must be issued within a reasonable period of time (Article 8a, paragraph 5 – this is described in detail in Part B section 3 below). This decision is furthermore required to include a number of elements, such as the Reasoned Conclusion and any environmental conditions attached to the decision such as Mitigation, Compensation, and Monitoring Measures (Article 8a).

These and other changes to the Directive, and how they should be implemented in practice, are presented in greater detail in Part B of this Guidance Document.

PART B - PRACTICAL GUIDANCE ON THE PREPARATION OF THE EIA REPORT

INTRODUCTION

This part of the Guidance Document gives practical guidance on the preparation of the EIA Report. It covers the following aspects:

- **The information requirements of the EIA Report.** This section reviews all of the information that Developers must include in the EIA Report. It is important to note that the content of the EIA Report may not include all of the information uncovered during the process of preparation of the EIA Report. The Directive requires that the EIA Report covers the Project and Baseline description, environmental factors, the assessment of effects on the environment, Project Alternatives, identification of Mitigation and Compensation Measures, as well as monitoring requirements;
- **The quality of the EIA Report.** This section covers the format and presentation of the EIA Report, as well as requirements concerning the expertise of those who prepare, examine and evaluate the EIA Report. It also addresses the Non-Technical Summary that must be included in the EIA Report;
- **Consultations and decision-making.** The EIA Directive has specific requirements regarding the use of the EIA Report, both as a tool to inform concerned stakeholders and the public, as well as to make decisions regarding Development Consent for Projects. This section reviews these procedures.

1 THE EIA REPORT'S CONTENT REQUIREMENTS

1.1 PROJECT DESCRIPTION

This section outlines what is required by the Developer when describing the Project, as required under Article 5 and Annex IV of the EIA Directive.

Box 4: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1)
The information to be provided by the developer shall include at least [...] a description of the project comprising information on the site, design, size and other relevant features of the project.

Annex IV, point 1

- a) a description of the location of the project
- b) a description of the physical characteristics of the whole project, including, where relevant, requisite demolition works, and the land-use requirements during the construction and operational phases;
- c) a description of the main characteristics of the operational phase of the project (in particular any production process), for instance, energy demand and energy use, nature and quantity of the materials and natural resources (including water, land, soil and biodiversity) used;
- d) an estimate, by type and quantity, of expected residues and emissions (such as water, air, soil and subsoil pollution, noise, vibration, light, heat, radiation) and quantities and types of waste produced during the construction and operation phases.

The Directive is relatively detailed in its requirements, and Developers should provide an overview of:

- the location, site, design, size, etc.;
- the physical characteristics of Project (including any demolition or land-use requirements);
- the characteristics of the operational phase of the Project;
- any residues, emissions, or waste expected during either the construction or the operational phase.

While the list in Annex IV outlining the specific characteristics to be included is only indicative, it has been developed through different iterations of the EIA Directive (see the box below In practice - 2014 amendments), and so should be thoroughly considered by practitioners. In any case, Developers should include any additional relevant characteristics of either the operational or construction phases.

Box 5: In practice – 2014 amendments to the Project description

The requirement to include a description of the Project in the EIA Report is not new, and earlier iterations of the Directive have also been quite prescriptive in this regard.

The key difference brought about by the 2014 amendments is the inclusion of relevant requisite demolition works during the construction and operational phases. In addition, an estimate of residues and emissions during the construction phase is to be included, where previously such estimates concerned only the operational phase. This change broadens the scope of the description of the Project, and aims to identify more potential environmental effects.

Other changes faced by Developers are relatively minor:

- Article 5 requires other relevant features of the Project to be included;
- A description of the location of the Project is now specifically required by Annex IV;
- The operational phase of the Project is not limited to production processes, as it was previously.

In addition, the lists of characteristics given in Annex IV, point 1 have been expanded upon:

- Any requisite demolition works must now be described, where relevant;
- Energy demand and energy used should be described in context of the operational phase;
- Natural resources must now be described in the context of the operational phase, with the Directive giving some examples;
- The list of expected residue and emission estimates is no longer exhaustive, and subsoil has been added as type of pollution;
- Estimates of quantities and types of waste produced must now be given.

1.2 BASELINE SCENARIO

This section introduces the Baseline scenario, which is typically the starting point of the assessment process. It covers the legal requirements concerning the Baseline scenario, including the 2014 amendments to the Directive, as well as some practical steps regarding data collection and points to consider when beginning to compile a Baseline scenario.

1.2.1 The notion of Baseline

Defining Baseline scenario: a description of the current status of the environment

The Baseline is a description of the current status of the environment in and around the area in which the Project will be located. It forms the foundation upon which the EIA will rest.

Specifically, developing a robust Baseline scenario for the EIA serves two key purposes:

- it provides a description of the status and trends of environmental factors against which significant effects can be compared and evaluated;
- it forms the basis on which ex-post monitoring can be used to measure change once the Project has been initiated. See the section on monitoring for more information.

Legal requirements of the Baseline scenario in the EIA Directive

In practice, an assessment of the existing and future environmental situation has, typically, always been the EIA procedure's starting point. However, after the 2014 revisions to the Directive, the description of the Baseline scenario, and likely future developments, is now specifically required as part of the Environmental Report. The exact references are shown in the box below.

Box 6: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1) of the Directive states that:
'The information to be provided by the developer shall include at least…any additional information specified in Annex IV relevant to the specific characteristics of a particular project or type of project and to the environmental features likely to be affected.'

Annex IV, point 3 outlines the information for the Environmental Impact Assessment Report, and includes:
'A description of the relevant aspects of the current state of the environment (baseline scenario) and an outline of the likely evolution thereof without implementation of the project as far as natural changes from the baseline scenario can be assessed with reasonable effort on the basis of the availability of environmental information and scientific knowledge.'

It is important to bear in mind that the EIA Directive requires the inclusion of both:

- a description of the current state of the environment in the EIA Report; and
- an outline of what is likely to happen to the environment should the Project not be implemented – the so-called ‘do-nothing’ scenario.

The state of the environment and the nature of impacts such as pollution rates or emission limits change over time, and this has to be accounted for in the Baseline assessment. In addition, the Baseline should consider Projects in the vicinity that exist and/or that have been approved (see Part B section 1.4.3 on Cumulative Effects). The Baseline should, therefore, be dynamic, going beyond a static assessment of the current situation. This is especially important for issues where there is considerable uncertainty, such as climate change, or for longer-term developments, such as large infrastructure Projects. Predicting uncertain elements can be challenging, particularly concerning the availability of information, as well as ensuring that the assessment is carried out with reasonable effort.

Tips on understanding how to carry out the Baseline assessment are provided in the following sections. The box below summarises the changes arising from the 2014 amendments to the EIA Directive.

Box 7: In practice – 2014 amendments to the Baseline

The specific requirement to include the Baseline scenario in the EIA Report is a new provision of the 2014 EIA Directive. However, in most cases, the changes will not have much of an effect on those carrying out the EIA:

- EIAs carried out prior to this requirement have established some kind of Baseline on which to assess the Project;
- The new provision formalises this step in the EIA process and aims to bring about some consistency between EIAs, between practice in Member States, and with the provisions on the SEA Directive’s baseline (see the section below on sharing baseline assessment results).

The new provisions require consideration of:

- The ‘do-nothing’ scenario: the evolution of the Baseline, i.e. how the situation would be expected to develop over time, (rather than a static description of the state of the environment at the time of the assessment);
- The proportionality of the efforts to be expended, making sure resources are not spent collecting data if the cost outweighs the benefits

1.2.2 Carrying out the Baseline assessment

The Baseline forms the foundation against which the Alternatives and the Project itself are assessed. As such, the description of the current state of the environment must be sufficiently detailed and accurate to ensure that the effects, arising both during the development of the Project and in the future, can be adequately assessed. At the same time, the collection of data and the assessment of the Baseline need to be completed with reasonable effort. Developers and practitioners alike need to determine what aspects are important and can be readily understood and where qualified assumptions or estimates can be made to ensure the timely completion of the EIA.

Essentially, carrying out the Baseline assessment involves determining what is relevant and finding the data and information necessary to set the framework against which to assess impacts on the environment.

The collection of relevant data

The development of the Baseline can often comprise the bulk of the EIA process, and can occupy a significant proportion of the final EIA Report. However, care must be taken to ensure that data collection efforts are focused on those aspects of the environment most likely to be significantly impacted, and that environmental data and scientific knowledge are reasonably available. The EIA Directive requires that only the 'relevant aspects' be investigated, and the over-collection of data can result in unnecessary costs. Detailed and thorough Scoping, undertaken at the outset of the Project, will go a long way to avoiding this issue (see the Guidance Document on Scoping). In some cases, communication with the Competent Authority about the scope of significant impacts, and what can be considered reasonable in terms of data availability, is also very helpful.

More generally, the scope of the Project will determine what level of detail is required, and how far the Baseline should extend. A small Project will likely only require that a small area be covered, but the nature of the Project may well mean that a high level of detail is required. A large Project may require a bigger area, but environmental effects may be small and it may be that only a broad level of detail is needed. Another issue concerns the timeline. Practitioners will need to decide how far into the future the Baseline will stretch. This will be decided on a case-by-case basis, but should at least be far enough in the future to show the development of the Project. However, a Baseline looking 100 years into the future will be less accurate than one working on a shorter timeframe. The use of existing plans and programmes, such as spatial plans and their SEAs, can also be a good way to determine the time frame, given that the scales may be similar and appropriate data are likely to be available.

Depending on the type of Project or specific environmental aspect, practitioners will need to gauge what is relevant when developing a Baseline. Keeping this in mind, the box below gives an overview of the types of data typically used in developing the Baseline assessment.

Box 8: Types of data to be considered for the Baseline scenario

Physical: topography, geology, soil types and quality, surface, ground and coastal water quality, pollution levels, meteorological conditions, climate trends, etc.

Biological: ecosystems (both terrestrial and aquatic), specific flora and fauna, habitats, protected areas (Natura 2000 sites), agricultural land quality, etc.

Socio-economic: demography, infrastructure facilities, economic activities (e.g. fisheries), recreational users of the area, etc.

Cultural: location and state of archaeological, historical, religious sites, etc.

Accessing data for the Baseline assessment

If Scoping has been carried out, it is possible that initial data has already been collected, which can be used for developing the Baseline. In such cases, data should be checked for relevance and accuracy, and if necessary, expanded upon. The Guidance Document on Scoping includes some guidelines on where initial data can be found, but this section is intended for those cases in which Scoping has not been carried out, or information identified during Scoping has proven to be insufficient.

Data should be collected and interpreted by the relevant experts (see the section on competence of expertise and quality control). If highly technical data are used, then data should be verified for the accuracy of interpretation and its relevance. Where no such experts are available in-house, external experts should be used. Experts may also be found at the local level, given that communities may have local knowledge which is highly relevant to understanding the Baseline conditions.

Data may be difficult to find; in some cases, proxy indicators can be used that can help to understand the environmental situation in other ways. For example, a lack of air quality monitoring data from an urban area could be resolved if there are data outlining trends in traffic flows/volumes over time, or trends in emissions from stationary sources. Assumptions about the environment can be generated from other available data and can be useful in determining the relevance of impacts.

Practitioners should be aware that data sources may differ from case to case, and the most high-tech or extensive collection method may not be the best one. In some cases, desk research may be more effective than field surveys, and Google Earth may be just as useful as satellite imagery that has been purchased.

In many Member States, data are collected either nationally or regionally, and include not only data from EIAs, but also from other environmental assessments and monitoring schemes. This practice is also encouraged by other EU level Guidance Documents (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). These databases help to speed up the preparation of environmental assessments. Frequently updated databases will also facilitate transboundary consultations and the linkages between strategic and Project level environmental assessments. Practitioners should always first check what institutions are already in place, and what data are already available, before starting data collection for the Baseline scenario. In addition, Article 5(4) of the EIA Directive requires Member States to, if necessary, ensure that any authorities holding relevant information make this information available to the Developer. This means that the Developer should be able to easily obtain relevant information from the different relevant authorities and to obtain guidance to that effect from the Competent Authority.

Some typical sources of information used for collecting Baseline data are listed below.

- National/regional databases of previous EIAs;
- Data collected under other EU legislation (especially the SEA Directive and the INSPIRE Directive);
- EU level and other international databases (see the box below);
- Local level/community experts; and
- Primary research carried out by competent experts.

Box 9: Some examples of supra-national level environmental databases

General datasets

- European Commission – Eurostat database;
- European Environment Agency (including national emissions, water, land cover, etc.);
- European Environment Information and Observation Network (EIONET);
- Copernicus (previously Global Monitoring for Environment and Security);
- Infrastructure for Spatial Information in the European Community (INSPIRE);
- United Nations Environmental Data Explorer.

Biodiversity and climate change datasets

- Biodiversity Information System for Europe (BISE);
- Global Biodiversity Information Facility (GBIF);
- Natura 2000 Network Viewer;
- Reporting under Habitats Directive and Birds Directive;
- Common Database on Nationally Designated Areas (CDDA) managed by the European Environment Agency;
- Ecosystem assessments (MAES)
- Group on Earth Observations Biodiversity Observation Network (GEO BON);
- EuMon (species and habitats of Community interest);
- IPCC Data Distribution Centre.

Water & Marine datasets

- Water Information System for Europe (WISE);
- European Marine Observation and Data Network (EMODNET);
- Environmental Marine Information System (EMIS) ;
- European Atlas of the Seas.

Chemicals and industrial datasets

- Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH);

- Major Accident Reporting System (MARS);
- Community Documentation Centre on Industrial Risk (CDCIR);
- European Pollutant Release and Transfer Register (ePRTR).

An example of data sharing platforms is provided in the box below.

Box 10: An example of data sharing

In Italy, several environmental and territorial databases are available for public access via a website dedicated to the SEA/EIA procedures. The ministry of the environment provides a catalogue of environmental data at the national and regional levels which is updated regularly. Sources include databases, web resources, documents, spatial datasets (webGIS service, Google Earth, WMS and WFS). Specific criteria are used to ensure the reliability and quality in accordance with national and EU provisions.

Information from the Italian's government website Ministero dell'Ambiente.

Sharing Baseline assessment results

Sharing results from other types of environmental assessment procedures or similar Projects' EIAs is also important for the Baseline's assessment. For example, if one year is spent collecting Baseline data for a windfarm, a similar windfarm Project in a similar location would be able to use much of the data already collected for the first Project.

The SEA, WFD, IED, and Habitats Directive (see the Annex to this Guidance Document on Links with Other EU Instruments) all require that some form of baseline be developed: for instance, under the Habitats Directive the baseline would be the conservation objectives of the Natura 2000 site. But very few Member States have provisions on how this is to be done. In any case, practitioners should check the Baseline scenario, as well as environmental reports and other relevant assessments of the status of the environment carried out under the SEA and Habitats Directives, the WFD, and the IED if they are carried out in the vicinity of the Project covered by the EIA. Care should be taken to ensure that the data are still up to date and relevant, keeping in mind the differences in scope of the different instruments.

The similarities between the SEA and EIA provisions also mean that SEA guidance documents and reports prepared in this context may be used to inspire an EIA. Below is an example from the 2001 SEA Guidance Document issued by the European Commission (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). It should be borne in mind that similar documents may exist at the national level, and would include information which may differ from this guidance and provide additional information.

Box 11: SEA Guidance Document: a comparison with EIA Baseline provisions

The SEA baseline provisions were first introduced in 2001, and guidance and lessons learnt have been developed since then. The SEA Guidance can prove useful to applying the EIA provisions to the Baseline. Below are the phrases that appear in both Directives in **bold**, and how they are covered in the SEA Guidance Document.

PART A '**the relevant aspects**' refer to environmental aspects that are relevant to the likely significant environmental effects of the plan or programme. These aspects could be either positive or negative. This concept should be considered in the same way during both assessments, but the aspects themselves may differ between EIA and SEA. An SEA, for example, may cover a large area of land and, therefore, may have much broader aspects that may be affected than an EIA, which may be assessed at a much smaller level of detail.

PART B '**current state of the environment**' requires that the information be up-to-date. Both the SEA and EIA will benefit from the data being up-to-date (see the section on decision-making).

PART C '**likely evolution of the relevant aspects without the implementation** of the plan or programme gives a foundation upon which the plan or programme (if it does go ahead) can be assessed. For an SEA, the description of the evolution should cover roughly the same time horizon as that envisaged for the implementation of the plan or programme. The same timeframe could be used for an EIA falling under such an SEA.

Information collected under the other environmental assessments may provide a starting point for an EIA, given that Developers must provide authorities with data on various issues regularly. EU-level initiatives such as INSPIRE provide standardised data collection, making comparison between different environmental assessments easier. The IED, for example, requires that Developers provide annual information on their emissions with regards to different mediums, volume, and amount of materials on-site (stocked, disposed of, etc.). Such information, collected solely for the purposes of the IED, may not be directly transferrable to the EIA Report, given that the scope and purpose of these collections may differ from EIA requirements. However, previously reported information may prove invaluable for establishing a Baseline and mapping trends over time.

1.2.3 Baseline: In a nutshell

- The Baseline assessment is the starting point of an EIA. The Baseline scenario and its assessment provide a description of the affected environment as it is currently, and as it could be expected to develop if the Project were not to proceed;
- A Baseline has typically always been included in EIAs, but the 2014 amendments to the EIA Directive specify that a Baseline must be included in the EIA Report and that it must include the current environmental situation as well as expected future developments ('do-nothing' scenario);
- The Baseline assessment needs to be detailed and comprehensive enough to allow for an understanding of the extent of environmental impacts, but must be conducted within a reasonable time and with a reasonable amount of effort on the part of the Developer. Scoping helps to understand this in advance;
- The collection of relevant data is critical to a robust assessment of the Baseline. Data should be identified and assessed by qualified experts;
- Efficiencies in data collection from existing databases, free services, and other relevant environmental assessments should always be investigated.

1.3 ENVIRONMENTAL FACTORS

This section reviews the scope of the environmental factors covered by the Directive, with a focus on those factors that have been expanded in the 2014 amendments to the Directive.

1.3.1 Scope of environmental factors covered by the Directive

As shown in the box below, Article 3 sets out those environmental factors that EIAs have to consider relevant for particular Projects. These factors are described further in Annex IV, point 4 to the Directive, which provides details about the information required for the EIA Report.

Box 12: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 3

1. The environmental impact assessment shall identify, describe, and assess in an appropriate manner, in the light of each individual case, the direct and indirect significant effects of a project on the following factors:

- (a) population and human health[2];

[2] Human health is a very broad factor that would be highly Project dependent. The notion of human health should be considered in the context of the other factors in Article 3(1) of the EIA Directive and thus environmentally related health issues (such as health effects caused by the release of toxic substances to the environment, health risks arising from major hazards associated with the Project, effects caused by changes in disease vectors caused by the Project, changes in living conditions, effects on vulnerable groups, exposure to traffic noise or air

- (b) biodiversity, with particular attention to species and habitats protected under Directive 92/43/EEC and Directive 2009/147/EC;
- (c) land, soil, water, air and climate;
- (d) material assets, cultural heritage and the landscape;
- (e) the interaction between the factors referred to in points (a) to (d).

2. The effects referred to in paragraph 1 on the factors set out therein shall include the expected effects deriving from the vulnerability of the project to risks of major accidents and/or disasters that are relevant to the project concerned.

In particular, the requirements have been expanded to cover some of these factors in greater detail, in response to the evolution of the understanding of the interaction between Projects and the environment, and other policy actions taken in light of these developments. These elements are:

- Climate change – both mitigation and adaptation;
- Risks of major accidents and disasters;
- Biodiversity;
- Use of natural resources.

Developers are, therefore, expressly required to assess a broader scope of impacts with respect to these issues wherever relevant. These issues are each treated specifically in the following sections.

1.3.2 Impacts related to Climate change

Legislative requirements and key considerations

Box 13: Directive 2011/92/EU as amended by Directive 2014/52/EU

Annex IV point 4

A description of the factors specified in Article 3(1) likely to be significantly affected by the project: … climate (for example greenhouse gas emissions, impacts relevant to adaptation) …

Annex IV point 5(f)

A description of the likely significant effects of the project on the environment resulting from, inter alia:

- (f) the impact of the project on climate (for example the nature and magnitude of greenhouse gas emissions) and the vulnerability of the project to climate change; …

Annex IV to the EIA Directive includes direct reference to climate and climate change in two provisions. The emphasis is placed on two distinct aspects of the climate change issue:

- **Climate change mitigation**: this considers the impact the Project will have on climate change, through greenhouse gas emissions primarily;
- **Climate change adaptation:** this considers the vulnerability of the Project to future changes in the climate, and its capacity to adapt to the impacts of climate change, which may be uncertain.

In 2013, the European Commission issued a guidance document on integrating climate change and biodiversity into Environmental Impact Assessment (see the Annex to this Guidance Document on Other Relevant Guidance). This guidance document provides information about the legal aspects of understanding these issues in EIAs, the benefits and challenges of integrating them into assessment

pollutants) are obvious aspects to study. In addition, these would concern the commissioning, operation, and decommissioning of a Project in relation to workers on the Project and surrounding population.

procedures, and detailed methodological approaches to carrying out assessments on these issues. It should be read alongside this section of the EIA guidance document.

Climate change mitigation: Project impacts on climate change

Most Projects will have an impact on greenhouse gas emissions, compared to the Baseline (see the section on Baseline), through their construction and operation and through indirect activities that occur because of the Project. The EIA should include an assessment of the direct and indirect greenhouse gas emissions of the Project, where these impacts have been deemed significant:

- direct greenhouse gas emissions generated through the Project's construction and the operation of the Project over its lifetime (e.g. from on-site combustion of fossil fuels or energy use)
- greenhouse gas emissions generated or avoided as a result of other activities encouraged by the Project (indirect impacts) e.g.
  - Transport infrastructure: increased or avoided carbon emissions associated with energy use for the operation of the Project[3];
  - Commercial development: carbon emissions due to consumer trips to the commercial zone where the Project is located.

The assessment should take relevant greenhouse gas reduction targets at the national, regional, and local levels into account, where available. The EIA may also assess the extent to which Projects contribute to these targets through reductions, as well as identify opportunities to reduce emissions through alternative measures.

Climate change adaptation: the vulnerability of the Project to climate change

The Directive also requires that Environmental Impact Assessments consider the impacts that climate change may have on the Project itself — and the extent to which the Project will be able to adapt to possible changes in the climate over the course of its lifetime. This aspect of the issue of climate change can be particularly challenging as 1) it requires those carrying out the assessment to consider the impacts of the environment (the climate in this case) on the Project, rather than vice-versa; and 2) it often involves a considerable degree of uncertainty, given that the actual climate change impacts, especially at local levels, are challenging to predict. To this end, the EIA analysis should take trends and risk assessment into consideration.

In April 2013, the European Commission adopted the EU Strategy on adaptation to climate change (COM(2013) 216 final), which sets out a framework to prepare the EU for climate impacts now and in the future. One of its main objectives is related to the promotion of better-informed decision-making through initiatives such as the European Climate Adaptation Platform (CLIMATE-ADAPT)[4] which was designed, as a web-based platform, to support policy-makers at the EU, national, regional, and local levels in the development of climate change adaptation measures and policies. The Strategy comprises a set of documents that are useful to a wide range of stakeholders. In relation to the adaptation measures considered within EIAs, the Commission Staff working document entitled Adapting infrastructure to climate change (SWD(2013) 137 final), as well as Guidelines for Project Managers: Making vulnerable investments climate resilient (DG Climate Action, Non-paper) are of particular importance.

[3] For example, such a requirement is already included in the French legislation concerning EIAs.

[4] http://climate-adapt.eea.europa.eu/about.

- Integration of climate change mitigation considerations into EIAs

The effective assessment of impacts on climate change mitigation within EIAs is heavily dependent upon the methodology employed, and a number of standardised methodologies for calculating greenhouse gas emissions already exist. The extent to which they will be applicable to the specific case in question will be important, as well as issues relating to data collection. Calculating direct impacts will be more straightforward than indirect impacts – and assessments will have to rely on estimates in some cases.

