elementenergy

Imperial College London Consultants

SUSTAINABLE GAS INSTITUTE

Assessment of Options to Reduce Emissions from Fossil Fuel Production and Fugitive Emissions

Final report

for

The Committee on Climate Change

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1 Executive summary

1.1 Motivation and methodology

The Climate Change Act sets the framework for the UK to transition to a low-carbon economy, requiring that UK emissions of greenhouse gases in 2050 are reduced by at least 80% compared to 1990 levels. The UK Government asked the Committee on Climate Change (CCC) for formal advice on the feasibility of the more ambitious target of reaching net zero emissions, the date by which this could be achieved and on how the necessary emissions reductions could be delivered. In order to answer these questions, the CCC's Fifth Carbon Budget scenario models must be updated to include a more comprehensive set of abatement options, many of which are more expensive.

In light of this set of modifications to the CCC's modelling, the scope of this study is focused on greenhouse gas (GHG) emissions from fossil fuel production and fugitive emissions. The outputs of this work are used to inform recommendations in the CCC's net-zero report in 2019.

The study was developed through the following steps:

- Characterisation of emission sources;
- Development of future baseline emissions projections;
- Identification of emission sources relevant from 2040 onwards;
- Selection of technological and operational abatement options for each relevant emission source;
- Quantification of the abatement potential and cost effectiveness of each abatement option;
- Estimation of the timeline for maximum uptake of each abatement option;
- Identification of non-technoeconomic costs, barriers and benefits associated with mitigation;
- Projection of future emissions considering the identified abatement options.

1.2 Baseline emissions

Emission sources in the scope of this study were characterised through mapping of the UK's coal, oil and natural gas supply chains. Emissions entries from the UK National Atmospheric Emissions Inventory (NAEI) were allocated to one or more sources in the appropriate supply chain. These sources were then categorised by the type of originating process, such as fuel combustion, fugitive emissions, venting or flaring.

In order to model a projection of baseline emissions, a number of triggers covering all emission sources were identified with available long-term forecasts from relevant institutions. Each emission source of the NAEI inventory in our scope was assigned to a trigger (e.g. oil production, LNG import, etc.). The review of relevant forecasts showed a consistent level of reduction for most triggers, but a high uncertainty in the projections for shale gas production and natural gas demand.

Baseline emissions projections for the sources in the scope of this study were calculated, based on trigger projections and 2016 emissions from the NAEI inventory, and these are summarised in Figure 1. Total baseline emissions are projected to decrease from roughly 24MtCO_2e in 2016 to 8MtCO_2e in 2070.

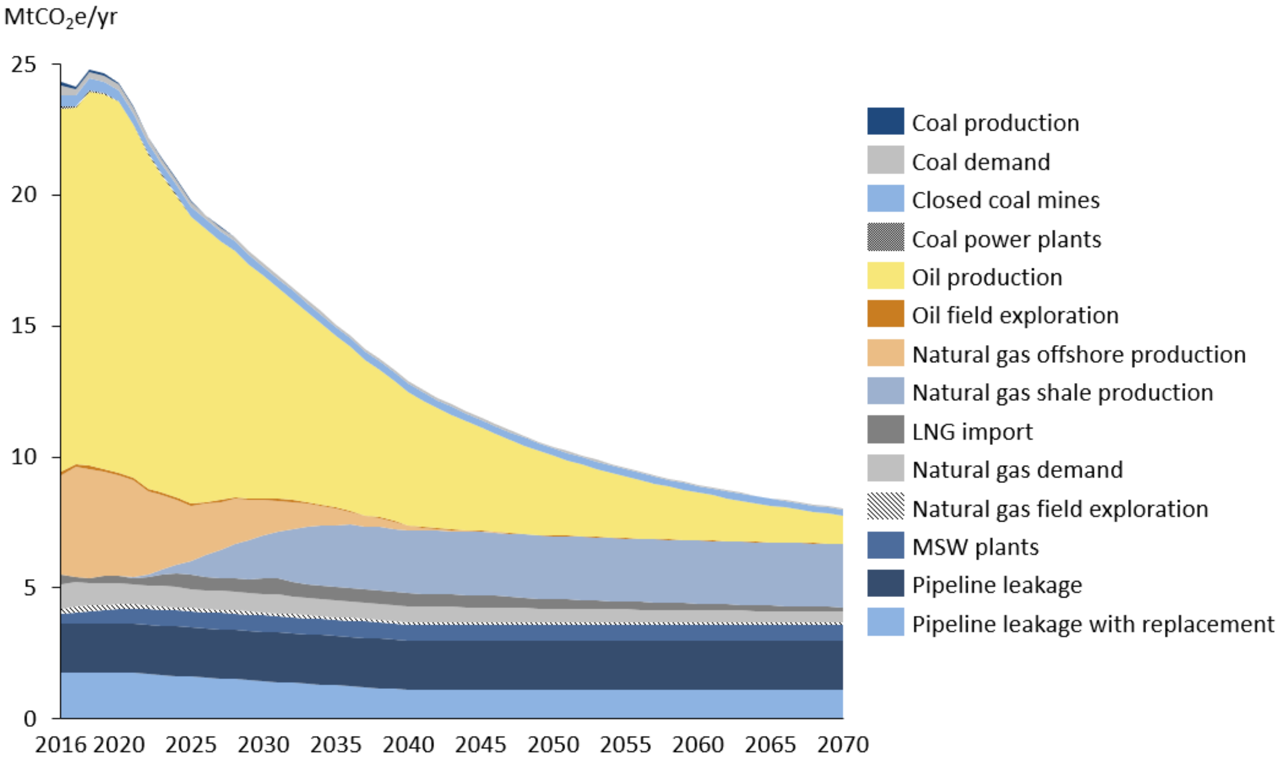


Figure 1: Baseline emissions by trigger

The main contributions to emissions between 2040 and 2070 are projected to originate from sources associated with offshore oil production, natural gas shale production (though highly uncertain) and from pipeline leakage. Baseline emissions related to oil production are projected to drop from 39% in 2040 to 14% in 2070, whereas emissions related to natural gas shale production are projected to increase from 19% in 2040 to 30% in 2070, based on our extrapolation of FES 2018 shale gas production projections used here[1]. Baseline emissions related to all pipeline leakage remain constant between 2040 and 2070.

Overall pipeline leakage constitutes a large fraction of baseline emissions, contributing to 23% of total baseline emissions in 2040 and 33% of total baseline emissions in 2060. The amount of these emissions is highly dependent on the future of the gas grid (and related decisions on gas use elsewhere in the economy) and may change in the case of closure of the gas grid, or parts of it, or in the case of grid switchover from natural gas to hydrogen. Considering 90% grid closure and/or switchover to hydrogen, total emissions could be expected to reduce from roughly 24MtCO_2e in 2016 to 5.3MtCO_2e in 2070.[2]

Other triggers such as coal demand, closed coal mines, liquefied natural gas (LNG) import, natural gas demand, natural gas field exploration and municipal solid waste (MSW) plants are each responsible for a minor contribution to total emissions, making up a total of 17% of emissions in 2040 and 19% in 2070.

1.3 Abatement technologies

A number of mitigation options applicable to the sources in the scope of this study were identified, broadly divided into three categories: fuel switching, carbon capture and storage, and process or technology specific measures. Cost effectiveness and GHG mitigation potentials for these technologies are summarised in Table 1, with abatement costs varying significantly among different technologies. The lowest cost abatement options were gas recovery to sales[3], reduced venting with flare and leak detection and repair (LDAR), with the gas

[1] Employed values are the average of Consumer Evolution scenario and Community Renewables scenario values.
[2] This amended baseline reflects abatement of natural gas use elsewhere in the economy.
[3] Recovery of fugitive gas for sales as grid gas or as LNG.

recovery option resulting in a negative cost per tonne due to additional sales when there is already a pipeline in place.

A value of technology readiness level (TRL) measuring the maturity of the technologies considered was also estimated and both the year of first deployment and year of maximum deployment were calculated accordingly.

Table 1: Summary of mitigation option costs and direct abatement potentials

Option	2016 Cost (£/tCO_2e)	Direct abatement potential
CCS offshore well – low CO_2 concentration	£284	90%
CCS onshore well – low CO_2 concentration	£152	90%
CCS offshore well – high CO_2 concentration	£226	90%
CCS onshore well – high CO_2 concentration	£94	90%
CCS SSF[4] oven, calcium looping	£144	90%
CCS SSF oven, amines	£224	90%
Hydrogen fuel switch	£200 - £209	100%
Electricity fuel switch from grid	£28 - £473	100%
Electricity fuel switch from wind with battery	£766	100%
Electric compressors from grid	£596 - £686	100%
Electric compressors from wind with battery	£1,101 - £1,180	100%
Heating fuel switch to electric grid	£478	100%
Gas recovery to sales	-£104 - -£17	50%
Continuous monitoring	£98	90%
LDAR	£15	40%
Strong LDAR (x6)	£66	80%
RECs[5]	£240	71%
Reduce vent and flare	£13	40%

A number of costs, benefits and barriers additional to the reported direct economic costs and climate change benefits are also associated to these abatement technologies.

Implementation of new abatement technologies would have a positive impact on the UK economy, helping to build new industry. It could also prolong the lifespan of the UK fossil fuel industry. The implementation of mitigation options also has implications for UK infrastructure, including pipeline upgrade in the case of hydrogen fuel switching, CO_2 storage infrastructure and electricity grid impacts.

Potential for unintended consequences should also be considered, such as the risk that oil and gas operators may prefer to decommission their fields earlier instead of investing in decarbonisation measures. We expect most/all existing oil and gas fields in the UK continental shelf (UKCS) to be beyond their production peak year rate after 2040, so that the remaining lifetime of these fields will not be enough to justify investment in abatement measures.

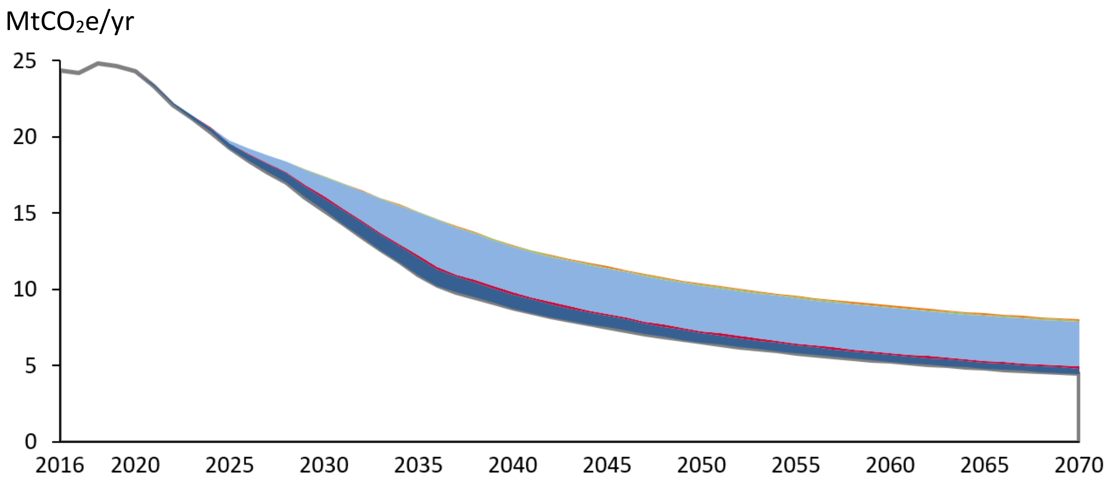
[4] Solid smokeless fuel (SSF)
[5] Reduced emissions completions (RECs)

1.4 Abatement of UK emissions

Up to three of the mitigation options were assigned to each emissions entry in the inventory.

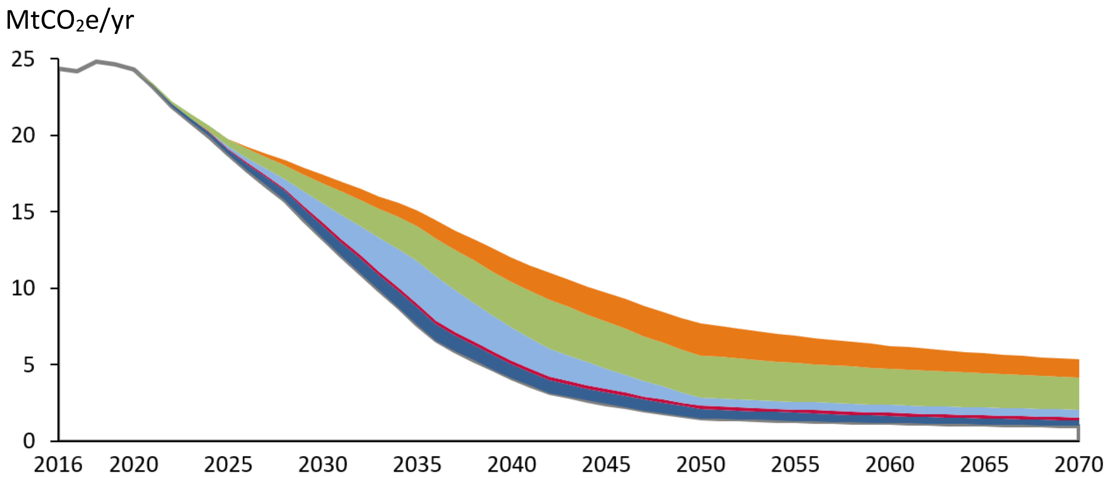
Separate technology scenarios were developed: a core scenario (employing mitigation options with cost-effectiveness below £100/tCO_2e), a further ambition scenario (with a cost-effectiveness limit of £400/tCO_2e) and a speculative scenario (employing any technology). The core scenario was assigned the baseline emissions profile shown in Figure 1, whereas the further ambition and speculative scenarios were assigned a lower profile of baseline emissions, with fewer emissions from pipe leakage due to an assumed 90% gas grid closure and/or switchover to hydrogen. Finally, slow, central and fast rollout profiles were considered for each technology, hastening or delaying the year of first deployment and the year of maximum deployment of the technology.

The abatements achieved in the core and further ambition scenarios with central rollout are summarised in Figure 2 and Figure 3 respectively.