The European Commission Guidance Document on integrating climate change and biodiversity into EIA identifies key European sources of data, including data repositories and online digital datasets thought to be useful when integrating climate change in EIA. This guidance document also provides links to carbon calculators and to other methodologies, including to the methodology for calculating absolute and relative GHG emissions piloted by the European Investment Bank (EIB) (EIB, Methodologies for the Assessment of Project GHG Emissions and Emission Variations) – see the Annex to this Guidance Document on Other Relevant Guidance and Tools.

On the global level, in 2011 the United Nations Framework Convention on Climate Change issued a paper on 'Assessing climate change impacts and vulnerability, making informed adaptation decisions' (UNFCCC, Highlights of the contribution of the Nairobi work programme, Assessing climate change impacts and vulnerability, making informed adaptation decisions) which contains sections on, inter alia, the development and dissemination of methods and tools, the provision of data and information, and the assessments of impacts and vulnerability at different scales and in different sectors.

The Life Cycle Assessment (LCA) can be used to consider a Project's overall direct and indirect greenhouse gas emissions balance.

- Integration of climate change adaptation considerations into EIAs

As discussed above, the integration of climate change adaptation considerations into EIAs is challenging; it requires a shift in thinking about assessments and taking possible long-term risks and uncertainty into account. Recent improvements in the information base for understanding climate change impacts and risks for a variety of sectors and locations has made this challenge less daunting, however, and the information base and acquisition of experience on this topic is growing rapidly. The European Climate Adaptation Platform, known as Climate-ADAPT, is a good place to start to find support tools and links to the latest adaptation knowledge, including detailed studies on vulnerabilities and risks.

The European Commission Guidance Document on integrating climate change and biodiversity into EIA is another important source of information and ideas on how to carry out the assessment (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). It provides examples of key questions to ask to identify climate change adaptation concerns; these consider major impacts such as heat waves, droughts, extreme rainfall, storms and winds, landslides, rising sea levels, and others. The guidance document also explains how to take account of trends, drivers of change, and risk management approaches in EIAs. It suggests approaches to building adaptive capacity into Projects through alternative measures, such as changes in the use of materials or construction designs that will be more resilient to expected risks. It also shows how EIAs can facilitate adaptive capacity and management in Projects by clearly acknowledging their assumptions and uncertainty in climate impacts and by proposing practical monitoring arrangements to verify the validity of predictions and responses over time.

1.3.3 Impacts related to risks of major accidents and disasters

Legislative requirements and key considerations on accidents and disaster risks

Box 14: Directive 2011/92/EU as amended by Directive 2014/52/EU

Annex IV point 5(d)

A description of the likely significant effects of the project on the environment resulting from, inter alia:

- (d) the risks to human health, cultural heritage or the environment (for example due to accidents or disasters) and

Annex IV point 8

(8) A description of the expected significant adverse effects of the project on the environment deriving from the vulnerability of the project to risks of major accidents and/or disasters which are relevant to the project concerned. […] Where appropriate, this description should include […] details of the preparedness for and proposed response to such emergencies.

Annex IV contains direct reference to accidents and disaster risks in two provisions. The Directive uses the terms 'major' accidents and 'disasters', which are tied to the notion of significant effects (see the section below on assessing effects on the environment): the focus of these provisions is on significant risk and/or a risk that could cause significant environmental effects.

Two key considerations emerge therefrom, namely:

- The Project's potential to cause accidents and/or disasters

In this case, the Directive explicitly refers to considerations for human health, cultural heritage, and the environment.

- The vulnerability of the Project to potential disaster/accident

In this case, the requirement covers both natural (e.g. earthquakes) and man-made disasters (e.g. technological hazards) that could significantly impede the Project's activities and objectives and which might have adverse effects. In its 2009 Prevention Communication, the Commission has committed itself to mainstream disaster prevention concerns in the EU legislation and in the EIA Directive in particular. The need to build 'resilience to natural and man-made disasters' and to invest in risk prevention is envisaged in several EU strategies and proposals[5]. Some relevant information on these topics is readily available and can be obtained through risk assessments pursuant to other EU legislation, such as the Seveso III Directive on the control of major-accident hazards involving dangerous substances[6] or the Directive establishing a Community framework for the nuclear safety of nuclear installations[7]. Other relevant assessments, carried out pursuant to national legislation, may also be used for this purpose provided that the requirements of these Directives have been met.

An example from Ireland, presented in the box below, illustrates the necessity to consider the adverse impacts of natural disaster/risks when constructing a Project.

[5] E.g. the EU Internal Security Strategy COM(2010)673, the Commission's proposal for the Cohesion fund for 2014-2020 COM(2011)612, the Commission's Communication on the prevention of natural and man-made disasters COM(2009)82.

[6] Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major-accident hazards involving dangerous substances, amending and subsequently repealing Council Directive 96/82/EC.

[7] Council Directive 2009/71/EURATOM of 25 June 2009 establishing a Community framework for the nuclear safety of nuclear installations.

Box 15: Assessment of natural disasters risk in an EIA in Ireland – CJEU, C-215/06, *Commission v Ireland*

In 2008, the ECJ ruled that Ireland had failed to fulfil its obligations under several Articles of the EIA Directive. This case concerned the construction of the largest terrestrial wind-energy development ever planned in Ireland and one of the largest in Europe.

When initial phases for development consent were granted in 1998, wind farms were not included in either Annex I or II to the Directive and, therefore, were not subject to an EIA. However, wind farm construction required a number of works, including the extraction of peat and of minerals other than metalliferous and energy-producing minerals, as well as road construction, which were listed in Annex II to the EIA Directive requiring Screening to be carried out. The competent authority in Ireland assessed that no EIA for these supplementary works was required, given that their impact would not significantly impact the environment.

Subsequently, a landslide occurred in October 2003, which the Commission claimed lead to a large-scale ecological disaster, when the mass of peat which was dislodged from an area under development for the wind farm polluted the Owendalulleegh River, causing both the death of about 50,000 fish and lasting damage to the fish spawning beds. Ireland contended that the landslide was caused by the construction methods used and that there was no question of difficulties which could have been anticipated by an EIA, even one in conformity with the Community requirements.

The ECJ stated that the intended Projects of peat and mineral extraction and road construction were not insignificant and that the EIA should have been carried out.

Given that it was not undertaken, the question of soil stability, even though it is fundamental when excavation is intended, was not assessed.

Integration of disaster/accident risk considerations into EIAs

Box 16: Key considerations on disaster/accident risk

Including disaster/accident risk assessment in EIAs should address issues such as:

- What can go wrong with a Project?
- What adverse consequences might occur to human health and to the environment?
- What is the range of magnitude of adverse consequences?
- How likely are these consequences?
- What is the Project's state of preparedness in case of an accident/disaster?
- Is there a plan for an emergency situation?

- Assessment of the Project's vulnerability to disaster risks

An integrated assessment of vulnerability to disaster risks and hazards aims to assess whether the Project is indeed vulnerable to such events and, if so, to provide recommendations to avoid/minimise those risks. Where relevant, a multi-risk approach should be followed to cover the climate-related hazards, discussed previously in the section concerning climate change (see section above on climate change). The study on the EIA and risk assessment undertaken as part of the Sixth Framework Programme (the Sixth Framework Programme covers EU activities in the field of research, technological development and demonstration) contains useful information concerning risk assessment and risk management, lists existing guidelines on the subject and the results of the EIA's application in terms of risk assessment in several Member States (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). It examines the ways in which, and the extent to which, extraordinary hazards and risks are dealt with in the EIA in the EU Member States, both within the regulatory framework and in EIA practice. The study also lists qualitative, semi-quantitative, and quantitative methods by which to assess risk of accident/disasters.

- Tools: prevention, monitoring and early warning

After the major natural and man-made risks have been identified and assessed, measures to control and manage their significant impacts should then be taken, e.g. to ensure compliance with existing minimum prevention standards, safety requirements, building codes, improved land use planning, etc. These could be integrated into a coherent risk management plan that also includes sufficient preparedness and emergency planning measures to ensure an effective response to disasters or to the risks of accidents (cf. 2012 IA Study, page 140).

1.3.4 Impacts related to biodiversity

Legislative requirements and key considerations on biodiversity

Box 17: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 3

The environmental impact assessment shall identify, describe and assess in an appropriate manner, in the light of each individual case, the direct and indirect significant effects of a project on the following factors:

- (b) biodiversity, with particular attention to species and habitats protected under Directive 92/43/EEC and Directive 2009/147/EC;

Annex IV point 4

A description of the factors specified in Article 3(1) likely to be significantly affected by the project:

… biodiversity (for example fauna and flora) …

Annex IV (4) refers to biodiversity and includes, inter alia, fauna and flora. The reference to the assessment of impacts on 'biodiversity' was added to the Directive in the 2014 amendments, which previously referred only to 'fauna and flora'. This is important: fauna and flora taken individually refer to animal and plant life in a particular zone or time, it involves a somewhat individual perspective, while biodiversity refers to the interactions and variety of, and variability within, species, between species, and between ecosystems; this is, therefore, a much broader concept than simply looking at the impacts on fauna and flora individually. This change is in line with some of the actions of the 2006 EU Biodiversity Action Plan requiring that 'all EIAs should take full account of biodiversity concerns' (Halting the loss of biodiversity by 2010 - and beyond - Sustaining ecosystem services for human well–being, SEC(2006)621). This is particularly important, given that the EU has missed its 2010 target of halting the loss of biodiversity and the new 2011 EU Biodiversity Strategy reiterates that this target is to be achieved by 2020 (Our life insurance, our natural capital: an EU biodiversity strategy to 2020, COM (2011) 244 final).

In addition, Article 3(1) also spells out the need to assess both the direct and indirect significant effects of the Project on, inter alia, biodiversity, with particular attention being paid to species and habitats protected under the Habitats Directive and the Birds Directive. The reference to these Directives was also added in the 2014 amendments.

Integration of biodiversity considerations into the EIAs

A number of key issues need to be addressed by Developers in relation to biodiversity concerns. These include, for instance, the degradation of ecosystem services[8], the loss and degradation of habitats, the loss of species diversity, and the loss of genetic diversity.

[8] Ecosystem services are understood as the ecosystem's capacity for (i) provisioning, (ii) regulating, (iii) supporting, and (iv) providing cultural benefits. This means, for instance, that if pollution to a water stream is taking place, then this could result in degradation of the stream's capacity to (i) provide clean water, ensuring thereby that fish and aquatic plants are (ii) healthy and (iii) thriving, leading to (iv) the depreciation of the site's value for local fishermen.

The European Commission issued guidance concerning the integration of biodiversity into the EIA in 2013 (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). This guidance document lists key concerns and includes examples of key questions that should be asked, in order to assess impacts on biodiversity effectively. There are also several other guidance documents that are useful for the integration of biodiversity concerns into the EIAs. Some of these documents are listed in the box below, please also refer to the Annex to this Guidance Document on Other Relevant Guidance and Tools.

Box 18: Guidelines on biodiversity integration in the EIA

- Commission, Assessment of plans and Projects significantly affecting Natura 2000 sites, Methodological guidance on the provisions of Article 6(3) and (4) of the Habitats Directive 92/43/EEC.
- Netherlands Commission for Environmental Assessment & CBD-Ramsar-CMS, Voluntary Guidelines on biodiversity-inclusive Environmental Impact Assessment.
- Slootweg, Roel; Kolhoff, Arend, Generic approach to integrate biodiversity considerations in screening and Scoping for EIA.
- Chartered Institute of Ecology and Environmental Management, Guidelines for ecological impact assessment in the UK and Ireland, Terrestrial, Freshwater, and Coastal, January 2016.

In cases in which Projects are likely to have significant effects on a site protected under the Habitats and Birds Directives, the assessment of effects of Projects on biodiversity will be carried out as part of an Appropriate Assessment according to Article 6(3) of the Habitats Directive. The 2014 amendments to the EIA Directive require that this assessment be carried out in coordination with the EIA, according to procedures specified in the European Commission guidance on streamlining environmental assessments under Article 2(3) of the EIA Directive (see the Annex to this Guidance Document on Other Relevant Guidance and Tools). It is important to bear in mind that EIAs must assess impacts on biodiversity even in cases in which certain Projects do not impact upon a Natura 2000 site.

Integration of marine biodiversity into the EIAs

Following the adoption of the Marine Strategy Framework Directive (MSFD), in 2008[9], impacts on the marine environment are to be further considered in EIAs for Projects within marine areas. These could include Annex I Projects, such as trading ports, or Annex II Projects such as extracting minerals by dredging, wind farms, shipyards, coastal work to combat erosion, for example, moles and jetties.

Contrary to biodiversity on land, which has been covered by EU law since the 1980s, a thorough analysis of biodiversity in the sea only became required with the adoption of the MSFD. The issue of data gathering and problems with the lack of data may, therefore, be greater than it is for other Projects. However, a number of tools, databases, and information systems are now available and aim to preserve the natural resources and biodiversity, while keeping the marine economic sectors viable.

These include:

- Several tools developed to support the assessment of the marine environment under the MSFD. Member States are required under Article 8 of the MSFD to carry out an assessment of their marine waters every 6 years. This can be considered as a form of baseline. In addition, according to Article 11 of the MSFD, Member States must establish a monitoring programme, reviewed every 6 years, which should also gather data for the purposes of achieving good environmental status;

[9] Directive 2008/56/EC of 17 June 2008 establishing a framework for community action in the field of marine environmental policy (Marine Strategy Framework Directive).

- There are also regional sea conventions that have relevant information concerning data on marine biodiversity and sea such as the Helcom[10] in the Baltic region, OSPAR for the North East Atlantic, the Barcelona Convention for the Mediterranean and the Bucharest Convention for the Black Sea;
- The Global Marine Information System has been developed by the JRC to provide the stakeholders with an appropriate set of bio-physical information (GIS functionalities) that is important in conducting water quality assessments and resource monitoring in the coastal and marine waters;
- The Global Marine Environment Protection (GMEP) Initiative is a best practices-sharing mechanism that was prompted by several high profile offshore drilling accidents. GMEP was conceived by the G20 Leaders at the Toronto Summit in 2010 to protect the marine environment.

See the Annex to this Guidance Document on Other Relevant Guidance and Tools for full references.

In 2014, the Commission also adopted a Directive establishing a framework for maritime spatial planning[11] that requires Member States to establish so-called maritime spatial plans with the overall objective of achieving the sustainable use of marine resources. This Directive requires Member States to establish the maritime spatial plans as soon as possible, and at the latest by 31 March 2021. Several types of Projects within the maritime spatial plans, such as those concerning renewable energy development, oil and gas exploration and exploitation, maritime shipping and fishing activities, ecosystem and biodiversity conservation are all subject to the EIA and the Developer will have to ensure that they are in line with their respective maritime spatial plan objectives.

Several guidance documents have been written in relation to the assessment of environmental impacts of Projects in the marine environment, at the EU as well as national levels. Some are listed in the box below and are part of the list provided under the Annex to this Guidance Document on Other Relevant Guidance and Tools.

Box 19: Relevant Guidance documents

EU Guidance Documents

- Commission guidance on wind energy development in accordance with the Natura 2000

Other Guidance Documents

- OSPAR, Assessment of the Environmental Impact of Offshore Wind-farms
- RPS, Environmental impact assessment practical guidelines toolkit for marine fish farming
- EMEC, Environmental impact assessment (EIA) guidance for developers at the European Marine Energy Centre

A good practice example from Italy and Malta, involving the assessment of impacts on marine biodiversity as part of the EIA, is described in the box below.

Box 20: Minimising cable impact on marine ecosystem by Terna

Terna, the Italian electricity grid operator, has developed an innovative methodology for the installation of marine cables that minimises the environmental impact of submarine grid interconnections between Malta and Sicily and protects meadows of the rare sea grass 'Posidonia oceanica'.

The corridor foreseen for this cable crossed an area that is home to 'Posidonia oceanica', a seagrass that is declining (according to the RedList) and provides a habitat for many species. In order to protect the 'Posidonia oceanica' as well as other seabed species from harm, Terna refrained from the drilling technique most commonly used for marine cable installation.

[10] http://www.helcom.fi/baltic-sea-trends/data-maps/.

[11] Directive 2014/89/EU of the European Parliament and of the Council of 23 July 2014 establishing a framework for maritime spatial planning.

This technique would have involved the use of bentonite to lubricate and consolidate the sand around the drilling head, which could have potentially suffocated the 'Posidonia oceanica' due to the bentonite debris. The innovative solution applied used Xanthan gum, a polysaccharide sometimes employed as a food additive that can easily be biodegraded.

Good Practice of the Year 2016 award, [redacted]

1.3.5 Impacts related to the use of natural resources (depletion risks, resource use considerations)

Legislative requirements and key consideration on use of natural resources

Box 21: Directive 2011/92/EU as amended by Directive 2014/52/EU

Annex IV point 1(c)

Description of the project, including in particular:

- (c) a description of the main characteristics of the operational phase of the project (in particular any production process), for instance, energy demand and energy used, nature and quantity of the materials and natural resources (including water, land, soil and biodiversity) used;

Annex IV point 5(b)

A description of the likely significant effects of the project on the environment resulting from, inter alia:

- (b) the use of natural resources, in particular land, soil, water and biodiversity, considering as far as possible the sustainable availability of these resources;

Annex IV (1) and (5) requires the Developer to assess the use of natural resources and the impacts of the Project resulting from their use/depletion. In this context, the Directive requires the assessment to consider the sustainability of resources as far as possible, in particular land, soil, water, and biodiversity, as well as energy. The requirement for the assessment of a Project's impacts on the availability of natural resources is additional to the requirement to assess the impact on the resources — and a slightly different emphasis needs to be taken into account by Developers and practitioners. This emphasis reflects a shift in environmental policy focus from one of protecting natural resources — through assessing and mitigating impacts — to one of preserving the availability of natural resources for human activity. In this sense, assessments should also focus on the efficiency of resource use; can Projects do more with less in terms of energy use, water intake, land and soil use, etc.?

The integration of the use of natural resources into EIAs

The European Commission's Thematic Strategy on the Sustainable Use of Natural Resources (COM(2005) 670) has defined three types of indicators needed to measure resource efficiency:

- Resource use indicators

Indicators of resource use should inform not only on the quantities of resources extracted, but also their quality, abundance (e.g. renewable, non-renewable, exhaustible, non-exhaustible), availability and location.

- Environmental impact indicators

Resource use also impacts the environment and human health through a sequence of changes in the state of the_natural environment. Life Cycle Assessment (LCA) methodology provides a framework for describing environmental impacts. An LCA quantifies all of the physical exchanges with the environment, be they inputs (materials, water, land use, and energy) or outputs (waste and emissions to air, water, and soil). These inputs and outputs are then assessed in relation to specific environmental impact potentials (e.g. climate change, eutrophication, ecotoxicity). These so-called midpoint impacts can then, once more, be related to endpoint impacts such as human health, the natural environment, and natural resources (for full references to the European Commission, Assessment of resource efficiency indicators and targets see the Annex to this Guidance Document on Other Relevant Guidance and Tools).

- Socio-economic indicators

Indicators of socio-economic benefits are not just limited to the market value of resources, but also to those aspects of resource use related to well-being and to quality of life that are not measured within the economy.

Methodologies for the assessment of resource use and efficiency are fairly recent, and only a few documents providing details thereon are currently available. These are provided in the box below and are part of the list provided under the Annex to this Guidance Document on Other Relevant Guidance and Tools.

Box 22: Methodologies on the assessment of natural resources use

- European Commission. 2012. Life cycle indicators framework: development of life cycle based macro-level monitoring indicators for resources, products and waste for the EU-27. European Commission, Joint Research Centre, Institute for Environment and Sustainability
- Assessment of resource efficiency indicators and targets, Final report, European Commission, DG Environment, 19 June 2012
- Land and Ecosystem Accounting (LEAC), European Topic Centre Terrestrial Environment, LEAC methodological guide book, July 2005

1.3.6 Environmental factors: In a nutshell

- Article 3 of the EIA Directive provides the scope of environmental factors that should be assessed by the EIA. This list of environmental issues was broadened by the 2014 amendments to the Directive, by adding the following factors in particular: climate change – both mitigation and adaptation; risks of major accidents and disasters; biodiversity; and the use of natural resources;
- These factors sometimes require EIA practitioners to pay greater attention to issues of risk, uncertainty and resource use related to a Project than they may have previously – in some cases new assessment methods or techniques will be necessary;
- In addition to the guidance provided in this section, reference is made to a large number of initiatives, mostly at the EU-level, to further assist practitioners in their assessment. Practitioners are encouraged to make use of these tools, many of which are listed under the Annex to this Guidance Document on Other Relevant Guidance and Tools.

1.4 ASSESSING EFFECTS ON THE ENVIRONMENT

Article 3 requires that the EIA Report identify, describe, and assess significant effects. Section 1.3 above concerns the identification of the environmental factors likely to be impacted upon by the Project. This section focuses on the phrase 'significant effects'; that is, identifying which effects are to be considered and which are determined to have only a negligible effect on the environment. The concept of cumulative effects has also been included in this section, given that effects considered to be insignificant in isolation may have a significant impact on the environment when they interact with other effects.

1.4.1 Legal framework of significant effects

The EIA Directive stipulates that 'significant' effects must be considered when it comes to assessing the effects (or impacts) on the environment. The concept of significance considers whether or not a Project's impact could be determined to be unacceptable in its environmental and social contexts. The assessment of significance relies on informed, expert judgement about what is important, desirable or acceptable with regards to changes triggered by the Project in question.

This limits the assessment to those impacts that are likely to have a significant or important enough impact on the environment to merit the costs of assessment, review, and decision-making. While the concept of significant effects is referred to several times throughout the EIA Directive (see the box below), no clear definition is provided, and significance has to be assessed in light of the Project's specific circumstances. If Scoping has been carried out, the significance of effects may have been either indicated or, in some cases, already determined at the Scoping stage and, therefore, practitioners should refer to the Guidance Document on Scoping.

Box 23: Directive 2011/92/EU as amended by Directive 2014/52/EU

The phrase 'significant effect' is used throughout the Directive, in various contexts. The following extracts highlight only those relevant for understanding the phrase in the context of the EIA Report. References to cumulative effects have also been highlighted.

Article 1(1) of the Directive states that:
'This Directive shall apply to the assessment of the environmental effects of those public and private projects which are likely to have **significant effects** on the environment.'

Article 3(1) of the Directive states that:
'The environmental impact assessment shall identify, describe and assess in an appropriate manner, in the light of each individual case, the **direct and indirect significant effects** of a project on the following factors ….'

Article 5(1) of the Directive states that:
'where an environmental impact assessment is required, the developer shall prepare and submit an environmental impact assessment report. The information to be provided by the developer shall include at least:
(…)
(b) a description of the **likely significant effects** of the project on the environment
(c) a description of the features of the project and/or measures envisaged in order to avoid, prevent or reduce and, if possible, offset **likely significant adverse effects** on the environment;
(…)'

Annex IV point 5 to the Directive states that:
5. A description of the **likely significant effects** of the project on the environmental resulting from, inter alia:
(…)
(e) a **cumulation of effects** with other existing and/or approved projects, taking into account any existing environmental problems relating to areas of particular environmental importance likely to be affected or the use of natural resources;
(…)
The description of the **likely significant effects** on the factors specified in Article 3(1) should cover the **direct effects and any indirect, secondary, cumulative, transboundary, short-term, medium-term and long-term, permanent and temporary, positive and negative effects** of the project…'

As seen in the box above, the concept of significance is a core concept for the EIA Directive; it is one that, in essence, guides the EIA process. In addition to the present section, further information on this concept can be gathered from the Guidance Documents on Screening and Scoping.

1.4.2 Significance in the context of the preparation of the EIA Report

Those preparing the EIA Report may have to determine the significance of the effects of the Project upon the environment. This could be because Scoping was not undertaken earlier in the EIA process, or additional effects and/or data surface during the evolution of the EIA Report. In these instances, the assessment of significance should be based on clear and unambiguous criteria:

- Significance criteria take both the characteristics of an impact and the values associated with the environmental issues affected into account;
- Significance is always context-specific and tailored criteria should, thus, be developed for each Project and its settings.

Furthermore, the EIA Directive requires that significant effects be described in the EIA Report in an *appropriate manner* (Article 3 of the Directive), so that it ultimately allows for decision-making. For this reason, significance determinations must be substantiated: it is important that the assessors set out a transparent methodology that explains how they approach the assessment and that they then demonstrably apply that methodology in their assessment. The methodology should explain how the assessor deems whether or not a significant effect will occur, allowing others to see the weight attached to different factors and can understand the rationale of the assessment (see the box below).

Box 24: Methodological considerations on the assessment of significant effects in the EIA Report

As mentioned in the IEMA Special report:

'In order to provide justifiable results, EIA practitioners gather evidence to inform and explain the evaluation of an individual effect. Effective EIA practice ensures that the methods used are clearly explained in the environmental statement (now EIA Report) so that they can be readily understood by the stakeholders and the public consulted. The assessment's findings are regularly set out as different levels of significance (e.g. major, moderate, minor, etc.).

This approach is considered good practice: whilst recognising the inherent subjectivity of the assessment, it attempts to aid communication of the scale of the impact by introducing a classification. This approach also allows the practitioner to identify and discuss effects that some groups may consider significant, whilst others would not. For example, a negative landscape effect described as being of 'minor significance' might be considered to indicate that a majority of people would not consider the effect to be significant; however, a smaller group, perhaps within the local community, may disagree and consider the effect to be significant.'

IEMA special report: The State of Environmental Impact assessment practice in the UK

At the same time, significance determinations should not be the exclusive prerogative of 'experts' or 'specialists': significance should be defined in a way that reflects what is valued in the environment by regulators and by public and private stakeholders. A common approach used in EIA is the application of a multi-criteria analysis. Common criteria used to evaluate significance include the magnitude of the predicted effect and the sensitivity of the receiving environment:

- **Magnitude** considers the characteristics of the change (timing, scale, size, and duration of the impact) which would probably affect the target receptor as a result of the proposed Project;
- **Sensitivity** is understood as the sensitivity of the environmental receptor to change, including its capacity to accommodate the changes the Projects may bring about.

A LIFE + Project has developed a practical tool that uses the multi-criteria analysis to assess the most significant environmental impacts of various Projects and to illustrate the results thereof. This Project is detailed in the box below.

Box 25: IMPERIA project: improving environmental assessment by adopting good practices and tools of multi-criteria decision analysis

The aim of the IMPERIA Project was to collect good practices and to develop new methods and tools to enhance effective and good-quality impact assessments with transparent and clear reporting in the context of EIA and SEA.

The Project proposes the use of multi-criteria analysis methods to collect, organise and to present the possible impacts of developments and plans in a systematic, comprehensive and transparent way. The tools developed in IMPERIA enable the structured comparison of impacts affecting different objects, acting in different directions, and involving different scales.

The ARVI method is the key deliverable of the Project: it is an excel-based tool for impact significance assessment and for the comparison of Alternatives. It allows experts assessing different types of impacts to follow uniform principles and to report about the reasoning chains in an illustrative manner.

IMPERIA project: Improving Environmental Assessment by Adopting Good Practices and Tools of Multi-Criteria Decision Analysis

1.4.3 Cumulative effects

It is important to consider effects not in isolation, but together; that is, cumulatively. Data collected during this stage may indeed show that analysed impacts become significant when they are added together or with other effects. While the concept of cumulative effects ties in closely with significant effects, as seen in the legislation box above, Annex IV, point 5 (e) of the EIA Directive requires that the cumulation of effects with other existing and/or approved Projects are described in the EIA Report. Cumulative effects are changes to the environment that are caused by an action in combination with other actions. They can arise from:

- the interaction between all of the different Projects in the same area;
- the interaction between the various impacts within a single Project (while not expressly required by the EIA Directive, this has been clarified by the CJEU – see the box below).

The coexistence of impacts may increase or decrease their combined impact. Impacts that are considered to be insignificant, when assessed individually, may become significant when combined with other impacts. The box below provides clarification on these points, in light of case-law from the CJEU.

Box 26: Cumulative effects - useful interpretation from CJEU case-law

Interaction between different Projects in the same area:

- 'Not taking account of the cumulative effect of Projects means in practice that all Projects of a certain type may escape the obligation to carry out an assessment when, taken together, they are likely to have significant effects on the environment within the meaning of Article 2(1) of the Directive.' CJEU, C-392/06, *Commission v Ireland*.
- 'A national authority must examine [a Project's] potential impact jointly with other Projects. Moreover, where nothing is specified, that obligation is not restricted only to Projects of the same kind.' CJEU, C-531-13, *Marktgemeinde Straßwalchen and Others*.

Interaction between the various impacts within a single Project:

- 'The Court indicated as much for road Projects (CJEU, C-142/07, *Ecologistas en Accion-CODA*) as for transboundary Projects (CJEU, C-205/08, *Umweltanwalt von Kärnten*) that the whole Project should be considered: the division into fifteen sub-Projects of a road Project or the existence of a border splitting a power line Project in two sections does not mean the Project is below the threshold set by the Directive' (M.Clément, *Droit Européen de l'Environnement, Jurisprudence commentée*, 3ème edition 2016, p. 147-148).

Cumulative effects can occur at different temporal and spatial scales. The spatial scale can be local, regional or global, while the frequency or temporal scale includes past, present and future impacts on a specific environment or region.

Because of their complex nature, significance thresholds and criteria for the assessment of cumulative effects should be defined through a collaborative approach, involving all of the interested and affected parties in the process of data collection and analysis. They may also need to make greater use of interdisciplinary perspectives and methods: e.g. network diagrams and models that identify the cause-effect relationships which result in cumulative effects, trend analyses that identify historical, current and future trends for a given resource, and interactive matrices that consider the interactions of magnitude of the impacts assessed individually (for full reference to Lawrence D. (2005), Significance Criteria and Determination in Sustainability-Based Environmental Impact Assessment see the Annex to this Guidance Document on Other Relevant Guidance and Tools).

Box 27: In practice – 2014 amendments to the EIA Directive

The concept of significance is not a new concept for the EIA Directive; however, the use of the word is more noticeably present in the aftermath of the 2014 changes. In many instances, the addition of the word would have little impact for practitioners, as the effects identified and studied would have often been significant. However, it should be noted that:

- The 2014 amendments align the EIA Directive with the SEA Directive (Annex I(f) to the SEA Directive);
- Practitioners are dissuaded from using resources to investigate insignificant effects;
- Practitioners should make sure that they have grounds for determining significance, which can be defended if need be;
- The cumulation of effects is now specifically mentioned in a stand-alone paragraph, under Annex IV, point 5(e), in addition to being iterated in the list of Annex IV, point 5 last paragraph.

1.4.4 Assessing effects on the environment: In a nutshell

- Effects to be assessed in the EIA should be determined to be significant. This ensures that effort is not wasted on insignificant effects.
- Significance is covered in detail in the Guidance Document on Scoping, which should be read by anyone preparing an EIA Report who is forced to determine the significance of environmental effects.
- Practitioners should determine significance based on their own judgement, clearly stating their methodology and reasons for the conclusion. At the same time, there are various criteria available for use, including a multi-criteria analysis.
- When considering significance, the cumulative effects of all of the Projects in the area, both spatial and temporal, should be considered.

1.5 MANDATORY ASSESSMENT OF ALTERNATIVES

This section covers the selection, description, and assessment of the reasonable Alternatives required by the EIA Directive. Within the context of the EIA process, Alternatives are different ways of carrying out the Project in order to meet the agreed objective. Alternatives can take diverse forms and may range from minor adjustments to the Project, to a complete reimagining of the Project.

1.5.1 The notion of Alternatives

The identification of Alternatives to the Project is a long-standing requirement of the EIA Directive, but it is often mentioned by practitioners as comprising a difficult element of the EIA process. The consideration of Alternatives is an important part of the EIA process, which ought to be reflected in the effort and resources allocated to this part of the EIA process (see e.g. Jalava, K., et al., (2010) Quality of Environmental Impact Assessment, full references in the Annex to this Guidance Document on Other Relevant Guidance and Tools).

Identifying and considering Alternatives can provide a concrete opportunity to adjust the Project's design in order to minimise environmental impacts and, thus, to minimise the Project's significant effects on the environment. Additionally, the proper identification and consideration of Alternatives from the outset can reduce unnecessary delays in the EIA process, the adoption of the EIA decision, or the implementation of the Project.

The legal requirements of the EIA Directive, relating to the assessment of Alternatives, are presented in the box below.

Box 28: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1) states that the developer shall include at least:

- d) a description of the reasonable alternatives studied by the developer, which are relevant to the project and its specific characteristics, and an indication of the main reasons for the option chosen, taking into account the effects of the project on the environment;
- f) any additional information specified in Annex IV relevant to the specific characteristics of a particular project or type of project and to the environmental features likely to be affected.

Annex IV point 2 expands further:

2) A description of the reasonable alternatives (for example in terms of project design, technology, location, size and scale) studied by the developer, which are relevant to the proposed project and its specific characteristics, and an indication of the main reasons for selecting the chosen option, including a comparison of the environmental effects.

Put simply, the Developer needs to provide:

- A description of the reasonable Alternatives studied; and
- An indication of the main reasons for selecting the chosen option with regards to their environmental impacts.

The number of Alternatives to a proposed Project is, in theory, infinite, considering that the Directive does not specify how many Alternatives should be considered. National legislation or general practice may, however, dictate how many Alternatives are to be considered. The number of alternatives to be assessed has to be considered together with the type of alternatives, i.e. the 'Reasonable Alternatives' referred to by the Directive. 'Reasonable Alternatives' must be relevant to the proposed Project and its specific characteristics, and resources should only be spent assessing these Alternatives. In addition, the selection of Alternatives is limited in terms of feasibility. On the one hand, an Alternative should not be ruled out simply because it would cause inconvenience or cost to the Developer. At the same time, if an Alternative is very expensive or technically or legally difficult, it would be unreasonable to consider it to be a feasible Alternative.

Section 1.7 below expands further on Monitoring Measures, but if significant adverse effects can be avoided, prevented, reduced, or offset, it is likely that Monitoring Measures will be required. The costs of these Monitoring Measures should be considered, given that they may lead to the economic unfeasibility of the Project. In this regard, the costs of the Mitigation/Compensation Measures may also need to be considered.

Ultimately, Alternatives have to be able to accomplish the objectives of the Project in a satisfactory manner, and should also be feasible in terms of technical, economic, political and other relevant criteria. A brief checklist, highlighting key reasons why an Alternative might *not* be considered to be reasonable, is provided in the box below.

Box 29: An Alternative may be considered unreasonable/infeasible if:

- There are technological obstacles: high costs of a required technology may prevent it from being considered to be a viable option, or the lack of technological development may preclude certain options from consideration;
- There are budget obstacles: adequate resources are required to implement Project Alternatives;
- There are stakeholder obstacles: stakeholders opposed to a Project Alternative may make a particular option unattractive;
- There are legal or regulatory obstacles: regulatory instruments may be in place that limit/prohibit the development of a specific Alternative.

The feasibility of the Alternatives proposed can be determined on a case-by-case basis. The final set of reasonable Alternatives identified will then undergo a detailed description and assessment in the EIA Report.

Box 30: In practice – 2014 amendments to Alternatives

- In Article 5, the 'outline of the main Alternatives' has been replaced with a 'description of the reasonable Alternatives' studied by the Developer.
- Annex IV provides examples of the types of reasonable Alternatives (Project design, technology, location, size, and scale). Annex IV also requires a comparison of the environmental effects across the options as justification for selecting the chosen option, whereas previously the requirement was that such effects had to be 'taken into account'.

- Prior to 2014, 13 Member States[12] had already introduced a legal obligation to consider different types of Alternatives (including the 'do-nothing' scenario in some cases – see below).

1.5.2 Identifying Alternatives

This section further explains the types of Alternatives that should be identified and assessed in the EIA Report. It should be noted that each Project and each EIA is different, and there can be no definitive list prescribing how Alternatives are to be identified and assessed. Practices and legal requirements vary greatly between Member States, and practitioners should check these before beginning to consider Alternatives. In some cases, Alternatives will have been developed at the plan stage (e.g. a plan for the transport sector, a regional development plan, or a spatial plan) or by the Developer during the Project's initial design. In such cases, some Alternatives may have already been excluded, in which case, it would likely be unnecessary to consider them again. In other cases, the EIA practitioner may have to work out Alternatives or variants of Project components in order to mitigate significant environmental impacts that emerge during assessment. The process is iterative and requires some flexibility and good communication between all parties.

An open mind should be kept when considering the scope and nature of Alternatives. Indeed, depending on the Project at hand, Alternatives that should be considered may refer to the fundamental design of the Project itself, or may concern finer details, such as the technical specifications of the Project. In some cases, Alternatives to the type of Project should also be considered. It may even be the case that important Alternatives fall outside the expertise or remit of the Developer (i.e. that could not be implemented by the Developer). If relevant, these should not to be dismissed as being unreasonable from the outset.

The identification of Alternatives can be facilitated on the basis of information available at the planning level or the information received through the public consultation. If Project Alternatives have been explored in a plan or programme, practitioners should check SEAs and other environmental assessments undertaken in the near vicinity for similar Projects for Alternatives which may be relevant for the EIA. Public consultations can also help to identify reasonable Alternatives. Not only do the public concerned have local knowledge, which should be utilised, they may also give an indication of the reasonableness of an Alternative. Moving a bridge 15km downstream may increase environmental benefits, but if Developers have to fight or compensate commuters upset about an increased journey to work, then the Alternative may be deemed unreasonable.

However, Alternatives are to be identified and assessed both by the developer and the competent authorities and it is very important that the identification and consideration of Alternatives should not be treated as a mere formality.

Types of Alternatives to be considered

Annex IV to the Directive gives some examples of the types of Alternatives to be considered and which include:

- Project design;
- technology;
- location;
- size;
- scale.

[12] According to IA in 2012: Bulgaria, Denmark, Estonia, Finland, Germany Greece, Italy, Netherlands, Poland, Romania, Slovakia, Spain.

This list serves as inspiration for a multitude of other Alternatives. These roughly relate to the categories above. Some such Alternatives are listed below:

- the nature of Project;
- timeframes for construction or the lifespan of the Project;
- process by which the Project is constructed;
- equipment used either in the construction or running of the Project;
- site layout (e.g. location of buildings, waste disposal, access roads);
- operating conditions (e.g. working schedule, timing of emissions);
- physical appearance and design of buildings, including the materials to be used;
- means of access, including principal mode of transport to be used to gain access to the Project.

The Competent Authority in charge of the Scoping phase may already have highlighted, if not required, the consideration of certain Alternatives during the preparation of the EIA Report (see the Guidance Document on Scoping). As highlighted in the example below, a number of Alternatives can be indicated during the Scoping phase. A number of reasons may lie behind these choices, including the key EIA concepts of significant effects and reasonableness.

Box 31: Examples of Alternatives identified and considered in the construction of a power line in Portugal

The Project concerned the construction of a power line crossing the Alto Douro Wine Region (UNESCO World Heritage). During the Scoping phase several points were identified:

- Aerial vs. underground lines;
- 400 kV vs. 220 kV line capacity;
- 6 possible points of connection to the national grid, and 9 different routes were indicated.

1.5.3 Assessing Alternatives

Methods for assessing Alternatives

The EIA Directive requires that Developers provide the main reasons for selecting the option chosen. This means that the resources should not be spent on an intricate explanation; however, the reasons should be transparent.

The method for assessing Alternatives will depend on the type of Alternatives; the only requirement in the EIA Directive is a comparison of the environmental effects (Annex IV to the EIA Directive). However, Developers should be flexible during the assessment of Alternatives. During the assessment, one preferred Alternative may transpire to be 'unreasonable'; in other cases, one Alternative may inspire other Alternatives. The level of detail concerning the description of the environmental effects of the Alternatives may be less than for the chosen option. Nevertheless, the aim of the exercise is to provide a transparent and well justified comparison.

Local knowledge and interests are also very important during the assessment of Alternatives and, therefore, dialogues with the public concerned on Alternatives are encouraged where appropriate. In certain situations, this may already be required by other permitting processes parallel to the EIA (e.g. when deciding on an electricity line's route planning, national law may mandate for dialogue with land-owners in addition to organising public consultations as part of the EIA). In addition, after the EIA Report has been drafted (see section B.3.) during public consultations ensuring the public is aware that Alternatives have been considered, and providing clear reasons why the final choice was made, increases transparency. Ensuring early participation with the public concerned on Alternatives is a good practice that could not only save resources, but also reduce delays as a result of challenges arising from the public or other organisations/authorities.

Assessing the 'do-nothing' scenario

The 'do-nothing' scenario or 'no Project' Alternative describes what would happen should the Project not be implemented at all. In some Member States, national legislation requires the 'do-nothing' scenario to be considered and included in the EIA Report. In some cases, however, the 'do-nothing' scenario cannot be considered a feasible policy option, as a Project is very clearly needed: for example, if another policy dictates an action, such as a waste management plan, which requires improved waste management, then a new plant must be built.

The 'do-nothing' scenario is heavily based on the Baseline. Therefore, the section of this Guidance Document on developing the Baseline should be consulted, in order to ensure a solid foundation for the 'do-nothing' scenario.

1.5.4 Mandatory assessment of Alternatives: In a nutshell

- The EIA Directive requires Developers to describe the reasonable Alternatives that have been identified and studied and to compare their environmental impacts against the Project option chosen. This is an important aspect of the EIA Report and one that often challenges practitioners and Developers. Alternatives have to be 'reasonable', meaning that feasible Project options meet the Project's objectives.
- The 2014 amendments to the Directive now require the EIA Report to include a description of the reasonable Alternatives (as opposed to an 'outline') studied by the developer who holds the pen. They also suggest types of Alternatives, such as Project design, technology, location, size, and scale.
- The approach to identifying Alternatives is highly Project-specific. Some Alternatives are overarching and may be identified in plans and programmes (e.g. transport plans or regional development programmes) or by the Competent Authority at the EIA Scoping stage. Others might concern the technical design and are identified by the Developer. In cases, EIA practitioners may identify Alternatives and propose them to the Developer. The process of identifying and assessing Alternatives is iterative and requires some flexibility and good communication between all parties.
- Consultation with the public is usually very important both for identifying and assessing Alternatives. A clear presentation of Alternatives, and how they have been assessed, also lends transparency to the process and can improve public acceptance and support for Projects.
- The environmental assessment of Alternatives should be targeted and focused on the comparison of impacts between several options and presented as such in the EIA Report.

1.6 MITIGATION AND COMPENSATION MEASURES

Measures envisaged to avoid, prevent, reduce or, if possible, offset any identified significant adverse effects on the environment are described in the EIA Report. These measures are commonly referred to as 'Mitigation Measures', with the exception of the last action, offsetting, which can be considered to be a Compensation Measure. The box below sets out the legislative requirements.

Box 32: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1) of the Directive states that:
'(...) the developer shall include at least:

- (c) a description of the features of the project and/or measures envisaged in order to avoid, prevent or reduce and, if possible, offset likely significant adverse effects on the environment;'

Annex IV point 7 states that:
'A description of the measures envisaged to avoid, prevent, reduce, or if possible, offset any identified significant adverse effects on the environment and, where appropriate, of any proposed monitoring arrangements (for

example the preparing of a post-project analysis). That description should explain the extent, to which significant adverse effects on the environment are avoided, prevented, reduced or offset, and should cover by the construction and operational phases.'

In addition to the legislative requirements, Recital 35 of the 2014 Directive amending the EIA Directive references 'mitigation and compensation measures', noting that such measures should be appropriately monitored.

Box 33: In practice – 2014 amendments to the measures to mitigate and compensate

- In Article 5, the actions 'prevent' and 'offset' have been added.
- Annex IV point 7 now includes 'avoid' (although 'prevent' is not new to Annex IV).
- Annex IV also includes the new provision to provide Monitoring Measures, and a description explaining the extent to which significant adverse effects on the environment are avoided, prevented, reduce or offset, specifically referencing that these apply to both the construction and operational phases.

When considering Alternatives, such Mitigation Measures might influence how Alternatives are assessed. For example, an Alternative might be considered unfeasible until a Developer factors in a Mitigation or Compensation Measure that reduces the impact of the Alternative. In addition, by considering Mitigation Measures when considering all Alternatives, even feasible Alternatives may benefit from a more environmentally sound Project design, ultimately ensuring a high level of environmental protection.

Different types of Mitigation Measures act in different ways to reduce adverse impacts:

Box 34: Types of Mitigation Measures

Type of measure	How it works
Measures to prevent	Impact avoidance by: - Changing means or techniques, not undertaking certain Projects or components that could result in adverse impacts. - Changing the site, avoiding areas that are environmentally sensitive. - Putting in place preventative measures to stop adverse effects from occurring.
Measures to reduce	Impact minimisation by: - Scaling down or relocating the Project. - Redesign elements of the Project. - Using a different technology. - Taking supplementary measures to reduce the impacts either at the source or at the receptor (such as noise barriers, waste gas treatment, type of road surface).
Measures to offset	Offset or compensate for residual adverse impacts that cannot be avoided or further reduced in one area with improvements elsewhere with: - Site remediation / rehabilitation / restoration. - Resettlement. - Monetary compensation.

For the purposes of the Directive, in accordance with the precautionary and preventive action principle, a long-term approach should be promoted, and priority should be given to avoiding impacts (prevention measures), while remediation and Compensatory Measures should only be considered as a last resort.

Mitigation and Compensation Measures are assessed on the basis of how effective they are in reducing potentially significant adverse environmental impacts. In some cases, existing legislation (e.g. the IED - see the Annex to this Guidance Document on Other Relevant Guidance and Tools), refers to the use of best available techniques, as set out in reference documents, in order to ensure that operators use the latest, most effective and economically justified technology to protect the environment. From this perspective, best available techniques can provide a very reliable starting place for Developers to identify risk management approaches and technologies that may be in turn be suggested as Mitigation Measures in an EIA Report. The EIA Report should clearly describe the adverse impact each measure is intended to avoid, mitigate or compensate when implemented. It should also describe the effectiveness of such measures, their reliability and certainty, as well as the commitment to ensuring their practical implementation and monitoring of the results.

1.6.1 Mitigation and Compensation Measures: In a nutshell

- Mitigation and Compensation Measures should be considered when assessing Alternatives, both with a view to strengthening the feasibility of Projects, and to improving the Project's design.
- Both Mitigation and Compensation Measures may be costly, and may influence the choice of Alternatives
- Mitigation and Compensation Measures may apply to both the construction and operational phases of the Project.
- A description of Mitigation and Compensation Measures for significant adverse effects must be incorporated in the decision to grant Development Consent for a Project (see section 3.2. on 'Decision-making: Reasoned Conclusion and Development Consent' of this Guidance Document).

1.7 MONITORING

This section covers the legislative requirements of the EIA Directive to ensure that adequate Monitoring Measures are in place, both during the construction and operational phases of the Project. It also sets out some guidelines to help practitioners to identify possible Monitoring Measures.

1.7.1 Legislative requirements for EIA monitoring

Monitoring Measures must be incorporated in the Development Consent for a Project if the Project is likely to have significant adverse effects (see the section on decision-making below). Monitoring Measures are, therefore, referred to in Article 8a of the EIA Directive, which outlines the information to be incorporated in the Development Consent, and the Monitoring Measures proposed (if appropriate) should be included in the EIA Report. The description of Monitoring Measures is linked to the description of measures proposed to mitigate significant adverse effects on the environment and should be directly linked to ensuring these measures are carried out successfully.

Monitoring Measures may be developed directly for the Project in question, or may arise from other requirements – EU or national legislation governing the operation of a Project, funding requirements or other sources. It is important – and a requirement of the Directive – that there is no duplication or inconsistency of effort in monitoring. With a view to avoiding duplication, if Monitoring Measures stem from other EU or national legislation, then this should be reflected in the EIA Report so as to inform the Competent Authority. The Competent Authority may then decide to use these existing measures if appropriate (Article 8a (4) 3rd paragraph). Indeed, the 2012 Impact Assessment for the review of the EIA Directive estimated that 50% of Projects developed each year would fall under other EU legislation requiring monitoring, and thus monitoring would be carried out regardless of EIA requirements.

The relevant requirements of the EIA Directive are given in the box below.