	2040	2050	2060	2070
CCS	0.0	0.1	0.1	0.1
Hydrogen fuel-switching	0.0	0.0	0.0	0.0
Electricity fuel-switching	0.1	0.1	0.1	0.1
Process upgrade	3.0	2.9	2.9	2.9
Material upgrade	0.2	0.1	0.1	0.1
Gas recovery	0.9	0.6	0.5	0.4
Unabated	**8.8**	**6.5**	**5.3**	**4.5**

Figure 2: Direct emissions abatement by technology - Core scenario, central rollout



	2040	2050	2060	2070
CCS	1.6	2.1	1.5	1.2
Hydrogen fuel-switching	0.0	0.0	0.0	0.0
Electricity fuel-switching	3.0	2.7	2.4	2.1
Process upgrade	2.2	0.5	0.5	0.5
Material upgrade	0.2	0.2	0.2	0.2
Gas recovery	0.9	0.6	0.5	0.4
Unabated	**4.1**	**1.5**	**1.2**	**1.0**

Figure 3: Direct emissions abatement by technology - Further ambition scenario, central rollout

The core scenario reduces emissions by 66% compared to 2016 levels[6] by as early as 2042, and at a marginal cost below £100/tCO_2e. The total abatement achieved in further ambition and speculative scenarios is larger than the abatement achieved in the core scenario. Unabated emissions from the sources in this scope could be reduced to between 8.8MtCO_2e and 2.9MtCO_2e in 2040 and between 4.5MtCO_2e and 0.9MtCO_2e in 2070 in the three technology scenarios with central rollout, achieving a total mitigation of 64-88% in 2040 and 82-96% in 2070 compared to emissions in 2016.

Process upgrade technologies (continuous monitoring and LDAR) make up a large portion of abatement in the core scenario compared to other technology categories which are mostly higher cost than the £100/tCO_2e threshold used in the core scenario. A large portion of emissions in the further ambition and speculative scenarios are abated by CCS and electricity fuel-switching, accounting for 75% and 76% of abatement in 2070 respectively.

Due to its low TRL, hydrogen fuel switching is responsible for a significant amount of abatement only with the fast rollout profile. With slow and central rollout profiles, electricity fuel-switching is preferred to hydrogen fuel-switching, despite the lower costs of abatement of the latter. In practice, hydrogen rollout will be strongly affected by any rollout in the rest of the economy – the fuel-switching potential should therefore be interpreted as subject to uncertainty regarding the future fuel mix, with some cost savings possible if deploying a greater share of hydrogen.

[6] Overall UK GHG emissions must reduce by 66% compared to 2016 levels in order to meet the current 2050 target.

Marginal abatement cost curves (MACC) for the core and further ambition scenarios with central rollout are displayed in Figure 4 and Figure 5 respectively. The figures refer to discounted cost of abatement and abatement of direct emissions.

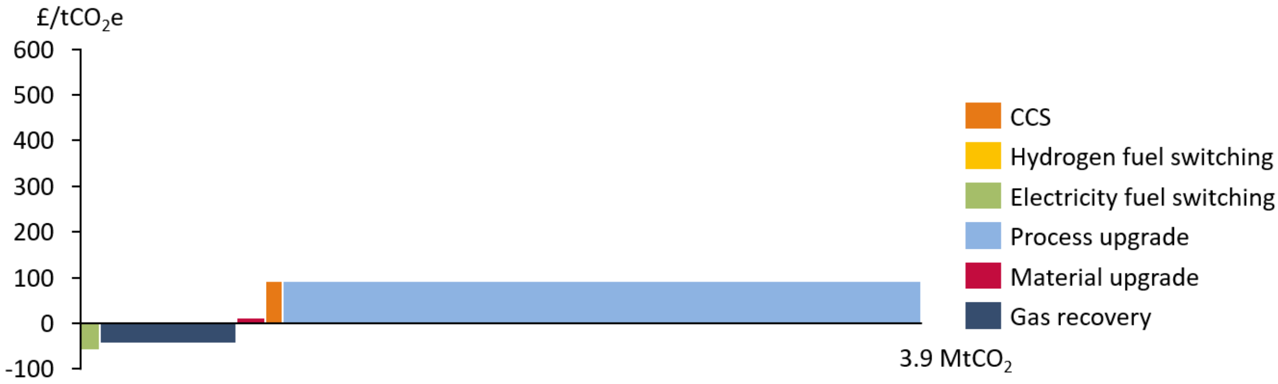


Figure 4: MACC 2050 - Core scenario, central rollout

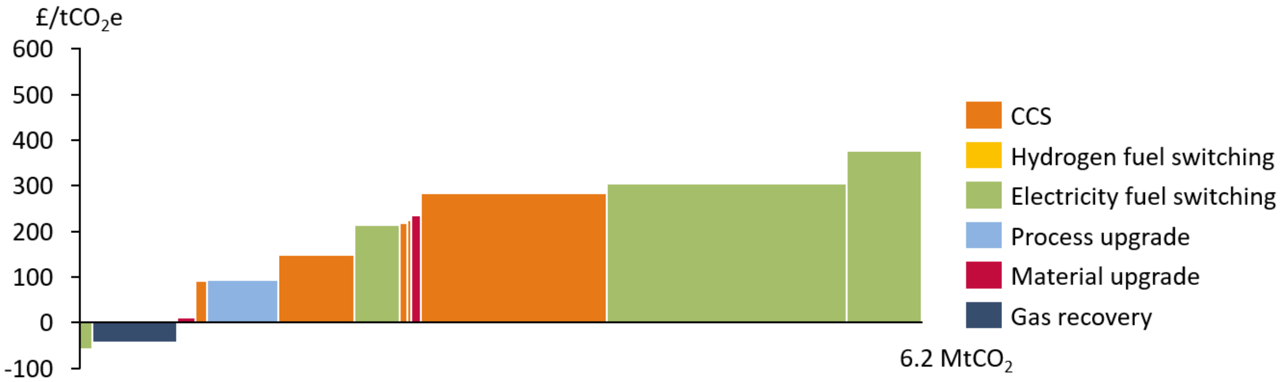


Figure 5: MACC 2050 - Further ambition scenario, central rollout

In both scenarios with central rollout, two technologies produce negative abatement costs together with a total abatement of 0.7 $MtCO_2e$: electricity grid connection (onshore gas, replacing gas oil) and gas recovery for sales - offshore oil/shale gas.

The progression to a higher cost cap from the core scenario to the further ambition scenario shows the implementation of an additional set of technologies, contributing further abatement. However, the abatement achieved by process upgrade technologies is reduced due to the lower amount of baseline fugitive emissions from pipeline leaks in the further ambition scenario (reflecting partial gas grid closure and/or switchover to hydrogen).

Unabatable emissions after the implementation of all available technologies delivering the highest abatement at any cost, with their earliest possible implementation, corresponding to the speculative scenario with fast rollout, are reported in Figure 6.

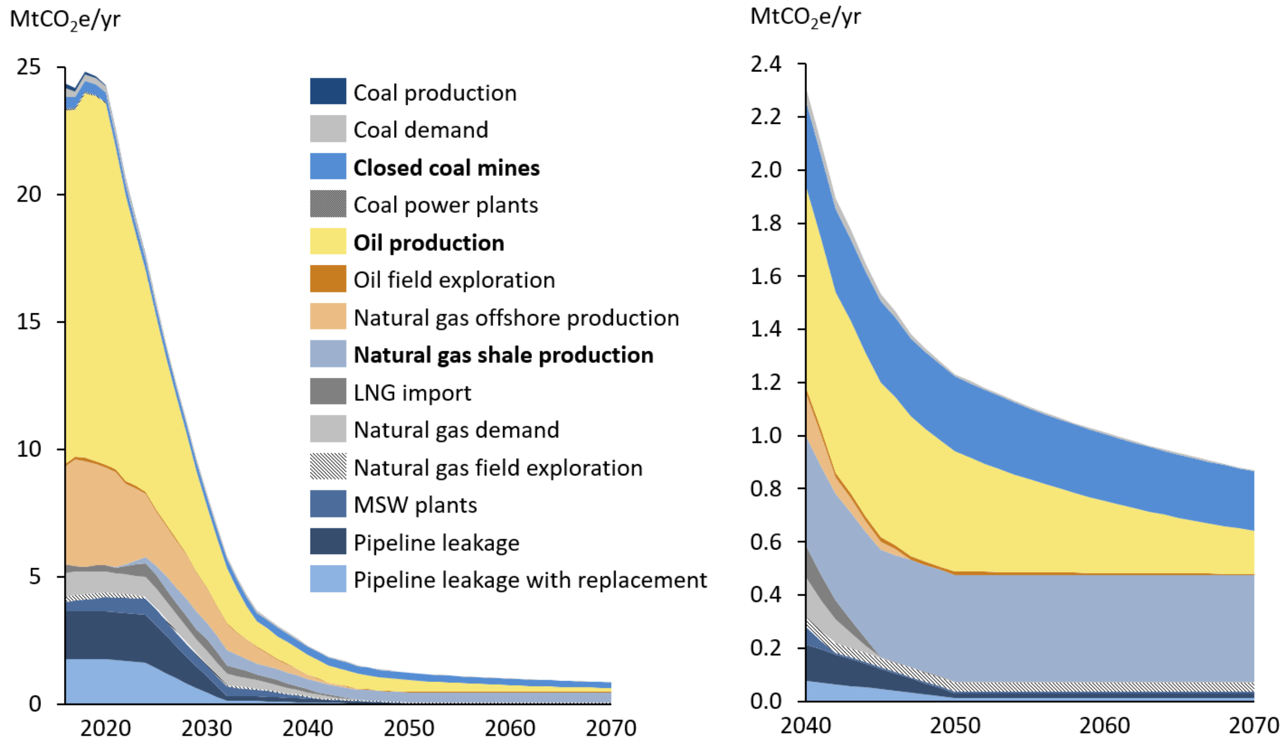


Figure 6: Unabatable emissions by trigger point (left: 2016-2070 projection, right: 2040-2070 closeup) - Speculative scenario, fast rollout

Remaining emissions amount to 2.3MtCO$_2$e in 2040 and 0.9MtCO$_2$e in 2070, corresponding to a reduction in emissions of 81% of total baseline emissions in 2040 and 84% of total baseline emissions in 2070. Compared to 2016 values, this would correspond to a total abatement of emissions of 90% in 2040 and 96% in 2070. The main contributors to remaining emissions after 2040 are sources associated with natural gas shale production, closed coal mines and oil production. Remaining emissions in 2070 would stem almost exclusively from fugitive emissions, while emissions from combustion processes could be abated almost entirely. In fact, some of the abatement technologies considered for fugitive emissions associated with natural gas shale production and oil production, such as gas recovery for sales and flaring, are capable of reducing 2016 emissions only by 50% and 40% respectively at their maximum deployment. No abatement technology was identified to further reduce fugitive emissions from closed coal mines.

1.5 Conclusions

- **Baseline emissions are estimated to reduce before allowing for mitigation measures.** The main reason is the reduction of domestic production of fossil fuels, not matched by an equal reduction in demand, and therefore resulting in 'offshoring' of part of these emissions. Total direct emissions are expected to reduce by 67% between 2016 and 2070, going from about 24MtCO_2e/yr in 2016 to 8MtCO_2e/yr in 2070. Furthermore, if partial gas grid closure and/or switchover to hydrogen is considered, the reduction in emissions is more substantial, leading to 5.3MtCO_2e/yr baseline emissions in 2070 (a 78% reduction compared to 2016).
- **Baseline GHG emissions between 2040 and 2070 are expected to stem mainly from pipeline leakage, shale gas production and oil production.** However, the future relevance of the first two sectors has a high level of uncertainty, depending on the future of the gas grid and on the future of UK shale gas production, which are both still largely unclear.
- **A variety of abatement options applicable to the sources in the scope of this study were identified.** These include fuel switching, CCS and equipment/process-specific options such as gas recovery for sales, continuous monitoring, LDAR, RECs and vent reduction, with considerable abatement cost differences.
- **High costs and the technical difficulty of implementation for some of the abatement technologies might bring about unintended consequences.** For instance, while the uptake of GHG abatement technologies could be responsible for the creation of a new industry or the prolonged lifespan of the UK fossil fuel industry, there is also a risk that oil and gas operators may prefer to decommission their fields earlier instead of investing in decarbonisation measures.
- **When mitigation options are implemented, baseline direct emissions can be abated by up to 88% in 2040 and by up to 96% in 2070, when compared to 2016 levels.** The implementation of cheaper mitigation options with a cost-effectiveness of abatement smaller than £100/tCO2e enables mitigation of 64% of direct emissions in 2040, 73% in 2050 and 82% in 2070, compared to 2016 levels. The increase in indirect emissions resulting from a larger use of electricity and hydrogen would not be significant in the core scenario. In comparison, overall UK GHG emissions in 2050 must be reduced by at least 66% compared to 2016 levels, in order to meet current UK national emissions targets.
- **Net zero abatement from the fossil fuel production and fugitive emissions scope is not achievable alone through the implementation of the investigated abatement technologies in the timeframe considered**. Direct emissions abatement achievable in the core scenario compared to 2016 increases progressively from 73% in 2050 to 78% in 2060 and 82% in 2070. This value reaches 96% in both further ambition and speculative scenarios, considering partial gas grid closure and/or switchover to hydrogen. The target of net zero emissions from the sources in the scope of this study can only be attained through the implementation of GHG removal options delivering an additional negative emissions contribution.
- **Future work is recommended in the following areas:**
  - a bottom-up assessment of the abatement potential and cost effectiveness for individual installations;
  - applicability and effectiveness of some of the less mature technologies, such as offshore small-scale carbon capture and storage (CCS), use of hydrogen for various applications, use of hydrogen for carbon capture, usage and storage (CCUS) for heating to reduce indirect emissions and increasing the capture rate of CCS;
  - unintended consequences, to be assessed through engagement with relevant industries, government bodies and relevant stakeholders;
  - uncertainty in emissions estimates.

2 Introduction

2.1 Background

The 'Paris Agreement', reached at the 2015 United Nations Climate Change Conference, COP 21, committed signatory parties, including the UK, to keep global temperature rise this century to below 2°C above pre-industrial levels, and to pursue efforts towards a lower target of 1.5°C.