Box 35: Directive 2011/92/EU as amended by Directive 2014/52/EU

Annex IV point 7 on the information referred to in Article 5(1) sets out the information for the EIA Report and includes:

- (7) A description of the measures envisaged to avoid, prevent, reduce or, if possible, offset any identified significant adverse effects on the environment and, where appropriate, of any proposed monitoring arrangements (for example the preparation of a post-project analysis). That description should explain the extent, to which significant adverse effects on the environment are avoided, prevented, reduced or offset, and should cover both the construction and operational phases.

As the proposed monitoring measures mentioned above are used to develop the final measures issued with the development consent, Article 8a is also relevant. This Article states:

- (1) The decision to grant development consent shall incorporate at least the following information: [….]
  (b) any environmental conditions attached to the decision, a description of any features of the project and/or measures envisaged to avoid, prevent or reduce and, if possible, offset significant adverse effects on the environment as well as, where appropriate, monitoring measures.

In addition, Article 8a also states:

- (4) In accordance with the requirements referred to in paragraph 1(b), Member States shall ensure that the features of the project and/or measures envisaged to avoid, prevent or reduce and, if possible, offset significant adverse effects on the environment are implemented by the developer, and shall determine the procedures regarding the monitoring of significant adverse effects on the environment.

  The type of parameters to be monitored and the duration of the monitoring shall be proportionate to the nature, location and size of the project and the significance of its effects on the environment.

  Existing monitoring arrangements resulting from Union legislation other than this Directive and from national legislation may be used if appropriate, with a view to avoiding duplication of monitoring.

Monitoring is also referenced in Recital 35[13] of the 2014 Directive amending the EIA Directive. Although it is not legally binding, it explains the intent of the Directive on monitoring, emphasising the need for the results of the EIA to be implemented in practice, and for procedures to be put in place to ensure that this is the case.

The 2014 amendments to the Directive have strengthened the requirements for monitoring in both the EIA Report and the Development Consent. A summary is given in the box below.

Box 36: In practice – 2014 amendments to measures to monitor

- Monitoring of significant adverse effects on the environment and/or measures taken to mitigate them is now required (where appropriate) when issuing Development Consent.
- Monitoring arrangements may be required by other EU legislation and, therefore, monitoring carried out under the EIA Directive should not result in duplication.
- Monitoring arrangements have to be examined, where appropriate, during the preparation of the EIA Report and are to be included in the EIA Report.

---

[13] Recital 35 of the 2014 Directive amending the EIA Directive: 'Member States should ensure that mitigation and compensation measures are implemented, and that appropriate procedures are determined regarding the monitoring of significant adverse effects on the environment resulting from the construction and operation of a project, inter alia, to identify unforeseen significant adverse effects, in order to be able to undertake appropriate remedial action. Such monitoring should not duplicate or add to monitoring required pursuant to Union legislation other than this Directive and to national legislation'.

1.7.2 Objectives of Monitoring Measures

The monitoring requirements can help ensure:

- Significant adverse impacts from the construction and operation of Projects do not exceed impacts Projected in the EIA Report and that measures taken to offset such impacts are carried out as planned;
- the methods with which significant adverse effects can be assessed for robustness. This can help to improve the identification of impacts in future EIA Reports;
- the EIA is in line with other EU legislation, especially the SEA Directive[14].

These three points are examined below in turn.

Monitoring ensures the Project meets predicted impacts

The EIA Directive aims to reduce Projects' significant adverse effects on the environment, as much as possible; however, some Projects cannot be implemented without significant impacts on the environment. During the EIA process, such impacts are not only identified, but their evolution is also forecasted. The systematic ex-post impact monitoring of adverse significant effects, resulting from the Project, offers an opportunity to identify if forecasted impacts are not developing as predicted, so that steps may be taken for rectification. This monitoring also tracks the effectiveness of measures set in place to mitigate or to compensate for significant effects. Monitoring also allows for additional or unforeseen relevant information to be taken into account, climate change or cumulative impacts for example, again allowing for remedial action.

Assessment for future EIAs

In addition to evaluating the impacts of a Project, ex-post Project monitoring can also shed light on the effectiveness of the EIA procedure, with regards to the quality of the data used and the accuracy of the approaches and methods. This can improve the transparency, legitimacy, and effectiveness of the EIA process, especially if documented evidence of the actual environmental impacts of a Project is publicly available.

Other EU legislation

The SEA Directive, IED, and WFD all require ex-post monitoring, and the Habitats Directive recommends monitoring, after an Appropriate Assessment, to be a good practice (more information about these other EU instruments can be found in the Annex to this Guidance Document on Links with Other EU Instruments). The MSFD also requires Member States to establish and implement coordinated monitoring programmes for the ongoing assessment of the environmental status of their marine waters. Further consideration of these Directives, as well as associated EU, or national-level, guidance documents should be carried out, not only as a means to avoid duplication when a Project falls under more than one Directive, but also as a baseline upon which to develop guidance on ex-post EIA monitoring. In more practical terms, monitoring should not duplicate the monitoring carried out under other assessments; therefore, practitioners should make themselves aware of other such arrangements.

The European Commission already had the opportunity to publish a guidance document on streamlining environmental assessments, including monitoring. Information from this document is

[14] For more information on the importance and utility of EIA follow-up, please refer to Morrison-Saunders A., R. Marshall and J. Arts 2007 EIA Follow-Up International Best Practice Principles. Special Publication Series No. 6. Fargo, USA: International Association for Impact Assessment.

relevant and a selection from which is presented in the box below.

Box 37: Monitoring requirements for other EU environmental legislation	
Appropriate assessment (Habitats Directive)	■ Monitoring is considered good practice. ■ In particular, the monitoring of Mitigation or Compensation Measures will help to ensure effectiveness (either ensuring that there are no adverse effects on the integrity of the site or by maintaining network coherence).
SEA	■ Member States monitor the significant environmental effects of the implementation of plans and programmes to identify at an early stage unforeseen adverse effects, and to be able to undertake appropriate remedial action (Article 10(1)). ■ The EIA Report shall include 'a description of the measures envisaged concerning monitoring' (Annex I (i)). ■ Monitoring allows the actual significant environmental effects of implementing the plan or programme to be tested against those predicted. Any problems that arise during implementation, whether they have been foreseen or not, can be identified and future predictions can be made more accurately. ■ Monitoring can be integral in compiling baseline information for future plans and programmes, and in preparing information which will be needed for EIAs of Projects.
IED	■ Member States shall take the necessary measures to ensure that the Competent Authority periodically reconsiders all permit conditions and, where necessary to ensure compliance with the IED Directive, updates those conditions. ■ If the Competent Authority so requests it, the operator shall submit all information necessary for reconsidering the permit conditions, including, in particular, results of emission monitoring and other data, that enables a comparison of the operation of the installation with the best available techniques and with the emission levels associated with the best available techniques (Article 21 (1)-(2)). ■ Member States shall ensure that the monitoring of air polluting substances is carried out (Article 38). The monitoring of the emissions is prescribed in Article 48, Article 60, Article 70, and it depends on the type of the installations.
WFD	■ The WFD includes the requirement to establish monitoring programmes for the monitoring of water status in order to establish a coherent and comprehensive overview of water status within each river basin district (Article 8 and Annex V).
Extracts from: European Commission, 2016, Commission guidance document on streamlining environmental assessments conducted under Article 2(3) of the EIA Directive, OJ C 273/1, 27.07.2016	

1.7.3 Developing Monitoring Measures

Developing monitoring indicators is an essential first step for any monitoring activity. These indicators are highly dependent upon the type of Project concerned; however, consultation of the Baseline (see the section concerning the Baseline) may guide Developers in identifying the right indicators. In addition, some indicators, water and air for example, may come from EU legislation such as the WFD and the IED.

Taking the legislative requirements outlined in this section into account, as well as Recital 35, Monitoring Measures could:

- Make sure that the significant effects identified develop as predicted;
- Ensure that the measures in place to mitigate and compensate significant adverse effects are carried out;
- Identify unpredicted significant adverse effects.

The types and number of environmental parameters to monitor, and the monitoring frequency, are very Project-specific, and need to be proportionate to the Project's relevant parameters. The Directive provides some suggestions on these in Article 8a(4): the 'nature, location and size of the Project and the significance of its effects on the environment'. In essence, this means that the time, effort, and costs put into Monitoring Measures should be justified by how important the potential environmental impacts will be, as well as the complexity of any Mitigation and Compensation Measures recommended in the EIA Report to avoid, prevent, reduce or to offset effects. The cost of monitoring can indeed be a decisive factor when considering not only the Alternatives (as mentioned above), but also when developing Monitoring Measures. Other parameters, such as the sensitivity of the local environment, the number and type of affected stakeholders, and the level of uncertainty regarding the assumptions and Projections made in the assessment itself should also be taken into account.

Monitoring data collection and evaluation activities should be frequent enough so that the information generated is still relevant, but not so frequent as to be a burden to those implementing the process. Monitoring need not be difficult or overly technical, and could even be as simple as a photo taken from the same vantage point over time, if such a photo clearly documents the relevant indicator.

The EIA Directive does not specify how to carry out monitoring, who should do it or how monitoring results should be analysed and used. Below are some more practical suggestions that Developers and practitioners can take into account when designing Monitoring Measures as part of the EIA Report.

- Monitoring Measures should be detailed enough to allow for proper implementation – the parameters, frequency, methods, responsibilities, and resources should be identified in advance.
- Authorities issuing the Development Consent should be satisfied that monitoring results will be evaluated by relevant authorities, naming such authority if relevant (this could be done via random inspection). Rather than carrying out monitoring individually for each Project, measures could be coordinated at higher level (depending on the Projects this may take place in a variety of different fora such as municipal plans, via an SEA, or more informally). The section on Baseline recommends developing a database to reduce the time spent on extensive field surveys and to facilitate future environmental assessments for similar Projects. Such a database would also be closely linked to monitoring results from ongoing Projects.
- Discussions with authorities and communities during the Scoping stage would help identify issues requiring monitoring. This can also build trust and partnerships that may become valuable when collecting data for monitoring.
- To the extent that it is reasonable, Monitoring Measures should have the capacity to identify any unforeseeable adverse effects, meaning that they should take the state of the affected environment, as well as the specific impacts (e.g. emissions, resource use) generated by the Project, into account.
- Monitoring results should be made available to the Competent Authorities and to the public.

Box 38: Examples of Monitoring Measures

The French 'Grenelle 2' law, n°2010-788 of 12 July 2010 introduced a requirement for EIAs to include a description of how the effectiveness of the main preventing/mitigating/offsetting measures would be monitored; it also introduced the possibility for Developers to be inspected in order to check that such measures have actually been implemented (cf. 2012 IA).

A good practice example, recommended by the European Commission Guidance Document on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (see the Annex to this Guidance Document on Other Relevant Guidance and Tools), involves the ex post monitoring programme established for wind farm developments in the North Sea. In the Belgian part of the North Sea, several areas within a specifically designated zone have been given in concession to wind farm operators. The Belgian Competent Authority has set up a joint monitoring programme that is financed by the wind farms in operation, given that it is not efficient to require each wind farm operator to run a similar ex-post monitoring programme independently.

1.7.4 Monitoring: In a nutshell

- Monitoring Measures for Projects with significant adverse effects must be incorporated in the decision to grant Development Consent for a Project and, as such, should generally be included in the EIA Report. Monitoring Measures may be linked to other legal requirements, such as those stemming from the IED, WFD or the Habitats Directive. Care must be taken to avoid duplication in Monitoring Measures in this regard. Requirements on Monitoring Measures were added to the EIA Directive as part of the 2014 amendments (Article 8a and Annex IV).
- Generally, Monitoring Measures can help to ensure that Projects meet all existing environmental legal requirements, and that impacts are in line with EIA Report Projections. They should also ensure that any Mitigation or Compensation Measures for expected significant effects are carried out as planned.
- Monitoring Measures can also provide insight into the quality of the EIA procedure carried out, and can generate lessons learned and good practices for future EIAs.
- Practitioners should first check which Monitoring Measures are required by other legislation. If these are not sufficient or appropriate for monitoring the expected environmental impacts or proposed Mitigation Measures, then additional measures may be proposed within the EIA Report. Monitoring Measures should always strive to be proportionate to the nature of the environmental impacts in terms of the time, costs, and other resources involved.
- Monitoring Measures should be specific and detailed enough to ensure their implementation, including defining roles, responsibilities, and resources. In some cases, economies of scale can be achieved through the joint monitoring of related Projects. Measures should also be capable of identifying important unforeseen effects

2 QUALITY OF THE EIA REPORT

This section covers the quality of the EIA Report. It addresses the format and presentation of the EIA Report, and the more recent requirements concerning the competence of the experts involved in preparing and reviewing the EIA Report.

2.1 FORMAT AND PRESENTATION OF THE EIA REPORT

The main aim of an EIA Report is to provide prudent information for two types of audiences – decision-makers and people potentially affected by a Project. The Report, therefore, must communicate effectively with these audiences.

2.1.1 The qualities of a good EIA Report

To this end, Article 3(1) of the EIA Directive requires that significant effects be identified, assessed and described in an 'appropriate manner'. Article 5(1) sets the form – the information should be presented in an EIA Report that enables stakeholders and authorities to form opinions and to take decisions regarding the proposed Project. While there are no formal requirements concerning the format and the presentation of the report, it is recommended that the EIA Report clearly sets out the methodological considerations and the reasoning behind the identification and assessment of significant effects, so that others can see the weight attached to different factors and can understand the rationale of the assessment.

The box below provides some of the main characteristics that a good EIA Report should have to meet this objective.

Box 39: The qualities of a good EIA Report

- A clear structure with a logical sequence that describes, for example, existing Baseline conditions, predicted impacts (nature, extent and magnitude), scope for mitigation, proposed Mitigation/Compensation Measures, significance of unavoidable/residual impacts for each environmental factor;
- A table of contents at the beginning of the document;
- A description of the Development Consent procedure and how EIA fits within it;
- Reads as a single document with appropriate cross-referencing;
- Is concise, comprehensive and objective;
- Is written in an impartial manner without bias;
- Includes a full description and comparison of the Alternatives studied;
- Makes effective use of diagrams, illustrations, photographs and other graphics to support the text;
- Uses consistent terminology with a glossary;
- References all information sources used;
- Has a clear explanation of complex issues;
- Contains a good description of the methods used for the studies of each environmental factor;
- Covers each environmental factor in a way which is proportionate to its importance;
- Provides evidence of effective consultations (if some consultations have already taken place)
- Provides basis for effective consultations to come;
- Makes a commitment to mitigation (with a programme) and to monitoring;
- Contains a Non-Technical Summary which does not contain technical jargon;
- Contains, where relevant, a reference list detailing the sources used for the description and assessments included in the report.

2.1.2 The Non-Technical Summary

As can be seen in the box above, Article 5(1)(e) of the EIA Directive requires Developers to include a Non-Technical Summary of the EIA Report. This obligation is reiterated under Annex IV, point 9.

Box 40: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(1)

1. Where an environmental impact assessment is required, the developer shall prepare and submit an environmental impact assessment report. The information to be provided by the developer shall include at least:

- (e) a non-technical summary of the information referred to in points (a) to (d);

Annex IV point 9

9. A non-technical summary of the information provided under points 1 to 8.

The contents of that summary are broad: Article 5(1) lists points (a) to (d) which includes almost all of the elements listed under Article 5(1), while Annex IV point 9 lists points 1 to 8, again almost all of the elements included in this Annex. This summary is, therefore, broadly encompassing as it needs to include the description of the Project, the significant effects, Mitigation Measures, Monitoring Measures, the Baseline, and reasonable Alternatives, as well as the methods used for the assessment including explanations on any hurdles encountered during the analysis. This indicates that the Non-Technical Summary ought to be more than just a few pages long. However, it should be borne in mind that it is a summary and needs to be concise and engaging enough to enable stakeholders and the public to get a proper sense of the key issues at stake and the proposed way forward. Depending on the Project, and the degree of complexity of the environmental issues involved, a Non-Technical Summary of 10 to 30 pages in length is generally considered to be good practice.

Moreover, the term ‘non-technical’ indicates that this summary should not include technical jargon. It should be understandable to someone who does not have a background in the environment or in-depth knowledge of the Project, and should be easily identifiable within the EIA Report –provided either at the very beginning or at the very end of the document.

EIA Report authors may also consider providing context about the methodology for carrying out the EIA, highlighting any significant uncertainties about the outcomes. It may also be useful to describe the Development Consent process for the Project, and the role of the EIA in this process, to help lay members of the public to understand the context for the EIA.

The box below summarises elements that are typically found in a good Non-Technical Summary for an EIA Report. These points are further reiterated in the checklist under Part C.

Box 41: The qualities of a good Non-Technical Summary

- The Non-Technical Summary is easily identifiable and is accessible within the EIA Report;
- The Non-Technical Summary provides a concise, but comprehensive description of the Project, its environment, the effects of the Project on the environment, the proposed Mitigation Measures, and the proposed monitoring arrangements;
- The Non-Technical Summary highlights any significant uncertainties about the Project and its environmental effects;
- The Non-Technical Summary explains the Development Consent process for the Project and the role of the EIA in that process;
- The Non-Technical Summary provides an overview of the approach to the assessment;
- The Non-Technical Summary is written in non-technical language, avoiding technical terms, detailed data and scientific discussion;
- The Non-Technical Summary is comprehensible to a lay member of the public.

2.2 THE COMPETENCE OF EXPERTISE AND QUALITY CONTROL

2.2.1 Legal requirements

The effectiveness of the EIA procedure relies upon high-quality EIA Reports that can be properly reviewed and evaluated by competent experts and which can contribute to sound decision-making. In order for this to be possible, the competent experts must be involved in both the preparation and in the review of the EIA Report.

A high-quality EIA Report must be prepared by competent experts, experts who understand the relevant legislation and technical parameters involved in carrying out an effective assessment and in the preparation of a high-quality report. In turn, the Competent Authority responsible for evaluating the report must have access to sufficient expertise to judge its quality and request revisions as appropriate. This section covers the legislative requirements and changes in place to ensure the quality of the experts and those reviewing the EIA.

Article 5(3) of the EIA Directive refers to the quality of the expertise used to carry out the EIA report and the need for sufficient information in order for the Competent Authority to reach a conclusion about the Project's effects on the environment. The text is given in the box below.

Box 42: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 5(3)

In order to ensure the completeness and quality of the environmental impact assessment report:

- (a) the developer shall ensure that the environmental impact assessment report is prepared by competent experts;
- (b) the competent authority shall ensure that it has, or has access as necessary to, sufficient expertise to examine the environmental impact assessment report; and
- (c) where necessary, the competent authority shall seek supplementary information from the developer, in accordance with Annex IV, which is directly relevant to reaching the reasoned conclusion on the project's significant effects on the environment.

In short, the Directive requires the following:

- the Developer needs to ensure the quality of the experts who prepare the EIA Report;
- the Competent Authority needs to ensure that it has access to the necessary expertise to review and to evaluate the EIA Report; and
- the Competent Authority must be able to request more information, where relevant, from the Developer.

These three aspects are discussed in greater detail in the following sections.

2.2.2 Experts used by Developers

This section examines how experts, used by a Developer to prepare EIA Reports, can be considered to be competent and looks at the different systems used in Member States to ascertain the competence of EIA experts.

Defining 'competent experts' (Developers)

It is important that Developers understand the concept of 'competence', with regards to experts preparing the EIA Report. The EIA Directive does not go into detail, requiring that experts be for instance external consultants instead of in-house experts, rather the Directive simply requires that experts be competent, leaving it up to the interpretation by the Member States concerned.

The original approach proposed during the 2012 review of the EIA Directive was to include the phrase '**accredited** experts' in the amended Directive. Neither the words 'accredited' nor 'qualified' can be found in the operative provisions of the Directive; however, the latter term is included in Recital 33 of the 2014 Directive amending the EIA Directive: '[e]xperts involved in the preparation of environmental impact assessment reports should be qualified and competent…'. The non-specific requirement allows for greater flexibility for the Member States who can choose to establish an accreditation system, increase transparency, or can set out how to define how competences can be measured.

The box below stresses the recent changes brought about by the 2014 amendments relating to the competency of experts.

Box 43: In practice – 2014 amendments to the competency of experts

In most cases, the changes will not have much effect on those carrying out the EIA:

- At least 14 Member States already use accredited consultants;
- A large majority of Developers already hire specialist consultants who can be considered to be competent.

The new provisions provide a more formal check on the EIA Report:

- Experts must be proven to be competent, especially if the EIA is contested afterwards;
- Developers need to consider more seriously how they demonstrate the competence of those who prepare the EIA Report, and look to external expertise where required even if the costs incurred are higher.

Finding competent experts (Developer)

Different approaches to ensuring the competence of the experts engaged by Developers to prepare EIA Reports can be taken. Some of the examples listed directly below are discussed in greater detail in this section:

- Developers use a centralised list/standardised qualification to determine competence;
- Developers use experts from recognised institutions;
- Developers use experience of practitioners as a measure of competence;
- Developers use a more flexible approach, where transparency allows competence to be scrutinised easily.

These approaches to verifying competence can be used in isolation; however, a combination of these approaches can also be used. For instance, a list of accredited experts may be used and experts are then picked from that list on the basis of their experience or institutional affiliation. Choosing between one or several of the different approaches is important, and careful consideration should be given in implementing different approaches, as seen in the box below.

Box 44: Examples of the different approaches used in Poland to determine competent experts since the 1980s

Poland has employed several approaches to determine 'competent experts' since the 1980s (N.B. a form of EIA was undertaken early on in this country, before to their accession to the EU).

- A system of listing 'qualified' experts was set up, but in practice it did not work as expected and ended up being considered to be counterproductive. In addition, the list was set up at the national level, whereas most EIAs are done at a regional, decentralised level. The approach was, subsequently, abandoned.
- In Poland, the National Environmental Impact Assessment Commission has been functioning for years. It is an opinion-giving and advisory body of the General Director for Environmental Protection. The main task of the

- National Commission is to provide opinions on complex EIA matters and cases. There are also Regional EIA Committees, which act as advisory bodies for regional directors for environmental protection. The EIA Commission also takes part in proceedings where there are complex environmental issues.
- More recently, a more flexible approach has been adopted. National legislation sets criteria for experts requiring higher education (in various relevant fields including ecology, biology, etc.) and five years of proven experience doing EIAs under the supervision of more senior experts. Transparency also plays a considerable role, given that all of the Reports are to be made publicly available and in a formal register where anyone can challenge the study's accuracy (either formally or through public scrutiny).

Many Member States do have such approaches in place that allow for the discovery of EIA experts and to verify their competence. Developers hiring these experts should, therefore, check whether these accreditation systems are available to help them to ensure that any external experts they employ for the preparation of the EIA Reports have been duly certified. It should be noted that what makes an expert 'qualified' or indeed 'competent' may vary between different Member States.

- Qualification and/or centralised list

This approach requires experts who wish to prepare EIA Reports to undertake specialist training, either through a university or through another standardised provider, in order to ensure that they have the necessary skills. Once qualified through this procedure, experts can then join a central list held at the national or local levels or by the Developers themselves.

Box 45: Benefits and drawbacks of accreditation and listing

Benefits	Drawbacks
■ Experts have same minimum level of knowledge as peers; ■ Suitability checked using application criteria; ■ Developers can easily find suitable experts; ■ Added transparency to the process of selecting experts.	■ Limits the use of specialist experts not on the list; ■ False sense of security (especially where there is no way to check previous performance or no transparency regarding how people join the list, e.g. by paying a fee); ■ List must be updated regularly; ■ List must possess enough experts with a knowledge of each local level and each type of impact.

Examples of this approach exist in Belgium, where only accredited persons can be designated as EIA Report authors (*agrément des auteurs d'études d'incidences*) in the Walloon Region and in the Brussels Capital Region. The implementation of this approach in both Regions is briefly presented in the box below.

Box 46: An example of accreditation procedures: Walloon and Brussels-Capital Regions of Belgium

	Walloon Region	Brussels Capital Region
Date system first instituted	1985	1992
Framework	Single legislation (Walloon Code of Environment, Article R.58 and following), but several accreditations are required, depending on the type of Project (e.g. industrial, civil engineering, urbanism)	Different legislation and provisions depending on the Project's nature
Issuance	Walloon Minister responsible for urban and rural planning Publication in Official Journal (*Moniteur Belge*)	Brussels Government in Council Annual publication of the list of accredited individuals/companies in Official Journal (*Moniteur Belge*)
Validity	5 years (maximum), renewable with the relaunch of the procedure	15 years (maximum), renewable with the relaunch of the procedure

Changes	Holder of authorisation must notify the authority in case of changes made to the situation which might impact of one of the authorisations	
Sanctions	Temporary or permanent withdrawal under different circumstances: ■ disrespect of the Walloon Code of Environment ■ after prior warning and where a developed Project does 'not seem consistent with the rules of art' or is of a 'poor quality'. Prior warning can be triggered by different environmental administrations.	Temporary or permanent withdrawal under different circumstances: ■ the approval holder no longer meets the conditions for approval ■ the approval holder no longer has sufficient technical means at its disposal ■ after prior warning, if a Project developed is of 'unsatisfactory quality'

- Recognised institutions

Another similar approach to ensuring the demonstrable quality of experts is to pre-qualify the institutions from which they are supplied. The experts themselves may not hold the necessary qualifications or experience, but could work under the authority of their institution, which may be a university (or a specific department thereof) or a consultancy specialising in the field of impact assessment. This places a lot of trust in the institution to ensure that the expert is competent, given that having seen the expert work on other Projects, the recognised institution would be in a good position to vouch for the expert. The institution has its own name and reputation to uphold and is, therefore, incentivised to provide good quality work.

- Experience

Basing competence on experience would require experts to demonstrate their experience working on EIAs when being selected for the role of preparing the EIA Report, regardless of their formal qualifications. As time goes by, experts will gain more and more experience and, thus, the quality of the work they do will increase. Experience can be judged both on a set of criteria or on a case-by-case approach and should be demonstrable in case the quality of the EIA Report is questioned thereafter.

- Transparency

Selecting and verifying experts through a more ad hoc, transparent process allows for greater flexibility on the part of the Developers, given that it does not require a prescribed method for measuring competence. Instead, regardless of how experts are selected, the names and CVs of all of the consultants are included in the final report, and the reason(s) for employing them is clearly detailed. Competence can, therefore, be checked and scrutinised by the public and by the Competent Authority.

2.2.3 Quality control by Competent Authorities

Just as Developers need to ensure that the EIA Report is prepared by competent experts, authorities also need to be able to demonstrate that they have sufficient experts to examine and evaluate EIA Reports. Different approaches are adopted for this across the EU Member States.

Defining 'sufficient expertise' (Competent Authorities)

Article 5(3) of the EIA Directive requires that the Competent Authorities have access to the necessary expertise required to accurately assess an EIA Report. Recital 33 of the EIA Directive states that: 'Sufficient expertise, in the relevant field of the Project concerned, is required for the purpose of its examination by the component authorities in order to ensure that the information provided by the Developer is complete and of a high level of quality.' The Competent Authority needs to check the structure and logic of the EIA Report, as well as the overall quality of the data, judgements, and conclusions presented.

Competent Authorities can have expertise in-house or can access this expertise through external channels. In some Member States, where EIAs have been carried out for decades, those reviewing EIA Reports, in particular those within the Competent Authorities, have years of experience and they can, thus, be considered to be experts. In some cases, EU Cohesion Policy funds, including technical assistance available from the European Reconstruction Development Fund or training activities under the European Social Fund, may be available to support training for both authorities and for other stakeholders. Where expertise is not available in-house, research institutes and professional bodies may be asked to undertake reviews. In some Member States, a review body may be available to undertake the review (see box 47 below) [15].

Box 47: In practice – 2014 amendments on the expertise of Competent Authorities

In most cases, the changes will not have much of an effect on those examining the EIA Report:

- The Competent Authorities reviewing large number of EIAs already have the necessary expertise;
- Some Member States have already set up diverse review system mechanisms, including independent review bodies or inter-institutional platforms (see the box below presenting the systems in Cyprus, France, Italy, and the Netherlands).

The new provisions in Article 5(3)b require authorities to be able to demonstrate their experience:

- Experts must be proven to be competent;
- Where no suitable expert is available in-house, external experts should be used.

Finding sufficient expertise (Competent Authorities)

Competent Authorities can take various approaches to ensuring that they have access to the expertise necessary to examine EIA Reports, where this is not available in-house. If individual experts are contracted on a case-by-case basis, many of the approaches adopted by Developers in the past, detailed above, can also be used to find competent experts to carry out a review of the EIA Report on behalf of the Competent Authority. Another possible option is for Member States to set up a dedicated independent review body, a body which is always available to provide insight into the evaluation of EIA Reports.

Under Article 5(3)(c), the Competent Authority can request any supplementary information that it requires from the Developer before reaching its decision, as long as the information is directly relevant to reaching the Reasoned Conclusion. Competent Authorities need to ensure that the additional information that they request can be clearly linked to the decision-making process, and is not merely precautionary in nature.

Several Member States ensure that all authorities have access to sufficient expertise to review EIA Reports through the establishment of institutions to serve this purpose. These vary in composition, size, as well as their links to authorities.

[15] Examples of independent review bodies can be found in the Netherlands (Netherlands Commission for Environmental Assessment), France (*Conseil General de l'Environnement et du Développement Durable*; General Council of Environmental and Sustainable Development), and Italy (*Instituto Superiore per la Protezione e Ricerca Ambientale*; Superior Institute for Environmental Protection and Research).

In some Member States these can be considered to be independent: in the Netherlands, a Commission is appointed by the minister whose exclusive role is to maintain a pool of approximately 300 experts who are then responsible for providing opinions on EIAs. In France, the review body is made up of nine evaluation specialists, stemming from the Ministry of the Environment directly, as well as six external qualified experts.

Other Member States opted for mechanisms closer to that of an inter-institutional platform (which may include members of the civil society). For instance, in Cyprus, ten members comprise the EIA Committee, including representatives of different ministries, the chamber of engineers, the federation of environmental organisations, and two qualified experts. The box below presents four examples in greater detail.

Box 48: Examples of quality review in Cyprus, France, Italy and the Netherlands

Member State and body	**Cyprus** EIA Committee (Επιτροπή Εκτίμησης Περιβαλλοντικών Επιπτώσεων)[16]	**France** General Council of Environment and Sustainable Development (CGEDD) acting as Environmental Authority[17]	**Italy** Technical Commission for environmental impact assessment[18]	**Netherlands** Netherlands Commission for Environmental Assessment (NCEA)
Proximity to EIA procedure	Integrated into the EIA procedure	Integrated into the EIA procedure	Integrated into the EIA procedure	Integrated into the EIA procedure
Degree of involvement	▪ responsible for EIA Screening ▪ examines the content of each EIA Report ▪ consults the Competent Authority with regard to any EIA issues	Acts as Competent Authority for certain Projects (and all plans and programmes, cf. SEA). Oversees the EIA process: ▪ responsible for EIA Scoping ▪ issues an opinion on the quality of the EIA Report	Acts as an advisory body: ▪ upon request ▪ checks the applicability of exclusion conditions during the Screening stage ▪ checks compliance with the requirements contained in the EIA decision ▪ advises on the interpretation and application of the EIA decision ▪ advises during the Scoping stage.	During or after preparation of the EIA Report: ▪ responsible for Scoping of the EIA; ▪ interim recommendation can be submitted if requested; ▪ checks whether the EIA contains all of the necessary information once drafted.
Time taken for review		Opinion on the EIA Report issued within 3 months This opinion is published before the EIA Report is submitted to public consultations.	Opinion on EIA decision by 60 days after the start of the procedure (30 days to ask for additional documents if deemed necessary). No other specific timelines set.	Opinion on the EIA Report issued within 6 – 9 weeks.

[16] The creation of the Committee is provided under Article 5 of the main law on EIA (Law 140(I)/2005 – as amended).

[17] Autorité environnementale du Conseil général de l'Environnement et du Développement durable [redacted]

[18] The functioning and the organization of the Commission are established by Ministerial Decree GAB/DEC/150/07 of 18 July 2007.

Experts	The Committee is composed of ten members, including six administrators, and four civil society representative.	Nine qualified evaluation specialists from the Ministry of the Environment and six external qualified experts. Maintains a pool of relevant experts.	The Commission is composed of 50 members with adequate technical qualifications in environmental matters appointed by the Ministry of Environment.	Members of the commission are appointment by ministers. The commission maintains a pool/list of circa 300 relevant experts from the fields of industry, universities, government agencies or related groups.
Expert appointment on specific EIAs	The Committee can appoint special technical committees to examine specialised environmental issues that may arise during the examination of an EIA study.	Experts assigned according to relevance of expertise and availability. Each opinion adopted after review by all experts.		Assigned according to the relevance of expertise.
Nature of decision	Opinions are not binding and in certain cases the Committee only acts when consulted.	Opinions are not binding; however, they contain recommendations and are included in the documents for public consultation. Moreover, judges can rely on them in litigation.	Opinions are not binding and, in certain cases, the Commission only acts when requested (see row above on degree of involvement).	Opinions are not binding.

2.2.4 The competence of expertise and quality control: in a nutshell

The Directive requires that the EIA Report shall be prepared by competent experts:

- Where previously Developers were not formally obliged to use competent experts to prepare EIA Reports, they are now required to ensure that the EIA Reports are prepared by such experts;
- Many Member States have adopted systems to ensure that the EIA Report is prepared by competent experts, and Developers will have to comply with these requirements when selecting experts. These include accreditation systems and lists of pre-qualified experts or institutions.

The Directive requires that Competent Authorities have sufficient expertise to review an EIA Report:

- Several Member States already have systems in place, including the establishment of an independent review body. The functions of these bodies vary between Member States and Developers and Competent Authorities will need to check national provisions.
- The Competent Authorities should hire external experts if they do not have access to such experts internally, regardless of whether a formal review body is in place.
- Additional information can be requested by the Competent Authority, as long as the information is directly relevant to reaching a Reasoned Conclusion.

3 CONSULTATIONS AND DECISION-MAKING

The EIA Report is ultimately an informative decision-making tool: once it has been prepared by the Developer, it has to be examined by the public and various concerned authorities. This section sheds light on how these procedures are carried out, given that they are relevant to those gathering the information during the preparation of the EIA Report. It looks at the requirements of the EIA Directive with regards to public consultation and the role of EIA in the decision on Development Consent, including a discussion on time-frames applicable to both cases.

3.1 CONSULTATIONS ON THE EIA REPORT

Consultation procedures are often highly detailed in national legislation, and also fall under international legislation (Aarhus and Espoo Conventions – see the Annex to this Guidance Document on Links with Other EU Instruments). Practitioners must, therefore, consult all relevant national legislation and guidance. This guidance document provides an overview of consultation requirements and, in particular, of applicable time-frames as they impact on those preparing the EIA Report.

3.1.1 Legislative requirements for consultations

Articles 6 and 7 of the EIA Directive are the main provisions of the EIA Directive on consultations. A number of other provisions scattered throughout the Directive are also relevant: e.g. Article 4(5) on the Screening stage or Article 5(2) on the Scoping stage (see the Screening Guidance Documents and the Scoping Guidance Document of this series for more information).

Together, these provisions outline (i) what information is to be provided to the consultees, (ii) who is to be consulted during the EIA process, and (iii) lays out some minimum standards to ensure that this is done effectively (distinguishing information and participation, and setting time-frames). Furthermore, it should be borne in mind that Article 8 of the EIA Directive requires the results of these consultations to be duly taken into account in the Development Consent procedure (see the decision-making section below).

Box 49: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 6 (extracts)

(1) Member States shall take the measures necessary to ensure that the authorities likely to be concerned by the project by reason of their specific environmental responsibilities or local and regional competences are given an opportunity to express their opinion on the information supplied by the developer and on the request for development consent, taking into account, where appropriate, the cases referred to in Article 8a(3). To that end, Member States shall designate the authorities to be consulted, either in general terms or on a case-by-case basis. The information gathered pursuant to Article 5 shall be forwarded to those authorities. Detailed arrangements for consultation shall be laid down by the Member States.

(2) In order to ensure the effective participation of the public concerned in the decision-making procedures, the public shall be informed electronically and by public notices or by other appropriate means, of the following matters early in the environmental decision-making procedures referred to in Article 2(2) and, at the latest, as soon as information can reasonably be provided:

- (e) an indication of the availability of the information gathered pursuant to Article 5;

(3) Member States shall ensure that, within reasonable time-frames, the following is made available to the public concerned:

- (a) any information gathered pursuant to Article 5;

(4) The public concerned shall be given early and effective opportunities to participate in the environmental decision-making procedures referred to in Article 2(2) and shall, for that purpose, be entitled to express comments and opinions when all options are open to the competent authority or authorities before the decision on the request for development consent is taken.

(6) Reasonable time-frames for the different phases shall be provided for, allowing sufficient time for:

- (a) informing the authorities referred to in paragraph 1 and the public; and
- (b) the authorities referred to in paragraph 1 and the public concerned to prepare and participate effectively in the environmental decision-making, subject to the provisions of this Article.

(7) The time-frames for consulting the public concerned on the environmental impact assessment report referred to in Article 5(1) shall not be shorter than 30 days.

Article 7

(1) Where a Member State is aware that a project is likely to have significant effects on the environment in another Member State or where a Member State likely to be significantly affected so requests, the Member State in whose territory the project is intended to be carried out shall send to the affected Member State as soon as possible and no later than when informing its own public, inter alia:

- (a) a description of the project, together with any available information on its possible transboundary impact;
- (b) information on the nature of the decision which may be taken.

The Member State in whose territory the project is intended to be carried out shall give the other Member State a reasonable time in which to indicate whether it wishes to participate in the environmental decision-making procedures referred to in Article 2(2), and may include the information referred to in paragraph 2 of this Article.

Groups to be consulted

In accordance with these provisions, consultations on different information should take place with different groups:

- public authorities likely to be concerned (Article 6(1) of the EIA Directive):

Authorities likely to be concerned by the Project, due to specific environmental responsibilities or local/regional competencies, must be given an opportunity to express their opinion on the information supplied by the Developer, and on the Development Consent. Authorities can be identified either in general terms or on a case-by-case basis, and shall be given an opportunity to express their opinion on the information supplied by the Developer and on the request for Development Consent. Exactly how this is to be done is to be laid down by the Member States.

- the public concerned (Article 6(2), 6(3), 6(4) of the EIA Directive):

The public and the public concerned must have access to any information gathered during the preparation of the EIA Report, the reactions of the Competent Authority/Authorities at the time the information is made available, and any other relevant information which may arise later. The public concerned must be given early and effective opportunities to participate, and be able to provide their comments and opinions. Exactly how this is done is up to Member States to decide, although the EIA Directive does set out several provisions, including mandating what information should be available to the public. This information includes the EIA Report itself.

- relevant parties in affected other Member States (Article 7 of the EIA Directive):

If a Project is likely to cause significant environmental effects in another Member State, or if another Member State so requests, then transboundary consultations must be carried out. The Member State in whose territory the Project will be carried out will send the affected Member State a description of the Project (including any information on the likely transboundary impacts) and information about the nature of the decision which may be taken. The Member State affected must be given a reasonable period of time in which to indicate whether or not it will participate in decision-making procedures; if the Member State affected indicates that it will participate, then the authorities and the public in the Member State affected must be informed and given the opportunity to forward their opinion before the Development Consent is granted. These consultations may be conducted through an appropriate joint body, and some Member States may have national legislation which may lay out additional requirements.

Minimum standards for effective consultation

Consultations include two main elements:

- informing the consultees; and
- giving consultees, whether the public or public authorities, time to prepare and participate effectively in the environmental decision-making.

In addition, requirements on time-frames are provided in relation to consultations. The following time-frames are required by the Directive:

- an explicit time-frame is provided by the Directive in Article 6(7) whereby a minimum of thirty days is required for public consultation;
- no other minimum or maximum is provided, yet Article 6(6) of the EIA Directive requests that 'reasonable time-frames' are provided for consultations of public authorities and the public. This notion is further reiterated throughout the different paragraphs of Article 6, as well as in Article 7 in relation to transboundary consultations. The concept of reasonable time-frames is explored in the section below.

Some of the requirements detailed above were included in the EIA Directive in 2014 and are summarised in the box below.

Box 50: In practice – 2014 amendments on consultations

The 2014 amendments included significant changes to consultations and highlighted time-frames concerning consultations:

- The Directive now differentiates between information and participation;
- The provisions on public consultation require 'reasonable time-frames' for each of the different phases of consultation with regard to both the public and public authorities;
- A minimum of 30 days for public consultation is required. The Directive expressly refers to local or regional authorities as authorities likely to be concerned;
- The Directive now envisages information on public consultation to be made electronically available.

3.1.2 Consultations and 'reasonable time-frames'

The Developers and practitioners preparing EIA Reports need to be aware that information needs to be shared with relevant parties in a timely manner, which may be determined by national legislation specifically or by agreement with the relevant authorities more generally. Methods for disseminating the information are also left up to Member States; however, it is worth noting that the EIA Directive specifically envisages the electronic availability of information. In any case, clearly defined methods of dissemination, as well as time-frames, can enhance administrative certainty, prevent delays, and provide certainty that different steps in the EIA process will occur within a certain period of time.

Reasonable time-frames in EU Law

- Explanation of the use of the term 'reasonable' by the EIA Directive

Pursuant to the principle of subsidiarity, the EIA Directive leaves the precise determination of the time-frames applicable to consultations to Member States. Indeed, as is demonstrated in the box below, Projects requiring an EIA differ in size, scale, location and complexity, and therefore setting standard and explicit time limits applicable to all Projects for the different stages, may not be considered to be appropriate.

Box 51: Understanding the concept of 'reasonable' with regard to timing in the EIA procedure

- Recital 36 of the 2014 Directive amending the EIA Directive

'Member States should ensure that the various steps of the environmental impact assessment of Projects are carried out within a reasonable period of time, depending on the nature, complexity, location and size of the Project'

- Average duration of the EIA process

The average duration of an EIA procedure was estimated to be 11.3 months but figures range from 5 to 27 months. The average time taken to reach the final EIA decision after completion of the consultations was 2 months.

Source - GHK (2010), Collection of information and data to support the IA study of the review of the EIA Directive.

- Compliance Committee of the Aarhus Convention: Lithuania ACCC/2006/16; ECE/MP.PP/2008/5/Add.6, 4 April 2008, para. 69

'A time frame which may be reasonable for a small simple Project with only local impact may well not be reasonable in case of a major complex Project.'

- Defining reasonable time-frames in application of the EIA Directive

Article 6 of the EIA Directive makes several references to reasonable time-frames when it comes to carrying out public and other concerned authority consultations. In addition, Article 6(7) explicitly gives 30 days as the minimum amount of time for consulting the public on the EIA Report.

This concept of reasonable time-frames, with regards to public consultations, is widely covered by other documents on the subject, those concerning the Aarhus Convention in particular, as shown in the box below on case law. This guidance document can be used as an indication to establish time-frames applicable to the EIA procedure (see also the Annex to this Guidance Document on Other Relevant Guidance and Tools).

Box 52: Reasonable time-frames for public participation in case-law of the Aarhus Convention Compliance Committee

- Sufficient time-frame:

Case Law of the Aarhus Convention Compliance Committee determines that a total of 90 days, including 45 days to inspect the relevant information and prepare, plus a subsequent 45 days to comment, is sufficient.

- Insufficient time-frame:

Case Law of the Aarhus Convention Compliance Committee found that 10 working days, to inspect relevant information and to prepare to participate in decision-making, cannot be considered to be reasonable.

A. Andrusevych, T. Alge, C. Konrad (eds), Case Law of the Aarhus Convention Compliance Committee 2004-2011, 2nd edition, pages 44-45.

With regards to transboundary consultations, Article 7 addresses how Member States should approach EIAs for Projects that are likely to have significant effects on the environment in another Member State. Again, the word 'reasonable' is used when referring to the time at which information is to be shared with the public or concerned authorities. In addition, Article 7(5) states that time-frames should be determined based on those set out in Article 6. Here, the guidance materials developed concerning the Espoo Convention could support the interpretation and implementation of the EIA Directive in this context.

Practitioners developing the EIA Report should familiarise themselves with these Articles and national legislation in order to reduce delays and improve administrative certainty. At any rate, it should be noted that informing the affected Member State must be done at the latest when informing the public within the Member State where the Project takes place.

- Time-frames and streamlining environmental assessments across EU instruments

Projects are often subject to several environmental assessment procedures, including the EIA. Article 2(3) of the EIA Directive requires either a coordinated or joint procedure for Projects falling under the scope of both the EIA and the Birds/Habitats Directives. In addition, this Article encourages the use of coordinated procedures when assessments of the effects on the environment arise from the EIA and other EU legislation (for more information see the Annex to this Guidance Document on Links with Other EU Instruments). Joint or coordinated procedures for other EU environmental assessments can reduce overlapping procedures, which can then lead to unnecessary delays, discrepancies, and administrative uncertainty. Time-frames play an important role in the successful coordination or joint procedures, given that defined time-frames can help align procedures which may be headed by different parties.

The European Commission Guidance Document on streamlining environmental assessments conducted under Article 2(3) of the EIA Directive provides advice about how to manage different environmental assessments in the context of joint and/or coordinated procedures, and should be read in conjunction with this guidance document. In addition, other regulations may dictate the structure of the time-frames. The Trans-European Networks-Energy Regulation (see the Annex to this Guidance Document on Links with Other EU Instruments), for example, gives three and a half years as a binding time limit for the overall permit granting process (i.e. delivering the Development Consent decision) for relevant Projects. The European Commission has also issued a Guidance Document on streamlining environmental assessments within the context of the TEN-R Regulation (see the Annex to this Guidance Document on Other Relevant Guidance and Tools).

Box 53: Other relevant EU Guidance

Commission Guidance on streamlining environmental assessments for energy infrastructure Projects PCIs (Streamlining Guidance) July 2013

Commission guidance document on streamlining environmental assessments conducted under Article 2(3) of the Environmental Impact Assessment Directive (Directive 2011/92/EU of the European Parliament and of the Council, as amended by Directive 2014/52/EU) (2016/C 273/01)

Implementing reasonable time-frames in the national context

While they are not established at the EU level, explicit time-frames, with minimum and/or maximum limits, may be set out either by Member States in national legislation or by the Competent Authorities on a case-by-case basis.

In any case, if time-frames are set-out, Recital 36 of the 2014 Directive amending the EIA Directive indicates that they ought:

- to stimulate more efficient decision-making and increase legal certainty; and
- not to affect the achievement of the objective of the Directive which is to ensure a high level of protection of the environment and of human health.

The following box provides a few tips on setting reasonable time-frames for EIAs.

Box 54: Tips for setting explicit time-frames

- Time-frames should be proportionate to the nature, complexity, location and size of the Project.
- Time-frames should be clearly defined.
- Time-frames should be flexible enough to adjust to extenuating circumstances.
- Time-frames should aim to reduce unnecessary delays in assessment procedures and increase administrative certainty.
- Time-frames should in no way lower the quality of the environmental assessments performed.

3.1.3 Consultations: in a nutshell

- The EIA Directive requires consultations with three different groups on the content of the EIA Report: the public concerned must always be consulted; public authorities must be consulted when they are likely to be concerned; and other Member States for Projects with transboundary impacts.
- Consultations include both the provision of information and the possibility to effectively prepare and participate in decision-making.
- The Directive sets out an explicit minimum time-frame for public consultations on the EIA Report (at least 30 days).
- In other cases, the Directive refers to reasonable time-frames. The notion of reasonable time-frames should be refined at the national level, depending on the Project at hand, in order to enhance administrative certainty and to reduce delays.

3.2 DECISION-MAKING: REASONED CONCLUSION AND DEVELOPMENT CONSENT

3.2.1 Legislative requirements on decision-making

The definition of the EIA in Article 1 of the Directive refers to:

- a Reasoned Conclusion, essentially the decision of the Competent Authority on the environmental impacts of the Project based on the EIA Report and on other relevant information, including information received through the consultations;
- the incorporation of the Reasoned Conclusion in the Project's Development Consent, i.e. in the decision that either grants or refuses permission to carry out a Project.

Article 8 of the Directive also requires that, in order to make the Development Consent decision, the Competent Authority takes the results of consultations duly into account.