The UK Government and devolved administrations asked the Committee on Climate Change (CCC) for formal advice on the date by which the UK should achieve a net zero greenhouse gas or carbon target, and on how the necessary carbon emissions reductions could be delivered. The UK's current legally binding target is for greenhouse gas emissions to be reduced by at least 80% of 1990 levels by 2050 and does not specify any date by which net zero emissions should be achieved.

The CCC's Fifth Carbon Budget scenarios were developed in the context of this '80% by 2050' target, and therefore do not reach net zero emissions by 2050. This was true for the CCC's more ambitious Fifth Carbon Budget 'Max' scenarios, as well as the Central and Alternative scenarios. A key part of the question posed to the CCC is whether and when it is feasible to increase the ambition of carbon targets to achieve net zero emissions.

The Committee on Climate Change commissioned Element Energy and Imperial Consultants to update its assessment of the scope to reduce emissions from fossil fuel production and fugitive emissions, as part of a cost-effective approach to reducing all UK greenhouse gas emissions. The project aims to identify emission sources that are so infeasible or expensive to abate, that offsetting these emissions with greenhouse gas removal options might be necessary for the UK to reach net-zero emissions. The outputs of this work are used to inform recommendations in the CCC's net-zero report in 2019.

Whilst CO_2 emissions from the coal, oil and gas supply chains are relatively well understood, methane emissions are much more uncertain. Though previous work from Imperial Consultants (ICON) researchers[7] was used to inform the CCC 2016 report[8] on onshore unconventional oil and gas development, there is still significant work required to understand the scale of possible reductions of methane and CO_2 emissions. Low carbon fuels, as well as carbon capture, could substantially reduce CO_2 emissions, while there are several possible technical and operational measures to minimise methane emissions[9].

In particular, the issue of variable methane emissions from gas supply chains has been the focus of many studies in the US, with 'super emitters' being identified as a significant issue. The relevance of this to the UK supply chain is not known given the lack of available information, but more recent European studies find that emissions are higher than previously reported (e.g. the study on the Groningen region[10]). While most of the focus has been on natural gas supply chains, there are also likely to be significant emissions from oil[11] and coal[12] production too.

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[7] Balcombe, P., Anderson, K., Speirs, J., Brandon, N. & Hawkes, A. 2015. Methane and CO_2 emissions from the natural gas supply chain: an evidence assessment. In: Sustainable Gas Institute (ed.) White Paper Series. www.sustainablegasinstitute.org/publications/white-paper-1: Imperial College London.
[8] CCC 2016 The compatibility of UK onshore petroleum with meeting the UK's carbon budgets. Onshore Petroleum. London, UK: Committee on Climate Change.
[9] Balcombe, P., Brandon, N. P. & Hawkes, A. D. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. Journal of Cleaner Production, 172, 2019-2032.
[10] Yacovitch, T. I., Neininger, B., Herndon, S. C., Gon, H. D. V. D., Jonkers, S., Hulskotte, J., Roscioli, J. R. & Zavala-Araiza, D. 2018. Methane emissions in the Netherlands: The Groningen field. Elementa Science of the Anthropocene, 6, 57.
[11] IEA 2017. World Energy Outlook 2017, Paris, France.
[12] Warmuzinski, K. 2008. Harnessing methane emissions from coal mining. Process Safety and Environmental Protection, 86, 315-320.

In addition to helping the UK meet a net-zero target, reducing fossil fuel production and fugitive emissions in the natural gas supply chain will also be important in the potential hydrogen economy. Hydrogen is expected to play a role in decarbonising a number of sectors such as industry, transport and buildings. Steam methane reforming (SMR) and autothermal reforming (ATR) are expected to play an important role in future large-scale hydrogen production in the UK, so minimising upstream emissions in the natural gas supply chain will be key.

2.2 Scope

The scope of this study focuses on greenhouse gas (GHG) emissions from fossil fuel production and fugitive emissions in the UK. Emissions include CO_2, CH_4 and N_2O released into the atmosphere through these processes and activities.

The sources investigated in this scope include:

- Oil well exploration, extraction, production, transport, refining and storage
- Natural gas well exploration, extraction, production, processing, transmission, storage and distribution
- Flaring and venting during oil and gas production
- Underground and surface coal mines
- Solid fuel transformation and production
- Use of carbonates for flue gas desulfurisation in coal power stations
- Public heat generation from municipal solid waste

All GHG emission sources are grouped according to the nomenclature of the Intergovernmental Panel on Climate Change (IPCC) and of the UK National Atmospheric Emissions Inventory (NAEI) into Fuel combustion activities (1A), Fugitive emissions from fuels (1B) and Mineral products (2A), and these are listed in the Appendix in Table 11, Table 12 and Table 13 respectively.

As the future of natural gas production in the UK may include a share of production from onshore petroleum activities, a few additional sources representing emissions from shale gas were included in the scope of this analysis and are listed in Table 14 in the appendix.

2.3 Study approach

The study was carried out through a number of separate tasks summarised in Figure 7. The key stages of the study have been as follows:

- Characterisation of emission sources through mapping of the UK's coal, oil and natural gas supply chains;
- Development of future baseline emissions projections to 2070;
- Identification of emission sources relevant from 2040 onwards;
- Selection of technological and operational abatement options for each relevant emission source;
- Quantification of the abatement potential and cost effectiveness of each abatement option;
- Estimation of the timeline for maximum uptake of each abatement option, through assessment of technology readiness level, current global uptake and UK potential uptake;
- Identification of non-technoeconomic costs, barriers and benefits associated with emissions mitigation;
- Projection of future emissions considering the identified abatement options.

The next chapter of this report outlines the characterisation of emission sources and the projection of associated future baseline emissions. Chapter 4 describes available abatement technologies and their suitability to the emission sources in our scope. Finally, the results of the application of the investigated abatement technologies to the emission sources in our scope are summarised in chapter 5.

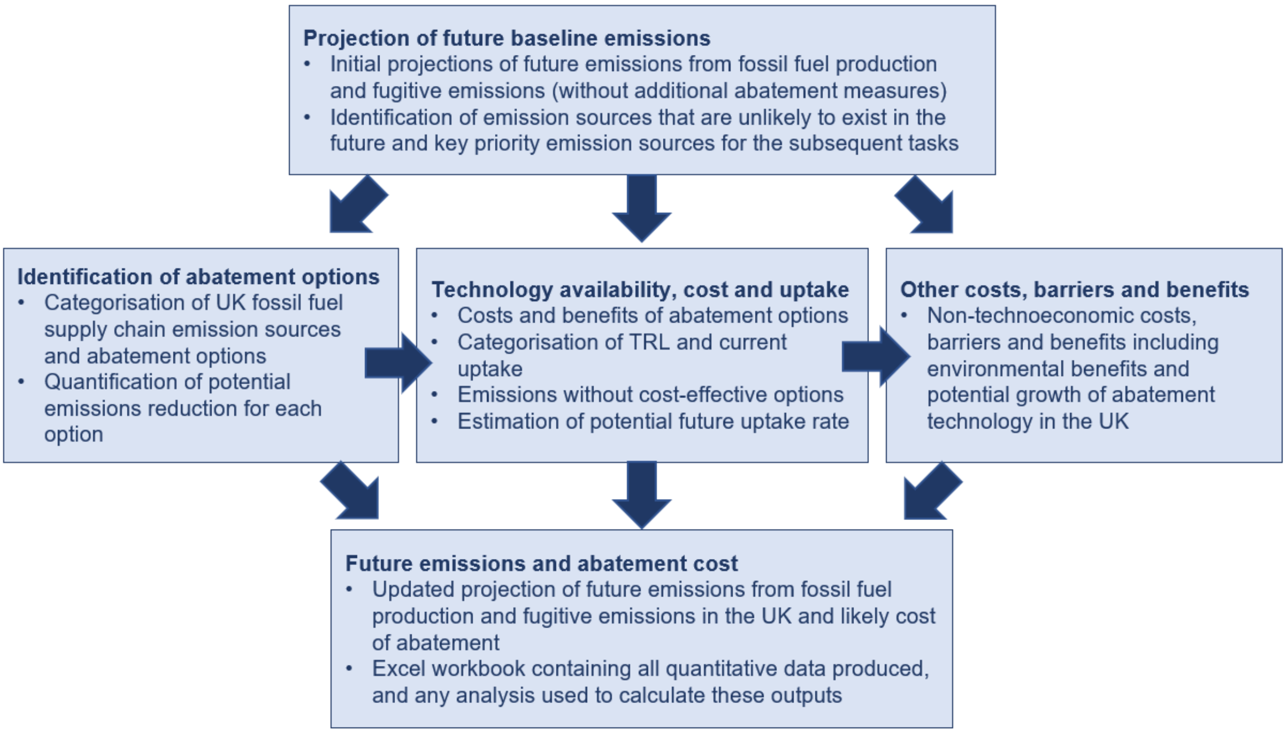


Figure 7: Methodology - Key tasks

3 Baseline emissions

3.1 Characterisation of emission sources

The UK fossil fuel supply chains were mapped using data from the UK's Digest of UK Energy Statistics (DUKES)[13] combined with the Department for Business, Energy and Industrial Strategy's (BEIS) UK Greenhouse gas inventory 1990-2016, using data on supply sources, processing and refining, storage and transportation, and end uses. A flow diagram for the supply chain of natural gas is presented in Figure 8, with the respective diagrams for the oil and coal supply chains in the Appendix. Emissions entries from the inventory were allocated to a supply chain stage based on the inventory entry description and discussions with the inventory developers. Some emissions entries cover numerous activities within a supply chain stage or even across multiple stages. For example, the entry '1A1ciii: Gas production' is assumed to cover fuel emissions relating to pre-production, production, gathering and processing. The mapping of emissions ensured that all types of emissions from each supply chain stage were considered and accounted for, including fuel combustion, fugitives, vents, and flares. This allows identification of the emission source and the correct mitigation option to be selected.

[13] BEIS. 2017. Digest of UK energy statistics (DUKES). Department for Business, Energy and Industrial Strategy (BEIS). London, UK. Available: https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2017-main-report

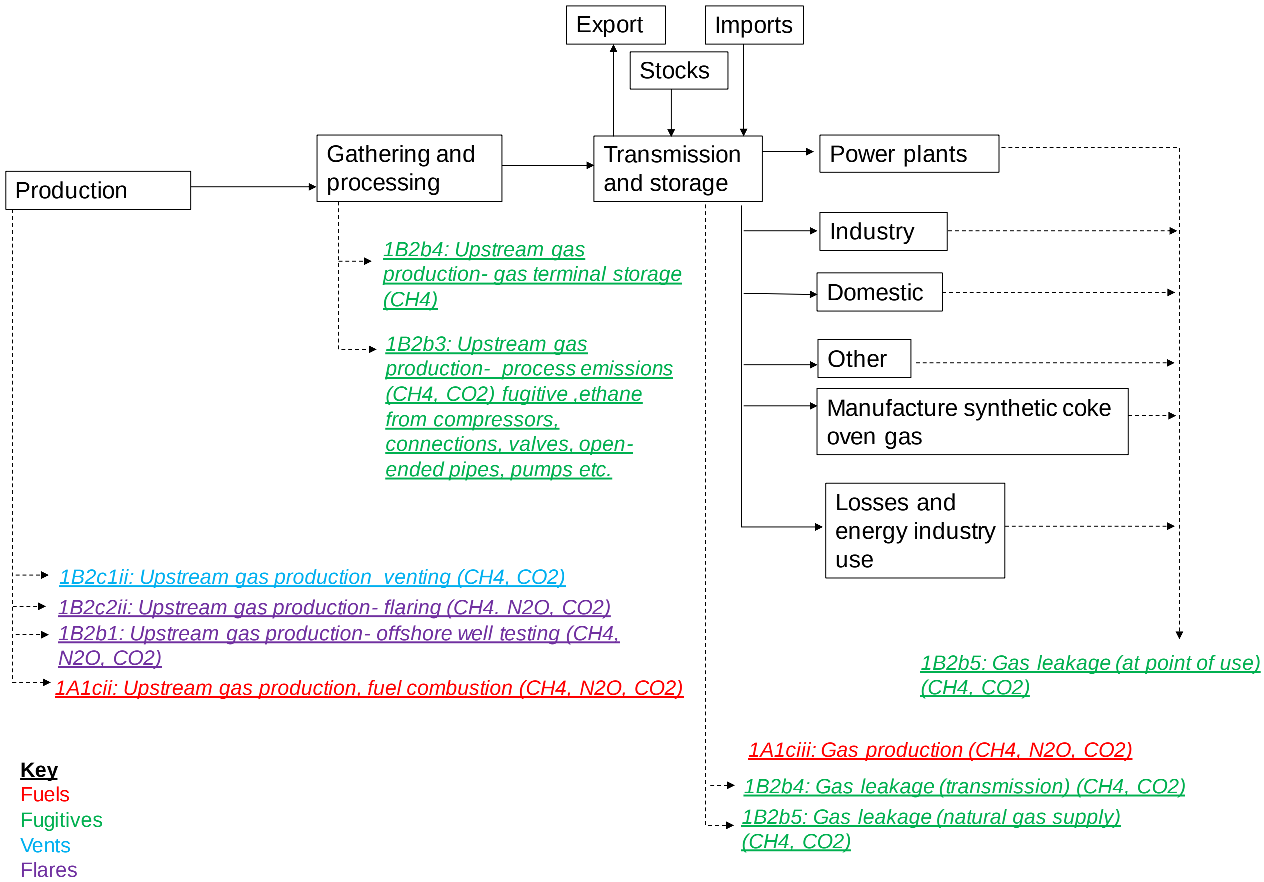


Figure 8: The gas supply chain and emissions categories

Once the emissions entries were assigned to a supply chain stage, specific emission sources were identified. This was done by characterising the types of emissions (fuel combustion, fugitive, vent, flare), for which a process (venting, well completions etc.) or equipment (compressors, pipelines etc.) could then be assigned.

For offshore combustion emissions, 2016 data from the Environmental and Emissions Monitoring System (EEMS) database[14] was used to identify emission sources. For fugitive emissions, vents and flares, data from previous reports by the Sustainable Gas Institute were used to allocate equipment and processes to common emission sources (Table 2)[15,16]. When an emissions entry had multiple potential emission sources, the sources were allocated a percentage of the total emissions based on data from previous work. Since abatement options are equipment specific, equipment-specific identifications of emission sources were made where possible. Further assumptions on the emission sources are reported in section 7.3 of the Appendix.

[14] Oil and Gas Authority 2017. Environmental and Emissions Monitoring System (EEMS) database. In: Oil and Gas Authority (OGA). London, UK.
[15] Balcombe, P., Brandon, N. P. & Hawkes, A. D. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. Journal of Cleaner Production, 172, 2019-2032.
[16] Balcombe, P., K. Anderson, J. Speirs, N. Brandon, A. Hawkes, The natural gas supply chain: the importance of methane and carbon dioxide emissions. ACS Sustainable Chemistry & Engineering, 2017. 5(1): p. 3-20.

Table 2: Typical types and sources of emissions

Type of emissions	Emission source(s)
Fuel combustion	Compressors Power generation Heaters
Fugitives	Pipeline leaks Leaks from metering and regulating stations Wet seal compressor Regasification terminal leaks
Vents	Flue gas venting
Flares	Flaring Well completions Flow testing

3.2 Emissions forecasts

A forecast of baseline emissions for the sources in our scope was built based on 2016 emissions recorded by the UK NAEI inventory[17]. A number of trigger points covering all emission sources was identified, together with publicly available long-term projections from relevant institutions (Table 3). Main data sources in our analysis are:

- BEIS projections 2017 (coal and gas demand until 2035);
- OGA Production and expenditure projections 2018 (oil and gas production and demand forecasts until 2035);
- Oil and Gas UK Economic Report 2018, “Vision 2035” scenario (oil production until 2035);
- National Grid Future Energy Scenarios (FES) 2018 (Natural gas UKCS and shale gas production; Continent, liquified natural gas (LNG) and generic imports and demand until 2050);
- CCC shale gas production scenarios until 2030

The review of relevant forecasts showed that coal demand and emissions from closed coal mines are in steady decline, while coal production and coal demand for power production are projected to reduce even more drastically. Furthermore, most scenarios assume a consistent level of reduction in the UK continental shelf (UKCS) offshore oil and gas production, even when considering more ambitious investment plans for the development of new wells.

There is a higher degree of uncertainty in the projections of shale gas production and natural gas demand. These are therefore employed as key drivers of the variability for emissions projections in this study:

- **Shale gas** ranges from zero production to up to 32bcm/yr by 2036 in the reviewed forecasts;
- **Natural gas demand** in the UK depends on the role of hydrogen in the UK and ranges from 30bcm/yr in 2050 (FES 2018 Community Renewables scenario) to 66bcm/yr in 2050 (FES 2018 Consumer Evolution scenario).

Using those ranges, we have developed a baseline scenario for this study using an average of FES 2018 consumer evolution scenario and community renewables scenario. The consumer evolution scenario presents high natural gas demand and high shale gas production, constituting a scenario of large investments in the shale gas infrastructure from the 2020s and widespread heating through gas boilers. The community renewables scenario, on the other hand, is associated with low natural gas demand and low shale gas

[17] http://naei.beis.gov.uk/

production, due to a high production of green gas from 2030s and predominant electric heating through heat pumps.

Detailed information on the sources and assumptions employed in the forecasts for each trigger are described in Table 3 below. Further information on trigger forecasts as well as trigger association to each emission source in our scope is reported in the appendix in sections 7.4 and 7.5 respectively.

Table 3: Trigger points forecasts

Trigger point	2016 emissions ($MtCO_2e$)	Data source and forecast assumptions
Coal production	0.17	Historical data until 2017 from DUKES 2018, UK coal production[18]. Extrapolation from 2018 to 2070 assumes an exponential decay.
Coal demand	0.36	Historical data and projection until 2035 from BEIS 2017 projections, solids demand[19]. Extrapolation from 2035 to 2070 assumes an exponential decay.
Closed coal mines	0.45	Historical data and projection until 2050 from WSP - DECC UK CH4 Emissions Abandoned Coal Mines 2013, net emissions from UK closed coal mines. Extrapolation from 2050 to 2070 assumes an exponential decay.
Coal power plants	0.07	Historical data until 2017 from DUKES 2018, historical data on UK coal use in electricity production[20]. Assuming reduction beyond 2018 compatibly with progressive restrictions leading to general coal power plants closure by 2026[21].
Oil production	13.87	Historical data and projection until 2035 from Oil & Gas Authority 2018, oil production projections[22]. Extrapolation from 2035 to 2070 assumes an exponential decay, compatible with the exponential drop of the Hubbert bell curve after reaching a well's maximum production peak and with the declining number of new exploratory wells in the UK[23].
Oil field exploration	0.11	Oil exploration activity assumed to be proportional to oil production.
Natural gas offshore production	3.81	Historical data and projection until 2050 from National Grid FES 2018[24], Annual gas supply pattern - UKCS. Employed values are the average of Consumer Evolution scenario and Community Renewables scenario values, representing a high offshore production and a low offshore production profile respectively. Extrapolation from 2050 to 2070 assumes a constant profile.
Natural gas shale gas production	0	Historical data and projection until 2050 from National Grid FES 2018, Annual gas supply pattern - Shale. Employed values are the average of Consumer Evolution scenario and Community Renewables scenario values. The Consumer Evolution scenario includes considerable uptake in shale gas production which is compatible with the high shale gas production scenario included in the CCC report on onshore petroleum 2016[25]. The Community Renewables scenario includes no uptake of shale gas. The average value of a high production scenario forecast and a zero-production scenario forecast was chosen to reflect the current high uncertainly regarding the future of shale gas in the UK. Extrapolation from 2050 to 2070 assumes a constant profile.

18 https://www.gov.uk/government/statistical-data-sets/historical-coal-data-coal-production-availability-and-consumption
19 https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2017
20 https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes
21 https://www.gov.uk/government/consultations/coal-generation-in-great-britain-the-pathway-to-a-low-carbon-future
22 https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/production-projections/
23 https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/well-data/
24 http://fes.nationalgrid.com/fes-document/
25 https://www.theccc.org.uk/wp-content/uploads/2016/07/CCC-Compatibility-of-onshore-petroleum-with-meeting-UK-carbon-budgets.pdf

LNG import	0.38	Historical data and projection until 2050 from National Grid FES 2018, Annual gas supply pattern - LNG plus an LNG-related portion of generic imports. This portion is assumed to be proportional to LNG over LNG plus continent (total import). Employed values are the average of Consumer Evolution scenario and Community Renewables scenario values, the values of the two scenarios representing the LNG import required to meet high demand with high shale gas production or low demand with low shale gas production respectively. Extrapolation from 2050 to 2070 assumes an exponential decay, compatible with the exponential decrease of natural gas demand and the constant profile of total natural gas production.
Natural gas demand	0.92	Historical data and projection until 2050 from National Grid FES 2018, Annual gas supply pattern - Demand. Employed values are the average of Consumer Evolution scenario and Community Renewables scenario values, representing these a high and a low demand profile respectively. Extrapolation from 2050 to 2070 assumes an exponential decay.
Natural gas field exploration	0.19	Natural gas exploration activity is assumed to be proportional to the sum of natural gas offshore production and natural gas shale production.
MSW plants	0.36	Historical data and projections until 2030 from a combination of sources: Digest of waste and resource statistics 2018[26], municipal solid waste (MSW) incineration capacity forecasts by DEFRA 2016[27], Biffa 2017 The Reality Gap[28], ESA - UK Residual Waste: 2030 Market Review (2017)[29]. Extrapolation from 2030 to 2070 assumes a constant profile.
Pipeline leakage	1.88	This trigger is associated with fugitive emissions from the gas transmission grid. These are expected to depend mainly on gas composition, on the pressure at which gas is transported and on the tightness of the grid infrastructure, rather than the volumetric throughput/ gas demand. Assuming regular grid maintenance and a continued delivery of 100% natural gas, a main forecast of this trigger was produced as a constant profile. An additional forecast for this trigger was also produced assuming a linear reduction by 90% between 2035 and 2050 due to partial gas grid closure and/or conversion to hydrogen.
Pipeline leakage with replacement	1.78	This trigger is associated with fugitive emissions from the gas distribution grid which will be affected by the ongoing replacement of iron mains with plastic pipework (Iron Mains Replacement Programme). This is assumed to reach completion by 2040. The abatement potential for replacing iron and steel pipes with plastic is approximately 75%[30], and as of 2016 ~50% of pipes have been replaced. Therefore, a linear profile of abatement equivalent to a 37.5% reduction between 2020 and 2040 was assumed for this trigger. Similar to the trigger forecasts for pipeline leakage, an additional forecast was also produced for this trigger, assuming a further reduction of 90% between 2035 and 2050 due to partial gas grid closure and/or conversion to hydrogen.

The value of each trigger over time, normalised to its value in 2016, was used as a multiplier to the 2016 emissions values of each associated emission source to produce the baseline emissions forecast of the source. Note that this approach assumes emissions will evolve proportionally to the associated trigger.

The resulting forecasts of baseline emissions from sources in our scope with a breakdown of trigger contributions are summarised in Figure 9. Total emissions are expected to go down from roughly 24MtCO_2e in 2016 to 8MtCO_2e in 2070.

[26] https://www.gov.uk/government/statistics/digest-of-waste-and-resource-statistics-2018-edition
[27] https://data.gov.uk/dataset/b99f22a0-e716-44bf-bff2-a12da2562e4f/waste-infrastructure-delivery-programme-widp-residual-waste-treatment-infrastructure-project-list-ipl
[28] https://www.biffa.co.uk/media-centre/publications
[29] http://www.esauk.org/application/files/6015/3589/6453/UK_Residual_Waste_Capacity_Gap_Analysis.pdf
[30] Balcombe, P., Brandon, N. P. & Hawkes, A. D. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. Journal of Cleaner Production, 172, 2019-2032.

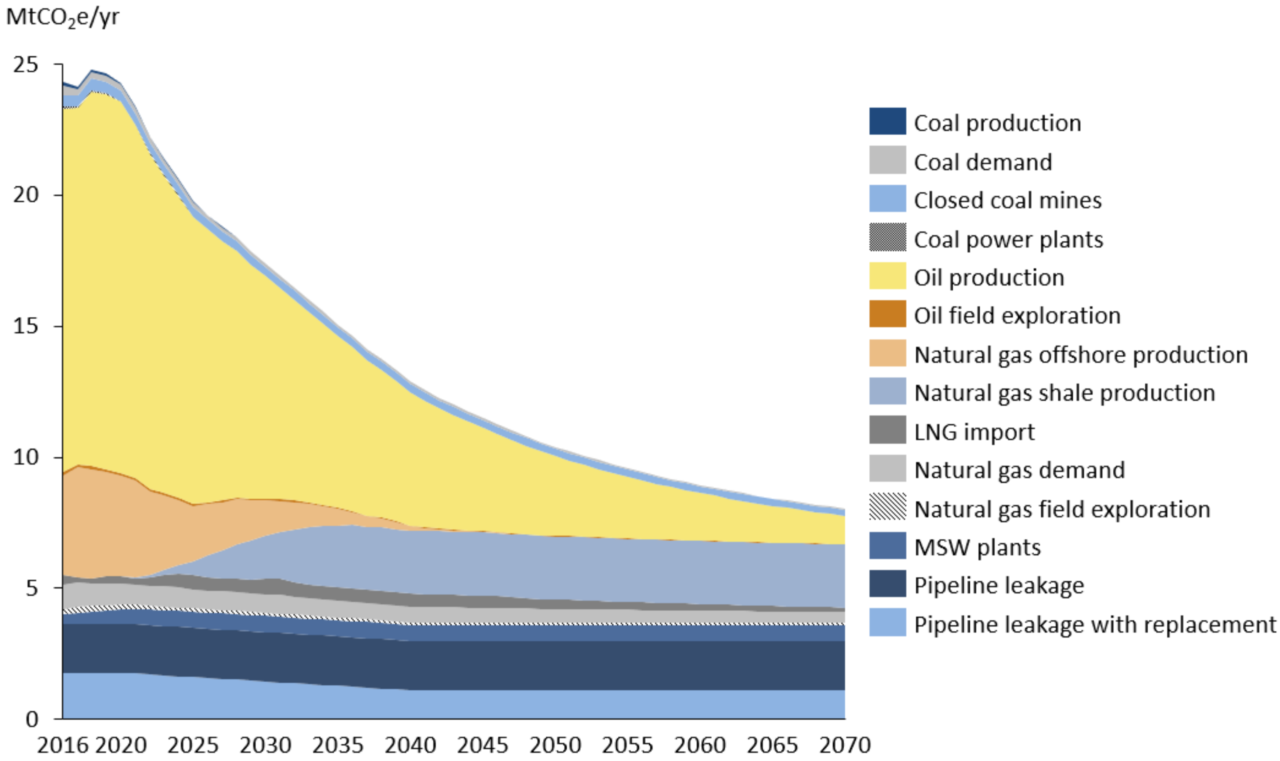


Figure 9: Baseline GHG emissions by trigger

Overall pipeline leakage constitutes a large fraction of emissions, contributing to 23% of total baseline emissions in 2040 and 33% of total baseline emissions in 2060. The amount of these emissions is highly dependent on the future of the gas grid and may reduce in the case of partial closure of the grid. Alternatively, the substitution of natural gas with hydrogen in the gas grid is also expected to result in a similar reduction in GHG emissions from pipeline leakage, as the global warming potential of hydrogen is zero. However, leakage of hydrogen was not further investigated in this study as it was not part of the scope.

Figure 10 shows the forecast of baseline emissions in the case of 90% gas grid closure and/or switchover to hydrogen. Total emissions are expected to reduce from roughly 24MtCO$_2$e in 2016 to 5.3MtCO$_2$e in 2070.