Box 55: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 1(2)(g)(iii), (iv) and (v)

For the purposes of this Directive, the following definitions shall apply:

(g) 'environmental impact assessment' means a process consisting of:

- (iii) the examination by the competent authority of the information presented in the environmental impact assessment report and any supplementary information provided, where necessary, by the developer in accordance with Article 5(3), and any relevant information received through the consultations under Articles 6 and 7;
- (iv) the reasoned conclusion by the competent authority on the significant effects of the project on the environment, taking into account the results of the examination referred to in point (iii) and, where appropriate, its own supplementary examination;
- (v) the integration of the competent authority's reasoned conclusion into any of the decisions referred to in Article 8a.

Article 8

The results of consultations and the information gathered pursuant to Articles 5 to 7 shall be duly taken into account in the development consent procedure.

Article 8a(1)

1. The decision to grant development consent shall incorporate the following information:

- (a) the reasoned conclusion referred to in Article 1(2)(g)(iv);
- (b) any environmental conditions attached to the decision, a description of any features of the project and/or measures envisaged to avoid, prevent or reduce and, if possible, offset significant adverse effects on the environment as well as, where appropriate, monitoring measures.

Article 8a(2)
(2) The decision to refuse development consent shall state the main reasons for the refusal.

Article 8a(6)
(6) The competent authority shall be satisfied that the reasoned conclusion, referred to in Article 1(2)(g)(iv), or any of the decisions referred to in paragraph 3 of this Article, is still up to date when taking a decision to grant development consent. To that effect, Member States may set time-frames for the validity of the reasoned conclusion referred to in Article 1(2) (g) (iv) or any of the decisions referred to in paragraph 3 of this Article.

Articles on decision-making ensure that a clear justification of the reasons and the conditions associated with the decision to grant (or refuse) Development Consent are provided and that environmental conditions stemming from the EIA decision are not sidelined when making the Development Consent decision. Thus, the aim is to ensure that the EIA process has informed the decision-making process, and that a high level of environmental protection can be guaranteed once the Project is implemented and operating.

Box 56: In practice – 2014 amendments on decision-making

The amendments of the different articles seek to strengthen decision-making in two ways; firstly, with regards to obtaining more formal and transparent justification of decision-making:

- Article 8 includes the words 'duly into account', thereby seeking to ensure that environmental considerations and the opinions of the public consulted are not side-lined when issuing Development Consent decisions;
- Article 8a(1) requires the integration of different elements into the Development Consent decision (e.g. Reasoned Conclusion, environmental conditions, Monitoring Measures);
- Article 8a(2) requires the justification of decisions to refuse Development Consent.

Secondly, the amendments seek to ensure that that environmental considerations remain under scrutiny during the actual Project construction phase and/or operational phase, as well as in any subsequent permitting procedures:

- Article 8a(1) requires the integration of different elements into the Development Consent decision (e.g. Reasoned Conclusion, environmental conditions, Monitoring Measures);
- Article 8a (6) requires that the Competent Authority checks that the Reasoned Conclusion is up-to-date.

3.2.2 Reasoned Conclusion

This section addresses the duties of the Competent Authority that adopts Reasoned Conclusions, and explains the two different systems envisaged by the EIA Directive that may be used in the Member States in relation to the adoption of a Reasoned Conclusion.

An assessment obligation for the Competent Authority

Article 1(2)(g) of the EIA Directive (introduced by the 2014 amendments), which defines the EIA process, uses the term 'examination' several times in relation to the tasks carried out by the Competent Authority adopting the Reasoned Conclusion. As discussed below, this term requires that the Reasoned Conclusion be the direct outcome of an obligation, on the Competent Authority's part, to assess the Project's significant effects. The Competent Authority must, therefore, not simply rely on the Developer's assessment and compile the information gathered through the consultations, but must also carry out its own separate assessment of the Project's significant effects.

Box 57: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 1(2)(g)(iii) and (iv)

- (iii) the examination by the competent authority of the information presented in the environmental impact assessment report and any supplementary information provided, where necessary, by the developer in accordance with Article 5(3), and any relevant information received through the consultations under Articles 6 and 7;

- (iv) the reasoned conclusion by the competent authority on the significant effects of the project on the environment, taking into account the results of the examination referred to in point (iii) and, where appropriate, its own supplementary examination;

The terminology 'examine' is used in a 2011 ruling of the Court of Justice of the European Union (CJEU). In this judgement, the Court ruled that Article 3 of the EIA Directive is a fundamental provision that should guide the whole EIA process. This provision requires the EIA process to not only identify and describe, but also to *assess*, the direct and indirect effects of the Project. This assessment, the Court ruled, involves an *examination* by the Competent Authority of both the information supplied in the EIA Report and of the results of the consultations.

A few key statements from the Court ruling in question are reproduced in the box below.

Box 58: CJEU, C-50/09, *Commission v. Ireland*

40 … Indeed, that assessment, which must be carried out before the decision-making process (…), involves an examination of the substance of the information gathered as well as a consideration of the expediency of supplementing it, if appropriate, with additional data. That competent environmental authority must thus undertake both an investigation and an analysis to reach as complete an assessment as possible of the direct and indirect effects of the Project concerned on the factors set out in the first three indents of Article 3 and the interaction between those factors.

41 […] Article 3 is a fundamental provision.

44. […] namely that of taking the results of the consultations and the information gathered for the purposes of the consent procedure into consideration. That obligation does not correspond to the broader one, imposed by Article 3 of Directive 85/337 on the competent environmental authority, to carry out itself an environmental impact assessment in the light of the factors set out in that provision.

The content of the Reasoned Conclusion

As described above, the Competent Authority must examine the information provided in the EIA Report, as well as the results of the consultations and, where appropriate, must request any supplementary information. The Reasoned Conclusion, as the direct outcome of this assessment, should detail these examinations.

The following box provides a few tips about how to develop a good Reasoned Conclusion.

Box 59: Tips for developing the Reasoned Conclusion

- Examine and justify the different tools and methods used during the preparation of the EIA Report, and subsequent consultations.
- Examine the information and data provided in the EIA Report and during consultations. Key messages of the Baseline conditions, significant effects, predicted impacts of the Project, suggested Monitoring and Mitigating Measures, and other relevant information should be highlighted.
- Clearly discuss the evidence with a view to reaching a conclusion, allowing for any additional arguments which may arise.
- State clearly what the Reasoned Conclusion is and the arguments on which it relies.
- Define a programme to mitigate and monitor the effects of the Project (in case significant adverse effects would be caused).

Two different systems of adopting Reasoned Conclusion and granting the Development Consent

Article 8a (1) deals with the decision to grant Development Consent, and reiterates the necessity for this decision to incorporate several elements, including the Reasoned Conclusion and Monitoring Measures (see also the section on monitoring).

In relation to this point, the EIA Directive allows for the existence of different EIA systems in the Member States as provided for under Article 2(2) of the Directive (see box below).

Box 60: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 2(2)

2. The environmental impact assessment may be integrated into the existing procedures for development consent to projects in the Member States, or, failing this, into other procedures or into procedures to be established to comply with the aims of this Directive.

The underlying idea, presented under Recital 21 of the 2014 Directive amending the EIA Directive, is that 'the Reasoned Conclusion […] may be part of an integrated Development Consent procedure or may be incorporated in another binding decision'. There are two main systems existing in the EU with regards to the implementation of the EIA Directive. These two systems can be described as, on the one hand, a separate EIA procedure, and an integrated procedure where the EIA is one of the assessments carried out in view to reach a decision on Development Consent on the other.

- The integrated procedure

The integrated procedure system consists of an EIA procedure carried out in parallel with other assessments in view of reaching a decision for Development Consent. The Reasoned Conclusion, as such, forms part of the final decision on the Project's Development Consent.

- The separate EIA procedure

Under the separate EIA procedure, the Reasoned Conclusion is adopted via a decision procedure that is separate from the one undertaken to grant Development Consent. In this case, the environmental conditions set out in the Reasoned Conclusion are binding. The requirement of Article 8a(1) of the EIA Directive ensures that the environmental conditions set out in the Reasoned Conclusion are included later on in the Development Consent decision. As the conditions set in the Reasoned Conclusion on the EIA are binding, they should be followed when the Development Consent is adopted.

3.2.3 Time-frames concerning decision-making

The obligation of reasonable time-frames in decision-making

Article 8a(5) of the EIA Directive concerns the time-frames set in which the decisions taken during the EIA process must be made.

Box 61: Directive 2011/92/EU as amended by Directive 2014/52/EU

Article 8a(5)

5. Member States shall ensure that the competent authority takes any of the decisions referred to in paragraphs 1 to 3 within a reasonable period of time.

This Article prescribes an overall obligation of 'a reasonable period of time'. This obligation is applicable not as a whole, but to different decisions, including inter alia the Reasoned Conclusion as well as the Development Consent decisions. There is no precise indication in the Directive about how long the reasonable period of time should be, and Developers should be aware that specific time-frames may be set out in national legislation or be applicable from other legislation (e.g. the TEN-E Regulation).

The time taken by the authorities to issue their decisions on the Development Consent can generate significant uncertainty and delays for the Developers, which may also lead to additional costs being incurred. Again, ensuring the decisions are taken within a 'reasonable period of time', can contribute to more efficient decision-making and increasing certainty as well as avoiding lengthy EIA procedures.

Time-frames for the validity of Reasoned Conclusion

The EIA Directive requires that the authority, competent for the Development Consent, must ensure that the Reasoned Conclusion is still up-to-date when taking its decision (Article 8a(6)).

Box 62: Directive 2011/92/EU as amended by Directive 2014/52/EU
Article 8a(6) 6. The competent authority shall be satisfied that the reasoned conclusion referred to in Article 1(2)(g)(iv), or any of the decisions referred to in paragraph 3 of this Article, is still up to date when taking a decision to grant development consent. To that effect, Member States may set time-frames for the validity of the reasoned conclusion referred to in Article 1(2)(g)(iv) or any of the decisions referred to in paragraph 3 of this Article.

These elements sheds additional light on the overall obligation of 'reasonable period of time' of Article 8a(5). Indeed, in the context of separate EIA procedure, the environmental assessment may have been completed years before a decision on Development Consent can be considered.

Member States in this context may establish time-frames for the validity of Reasoned Conclusion.

Box 63: The validity of Reasoned Conclusion in Croatia
'The Croatian Environmental Protection Act (*Zakon o zaštiti okoliša*) ('O.G.' No 80/13, 153/13 and 78/15) regulates the EIA procedure in Croatia. Its Article 92 sets the duration of validity of the final EIA decision for up to two years. More specifically, it renders the EIA decision invalid if an operator does not request a permit leading to the construction permit within two years of the date the decision entered into force

The Competent Authority should, in any case, be satisfied that the Reasoned Conclusion is up-to-date, regardless of time-frames that have not yet expired.

Time-frames for informing the public of the Development Consent decision

Once the Development Consent decision has been reached, the public must be informed of its outcome.

Box 64: Directive 2011/92/EU as amended by Directive 2014/52/EU
Article 9(1) 1. When a decision to grant or refuse development consent has been taken, the competent authority or authorities shall promptly inform the public and the authorities referred to in Article 6(1) [...]

The 2014 legislative change of the EIA Directive added the word 'promptly' to Article 9(1) so as to align it with Article 6(9) of the Aarhus Convention which already uses this term. It should be noted that 'promptly' can be interpreted differently from the phrase 'reasonable time-frame' used throughout the EIA Directive. This suggests that there is not a specified maximum period (time-frame) in which action should be taken, but rather that action should be taken as soon as possible[19].

At the Member State level, there may be national time limits established for challenging the decision that must be complied with.

---

[19] A. Andrusevych, T. Alge, C. Konrad (eds), Case Law of the Aarhus Convention Compliance Committee 2004-2011, 2nd edition, Page 87.

3.2.4 Decision-making on the EIA Report: in a nutshell

- Environmental considerations, and the opinions of the public consulted, shall be taken 'duly into account' during the decision-making steps (both in the Reasoned Conclusion and Development Consent).
- The Reasoned Conclusion is the outcome of an assessment undertaken by the Competent Authority that is separate from the Developer's assessment. It includes an assessment of the information provided in the EIA Report, an assessment of the results of consultations, and, if adequate, the Competent Authority's supplementary assessment and resulting decision on the environmental effects of the Project.
- Across the EU Member States, there are two main systems of adopting reasoned conclusion:
  - Integrated procedure – the Reasoned Conclusion is integrated in the decision on Development Consent;
  - Separated EIA procedure – the Reasoned Conclusion, as a legally binding environmental decision, is adopted pending the issuance of the decision on the Development Consent
- Before taking a decision on the Development Consent, the Competent Authority should check that the Reasoned Conclusion is up-to-date.
- Different elements must be integrated into the Development Consent decision, including the Reasoned Conclusion, environmental conditions, and Monitoring Measures.
- Decisions to refuse Development Consent should be justified.

PART C – THE EIA REPORT CHECKLIST

1 INTRODUCTION

This checklist is designed to support this Guidance Document's users with the preparation and reviewing of an EIA Report. The checklist is intended to be used in conjunction with this Guidance Document; it can be used at multiple stages of the EIA procedure in various ways:

- for planning and guiding the preparation of an EIA Report by Developers or practitioners;
- when reviewing a draft, to ensure that it is complete and complies with all requirements and can be used for consultation or submitted to the Competent Authorities;
- when reviewing if enough information has been provided to allow for the public and stakeholder groups to develop informed opinions and reactions; and
- for authorities to carry out the examination of the EIA Report once it has been submitted.

The checklist is organised into seven sections that follow the order of presentation of the issues under Part B:

- Description of the Project;
- Description of the environment likely to be affected by the Project (including Baseline);
- Description of the Project's likely significant effects;
- Alternatives;
- Description of Mitigation and Compensation Measures;
- Description of Monitoring Measures;
- Quality (presentation, Non-Technical Summary, and quality of experts).

Each section includes a number of questions for consideration. These questions are numbered per question in the first column and are stated in full in the second. The third and fourth columns concern if they are relevant and if they have been adequately addressed respectively. The final column is dedicated to the question of what further information is required.

Some instructions for using the checklist have been provided below, but the checklist has, in essence, been developed as a flexible tool to enable different actors in the EIA procedure to use it at different stages of the procedure.

2 INSTRUCTIONS

Reviewing the relevance of the checklist questions

The checklist has been intentionally designed to cover the wide range of eventual Project situations envisaged by the EIA Directive. It also covers different types of user responsibilities, such as confirming whether or not authorities have access to the necessary expertise. Therefore, the first step in using the checklist is to decide, for each of the questions, whether the question is relevant to:

- the specific Project;
- the stage of the EIA procedure (e.g. planning, draft report completed, final review etc.);
- the user in his/her own capacity (e.g. practitioner preparing the report, Developer reviewing a draft, authority examining a final report).

If the question is relevant, then enter 'Yes' in Column 3. At the end of each of the checklist's sections, consider whether or not there are any special features of the Project that mean that types of information that have not been identified in the checklist that could be relevant and add these to the checklist in the spaces provided.

Assessing the sufficiency of the information provided

For all of the questions that are relevant to the Project and context, the user may then:

- include the point in the planning of the EIA Report; or
- review the EIA Report in more detail and decide whether the particular information identified in the question is provided and is sufficient. If it is complete and sufficient, then enter: 'Yes' in Column 3. If it is not, then enter: 'No'.

In considering whether the information is complete and sufficient the reviewer should consider whether there are any omissions in the information and whether these omissions are vital to the consultation or decision-making processes. If these omissions are not vital, then it may be unnecessary to identify or request further information. This will avoid unnecessary delay to the EIA process. Factors to consider will include:

- Both the legal provisions that apply and the factors that the decision-maker is required to take into account at this stage in the consent process for the Project;
- The Project's scale and complexity and the sensitivity of the receiving environment;
- Whether the environmental issues raised by the Project are high profile;
- The views of the public and consultees about the Project and the degree of controversy.

Indication of necessity for supplementary information

If the answer to a review Question is 'No', consider what further information is required and note this in Column 4.

This situation may arise in a variety of situations, for instance:

- Developers reviewing the EIA Report, prior to submission, may find that the information provided by the EIA practitioners is not sufficient and may request that the practitioners gather more evidence and analyse it;

- members of the public participating in the consultation procedure may find that the information provided is not complete or is insufficient to allow for their effective participation in the consultation processes. They may indicate this to both the reviewers and the Competent Authority during the consultations. The Competent Authorities intervening in the EIA process must be satisfied that the information provided is sufficient for the purposes of adopting the Reasoned Conclusion and for arriving at a decision on Development Consent.

The user may also wish to make any suggestions about where or how the information might be obtained.

3 THE REVIEW CHECKLIST

SECTION 1 DESCRIPTION OF THE PROJECT				
No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
The Objectives and Physical Characteristics of the Project				
1.1	Are the Project's objectives and the need for the Project explained?			
1.2	Is the programme for the Project's implementation described, detailing the estimated length of time (e.g. expected start and finish dates) for construction, operation, and decommissioning? (this should include any phases of different activity within the main phases of the Project, extraction phases for mining operations for example)			
1.3	Have all of the Project's main characteristics been described? (for assistance, see the Checklist in Part C of the Scoping Guidance Document in this series)			
1.4	Has the location of each Project component been identified, using maps, plans, and diagrams as necessary?			
1.5	Is the layout of the site (or sites) occupied by the Project described? (including ground levels, buildings, other physical structures, underground works, coastal works, storage facilities, water features, planting, access corridors, boundaries)			
1.6	For linear Projects, have the route corridor, the vertical, and horizontal alignment and any tunnelling and earthworks been described?			
1.7	Have the activities involved in the construction of the Project (including land-use requirements) all been described?			
1.8	Have the activities involved in the Project's operation (including land-use requirements and demolition works) all been described?			
1.9	Have the activities involved in decommissioning the Project all been described? (e.g. closure, dismantling, demolition, clearance, site restoration, site re-use, etc.)			
1.10	Have any additional services, required for the Project, been described? (e.g. transport access, water, sewerage, waste disposal, electricity, telecoms)			
1.11	Are any developments likely to occur as a consequence of the Project identified? (e.g. new housing, roads, water or sewerage infrastructure, aggregate extraction)			
1.12	Have any existing activities that will alter or cease as a consequence of the Project been identified?			

SECTION 1 DESCRIPTION OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
1.13	Have any other existing or planned developments, with which the Project could have cumulative effects, been identified?			
1.14	Has the 'whole Project' been described, e.g. including all associated/ancillary works?			
1.15	Are any activities described as part of the 'whole Project' excluded from the assessment? Are such exclusions justified? (e.g. associated/ancillary activities can be included either because they fall under the scope of the Directive (Annex I or II) or because they can be considered as an integral part of the main infrastructure works using the 'centre of gravity test'. Guidance on associated and ancillary works has been published by the European Commission in an Interpretation Line available at: [redacted]			
The Size of the Project				
1.16	Is the area of land occupied by each of the permanent Project components quantified and shown on a scaled map? (including any associated access arrangements, landscaping, and ancillary facilities)			
1.17	Has the area of land required temporarily for construction been quantified and mapped?			
1.18	Is the reinstatement and after-use of the land occupied temporarily for the operation of the Project described? (e.g. land used for mining or quarrying)			
1.19	Has the size of any structures or other works developed as part of the Project been identified? (e.g. the floor area and height of buildings, the size of excavations, the area or height of planting, the height of structures such as embankments, bridges or chimneys, the flow or depth of water)			
1.20	Has the form and appearance of any structures or other works developed as part of the Project been described? (e.g. the type, finish, and colour of materials, the architectural design of buildings and structures, plant species, ground surfaces, etc.)			
1.21	For urban or similar development Projects, have the numbers and other characteristics of new populations or business communities been described?			
1.22	For Projects involving the displacement of people or businesses, have the numbers and other characteristics of those displaced been described?			

SECTION 1 DESCRIPTION OF THE PROJECT				
No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
1.23	For new transport infrastructure or Projects that generate substantial traffic flows, has the type, volume, temporal pattern, and geographical distribution of new traffic generated or diverted as a consequence of the Project been described?			
Production Processes and Resources Used				
1.24	Have all of the processes involved in operating the Project been described? (e.g. manufacturing or engineering processes, primary raw material production, agricultural or forestry production methods, extraction processes)			
1.25	Have the types and quantities of outputs produced by the Project been described? (these could be primary or manufactured products, goods such as power or water or services such as homes, transport, retailing, recreation, education, municipal services (water, waste, etc.)			
1.26	Have the types and quantities of resources, e.g. natural resources (including water, land, soil, and biodiversity), raw materials, and energy needed for construction and operation been discussed?			
1.27	Have the environmental implications of the sourcing of resources, e.g. natural resources (including water, land, soil and biodiversity), raw materials, and energy been discussed?			
1.28	Have efficiency and sustainability in use of resources, e.g. natural resources (including water, land, soil and biodiversity), raw materials, and energy been discussed?			
1.29	Have any hazardous materials used, stored, handled or produced by the Project been identified and quantified? • during construction; • during operation; • during decommissioning.			
1.30	Has the transportation of resources, including natural resources (including water, land, soil, and biodiversity) and raw materials to the Project site, and the number of traffic movements involved, been discussed? (including road, rail and sea transport) • during construction; • during operation; • during decommissioning.			

No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
SECTION 1 DESCRIPTION OF THE PROJECT				
1.31	Have the Project's environmentally relevant social and socio-economic implications been discussed? Will employment be created or lost as a result of the Project, for instance? • during construction; • during operation; • during decommissioning.			
1.32	Have the access arrangements and the number of traffic movements involved in bringing workers and visitors to the Project been estimated? • during construction; • during operation; • during decommissioning.			
1.33	Has the housing and provision of services for any temporary or permanent employees for the Project been discussed? (this is relevant for Projects that require the migration of a substantial, new workforce into the area, either for construction or in the long term)			
Residues and Emissions				
1.34	Have the types and quantities of solid waste generated by the Project been identified? (including the construction or demolition of wastes, surplus spoil, process wastes, by-products, surplus or reject products, hazardous wastes, household or commercial wastes, agricultural or forestry wastes, site clean-up wastes, mining wastes, decommissioning wastes) • during construction; • during operation; • during decommissioning.			
1.35	Have the composition and toxicity, or other hazards from all solid wastes produced by the Project, been discussed?			
1.36	Have the methods for collecting, storing, treating, transporting, and finally disposing of these solid wastes been described?			
1.37	Have the locations for the final disposal of all solid wastes been discussed, in consideration with the Waste Management Plan(s) concerned?			
1.38	Have the types and quantities of liquid effluents generated by the Project been identified? (including site drainage and run-off, process wastes, cooling water, treated effluents, sewage) • during construction; • during operation; • during decommissioning.			

SECTION 1 DESCRIPTION OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
1.39	Have the composition and toxicity or other hazards of all liquid effluents produced by the Project been discussed?			
1.40	Have the methods for collecting, storing, treating, transporting, and finally disposing of these liquid effluents been described?			
1.41	Have the locations for the final disposal of all liquid effluents been discussed?			
1.42	Have the types and quantities of gaseous and particulate emissions generated by the Project identified? (including process emissions, fugitive emissions, emissions from combustion of fossil fuels in stationary and mobile plant, emissions from traffic, dust from materials handling, odours) • during construction; • during operation; • during decommissioning.			
1.43	Have the composition and toxicity or other hazards of all of emissions to the air produced by the Project been discussed?			
1.44	Have the methods for collecting, treating, and finally discharging these emissions to the air described?			
1.45	Have the locations for discharge of all emissions to the air been identified and have the characteristics of the discharges been identified? (e.g. height of stack, velocity and temperature of release)			
1.46	Have the methods for capturing, treating, and storing these emissions been described?			
1.47	Have the locations for the storage of all emissions identified and the characteristics of the storage unit been identified? (e.g. type of storage unit, storing capacity, methods used)			
1.48	Has the potential for resource recovery from wastes and residues been discussed? (including re-use, recycling or energy recovery from solid waste and liquid effluents)			
1.49	Have any sources of noise, heat, light or electromagnetic radiation from the Project been identified and quantified? (including equipment, processes, construction works, traffic, lighting, etc.)			
1.50	Have the methods for estimating the quantities and composition of all residues and the emissions identified and any difficulties discussed?			
1.51	Have the uncertainty attached to estimates of residues and emissions been discussed?			