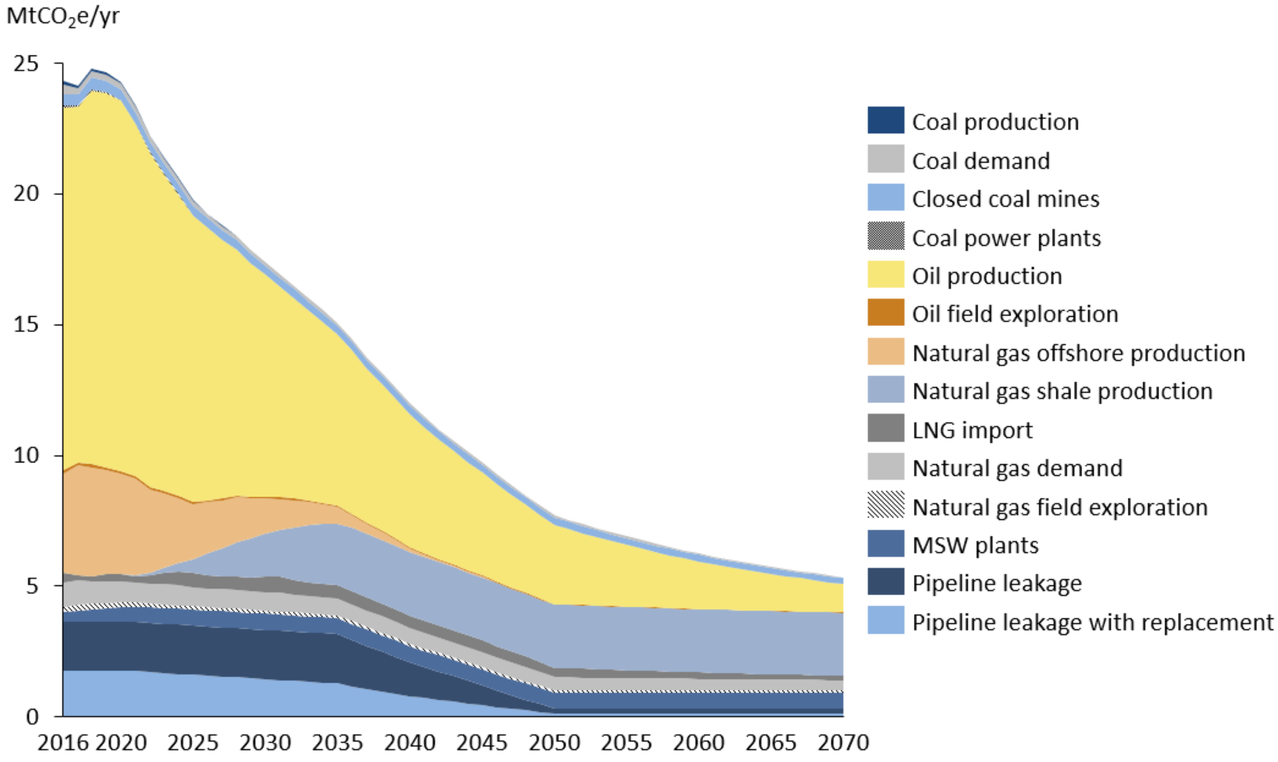


Figure 10: Baseline GHG emissions per trigger, with 90% gas grid closure and/or switchover to hydrogen

The main contributions to emissions between 2040 and 2070 are projected to originate from sources associated with Oil production and Natural gas shale gas production, and, in the case of no grid closure and/or switchover to hydrogen, also from Pipeline leakage and Pipeline leakage with replacement. In the case of no grid closure and/or switchover to hydrogen emissions related to Oil production are expected to drop from 39% in 2040 to 14% in 2070, whereas emissions related to Natural gas shale production would increase from 19% in 2040 to 30% in 2070. Emissions related to all pipeline leakage remain constant between 2040 and 2070 but increase in relation to total emissions from 23% to 37%. Note that in case of partial grid closure and/or switchover to hydrogen the contribution from all pipeline leakage is significantly smaller, reducing to 6% in 2070.

Other triggers such as Coal demand, Closed coal mines, LNG import, Natural gas demand, Natural gas field exploration and MSW plants are each responsible for a minor contribution in total emissions, making up for a total of 17% of emissions in 2040 and 19% in 2070.

Emissions from sources associated to Coal production and Coal power plants, on the other hand, are expected to completely disappear by 2040 and emissions related to Oil field exploration and Natural gas offshore production, while contributing to 1.6% of total emissions in 2040, are expected to be smaller than 10 ktCO_2e in 2070.

Table 4 lists all sources in our scope which are still relevant in 2040. Sources with negligible projected emissions < 10ktCO_2e in 2040 are not included here and were also not considered in the subsequent steps of this analysis.

Table 4: Relevant sources in scope - projected emissions >10ktCO$_2$e in 2040, without gas grid closure and/or switchover to hydrogen

NAEI / IPCC code	NAEI Source	NAEI Activity	GHG	Emissions (ktCO$_2$e)		Cumulative emissions [31] (%)
				2016	2040	2040
1B2b5	Gas leakage	Natural gas supply	CH_4	3,555	2,888	22%
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas	CO_2	6,887	2,523	42%
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas	CO_2	0	1,211	52%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CO_2	3,293	1,206	61%
1A1cii	Upstream Oil Production - Fuel combustion	Gas oil	CO_2	1,726	632	66%
1A1ciii	Gas production - Transmission and storage (72%)	Natural gas	CO_2	921	593	70%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CO_2	308	527	74%
1A1ciii	Gas production - Regasification (28%)	Natural gas	CO_2	358	465	78%
1B1a1iii	Closed Coal Mines	Non-fuel combustion	CH_4	448	317	80%
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CO_2	0	292	83%
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion	CH_4	0	282	85%
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	OPG	CO_2	743	272	87%
1B2b4	Upstream Shale Gas leakage - production and processing - Compressor stations (80%)	Non-fuel combustion	CH_4	0	203	88%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CH_4	370	136	90%
1A1cii	Upstream Gas Production - Fuel combustion	Natural gas	CO_2	2,657	114	90%
Others (complete list: see appendix, section 7.6)						100%

About two thirds of all baseline emissions expected in 2040 are produced by only six of the main sources in our scope. These are resulting from fuel combustion in the upstream processes of production of oil and shale gas, fugitive emissions from the low-pressure gas distribution network and gas flaring in the oil production industry.

[31] Cumulative emissions are calculated here by subsequent addition of the emissions share of each entry in the list.

4 Abatement of emissions

4.1 Abatement technologies: mitigation potential and cost

For each emission source, up to three mitigation options were considered. The emissions were divided up into those associated with fuel combustion, and those associated with vents, flares and fugitive emissions. Consequently, the mitigation options were characterised as either:

- fuel switching;
- carbon capture and storage; or
- process or equipment specific.

Each category of options is described in the following section, including a brief description of the technical, environmental and economic factors.

4.1.1 Fuel switching

The majority of emissions associated with fuel usage are due to the use of natural gas or gas oil as fuel, both onshore and offshore. The fuel use was either for heating, electricity generation or to drive compressors. Depending on the option and whether it is an onshore or offshore emissions, the alternative fuel options considered were:

- grid electricity;
- electricity produced from offshore wind with battery storage; and
- hydrogen.

Grid electricity. This option replaces the use of fuel by connection to the electricity grid. Grid electricity may directly replace power generation from gas oil, be used for heating or to drive compressors. The key aspects associated with this option are access to infrastructure and whether additional cabling or ancillary infrastructure are required. Additionally, the efficiency of the end-use is important in determining the cost. For both onshore and offshore emission sources, it was assumed that converters and transformers will be required to connect to onshore electricity facilities, which have a combined cost of £530k per MW additional capacity. For offshore sources, it is assumed that additional subsea cabling is required at a distance of 50 km. For the efficiency of fuel conversion at end-use, it is assumed that efficiency for heating is 100% and replaces natural gas heating at 90% efficiency. For power generation replacing gas oil, the gas oil is assumed to be used at 30% efficiency, with electricity supply at 100%. Electrical compressors are assumed to be at the same efficiency as natural gas compressors.

This option reduces direct emissions by 100% for CO_2, CH_4 and N_2O given the avoidance of direct combustion, whereas indirect emissions are governed by the electricity grid mix and time of use. The high cost of grid electricity results in a high cost of carbon abatement, particularly against very cheap natural gas, and less so against gas oil.

Electricity from wind and battery storage (offshore). This option replaces the use of fuel offshore via the installation of wind power and battery storage close to the emission source. This replaces both natural gas and gas oil combustion at offshore rigs, either avoiding the use of produced gas/ oil, or avoiding import for use to the rig. Given the requirement to provide power to meet continuous demand, wind turbines were matched with lithium batteries at a ratio of 1:1 on a power capacity basis.

We assume that this is sufficient to supply all electricity needs, but it is likely that the variation in wind generation will result in an additional backup source requirement, assumed to be delivered via incumbent conventional sources (gas and gas oil). For simplicity, this back-up contribution was assumed to be negligible, thus the direct abatement potential of this option is 100% for CO_2, CH_4 and N_2O.

Hydrogen. This option replaces the use of fuel onshore via connection to an available hydrogen infrastructure, projected to be in place at some point in the future, for heating and compressor fuel. Here we assume that the marginal cost of the end-use equipment is 20% above that of natural gas. We assumed that infrastructure is available but the cost of 10km of hydrogen pipeline installation is required at £6,068/km. The remaining cost of hydrogen was represented by the average fuel cost projected by CCC over time (as seen in paragraph 7.8 in the Appendix).

4.1.2 Carbon Capture and Storage

This option is applied to the combustion of natural gas and gas oil, for heating, compression, and electricity generation. Given the nature of the emission sources, the scale of capture is small, estimated to be typically 0.1 Mtpa CO_2. Based on previous work by Element Energy, the capture technology was assumed to be an amine scrubber, able to capture 90% of emissions, with an additional usage of 904 kWh heat coming from natural gas for offshore installations and from hydrogen for onshore installations, together with additional 27 kWh of grid electricity[32,33].

Flue gas capture costs (e.g. from electricity generation, compressors and heaters) were based on estimates of carbon capture and storage (CCS) from cement plants[34], scaled down to 0.1 Mtpa using a typical economies of scale factor (0.6 - the "0.6 rule"[35]), to £40.6m. For gas separation plants, CO_2 capture costs were much lower, based on a gas processing plant[36]. Annual operation and maintenance costs were estimated at 6% of capital costs and for offshore plants, an additional rig cost of £75m was accounted for. It was assumed that there is an available CCS infrastructure available to connect to at a distance. For onshore CCS, the capital cost associated with connection to infrastructure was estimated to be £0.43m/km[37], considering an average pipeline distance of 10 km. For offshore, costs were estimated for a pipeline distance of 25 km at £0.85m/km[38]. Storage costs of £13/tCO_2e and £18/tCO_2e were used for onshore and offshore sources, respectively.

4.1.3 Equipment and process specific

Leak detection and repair (LDAR). LDAR is the term for a set of operational and maintenance strategies, where natural gas fugitive leaks are periodically identified in equipment and pipelines, through surveying and inspection. When a leak is identified it is repaired or reduced where possible. LDAR is episodic, with high variation in frequency between different companies and supply chain stages, ranging from monthly, quarterly, annual or even less frequent. Leaks are detected using equipment such as infrared cameras and leaks are repaired upon identification, but the time required to fix leaks can vary depending on the cause of the leak.

[32] Element Energy for DECC and BIS, 2014, CO2 capture in the UK cement, chemicals, iron, steel and oil refining sectors, Available: https://www.gov.uk/government/publications/co2-capture-in-the-uk-cement-chemicals-iron-steel-and-oil-refining-sectors

[33] Element Energy for BEIS, 2018, Industrial carbon capture business models, Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759286/BEIS_CCS_business_models.pdf

[34] Irlam, Lawrence, 2017, Global cost of carbon capture and storage- 2017 update, CCS Institute. Available: https://hub.globalccsinstitute.com/sites/default/files/publications/201688/global-ccs-cost-updatev4.pdf

[35] Sinnott, R. K., J. M. Coulson, and J. F. Richardson. 2005. Coulson & Richardson's chemical engineering. Vol. 6. Oxford: Elsevier Butterworth-Heinemann.

[36] Irlam, Lawrence, 2017, Global cost of carbon capture and storage- 2017 update, CCS Institute. Available: https://hub.globalccsinstitute.com/sites/default/files/publications/201688/global-ccs-cost-updatev4.pdf

[37] DECC, 2013, CCS Cost Reduction Taskforce, Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf

[38] DECC, 2013, CCS Cost Reduction Taskforce, Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf

The mitigation potential of LDAR depends on many factors: it is highly variable on region and specific LDAR strategy and is relatively poorly understood. A study by ICF[39] was used to estimate that an additional LDAR campaign per year reduces emissions by 40%. Costs associated with LDAR were from equipment purchase but largely from labour cost, estimated to be £25.7/tCO_2e (value taken from the estimate of LDAR costs associated with distribution systems[40]). The increase in sales from reduced leakage was accounted for using natural gas price projections.

Given that LDAR is currently the only method to reduce fugitive emissions (other than installing effective best practice emission-minimising technology), the study also included a 'strong LDAR' mitigation option which includes more frequent LDAR campaigns for increased mitigation. It was assumed that additional LDAR campaigns further reduce emissions by 20% and thus six additional campaigns result in an emissions reduction of ~80%, costing £76.7/tCO_2e minus the increased gas to sales.

Continuous monitoring. Much of the current research and development is aimed at developing a cost-effective solution for continuous monitoring, with systems currently under trial in numerous regions. Whilst costs are currently prohibitive, US ARPA-E have funded various projects targeting a cost of £2.2k per site per year resulting in mitigation of 90%[41]. Consequently, this option was considered for future rollout. A credit for increased gas to sales is accounted for similarly to the LDAR option.

Reduced emissions completion (REC). The process of separating out methane from waste streams, typically flowback fluid from hydraulic fracturing of shale gas wells, is known as reduced emissions completions (or green completions). The waste stream passes through one or more separators, allowing the gas to be separated and recovered. Separation processes typically carried out in RECs include sand traps and three phase separators, from where the gas stream is sent to dehydrators or for sale. RECs are particularly applicable for shale gas production given the large volumes of flowback fluid, while conventional wells do not require hydraulic fracturing. The abatement potential for RECs was estimated to be 95% direct emissions per facility, assuming all wastewater is processed, and no recovered gas is flared or vented. As RECs is applicable for commercial wells and is not always economically viable for exploration wells, the direct emissions abatement for RECs to the shale gas industry was 71% (assuming 25% of wells drilled and developed are exploration wells[42]). It is expected that this mitigation option will be employed as soon as shale gas production has begun.

Flare gas recovery. An option to reduce the amount of gas sent to flaring is to recover the gas in waste gas streams and utilise them onsite for power generation or send to sales. The process is similar to REC in that methane is separated and cleaned, captured and sent to the natural gas sales line or can be compressed or liquefied. For oil wells it was assumed that additional piping is required to send gas to sales at £600k/km[43] with 10km for offshore wells.

The abatement potential for flare gas recovery was assumed to be 50%, assuming that the remaining half is sent to flare. The abatement potential could be higher, but flaring cannot be completely eliminated as it is used for site safety reasons (process abnormalities or to prevent over-pressuring).

Reduce venting and flare where needed. While flaring is not ideal for reducing emissions, the impact of vented CH_4 is much higher than if it were combusted because CH_4 has a global warming potential 25 times

[39] ICF, 2015, Economic analysis of methane emissions reduction opportunities in the Canadian oil and gas industry, EDF. Available: https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
[40] ICF, 2015, Economic analysis of methane emissions reduction opportunities in the Canadian oil and gas industry, EDF. Available: https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
[41] Willson, Brian, 2015, Methane quantification & ARPA-E's Monitor Program. Available: https://www.epa.gov/sites/production/files/2016-04/documents/21willson.pdf
[42] Crow, D., P. Balcombe, N. Brandon, A. Hawkes. *Assessing the impact of future greenhouse gas emissions from natural gas production*. Science of the Total Environment, 2019. 668: p 1242-1258
[43] Sari Energy, Natural gas value chain: pipeline transportation. Available: https://sari-energy.org/oldsite/PageFiles/What_We_Do/activities/GEMTP/CEE_NATURAL_GAS_VALUE_CHAIN.pdf

that of CO_2. For this, waste gas streams are connected to a flare. The abatement potential of flaring over venting is 80%, assuming a flaring efficiency of 90%. We assume that 50% of the vented gas can be flared to account for necessary venting in emergency conditions, thus the total mitigation potential is 40%.

4.1.4 Counterfactual equipment cost

For the fuel switching mitigation options, the relative cost associated with switching was also governed by the cost of the incumbent or counterfactual equipment costs. In other words, there would be a cost associated with replacing like-for-like at end-of-life. Here the fuel switching mitigation options were categorised into three discrete categories for modelling simplicity:

- Gas oil electricity generator
- Natural gas heating boiler
- Natural gas fuelled compression

A high capex cost of £70/kW was assumed for a gas oil generator[44] with an assumed annual utilisation of 40%. For a gas boiler a capex of £166/kW was taken from previous work by Element Energy, together with an opex of £3.32/kWpa, with an efficiency of 90% and an average utilisation of 80%, assumed for utilisation in a continuous process. For gas compression, a cost curve from an IEAGHG report was used[45], with an average capacity of 63 MW at £800k/MW capex at 75% efficiency. Annual opex was assumed to be 2% of total capex across all options, with an assumed lifetime of 20 years. Estimates of costs were calculated per tonne of CO_2e, that would be abated if the technologies were replaced, in order to fit the projection model.

Table 5. Counterfactual technology capital and operating costs

Technology	Capex (£/tCO_2e)	Opex (£/tCO_2e)
Diesel generator	£1	£0.5
Natural gas boiler	£5	£2
Natural gas compressor	£23	£9

[44] BEIS, 2016, Electricity Generation Costs. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf
[45] IEAGHG, 2002, Transmission of CO_2 and Energy. Available: https://ieaghg.org/docs/General_Docs/Reports/PH4_6%20TRANSMISSION%20REPORT.pdf

4.2 Summary of mitigation and cost effectiveness

The table below details a summary of the estimated cost effectiveness of each option, alongside their direct GHG mitigation potential. 2016 costs shown in Table 6 assume a discount rate of 3.5%, as well as a discounted emissions rate of 3.5%. Additionally, the cost of capital was included as an annual operating expense at a rate of 10%[46]. Some estimates included a range which depends on key factors as described above, such as whether it is onshore or offshore, oil or gas, and which fuel it is replacing (natural gas or gas oil). As can be seen in Table 6, there was a wide variation in abatement cost from -£104 to £1,180, with electricity supply to offshore via either the grid or local wind power with battery storage resulting in the highest mitigation costs. Additionally, offshore CCS represented a significantly higher cost due to the additional infrastructural costs assumed. The lowest cost abatement options were gas recovery to sales, reduced venting with flare and LDAR, with the gas recovery option resulting in a negative cost per tonne accounting for additional sales when there is already a pipeline in place.

Table 6: Summary of mitigation option costs and direct abatement potentials

Option	2016 Cost (£/tCO_2e)	Direct abatement potential
CCS offshore well – low CO_2 concentration	£284	90%
CCS onshore well – low CO_2 concentration	£152	90%
CCS offshore well – high CO_2 concentration	£226	90%
CCS onshore well – high CO_2 concentration	£94	90%
CCS SSF oven, calcium looping	£144	90%
CCS SSF oven, amines	£224	90%
Hydrogen fuel switch	£200 - £209	100%
Electricity fuel switch from grid	£28 - £473	100%
Electricity fuel switch from wind with battery	£766	100%
Electric compressors from grid	£596 - £686	100%
Electric compressors from wind with battery	£1,101 - £1,180	100%
Heating fuel switch to electric grid	£478	100%
Gas recovery to sales	-£104 - -£17	50%
Continuous monitoring	£98	90%
LDAR	£15	40%
Strong LDAR (x6)	£66	80%
RECs	£240	71%
Reduce vent and flare	£13	40%

4.3 Technology availability and TRL

This section outlines the basis for the projections of technology uptake of each mitigation option. The assessment of the technology readiness level (TRL), current uptake levels and broad assumptions of their development are detailed below.

The TRL measures a technology's maturity on a scale of 1-9, as described in Table 7. The TRL score of the abatement technologies investigated in our analysis is reported in Table 8 and was estimated on the basis of current availability and uptake.

[46] Note that a figure of 10% annual operating expense has a large impact on the final value of discounted cost of abatement. Repayment in yearly instalments spread across a technology lifetime of about 20 yr produces a cost of capital of roughly 1.14 times the capital cost.

Table 7: TRL scale descriptions[47]

TRL	Description
1	Basic principles have been established but no research conducted.
2	Research carried out linked to potential of technology through PhD project.
3	Prototype that is being developed in lab or university.
4	Using technology that is currently used for a similar function, but operating conditions are different, requiring major equipment modifications.
5	Using technology that is currently used for a similar function, but operating conditions are different requiring minor equipment modifications.
6	Using technology that is currently used for a similar function, but operating conditions are different, but not such that equipment modifications are needed.
7	Using existing technology that is actively used in another industry for a similar application in a new industry.
8	Undergoing active commissioning or testing of existing technology in a new environment.
9	Actively used in an active facility.

Table 8: Application of TRL to abatement options

Abatement option	TRL	Reasoning
Small scale CCS	5	Examples of offshore CCS projects in oil and gas production e.g. Sleipner CCS. However, CCS is currently applied to gas stream produced and not to fuel combustion emissions.
Fuel switch to hydrogen	5	Hydrogen injections into gas grid in Keele (HyDeploy) and Germany. However, no projects where 100% hydrogen fuel is used.
Fuel switch to electricity - connect to grid	9	Statoil's Johan Sverdrup oilfield connected to onshore electric grid
Fuel switch to electricity - connect to onsite renewable generation (wind turbines with battery storage)	6	Equinor evaluating potential to power installations with wind turbines. However, projects set to provide 35% of annual power demand of five platforms
Electric compressors	9	Equipment produced by manufacturers for use in oil and gas production
Electric heaters	9	Equipment produced by manufacturers for use in oil and gas production
Gas recovery for sales (as grid gas or as LNG)	9	Flare gas recovery units are used in oil and gas facilities, but gas recovery is typically for associated gas
Continuous monitoring	2-4	Operators are trialling systems for monitoring emissions (sensors, laser-based systems). Current practice is to bring in inspectors who use infrared cameras
LDAR	9	Actively used in USA and Canada
RECs	9	Actively used in USA and Canada and is recommended best practice in UK
Reduce venting and flaring where needed	9	Actively carried out zero routine flaring by 2030 initiative

[47] NDA. 2014. Guide to technology readiness levels for the NDA Estate and its supply chain. Nuclear Decommissioning Authority (NDA) Cumbria, UK. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/457514/Guide-to-Technology-Readiness-Levels-for-the-NDA-Estate-and-its-Supply-Chain.pdf

The year of first market deployment was estimated (Table 9) by applying literature technology development and market formation periods.[48] Where options are already available, 2020 was set as the first deployment date. The year of commercial uptake was defined as the year market penetration of the technology reaches 20-50%[48]; 20% for markets where there are multiple competing technologies and 50% for markets where there are only two competing technologies. These were then added to the year the technology was first developed/pioneered to estimate the year of commercial uptake. When the year of commercial uptake has been estimated the year for 100% technology deployment can be estimated. This was conducted assuming uptake growth is linear to a point between 2025-2035, from where growth is also linear but at a different rate. This is a simplified assumption which was made as technology growth trends follow an S-shaped curve[48].

Table 9. Assumed uptake year and year of maturity

Abatement option	TRL	Year of first deployment	Year of maximum deployment
Small scale CCS	6	2025	2050
CCS (SSF oven, calcium looping)	5	2030	2060
CCS (SSF oven, amines)	6	2025	2050
Fuel switch to hydrogen	6	2025	2055
Fuel switch to electricity - connect to grid	9	2020	2042
Fuel switch to electricity - connect to onsite renewable generation (wind turbines with battery storage)	6	2020	2050
Electric compressors	9	2020	2040
Electric heaters	9	2020	2040
Gas recovery for sales (as grid gas or as LNG)	9	2020	2035
Continuous monitoring	2-4	2024	2036
LDAR	9	2020	2025
RECs	9	2020	2035
Reduce venting and flaring where needed	9	2020	2030

4.4 Other costs, barriers and benefits

In addition to climate change benefits and direct economic costs, there are various other costs, benefits and barriers which can be attributed to abatement technologies for fossil fuel production in the UK. These are briefly described here and split into four impact categories: the UK economy, the UK regulatory system and infrastructure, human health and safety; and unintended consequences and additional drivers for decarbonisation.

4.4.1 UK Economy

The economic benefits attributed to the uptake of GHG abatement technologies relate to both the creation of a new industry or the prolonged lifespan of the UK fossil fuel industries (assuming those fossil fuels would otherwise be imported). The extended lifespan of these industries would also contribute towards reducing the UK's dependence on oil, natural gas and steel imports. If the UK were to develop abatement technologies domestically, there is potential for substantial job and revenue creation, which could be furthered if the UK was to export its technology and expertise. The longevity of the abatement technology industry is dependent on the continued production of fossil fuels in the case of process-specific technologies, but CCS and fuel switching

[48] Gross, R., Hanna, R., Gambhir, A., Heptonstall, P. & Speirs, J. 2018. How long does innovation and commercialisation in the energy sectors take? Historical case studies of the timescale from invention to widespread commercialisation in energy supply and end use technology. *Energy Policy,* 123**,** 682-699.

options would be resilient to this. While abatement technologies could prolong the longevity of UK oil and gas facilities, the closure of facilities if it is not economically viable to continue operations (low oil/gas prices and/or high abatement costs), would result in the UK oil and gas industry shrinking, as well as the potential impact of a UK abatement technology industry.

The UK's oil and gas industry is a large employer and source of income in the UK, employing 330,000 people (direct, indirect and induced) in 2016[49]. Nevertheless, oil and gas production has been in decline since the early 2000s. While abatement technologies could allow the lifespan of this industry to be extended, they are not likely to result in industry growth. On the other hand, the development of shale gas in the UK would only be compatible with current UK emissions targets if three tests, as previously set out by the CCC[50], are met, including application of emissions reductions technologies. While as of February 2019 there are no active commercial shale gas wells in the UK, if the industry developed there would be some jobs[51]. Shale gas could also increase domestic natural gas production, reducing the quantity of gas imported to the UK.

4.4.2 UK regulatory system and infrastructure

The uptake of abatement technologies in UK fossil fuel production would be a stressor for infrastructure, including the electric grid and any potential CCS infrastructure. Offshore oil and gas facilities are large consumers of energy (approximately 100 MW per facility[52]) while onshore facilities have more moderate energy consumption levels. However, other sectors are expected to become increasingly electrified in the future, particularly road transport. The added grid demand from electric vehicles was estimated to be 6-18 GW[53] and the current peak demand the electric grid is capable of sustaining is 60 GW[53]. Full electrification of oil and gas production and other downstream facilities would contribute towards substantial additional loading on the electric grid.

An alternative to electrification is to use hydrogen. The current natural gas grid could be used to transport hydrogen, requiring partial retrofitting. Note that some research suggest leakage rates of hydrogen would be negligible (0.001 vol% of throughput) but more research and evidence is needed[54]. The UK oil and gas industry could become an important source of low-carbon hydrogen, but only with CCS fitted. Methane produced can be converted into hydrogen through steam methane reforming.

Regarding CCS, the availability of storage reservoirs is a key infrastructural issue. Available reservoirs could become depleted or near full capacity if CCS is heavily used into the second half of the century. The UK has 7.4-9.9 GtCO_2 theoretical storage capacity in depleted oil and gas fields and 13.4-77.6 GtCO_2 theoretical storage capacity in saline aquifers[55]. If these facilities near depletion, transport and storage costs would rise substantially.

The growth in abatement measure uptake could also increase regulatory costs if abatement was mandated, requiring compliance inspections and associated work. In the UK, BEIS, the Environment Agency (EA) and

[49] Oil and Gas UK. 2018. Economic Report 2018. Oil and Gas UK. London, UK. Available: https://oilandgasuk.cld.bz/Economic-Report-2018/24/
[50] CCC 2016 The compatibility of UK onshore petroleum with meeting the UK's carbon budgets. Onshore Petroleum. London, UK: Committee on Climate Change.
[51] Lewis C, Speirs J, MacSweeney R. Getting ready for UK shale gas: supply chain and skills requirements and opportunities Retrieved from: London (UK): United Kingdom Onshore Oil and Gas and Ernst and Young; 2014 http://www.ey.com/Publication/vwLUAssets/Getting_ready_for_UK_shale_gas/$FILE/EY-Getting-readyfor-UK-shale-gas-April-2014.pdf
[52] Kavanagh, M. 2015. Offshore fields use power sent from land. The Financial Times (FT), 'Available:' https://www.ft.com/content/dace18a2-d927-11e4-b907-00144feab7de
[53] National Grid. 2017. Future Energy Scenarios- 2017. National Grid. London, UK. Available: http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf
[54] Dodds, P. E. & Demoullin, S. 2013. Conversion of the UK gas system to transport hydrogen. International Journal of Hydrogen Energy, 38, 7189-7200.
[55] DECC. 2010. CO_2 storage in the UK- industry potential. Department of Energy and Climate Change (DECC). London, UK. Available: https://ukccsrc.ac.uk/system/files/publications/ccs-reports/DECC_Gas_156.pdf

the Oil and Gas Authority (OGA) are the main regulatory bodies for fossil fuel production activities in the UK and BEIS and the EA could be responsible for inspecting compliance of CCS facilities and pipeline infrastructure.