SECTION 1 DESCRIPTION OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
Risks of Accidents and Hazards				
1.52	Have any of the risks associated with the Project been discussed? • risks from handling of hazardous materials; • risks from spills fire, explosion; • risks of traffic accidents; • risks from breakdown or failure of processes or facilities; • risks from exposure of the Project to natural disasters (earthquake, flood, landslide etc.).			
1.53	Have the measures to prevent and respond to accidents and abnormal events been described? (preventive measures, training, contingency plans, emergency plans, early-warning systems, etc.)			
1.54	Is there a plan in place detailing the preparedness for an emergency (e.g. suggested as part of the EIA Report's Mitigation measures) ?			
1.55	Is this plan in line with other EU legislation requirements, in particular Article 12 of the Seveso Directive (Directive 2012/18/EU on the control of major-accident hazards involving dangerous substances) which refers to emergency plans?			
Other Questions on Description of the Project				

SECTION 2 DESCRIPTION OF ENVIRONMENTAL FACTORS LIKELY TO BE AFFECTED BY THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
Baseline: Aspects of the Environment				
2.1	Have the existing land uses on the land to be occupied by the Project and the surrounding area described and are any people living on or using the land been identified? (including residential, commercial, industrial, agricultural, recreational, and amenity land uses and any buildings, structures or other property)			
2.2	Have the topography, geology and soils of the land to be occupied by the Project and the surrounding area been described?			
2.3	Have any significant features of the topography or geology of the area described and are the conditions and use of soils been described? (including soil quality stability and erosion, agricultural use and agricultural land quality)			
2.4	Has the biodiversity of the land/sea to be affected by the Project and the surrounding area been described and illustrated on appropriate maps?			
2.5	Have the species (including their populations and habitats), and the habitat types that may be affected by the Project been described? (Particular attention should be paid to any species and habitats protected under the Habitats and Birds Directives (Directives 92/43/EEC and 2009/147/EC).			
2.6	Have the Natura 2000 sites that may be affected by the Project been described?			
2.7	Has the water environment of the area been described? (including reference to any River Basin Management Plans/Programme of Measures under the WFD, running and static surface waters, groundwaters, estuaries, coastal waters and the sea and including run off and drainage. N.B. not relevant if water environment will not be affected by the Project)			
2.8	Have the hydrology, water quality, and use of any water resources that may be affected by the Project been described? (including any River Basin Management Plans/Programme of Measures under the WFD, use for water supply, fisheries, angling, bathing, amenity, navigation, effluent disposal)			
2.9	Have local climatic and meteorological conditions in the area been described? (N.B. not relevant if the atmospheric environment will not be affected by the Project)			
2.10	Has existing air quality in the area been described, including, where relevant, limit values set out by Directives 2008/50/EC and 2004/107/EC as well as relevant Programmes adopted under this legislation? (N.B. not relevant if the ambient air will not be affected by the Project)			

SECTION 2 DESCRIPTION OF ENVIRONMENTAL FACTORS LIKELY TO BE AFFECTED BY THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
2.11	Has the existing noise climate been described, including, where relevant, reference to noise maps and actions plans set out by the Environmental Noise Directive (2002/49/EU)? (N.B. not relevant if acoustic environment will not be affected by the Project)			
2.12	Has the existing situation regarding light, heat, and electromagnetic radiation been described? (N.B. not relevant if these characteristics of the environment will not be affected by the Project)			
2.13	Have any material assets in the area that may be affected by the Project been described? (including buildings, other structures, mineral resources, water resources)			
2.14	Have any locations or features of archaeological, historic, architectural or other community or cultural importance in the area that may be affected by the Project been described, including any designated or protected sites?			
2.15	Has the landscape or townscape of the area that may be affected by the Project been described, including any designated or protected landscapes and any important views or viewpoints?			
2.16	Have the demographic, social and socio-economic conditions (e.g. employment) in the area been described?			
2.17	Have any future changes in any of the above aspects of the environment, that may occur in the absence of the Project, been described? (the so-called Dynamic Baseline)			
Data Collection and Methods				
2.18	Has the study area been defined widely enough to include all of the areas likely to be significantly affected by the Project?			
2.19	Have all relevant national and local authorities been contacted to collect information on the Baseline environment?			
2.20	Have all the sources of data and information from existing databases, free services, and other relevant environmental assessments been investigated?			
2.21	Have sources of data and information on the existing environment been adequately referenced?			
2.22	Is justification provided about which particular existing datasets was(were) were relied upon, as opposed to others?			

SECTION 2 DESCRIPTION OF ENVIRONMENTAL FACTORS LIKELY TO BE AFFECTED BY THE PROJECT

No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
2.23	Where data collection has been undertaken to characterise the Baseline environment, have the methods used, any difficulties encountered, and any uncertainties been the data described?			
2.24	Were the methods used appropriate for the purpose?			
2.25	Have the methods used to predict the impact of the Project on climate changes been described? (if relevant)			
2.26	Have the methods used to predict climate change's impact on the Project been described?			
2.27	Is the uncertainty attached to the climate change evolution predictions discussed? (if relevant)			
2.28	Did you consider life cycle assessment of the Project to describe the Project's impact on climate change? (if relevant)			
2.29	Have any important gaps in the data on the existing environment/ evolution prediction identified (e.g. climate change), and the means used to deal with these gaps during the assessment, been explained?			
2.30	Where data collection would be required to adequately characterise the Baseline environment, but they have not been practicable for any reason, are the reasons explained and have proposals been set out for the surveys to be undertaken at a later stage?			
Other Questions on the Description of the Environment				

SECTION 3 DESCRIPTION OF THE LIKELY SIGNFICANT EFFECTS OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
Scoping of Effects				
3.1	Has the process by which the scope of the information for the EIA Report defined been described? (for assistance, see the Scoping Guidance Document in this series)			
3.2	Is it evident that a systematic approach to Scoping has been adopted?			
3.3	Was consultation carried out during Scoping?			
3.4	Have the comments and views of consultees been presented?			
Prediction of Direct Effects				
3.5	Have the direct, primary effects on land uses, people, and property been described and, where appropriate, quantified?			
3.6	Have the direct, primary effects on geological features and characteristics of soils been described and, where appropriate, quantified?			
3.7	Have the direct, primary effects on biodiversity been described and, where appropriate, quantified? (if relevant, are references made to Natura 2000 sites? (Directive 2009/147/EC and Directive 92/43/EEC))			
3.8	Have the direct, primary effects on the hydrology and water quality of water features been described and, where appropriate, quantified?			
3.9	Have the direct, primary effects on uses of the water environment been described and, where appropriate, quantified? (if relevant, are references made for River Basin Management Plans/Programmes of Measures under the WFD (2000/60/EC))			
3.10	Have the direct, primary effects on air quality been described and, where appropriate, quantified? (if relevant, are references made to Air Quality Plans under Directives 2008/50/EC and 2004/107/EC))			
3.11	Have the direct, primary effects on climate change been described and, where appropriate, quantified?			
3.12	Have the direct, primary effects on the acoustic environment (noise or vibration) been described and, where appropriate, quantified? (if relevant, are references made to Action Plans/Programme under the Environmental Noise Directive (2002/49/EU))			
3.13	Have the direct, primary effects on heat, light or electromagnetic radiation been described and, where appropriate, quantified?			

SECTION 3 DESCRIPTION OF THE LIKELY SIGNFICANT EFFECTS OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
3.14	Have the direct, primary effects on material assets and depletion of natural resources (e.g. fossil fuels, minerals) been described?			
3.15	Have the direct, primary effects on locations or features of cultural importance been described?			
3.16	Have the direct, primary effects on the quality of the landscape and on views and viewpoints been described and, where appropriate, illustrated?			
3.17	Have the direct, primary effects on environmentally relevant demography, social, and socio-economic condition in the area been described and, where appropriate, quantified?			
3.18	Have the secondary effects on any of the environment's aspects, above, caused by primary effects on other aspects been described and, where appropriate, quantified? (e.g. effects on biodiversity, including species and habitats protected under Directives 92/43/EEC and 2009/147/EC caused by soil, air or water pollution or noise; effects on uses of water caused by changes in hydrology or water quality; effects on archaeological remains caused by desiccation of soils)			
3.19	Have the temporary, short term effects caused only during construction or during time limited phases of Project operation or decommissioning been described? (e.g. emissions produced during the construction)			
3.20	Have the permanent effects on the environment caused by construction, operation or decommissioning of the Project been described?			
3.21	Have the long-term effects on the environment, caused over the lifetime of Project operations or caused by build-up of pollutants, in the environment been described?			
3.22	Have the effects that could result from accidents, abnormal events or exposure of the Project to natural or man-made disasters been described and, where appropriate, quantified?			
3.23	Have the effects on the environment, caused by activities ancillary to the main Project, been described? (ancillary activities are part of the Project but usually take place at a distance from the main Project location e.g. construction of access routes and infrastructure, traffic movements, sourcing of aggregates or other raw materials, generation and supply of power, disposal of effluents or wastes). For further guidance and explanation concerning ancillary works assessment see [redacted]			

SECTION 3 DESCRIPTION OF THE LIKELY SIGNFICANT EFFECTS OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
3.24	Have the indirect effects on the environment caused by consequential development been described? (consequential development is other Projects, not part of the main Project, stimulated to take place by implementation of the Project e.g. to provide new goods or services needed for the Project, to house new populations or businesses stimulated by the Project)			
3.25	Have the cumulative effects on the environment of the Project, together with other existing or planned developments in the locality, been described? (different future scenarios including a worst-case scenario should be described, as well as the effects on both climate change and biodiversity). For further guidance on the assessment of cumulative impacts see *http://europa.eu. environment/eia/eia-support* [redacted]			
3.26	Have the transboundary effects on the environment of the Project, either during construction or operation, been described?			
3.27	Have the geographic extent, duration, frequency, reversibility, and probability of occurrence of each effect been identified as being appropriate?			
Prediction of Effects on Human Health and Sustainable Development Issues				
3.28	Have the primary and secondary effects on human health and welfare described and, where appropriate, been quantified? (e.g. health effects caused by the release of toxic substances to the environment, health risks arising from major hazards associated with the Project, effects caused by changes in disease vectors caused by the Project, changes in living conditions, effects on vulnerable groups).			
3.29	Have the impacts on issues such as biodiversity, marine environment, global climate change, use of natural resources and disaster risk been discussed, where appropriate?			
Evaluation of the Significance of Effects				
3.30	Is the significance or importance of each predicted effect clearly explained with reference to legal or policy requirements, other standards, and the number, importance, and sensitivity of people, resources or other receptors affected?			
3.31	Where effects are evaluated against legal standards or requirements, have the appropriate local, national or international standards been used and has relevant guidance followed?			
3.32	Have the positive effects on the environment been described, as well as the negative effects?			

SECTION 3 DESCRIPTION OF THE LIKELY SIGNFICANT EFFECTS OF THE PROJECT				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
Impact Assessment Methods				
3.33	Have the methods used to predict the effects described, and the reasons for their choice, any difficulties encountered, and uncertainties in the results been discussed?			
3.34	Where there is uncertainty about the precise details of the Project, and its impact on the environment/climate change, have worst-case predictions been described?			
3.35	Where there have been difficulties in compiling the data needed to predict or evaluate effects, have these difficulties been acknowledged and their implications for the results been discussed?			
3.36	Has the basis for evaluating the significance or importance of impacts been described clearly?			
3.37	Have the impacts been described on the basis that all Mitigation Measures proposed have been implemented i.e. have the residual impacts been described?			
3.38	Is the level of treatment of each effect appropriate to its importance for the Development Consent decision? Does the discussion focus on the key issues and avoid irrelevant or unnecessary information?			
3.39	Is appropriate emphasis given to the most severe, adverse effects of the Project with lesser emphasis given to less significant effects?			
Other Questions relevant to Description of Effects				
	Have, with a view to avoiding duplication of assessments, the available results of other relevant assessments under Union or national legislation, in preparing the environmental impact assessment report been taken into account? If so, how was this done?			

SECTION 4 CONSIDERATION OF ALTERNATIVES

No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
4.1	Have the different Alternatives suggested during Scoping been considered and assessed, and if not has justification been provided?			
4.2	Have the Developer and practitioners, who are preparing the EIA Report, identified and assessed additional Alternatives (to the ones suggested during Scoping)?			
4.3	Have the process by which the Project was developed been described and are the Alternatives to the design of the Project considered during this process been described? (for assistance, see also the guidance on types of Alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.4	Have the Alternatives to the design considered during this process been described? (for assistance, see also the guidance on types of alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.5	Have the Alternatives to technology been considered during this process? (for assistance, see also the guidance on types of Alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.6	Have the Alternatives to the location considered during this process been described? (for assistance, see also the guidance on types of alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.7	Have the Alternatives to the size considered during this process been described (for assistance, see also the guidance on types of alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.8	Have the Alternatives to the scale considered during this process been described? (for assistance, see also the guidance on types of alternatives which may be relevant in the Scoping Guidance Document in this series)			
4.9	Has the Baseline situation in the 'do-nothing' scenario been described?			
4.10	Are the Alternatives realistic and genuine Alternatives to the Project? (i.e. feasible Project options that meet the objectives)			

4.11	Have the main reasons for choosing the proposed Project been provided, including an indication of the main reasons for selecting the chosen option, including a comparison of the environmental effects?			
4.12	Are the main environmental effects of the Alternatives compared to those of the proposed Project?			
4.13	Are Mitigation Measures considered in the assessment of Alternatives? (more on mitigation in section 5 below)			
Other Questions on Consideration of Alternatives				

SECTION 5 DESCRIPTION OF MITIGATION				
No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
5.1	Where there are significant adverse effects on any aspect of the environment, has the potential for the mitigation of these effects been discussed?			
5.2	Have the measures that the Developer has proposed to implement, in order to mitigate effects, been clearly described and is their effect on the magnitude and significance of impacts clearly explained?			
5.3	Have any proposed mitigation strategy's negative effects been described?			
5.4	If the effect of Mitigation Measures on the magnitude and significance of impacts is uncertain, has this been explained?			
5.5	Is it clear if the Developer has made a binding commitment to implement the mitigation proposed or acknowledged that the Mitigation Measures are just suggestions or recommendations?			
5.6	Do the Mitigation Measures cover both the construction and operational phases of the Project?			
5.7	Have the Developer's reasons for choosing the proposed mitigation been explained?			
5.8	Have the responsibilities for the implementation of mitigation including roles, responsibilities, and resources been clearly defined?			
5.9	Where the mitigation of significant adverse effects is not practicable, or where the Developer has chosen not to propose any mitigation, have the reasons for this been clearly explained?			
5.10	Is it evident that the practitioners developing the EIA Report and the Developer have considered the full range of possible approaches to mitigation, including measures to avoid, prevent or reduce and, where possible, offset impacts by alternative strategies or locations, changes to the Project design and layout, changes to methods and processes, 'end of pipe' treatment, changes to implementation plans and management practices, measures to repair or remedy impacts and measures to compensate impacts?			
Other Questions on Mitigation				

SECTION 5 DESCRIPTION OF MITIGATION				
No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?

SECTION 6 DESCRIPTION OF MONITORING MEASURES				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
6.1	Where adverse effects on any aspect of the environment are expected, has the potential for the monitoring of these effects been discussed?			
6.2	Are the measures, which the Developer proposes implementing to monitor effects, clearly described and has their objective been clearly explained?			
6.3	Is it clear whether the Developer has made a binding commitment to implement the proposed monitoring programme or that the Monitoring Measures are just suggestions or recommendations?			
6.4	Have the Developer's reasons for choosing the monitoring programme proposed been explained?			
6.5	Have the responsibilities for the implementation of monitoring, including roles, responsibilities, and resources been clearly defined?			
6.6	Where monitoring of adverse effects is not practicable, or the Developer has chosen not to propose any Monitoring Measures, have the reasons for this been clearly explained?			
6.7	Is it evident that the practitioners developing the EIA Report and the Developer have considered the full range of possible approaches to monitoring, including Monitoring Measures covering all existing environmental legal requirements, Monitoring Measures stemming from other legislation to avoid duplication, monitoring of Mitigation Measures (ensuring expected significant effects are mitigated as planned), Monitoring Measures capable of identifying important unforeseen effects?			
6.8	Have arrangements been proposed to monitor and manage residual impacts?			
Other Questions on Monitoring Measures				

SECTION 7 QUALITY				
No.	Review Question	Relevant?	Adequately Addressed?	What further information is needed?
Quality of presentation				
7.1	Is the EIA Report available in one or more clearly defined documents?			
7.2	Is the document(s) logically organised and clearly structured, so that the reader can locate information easily?			
7.3	Is there a table of contents at the beginning of the document(s)?			
7.4	Is there a clear description of the process that has been followed?			
7.5	Is the presentation comprehensive but concise, avoiding irrelevant data and information?			
7.6	Does the presentation make effective use of tables, figures, maps, photographs, and other graphics?			
7.7	Does the presentation make effective use of annexes or appendices to present detailed data that is not essential to understanding the main text?			
7.8	Are all analyses and conclusions adequately supported with data and evidence?			
7.9	Have all sources of data been properly referenced?			
7.10	Has terminology been used consistently throughout the document(s)?			
7.11	Does it read as a single document, with cross referencing between sections used to help the reader navigate through the document(s)?			
7.12	Is the presentation demonstrably fair and, as far as possible, impartial and objective?			
Non-Technical Summary				
7.13	Does the EIA Report include a Non-Technical Summary?			
7.14	Does the Summary provide a concise but comprehensive description of the Project, its environment, the effects of the Project on the environment, the proposed Mitigation Measures, and proposed monitoring arrangements?			
7.15	Does the Summary highlight any significant uncertainties about the Project and its environmental effects?			
7.16	Does the Summary explain the Development Consent process for the Project and the EIA's role in this process?			
7.17	Does the Summary provide an overview of the approach to the assessment?			

SECTION 7 QUALITY				
No.	**Review Question**	**Relevant?**	**Adequately Addressed?**	**What further information is needed?**
7.18	Has the Summary been written in non-technical language, avoiding technical terms, detailed data, and scientific discussion?			
7.19	Would it be comprehensible to a lay-member of the public?			
Expertise				
7.20	Is the competency of experts, who are responsible for the preparation of the EIA Report, indicated or otherwise explained in the EIA Report?			
7.21	Has the Developer complied with national or local legal requirements and practices for the selection of experts responsible for the preparation of the EIA Report?			
Other Questions on Quality of Presentation				

ANNEXES

ANNEX I – LINKS WITH OTHER EU INSTRUMENTS

The EIA Directive is just one of many pieces of EU legislation in place that affect environmental and Project planning. This poses the risk of duplication of assessments and procedures, and offers various possibilities for synergy. Under the principle of Better Regulation, whereby EU policies and laws should be designed and implemented so that they achieve their objectives at minimum cost[20], efforts are underway to 'streamline' these different assessments and procedures where possible. It is important to bear in mind that 'streamlining' in this context means improving and better coordinating environmental assessment procedures with a view to reducing unnecessary administrative burdens, create synergies and hence speed up the environmental assessment process, whilst at the same time ensuring a maximum level of environmental protection through comprehensive environmental assessments.

Streamlining measures can, therefore, be found in the EIA Directive:

- **Joint or coordinated procedures (Article 2(3) of the EIA Directive)**

Article 2(3) of the EIA Directive requires Member States to set up coordinated or joint procedures when an assessment is required, both under the EIA Directive and the Habitats Directive (see below). Moreover, Member States have the possibility to apply these joint or coordinated procedures to other environmental assessments stemming from EU legislation, in particular under the Water Framework Directive and the Industrial Emissions Directive. See below for more specific information on interactions with these pieces of legislation. Practitioners are advised to check their national legislation to see when and how coordination is required.

- **Consideration of other assessments (Article 4(4), Article 5(1) of the EIA Directive)**

Article 4(4) of the EIA Directive relating to the Screening stage of the EIA process, as well as Article 5(1) of the EIA Directive on the preparation of the EIA Report, requires practitioners to take the available results of other relevant assessments under other EU and national legislation into account.

- **Other relevant information held by authorities (Article 5(4) of the EIA Directive)**

In order to strengthen the availability of data, Article 5(4) of the EIA Directive requires any authorities holding relevant information to make it available to the Developers of Projects subject to EIA.

This section introduces the main pieces of EU legislation relevant for streamlining with EIA. Practitioners should always check whether their Project falls under other EU legislation, and their respective national transposing measures, and be aware that there are various other guidance documents issued at EU and national level to help practitioners untangle legislative complexities. Some of these EU guidance documents are referred to in the relevant sections under Part B of the EIA guidance documents and are also listed below as well as in another Annex to this Guidance Document on Other Relevant Guidance Documents.

The legislation covered in this section is by no means an exhaustive list, but the legislation with the most significance include the following (formal names are introduced below):

- SEA Directive;
- Birds and Habitats Directives;
- Water Framework Directive;
- Marine Strategy Framework Directive;
- Ambient Air Quality Directive and Heavy Metals in the Ambient Air Directive;
- Waste Framework Directive;

[20] European Commission Staff Working Document, *Better Regulation Guidelines*, SWD (2015) 111 final.

- Industrial Emissions Directive;
- Seveso Directive
- Trans-European networks: TEN-E, TEN-T and TEN-TEC Regulations;
- Aarhus and ESPOO conventions (including Directive 2003/4/EC and 2003/35/EC).

SEA DIRECTIVE

Name used	Formal name
Strategic Environmental Assessment (SEA) Directive	▪ Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment
Relevant EU guidance:	▪ Commission guidance document on Streamlining environmental assessments conducted under Article 2(3) of the EIA Directive; ▪ Commission guidance document on the implementation of Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment; ▪ Commission guidance on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (PCIs).

The SEA Directive concerns the Strategic Environmental Assessment, which is carried out on certain plans and programmes. In many cases, an SEA of a relevant plan or programme underpinning a proposed Project will have been carried out prior to the EIA. Article 3(2) of the SEA Directive requires an SEA to be undertaken if the plan or programme 'sets the framework' for a Project listed in Annexes I and II to the EIA Directive.

Opportunities for synergy
The SEA and EIA are similar procedures, despite the former being carried out on plans and programmes and the latter involving Projects. Both assessments can be summarised as follows: an environmental report is prepared in which the likely significant effects (of plans, programmes or Projects) on the environment and the reasonable alternatives are identified; the environmental authorities and the public (and affected Member States) must be informed and consulted; the Competent Authority decides, taking the results of consultations into consideration. The public is informed of the decision afterwards. While the scope of the two assessments usually differs, very often much of the work carried out under the SEA can be built upon for the EIA. Alternatives identified during the SEA may be relevant for the EIA, some of the data gathered under the SEA may be used to form the baseline of the EIA. Practitioners carrying out the EIA should consult the SEA report done for any relevant plans or programmes with a view of avoiding the duplication of work.

The Guidance document on Streamlining environmental assessments for energy infrastructure Projects of Common Interest (PCIs) (see the Annex to this Guidance Document on Other Relevant Guidance and Tools) provides guidance on how to take advantage of synergies between the SEA and EIA procedures. In addition, various guidance documents exist at national level.

During the Screening procedure of EIA Projects, assessments carried out under the SEA Directive may be directly relevant to the determination of whether or not the Project may have significant impacts on the environment. This may be the case if the assessment under the SEA Directive contains information on specific sensitivities of the local area to certain developments in which the Project is proposed.

Joint/coordinated procedures
Joint or coordinated procedures are not directly provided for by the provisions of the EIA and SEA Directives, given that one relates to projects (Article 2(3) of the EIA Directive) and the other to plans/programmes (Article 11(2) of the SEA Directive); moreover, each procedure must be carried out

on its own merits (Article 11(1) of the SEA Directive). The CJEU has indeed held that an assessment undertaken within the framework of the EIA Directive does not dispense with the requirement to carry out an assessment under the SEA Directive (cf. C-295/10, *Valčiukienė and Others*, para 55-63). However, in some cases a plan/programme, and the subsequent project development, can be subjected to an integrated assessment procedure: Member States are free to set up such mechanisms, as long as all of the requirements of both Directives are fulfilled. In this perspective, the CJEU also held, in the same decision, that a joint procedure may take place in which the requirements under both Directives are covered by a single environmental assessment procedure (cf. C-295/10, *Valčiukienė and Others*, para 55-63).