4.4.3 Human health and safety

The impacts to human health from the uptake of abatement measures are both physical and psychological. Physically, abatement measures and particularly CH_4 mitigation measures, will improve human health. As well as being a potent greenhouse gas, methane also impacts significantly on air quality, through tropospheric ozone creation. This causes significant respiratory health impacts, as well as harming ecosystems and reducing crop yield. As a result of this, estimates of the 'social cost' of methane are in the order of 100 times higher than CO_2[56]. In addition, methane is a highly flammable gas and minimising leaks will reduce the risk of explosions, thereby increasing safety. This is the main driver for the Iron Mains Replacement Programme (IMRP) to reduce the risk of injuries, fatalities and damage to buildings[57]. Therefore, while the CO_2e abatement cost is high (Table 6), it does not take into account additional costs and benefits to safety and health.

Improvement to air quality from other mitigation measures is not guaranteed: when fuel switching to hydrogen is considered, air quality will still be a factor via potential emissions of NO_x[58] unless technologies are designed to eliminate or mitigate accordingly.

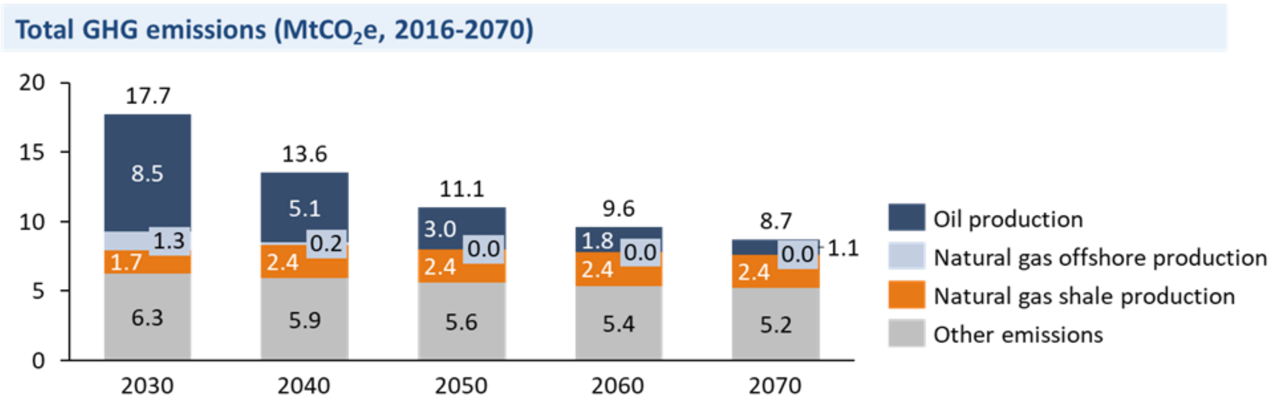
Other possible health impacts of abatement measures are the generation of noise and creation of visual obstructions from facilities, particularly onshore shale gas sites and CCS facilities. The construction of well sites (drilling equipment, compressor stations, substations and transformers etc.) and CCS facilities, if in rural areas, would be unpopular and could require the clearing of large areas of land. This would in turn affect local ecology and ecosystems. The development of shale gas is extremely unpopular and could cause stress to local residents concerned with environmental impacts, earthquakes and water contamination[59].

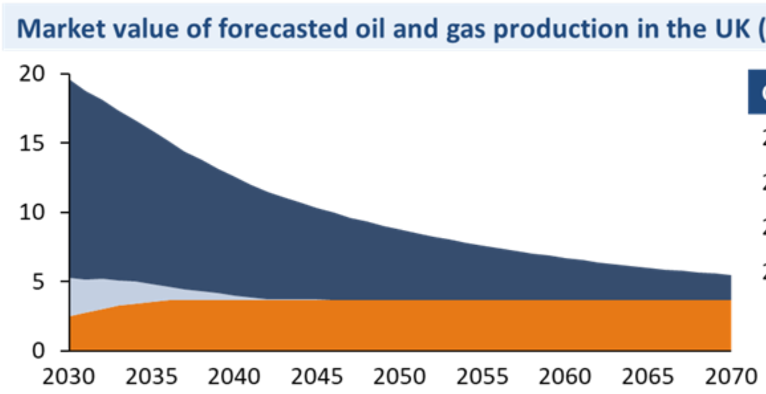
4.4.4 Unintended consequences and additional drivers for decarbonisation

There is a risk that oil and gas operators may prefer to decommission their fields earlier instead of investing in decarbonisation measures, if the remaining lifetime/reserve of the fields is not enough to justify these measures. It is difficult to estimate the actual level of risk in the UKCS as it would be field-specific, depending on the production profile and reserve of a given field, but it is reasonable to assume that most/all existing oil and gas fields post-2040 will be beyond their production peak year rate (i.e. production decline phase) so it will be difficult for them to invest in these technologies.

The chart below (Figure 11) shows the level of GHG emissions related to offshore oil and gas production, and onshore shale production. Assuming all offshore oil and gas fields move their Cessation of Production (CoP) dates to 2050 due to the decarbonisation drivers, around 3MtCO_2e would be offshored. However, this would correspond to a loss of ~£68 billion (in terms of market value of the produced oil that may be produced between 2050 and 2070). It should be noted that this estimate is based on our interpolation using existing scenarios, which do not cover that period.

[56] Shindell, D. T., Fuglestvedt, J. S. & Collins, W. J. 2017. The social cost of methane: theory and applications. *Faraday Discussions,* 200**,** 429-451.
[57] HSE. 2005. *Enforcement Policy for the replacement of iron gas mains 2006 - 2013 - December 2005* [Online]. London, UK: Health and Safety Executive (HSE). Available: http://www.hse.gov.uk/gas/supply/mainsreplacement/irongasmain.htm [Accessed March 2019 2019].
[58] Samuelsen, GS, Therkelsen, P., Werts, T., & McDonell, V. (2009). Analysis of NOx Formation in a Hydrogen-Fueled Gas Turbine Engine. Journal of Engineering for Gas Turbines and Power, 131(3), 653-664.
[59] Cooper, J., Stamford, L. & Azapagic, A. 2016. Shale Gas: A Review of the Economic, Environmental, and Social Sustainability. Energy Technology, 4, 772-792.





Cumulative market value of oil production	
2030-2070	£251 billion
2040-2070	£136 billion
2050-2070	£68 billion
2060-2070	£26 billion

Figure 11: GHG emissions by primary source and market value of UK oil and gas production

Conversely, oil and gas companies can easily implement some of these expensive abatement measures if the expected revenues from the operations justify them. The first cables to power offshore platforms with electricity produced onshore were installed in the Abu Safah development in Saudi Arabia in 2003. Since then, two Norwegian platforms have also been connected[60] and three more are in planning stage[61]. This is due to a demand from the Norwegian government for oil companies to power their offshore operations/platforms using electricity produced onshore via cables[62]. As discussed, this is an expensive measure based on £/tCO_2e; however, oil companies have found a way to justify electrification of their offshore operations.

Another potential driver for these technologies could be the hydrogen economy. If an oil and gas company is interested in producing hydrogen from natural gas, implementing some of these expensive abatement options can be justified within the overall hydrogen value chain (e.g. if that is the only way to sell natural gas in a net-zero economy).

Finally, although we assess these measures individually for each inventory row, some of them can be combined as a package of measures. For instance, in a 100% hydrogen for heat future, all/most of the methane emissions would disappear. Including the reduction in methane leakage on its own could justify some of the other more expensive measures across the gas supply-chain. Figure 12 below shows two different marginal abatement cost curves (MACCs) for all natural gas related emissions. Although most of the emissions in the upper chart have costs of more than £100/tCO_2e, the average cost of implementing all measures as a package is less than £50/tCO_2e in the lower chart, considering reduction in methane leakage.

[60] https://www.ft.com/content/dace18a2-d927-11e4-b907-00144feab7de
[61] https://www.equinor.com/en/news/11jun2018-electrification.html
[62] https://www.newsinenglish.no/2014/05/16/opposition-demands-rig-electrification/

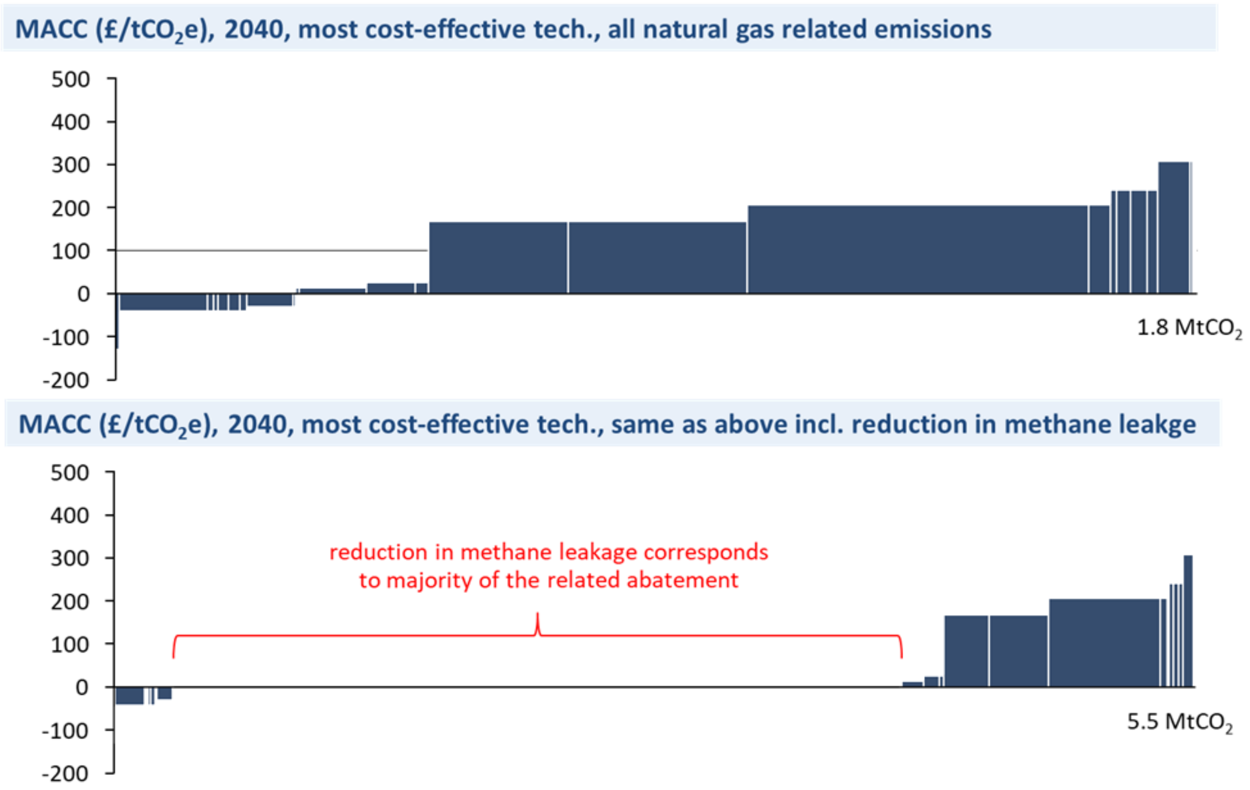


Figure 12: MACC 2040

5 Abatement of fossil fuel production and fugitive emissions in the UK

5.1 Abatement scenarios

For each emission source in our scope, up to three of the mitigation options described in chapter 4 were considered. The achievable abatement of emissions of each entry depends both on the chosen type of abatement technology and on the rate of its implementation. Therefore, different scenarios were considered in this study for the selection of the appropriate technology and for the speed of technology rollout.

5.1.1 Technology scenarios

Three technology scenarios were employed with different criteria for the selection of the appropriate abatement technology for each emission source, based on abatement potential and cost effectiveness of the available technologies in the year 2050:

- **Core scenario**: choosing only from technologies with cost-effectiveness below £100/tCO_2e. Among technologies offering the highest abatement potential, the cheapest option is selected.
- **Further ambition scenario**: choosing only from technologies with cost-effectiveness below £400/tCO_2e. Among technologies offering the highest abatement potential, the cheapest option is selected.
- **Speculative scenario**: choosing from all technologies. Among technologies offering the highest abatement potential, the cheapest option is selected.

For all abatement options based on CCS, 90% abatement potential was assumed in the core and further ambition scenarios, according to the estimates in paragraph 4.2. For the speculative scenario a more ambitious abatement potential of 99% was utilised, with associated 10% increase in cost of abatement (£/tCO_2e).

Additionally, the three technology scenarios are applied to different baseline emissions profiles. The core scenario refers to the standard baseline emissions displayed in Figure 9, whereas further ambition and speculative scenarios refer to baseline emissions with 90% gas grid closure and/or switchover to hydrogen, as shown in Figure 10.

5.1.2 Rollout profiles

Three different rollout profiles were considered for each technology, based on the year of first deployment and the year of maximum deployment of the technology from Table 9. These profiles were built though linear interpolation of different milestones, the years in which 0%, 20% and 100% of technology deployment is achieved.