BIRDS AND HABITATS DIRECTIVES

Name used	Formal name
Habitats Directive	■ Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna
Birds Directive	■ Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds
Relevant EU guidance:	■ Commission guidance document on Streamlining environmental assessments conducted under Article 2(3) of the EIA Directive; ■ Commission guidance on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (PCIs) ■ Commission guidance on Managing Natura 2000 sites: the provisions of Article 6 of Directive 92/43/EEC ■ Manual of European Union Habitats - EUR28.

The Habitats Directive, along with the Birds Directives (Directive 2009/147/EC), aim to contribute towards ensuring biodiversity through the conservation of natural habitats and of wild fauna and flora in the EU Members States. Together, these Directives set up a coherent network of sites (the Natura 2000 Network) hosting habitats and/or species that should be maintained or restored at favourable conservation status according to the terms of the Directives. Any plan or Project likely to have a significant effect on a site within the Natura 2000 site is subject to an Appropriate Assessment (AA) of the implications for the site in view of the site's conservation objectives (Habitats Directive, Article 6(3)). The AA decision is binding and determines whether a plan or Project may proceed, subject to specific provisions set out in Article 6(4).

Opportunities for synergy
The scope of the AA and the EIA is different – the EIA should consider all significant environmental effects, while the AA focuses on the conservation objectives and the integrity of the Natura 2000 site in question; however, as with the SEA detailed above, some of the information collected for one assessment can be used for the other.

Joint/coordinated procedures
Article 2(3) of the EIA Directive stipulates that when Projects have to be assessed under both the EIA and the Birds or Habitats Directives, Member States *shall, where appropriate*, ensure that coordinated and/or joint procedures are provided for. This differs from instances in which Projects also have to be assessed under other EU legislation, where Member States *may* provide for coordinated and/or joint procedures. The EIA Directive makes several references to the Habitats Directive, for example, when identifying significant impacts of a Project, particular attention must be paid to species and habitats protected by the Birds and the Habitats Directives. The EU has issued a guidance document to assist practitioners in the extent to which the results from an AA assessment is taken into account in an EIA Procedure (see the Guidance document on streamlining environmental assessments conducted under Article 2(3) of the EIA Directive, full references in the Annex to this Guidance Document on Other Relevant Guidance and Tools).

WATER FRAMEWORK DIRECTIVE

Name used	Formal name
WFD	■ Directive 2000/60/EC of the European Parliament and of the Council establishing a framework for the Community action in the field of water policy
Relevant EU guidance:	■ Commission guidance document on Streamlining environmental assessments conducted under Article 2(3) of the EIA Directive ■ Commission guidance on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (PCIs) ■ Common Implementation Strategy for the WFD: Guidance document no 7 Monitoring under the Water Framework Directive ■ Common Implementation Strategy for the WFD: Guidance document no 20 Exemptions to the Environmental Objectives

The WFD establishes a framework for the protection of inland surface waters, transitional waters, coastal waters, and groundwater. Under this Directive, River Basin Management Plans (RBMP) are established and updated every 6 years to coordinate and implement water status-related measures within each river basin. RBMPs must address the objectives set out by the WFD, and must include an analysis of the river basin's key characteristics, a pressures assessment, review of the impact of human activity on the status of water and measures to meet the Directive's objective of 'good status' for all waters.

Projects that may lead to failure of achieving good status of water bodies or lead to deterioration of quality elements need to be assessed and if possible, a more environmentally friendly alternative should be found. If no alternative can be found, then the Project can only go ahead when it can demonstrate that first all practicable Mitigation Measures are taken to reduce the impact. Secondly, it must also be demonstrated that the reasons for deterioration are of overriding public interest or that the Project's benefits otherwise outweigh failure to achieve the relevant environmental objectives (cf. conditions set out in Article 4(7) of the WFD). The process of identifying and assessing such impacts may be carried out jointly with the EIA procedure. However, the requirement of Article 4(7) of the WFD goes beyond the requirements of the EIA Directive in the sense that it covers activities that may not be listed in Annex I or II to the EIA Directive.

Opportunities for synergy
The WFD ensures that detailed environmental data are collected for water as part of the planning process of the RBMP. Hence, synergies can be gained for part of an EIA through data collection and the required assessments of effects on water bodies according to Article 4(7) of the WFD. As discussed above, if a Project listed in Annex I or II to the EIA Directive is found to impact the status of a water body as set out in the relevant RBMP, further assessment will be required to develop and review alternatives and possibly justify reasons of overriding public interest in line with the requirements of the Water Framework Directive. This may influence the scope and nature of an EIA Report in the sense that it must incorporate an assessment of the likely impacts of the Project on the objectives adopted for the water body in question.

Joint/coordinated procedure
Article 2(3) of the EIA Directive provides the option for joint or coordinated procedures where Projects also have to be assessed under other EU legislation, but it is not a requirement.

MARINE STRATEGY FRAMEWORK DIRECTIVE

Name used	Formal name
MSFD	■ Directive 2008/56/EC establishing a framework for community action in the field of marine environmental policy (Marine Strategy Framework Directive)
Relevant EU guidance:	■ Commission Final report on MSFD and licencing and permitting

The Marine Strategy Framework Directive (MFSD) establishes a framework to assess and implement good environmental status of the EU's marine waters by 2020. In doing so, the MSFD takes an ecosystem and integrated approach whereby environmental protection and sustainable use go hand in hand to prevent depletion of natural resources upon which marine-related economic and social activities are based.

Opportunities for synergy
The MSFD ensures that an environmental baseline for the marine waters are established. On the basis of this assessment and baseline, measures must be adopted and gradually implemented to ensure that good environmental status is achieved within a specified number of years. Unlike the WFD, there is no independent requirement in the MSFD to assess activities. However, the objectives and measures adopted in Member States may influence the scope and nature of an EIA Report in the sense that it must incorporate an assessment of the likely impacts of the Project on the objectives adopted for the marine water body in question.

Joint/coordinated procedure
Article 2(3) of the EIA Directive provides the option for joint or coordinated procedures where Projects also have to be assessed under other EU legislation, but it is not a requirement.

AMBIENT AIR QUALITY DIRECTIVE AND HEAVY METAL IN AMBIENT AIR DIRECTIVE

Name used	Formal name
AQD	■ Directive 2008/50/EC of the European Parliament and of the Council of 21 May 2008 on ambient air quality and cleaner air for Europe
HMAQD	■ Directive 2004/107/EC of the European Parliament and of the Council of 15 December 2004 relating to arsenic, cadmium, mercury, nickel and polycyclic aromatic hydrocarbons in ambient air
Relevant EU guidance:	■ N/A

The AQD establishes a framework for the active monitoring of ambient air and the removing of pollutants. The Directive establishes different air quality objectives (limit values, target values, critical levels and threshold) in relation to a wide range of pollutants (sulphur dioxide, nitrogen, dioxide, particulate matter, lead, benzene, carbon monoxide). It requires air quality plans when limit or target values are not complied with as well as short-term action plan when alert thresholds are exceeded. In addition, the Directive obliges Member States to keep the public informed and sets out requirements for the assessment of air quality (e.g., the monitoring network). In addition, the HMAQD sets limit values for the air pollutants arsenic, cadmium, nickel and benzo(a)pyrene.

Opportunities for synergy
During the preparation of the EIA Report, the existence of air quality objectives as well as existing air quality plans and short term action plans, provide a strong basis for the analysis of the Baseline, Alternatives to the Project, and environmental factors, in addition to any possible remedial action.

WASTE FRAMEWORK DIRECTIVE

Name used	Formal name
WasteFD	■ Directive 2008/98/EC of the European Parliament and of the Council of 19 November 2008 on waste and repealing certain directives
Relevant EU guidance:	■ Application of EIA Directive to the rehabilitation of landfills.

The WasteFD establishes a legal framework for the management and treatment of most waste types. The Directive sets out a waste hierarchy that ranges from prevention to disposal. Waste management under the Directive must be implemented without endangering human health and without harming the environment (e.g. without risk to water, air, biodiversity, and without causing nuisance). It also sets out rules for extended producer responsibility, effectively adding to the burdens of manufacturers to manage products returned after use.

Opportunities for synergy
The WasteFD requires the adoption and implementation of Waste Management Plans and Waste Prevention Programmes at the national and local levels. These plans and programmes should analyse the current situation with regards to waste treatment, as well as identify the measures needed to carry out waste management in the context of the WasteFD's objectives. This includes existing and planned waste management installations, which are likely to constitute Projects subject to the EIA Directive. As waste installations should be provided for under Waste Management Plans, they are also subject to the requirements of the SEA Directive (see above).

The EIA Directive may also bear relevance for any Project with regard to the waste produced not only during the construction and operation of the Project, but also, in particular, with regard to the decommissioning and/or rehabilitation of the site.

During the preparation of the EIA Report, the waste produced and returned to the Project location must be taken into consideration in assessing the Project's significant effects on the environment, and would be relevant for the establishment of Alternatives and Mitigation as well as Compensation Measures.

INDUSTRIAL EMISSIONS DIRECTIVE

Name used	Formal name
IED	■ Directive 2010/75/EU of the European Parliament and the Council on industrial emissions
Relevant EU guidance:	■ Guidance under Article 13(3)(c) and (d) of the IED; ■ Commission Communication on the elaboration of baseline reports under Article 22(2) of the IED.

The IED is the main EU instrument regulating pollutant emissions from industrial installations. Around 50,000 Projects undertaking the industrial activities listed in Annex I to the IED are required to operate in accordance with a permit, which should contain conditions set in accordance with the principles and provisions of the IED. As indicated in the Commission Guidance document on 'Interpretation of definitions of Project categories of Annex I and II to the EIA Directive' (see the Annex to this Guidance Document on Other Relevant Guidance and Tools): the EIA Directive and the Industrial Emissions Directive (IED) sometimes relate to the same type of activities. However, it is important to be aware of the differences that exist between the objective, the scope, classification systems, and thresholds of these two directives.

Opportunities for synergy
IED permits must take the whole environmental performance of the industrial plant into account, including emissions to air, water, and land, generation of waste, use of raw materials, energy efficiency, noise, prevention of accidents, and the restoration of the site upon closure. Such an exercise aligns closely with the EIA Directive and 'Member States have discretion to use the thresholds set by Annex I to the IED in the context of the EIA Directive' (Commission Guidance Document, Interpretation of definitions of Project categories of Annex I and II to the EIA Directive, see the Annex to this Guidance Document on Other Relevant Guidance and Tools).

In addition, permits issued under the IED are to be reconsidered periodically to ensure compliance. While monitoring carried out under the IED will likely not cover all environmental aspects to be considered, the IED does require specific monitoring, part of which can be used for the EIA. The approach to monitoring for the IED can also be adopted and broadened to cover other aspects outlined in EIA monitoring proposals.

Joint/coordinated procedure
Article 2(3) of the EIA Directive provides the option for joint or coordinated procedures where Projects also have to be assessed under other EU legislation, but it is not a requirement.

SEVESO DIRECTIVE

Name used	Formal name
Seveso Directive	Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major-accident hazards involving dangerous substances
Relevant EU guidance:	Commission guidance document on Streamlining environmental assessments conducted under Article 2(3) of the EIA Directive Guidance tools are collected on the Minerva portal at: https://minerva.jrc.ec.europa.eu/en/minerva

The Seveso Directive was adopted in response to the industrial accident releasing hazardous chemicals in the Italian city of Seveso in 1976. The Directive has since been revised several times. The aim of the Seveso Directivef is to prevent and, in case they occur, limit major accidents involving dangerous substances. It applies to establishments where dangerous substances may be present in quantities above a certain threshold. Certain industrial activities covered by other EU legislation are excluded from the Seveso Directive (e.g. nuclear establishments or the transport of dangerous substances).

The Seveso Directive takes a tiered approach to requiring safety measures at facilities based on the volumes of dangerous substances present at facilities. Seveso sites are categorised as lower-tier Seveso establishments or upper-tier Seveso establishments. Operators of lower-tier Seveso establishments have to notify the competent authority, design a major-accident prevention policy (MAPP), draw up accident reports and take into account land-use planning. In addition to these requirements, operators of upper-tier Seveso establishment must establish a safety report, implement a safety management system, define an internal emergency plan and provide the competent authorities with all necessary information. Furthermore, authorities are required inter alia to produce external emergency plans for upper tier establishments, deploy land-use planning for the siting of establishments, make relevant information publically available, ensure that any necessary action is taken after an accident including emergency measures, and conduct inspections.

Opportunities for synergy
The Seveso Directive is highly relevant to a number of assessments under the EIA Directive such as for instance impacts related to risks of major accidents and disasters, Mitigation, and climate change

adaptation. In addition, in light of the risk presented by establishments covered by the Seveso Directive, rules on permitting as well as regarding governance come into play, and as such the Seveso Directive is often directly linked to other legislation listed in this Annex, such as the IED and Aarhus convention. The Seveso Directive in this regard ensures that detailed information on installations are collected and employed in both land-use planning as well as in contingency planning. Synergies with EIA can be gained for a part of the EIA report containing the design of installations and the assessment of risk hazards that relates to the chosen design. The Seveso Directive can also be of use for the Screening, Scoping and Preparation of the EIA Report stages in relation to: quantitative thresholds for the assessment of significance, rules of public information in relation to governance, and finally the rules on Monitoring.

Joint/coordinated procedure
Article 2(3) of the EIA Directive provides the option for joint or coordinated procedures where Projects also have to be assessed under other EU legislation, but it is not a requirement.

TRANS-EUROPEAN NETWORKS IN TRANSPORT, ENERGY AND TELECOMMUNICATION

Name used	Formal name
TEN-T Regulation: Trans-European Transport Network	■ Regulation (EU) No 1315/2013 of the European Parliament and of the Council of 11 December 2013 on Union guidelines for the development of the trans-European transport network
TEN-TEC Regulation: Trans-European Telecommunication Network	■ Regulation (EU) No 283/2014 of the European Parliament and of the Council of 11 March 2014 on guidelines for trans-European networks in the area of telecommunications infrastructure.
TEN-E Regulation Trans-European Energy Network (PCI regulation)	■ Regulation (EU) No 347/2013 Of The European Parliament and of The Council ■ of 17 April 2013 on guidelines for trans-European energy infrastructure.
Connecting Europe Facility: financing for TENs	■ Regulation (EU) No 1316/2013 of the European Parliament and of the Council of 11 December 2013 establishing the Connecting Europe Facility.
Relevant EU guidance:	■ Commission guidance on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (PCIs).

The Trans-European Networks consists of lists of key transport, energy and telecommunications infrastructure Projects, known as Projects of common interest (PCIs). These Projects are designed to complete the European internal market and by interconnecting national infrastructure networks and ensuring their interoperability, thereby fulfilling e.g. the EU's energy policy objectives of affordable, secure and sustainable energy.

Under the TEN-E regulation for the energy sector, PCIs can benefit from accelerated planning and permit granting, due to streamlined environmental assessment processes.

AARHUS AND ESPOO CONVENTIONS

Name used	Formal name
Aarhus Convention	■ United National Economic Commission for Europe Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters.
Espoo Convention	■ United National Economic Commission for Europe Convention on Environmental Impact Assessment in a Transboundary context.
	■ Directive 2003/4/EC of the European Parliament and of the Council on public access to environmental information and repealing Council Directive 90/313/EEC.

	- Directive 2003/35/EC of the European Parliament and of the Council of 26 May 2003 providing for public participation in respect of the drawing up of certain plans and programmes relating to the environment and amending with regards to public participation and access to justice Council Directives 85/337/EEC and 96/61/EC - Statement by the Commission.
Relevant EU guidance:	- Guidance on the Application of the Environmental Impact Assessment Procedure for Large-scale Transboundary Projects; - Guidance document for member States' reporting under Article 9 of Directive 2003/4.

The Aarhus Convention establishes a number of rights of the public, both individuals and their associations, with regard to the environment. These rights are commonly depicted under the three pillars of access to environmental information, public participation in decision-making, and access to justice in environmental affairs. Parties to the Convention are required to make the necessary provisions so that public authorities will contribute to these rights to become effective. All EU Member States, as well as the EU itself, are parties to the Convention. The first two pillars are also part of EU law via Directives 2003/4/EC and 2003/35/EC, in addition a number of provisions in different EU instruments seek to implement these rights, such as the public participation and access to justice requirements under the EIA Directive, or the Access to Justice provisions under the IED Directive.

The Espoo Convention lays down the general obligation of States to notify and consult each other on all major Projects under consideration that are likely to have a significant adverse environmental impact across boundaries. Article 7 of the EIA Directive provides the legal basis for regulating Member States' rights and obligations in case of an EIA Procedure for a Project with transboundary impacts. Article 7(1) provides rights for the potentially affected Member States to be informed about e.g. a Screening procedure in another Member State. The affected Member State is to be informed at the latest by the time at which the public is informed in the Member State in which the Project is proposed for implementation.

Opportunities for synergy

The Aarhus Convention is the most comprehensive legal instrument relating to public involvement. By establishing rules on information and participation of the public, the Aarhus Convention has led to decisions setting precedents (e.g. on timeframes for informing the public), which can assist in the implementation of the EIA procedure. The main text indicates that public participation should be effective, adequate, formal, and provide for information, notification, dialogue, consideration, and response. Furthermore, just as the EIA Directive requires ‘reasonable timeframes’, so too does the Aarhus Convention. These may have an impact on the different stages discussed in the EIA Guidance Document series, for instance in relation to consultations, the EIA Directive establishes specific consultation requirements (see Part B Section 3.1).

ANNEX II – OTHER RELEVANT GUIDANCE AND TOOLS

- A. Andrusevych, T. Alge, C. Konrad (eds), Case Law of the Aarhus Convention Compliance Committee 2004-2011, 2nd edition

  [redacted]
- Chartered Institute of Ecology and Environmental Management, Guidelines for ecological impact assessment in the UK and Ireland, Terrestrial, Freshwater, and Coastal, January 2016

  [redacted]
- Commission, Assessment of plans and projects significantly affecting Natura 2000 sites, Methodological guidance on the provisions of Article 6(3) and (4) of the Habitats Directive 92/43/EEC

  [redacted]
- Commission, Assessment of resource efficiency indicators and targets

  [redacted]
- Commission Communication on the elaboration of baseline reports under Article 22(2) of the IED (European Commission Guidance concerning baseline reports under Article 22(2) of Directive 2010/75/EU on industrial emissions)

  [redacted]
- Commission, DG Climate Action, Non-paper, Guidelines for Project Managers: Making vulnerable investments climate resilient

  [redacted]
- Commission Final report on MSFD and licencing and permitting

  https://circabc.europa.eu/sd/a/ca90e911-6585-4de0-983f-dd07a5c2a519/MSCG_19-2016-04_Study%20on%20licencing%20and%20permitting%20and%20MSFD_Final%20Report%20Arcadis.pdf
- Commission guidance document on Non-energy mineral extraction and Natura 2000

  [redacted]
- Commission guidance document for Member States' reporting under Article 9 of Directive 2003/4 (Guidance document on reporting about the experience gained in the application of directive 2003/4/ec concerning on public access to environmental information)

  [redacted]
- Commission guidance document no 7. Monitoring under the Water Framework Directive

  [redacted]
- Commission guidance document no 20. Exemptions to the Environmental Objectives

  [redacted]
- Commission guidance document on Inland waterway transport and Natura 2000, Sustainable inland waterway development and management in the context of the EU Birds and Habitats Directives

  [redacted]
- Commission guidance on Aquaculture and Natura 2000, Sustainable aquaculture activities in the context of the Natura 2000 Network

  [redacted]
- Commission guidance on Managing Natura 2000 sites: the provisions of Article 6 of Directive

92/43/EEC

[redacted]

- Commission guidance document on Streamlining environmental assessments conducted under Article 2(3) of the EIA Directive

  [redacted]

- Commission guidance on the application of the Environmental Impact Assessment Procedure for Large-scale Transboundary Projects

  [redacted]

- Commission guidance on wind energy development in accordance with the Natura 2000

  [redacted]

- Commission guidance document on the implementation of Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment (Title: Directive 2001/42/EC of the European Parliament and of the Council of 27 June 2001 on the assessment of the effects of certain plans and programmes on the environment)

  [redacted]

- Commission guidance on Streamlining environmental assessment procedures for energy infrastructure Projects of Common Interest (PCIs)

  [redacted]

- Commission guidance under Article 13(3)(c) and (d) of the IED (Guidance document on the practical arrangements for the exchange of information under the Industrial Emissions Directive (2010/75/EU), including the collection of data, the drawing up of best available techniques reference documents and their quality assurance as referred to in Article 13(3)(c) and (d) of the Directive)

  [redacted]

- Commission guidelines for the assessment of indirect and cumulative impacts as well as impact interactions

  [redacted]

- Commission, interpretation manual of European Union habitats - EUR28

  [redacted]

- Commission, Interpretation of definitions of Project categories of annex I and II to the EIA Directive

  [redacted]

- Commission JRC Institute for Environment and Sustainability, Life cycle indicators framework: development of life cycle based macro-level monitoring indicators for resources, products and waste for the EU-27

  [redacted]

- Commission Services Non-Paper: Application of EIA Directive to the rehabilitation of landfills

  [redacted]

- Commission Services Non-Paper: Interpretation line suggested by the Commission as regards the application of Directive 85/337/EEC to associated/ancillary works

  [redacted]

- Commission Support assessment tools, Tools developed to support the assessment of the marine environment under the MSFD

  [redacted]

- Commission Staff Working Document, Better Regulation Guidelines

  [redacted]

- European Environment Agency Land and Ecosystem Accounting - European Topic Centre Terrestrial Environment, LEAC methodological guidebook

  [redacted]

[redacted]

- EMEC, Environmental impact assessment (EIA) guidance for developers at the European Marine Energy Centre

  [redacted]

- European Investment Bank, Methodologies for the Assessment of Project GHG Emissions and Emission Variations

  [redacted]

- Global Marine Environment Protection, Initiative

  [redacted]

- Global Marine Information System, Environmental Marine Information System

  [redacted]

- IEMA Quality Mark Article: 'What are the changes of that' – Probability and its Role in Determining Impact Significance

  [redacted]ce.pdf

- Imperia (EU LIFE+ funded project), Improving Environmental Assessment by Adopting Good Practices and Tools of Multi-criteria Decision Analysis

  [redacted]

- Jalava, K., et al., (2010) Quality of Environmental Impact Assessment: Finnish EISs and the opinions of EIA professionals, Impact Assessment and Project Appraisal, 28:1, 15-27

  [redacted]

- [redacted]ood Examples of EIA and SEA Regulation and Practice in five European Union Countries, 2008

  [redacted]

- [redacted]

- Netherlands Commission for Environmental Assessment & CBD-Ramsar-CMS, Voluntary Guidelines on biodiversity-inclusive Environmental Impact Assessment

  [redacted]

- [redacted].d2s

- Renewables Grid Initiative, Good Practice of the Year 2016 award

  [redacted]

- RPS, Environmental impact assessment practical guidelines toolkit for marine fish farming

  [redacted]

- Schmidt, M., Glasson, J., Emmelin, L. and Helbron, H., Standards and Thresholds for Impact Assessment, 2008.

- Scottish Natural Heritage, A handbook on environmental impact assessment: Guidance for Competent Authorities, Consultees and others involved in the Environmental Impact Assessment Process in Scotland http://www.snh.gov.uk/publications-data-and-research/publications/search-the-catalogue/publication-detail/?id=2098

- Sixth Framework Programme, Specific Targeted Research or Innovation Project Risk Assessment D 3.2 Report WP 3

  [redacted]

- Slootweg, Roel; Kolhoff, Arend, Generic approach to integrate biodiversity considerations in screening and scoping for EIA
- UK Environment Agency: Environmental Impact Assessment (EIA), A handbook for Scoping projects

  https://www.gov.uk/government/publications/handbook-for-scoping-projects-environmental-impact-assessment

- UK Department of Energy & Climate Change, Guidance notes on the offshore petroleum production and pipelines (assessment of environmental effects) regulations 1999(as amended), October 2011

  https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/193705/eiaguidancenote.pdf

- UNFCCC, Highlights of the contribution of the Nairobi work programme, Assessing climate change impacts and vulnerability, making informed adaptation decisions

  [redacted]

KH-04-17-939-EN-N

Publications Office