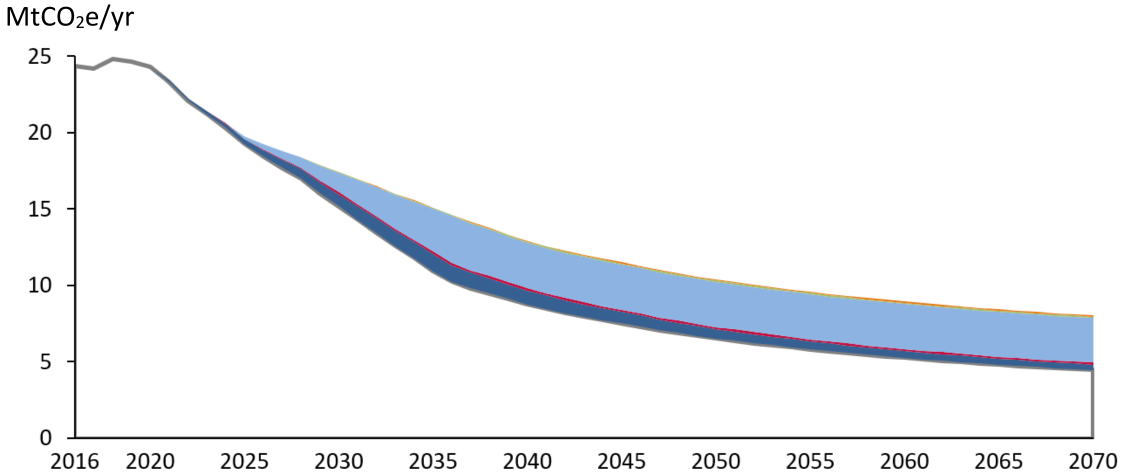
While **central** and **fast** scenarios initiate deployment on the same year and full deployment of the technology is reached at a higher rate in the fast scenario, in the **slow** scenario deployment starts later and full deployment is also reached at a lower rate. The technology deployment milestones utilised for the slow, central and fast scenarios are listed in section 7.9 of the appendix.

Depending on the scenario, the selected rollout profile is multiplied by the maximum abatement potential of the respective technology to produce the abatement potential profile over time.

5.2 Abatement potentials, costs and timescales

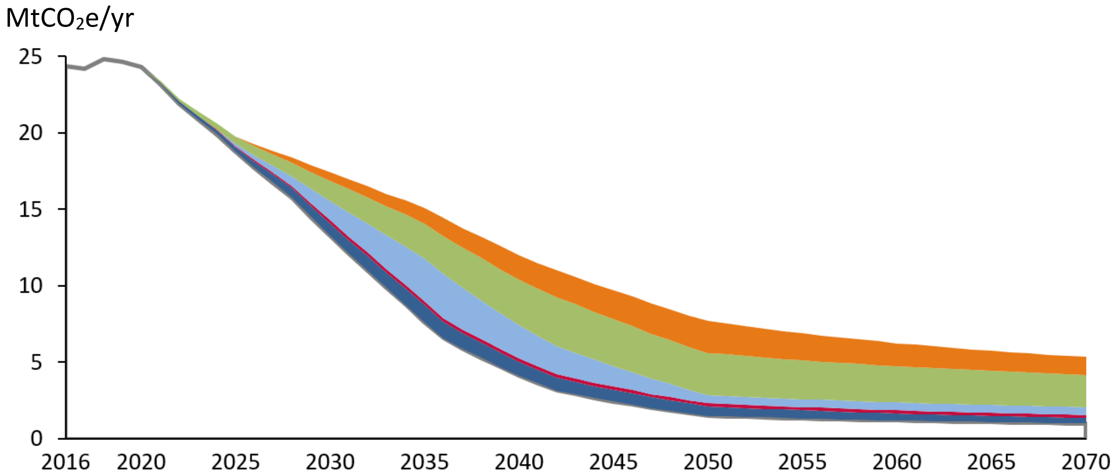
5.2.1 Direct abatement

The predicted achievable direct abatement of baseline emissions is displayed in Figure 13, Figure 14 and Figure 15 in the core, further ambition and speculative scenarios with central rollout profile, respectively. Direct abatement forecasts with slow and fast rollout profiles are reported in section 7.10 in the Appendix. The figures below show the mitigation results by technology category. Process upgrade includes continuous monitoring, LDAR and strong LDAR, whereas material upgrade comprises RECs and reduction of venting and flaring.



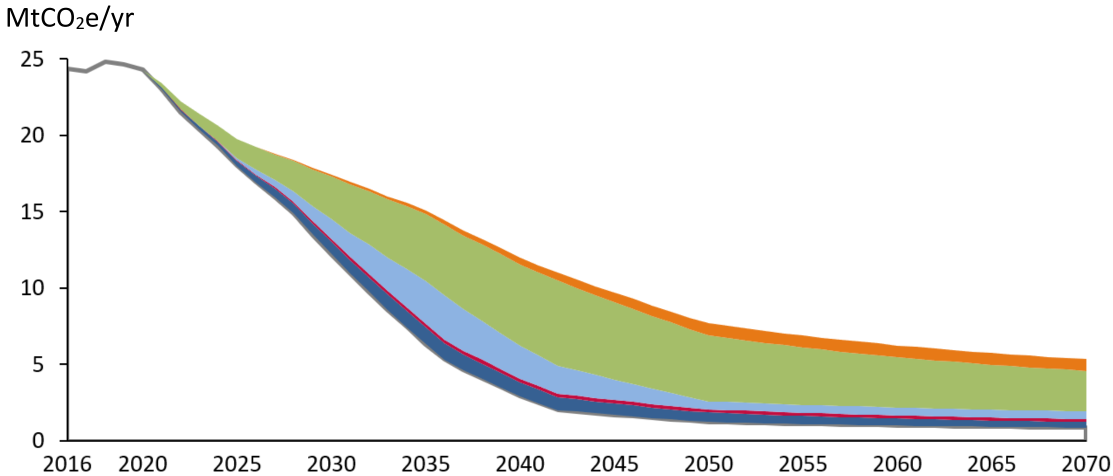
	2040	2050	2060	2070
CCS	0.0	0.1	0.1	0.1
Hydrogen fuel-switching	0.0	0.0	0.0	0.0
Electricity fuel-switching	0.1	0.1	0.1	0.1
Process upgrade	3.0	2.9	2.9	2.9
Material upgrade	0.2	0.1	0.1	0.1
Gas recovery	0.9	0.6	0.5	0.4
Unabated	**8.8**	**6.5**	**5.3**	**4.5**

Figure 13: Direct emissions abatement by technology - Core scenario, central rollout



	2040	2050	2060	2070
CCS	1.6	2.1	1.5	1.2
Hydrogen fuel-switching	0.0	0.0	0.0	0.0
Electricity fuel-switching	3.0	2.7	2.4	2.1
Process upgrade	2.2	0.5	0.5	0.5
Material upgrade	0.2	0.2	0.2	0.2
Gas recovery	0.9	0.6	0.5	0.4
Unabated	**4.1**	**1.5**	**1.2**	**1.0**

Figure 14: Direct emissions abatement by technology - Further ambition scenario, central rollout



	2040	2050	2060	2070
CCS	0.4	0.8	0.8	0.7
Hydrogen fuel-switching	0.0	0.0	0.0	0.0
Electricity fuel-switching	5.3	4.3	3.3	2.7
Process upgrade	2.2	0.5	0.5	0.5
Material upgrade	0.2	0.2	0.2	0.2
Gas recovery	0.9	0.6	0.5	0.4
Unabated	**2.9**	**1.2**	**1.0**	**0.9**

Figure 15: Direct emissions abatement by technology - Speculative scenario, central rollout

Baseline emissions in the period between 2040 and 2070 are lower in the further ambition and speculative scenarios, due to the different baseline emissions profile these two scenarios utilise (with 90% gas grid closure and/or switchover to hydrogen). Additionally, total abatement achievable in these two scenarios is larger than the abatement achieved in the core scenario. According to the forecasts of this study, unabated emissions from the sources in this scope could be reduced to between 8.8MtCO_2e and 2.9MtCO_2e in 2040 and between 4.5MtCO_2e and 0.9MtCO_2e in 2070 in the three technology scenarios with central rollout, achieving a total mitigation of 64-88% in 2040 and 82-96% in 2070 compared to emissions in 2016.

Process upgrade technologies (continuous monitoring and LDAR) make up a large portion of abatement in the core scenario compared to other technology categories which are mostly higher cost than the £100/tCO_2e threshold required by the core scenario.

Furthermore, the abatement achieved by process upgrade technologies in the core scenario is also larger than its respective abatement in the further ambition and speculative scenarios. This is due to the higher amount of fugitive emissions from pipeline leakage present in the baseline emissions mix of the core scenario, as these reduce over time in the further ambition and speculative scenarios, due to partial gas grid closure and/or switchover to hydrogen.

A large portion of emissions in the further ambition and speculative scenarios are abated by CCS and electricity fuel-switching, accounting for 75% and 76% of abatement in 2070 respectively. Although these technology groups achieve an almost equal abatement in the further ambition scenario, the portion abated by electricity fuel-switching in the speculative scenario is considerably larger. This technology group is often preferred in the speculative scenario due to its slightly larger abatement potentials and the lack of a threshold on abatement costs in the scenario. The contribution of material upgrade, on the other hand, is very small in all three scenarios, as the amount of baseline emissions that can be abated with these technologies is very small.

Hydrogen fuel switching does not feature in any of the scenarios with central rollout profile, however it is responsible for a significant amount of abatement in the further ambition and speculative scenarios with fast rollout profile. Despite the lower costs of abatement of this technology group compared to the costs of alternative technologies (mainly electricity fuel-switching), the low TRL of hydrogen fuel-switching excludes this technology from the selection with central and slow rollout profiles, as the portion of emissions that can be abated by hydrogen fuel-switching is only competitive with the abatement offered by other technologies when the rollout rates are accelerated. In practice, hydrogen rollout will be strongly affected by any rollout in buildings and industry – the fuel-switching potential should therefore be interpreted as subject to uncertainty regarding the future fuel mix, with some cost savings possible if deploying a greater share of hydrogen.

5.2.2 Net abatement

The implementation of CCS and of most fuel switching abatement options result in additional electricity, natural gas and hydrogen demand, which contributes to an increase in indirect emissions. When taking indirect emissions into account, the achievable net abatement of the technology selection for each scenario is minimally reduced.

Indirect emissions produced in the core scenario are never larger than 0.01MtCO_2e and are therefore considered negligible. This is because most of the emissions abatement is achieved through process upgrade, material upgrade or gas recovery, which do not result in additional fuel or electricity consumption, responsible for all indirect emissions in this study.

The largest amount of indirect emissions is produced in the speculative scenario, accounting for 8% of all cumulative unabated emissions in the timeframe from 2020 to 2070. This is due to the large use of electricity fuel-switching technologies from the early years and the substantial use of hydrogen fuel-switching technologies beyond 2035.

5.3 Marginal Abatement Cost Curves

Marginal abatement cost curves (MACC) were produced for each of the technology scenarios with central rollout, and are displayed in Figure 16, Figure 17 and Figure 18. The figures refer to discounted cost of abatement and abatement of direct emissions.

Figure 16: MACC 2050 - Core scenario, central rollout

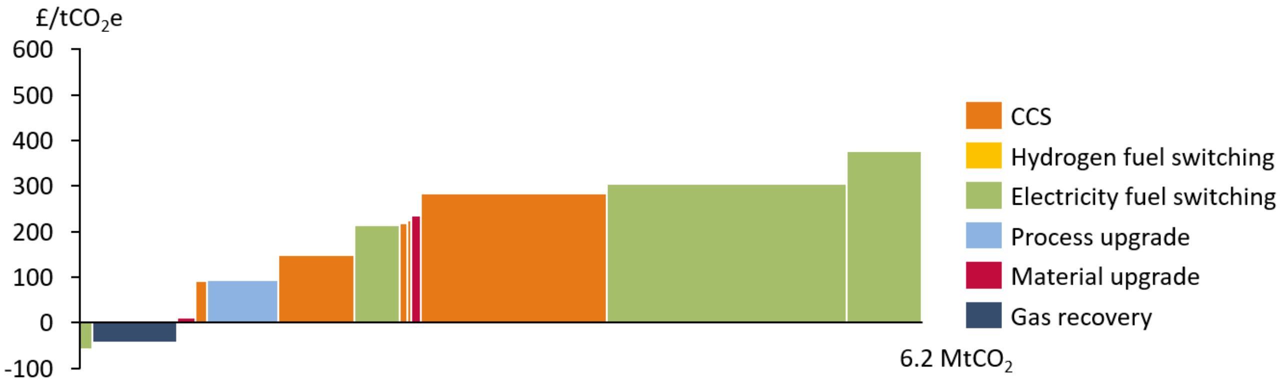


Figure 17: MACC 2050 - Further ambition scenario, central rollout

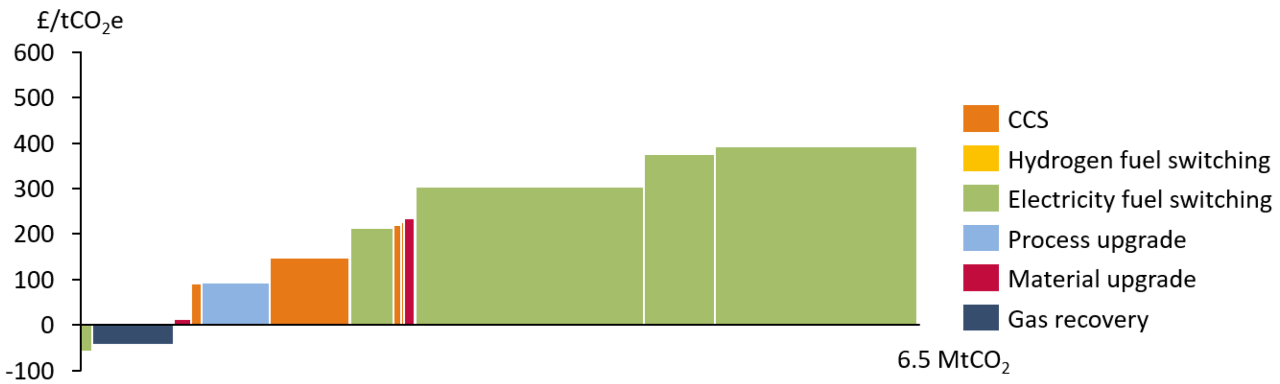


Figure 18: MACC 2050 - Speculative scenario, central rollout

In all scenarios with central rollout, two technologies produce negative abatement costs together with a total abatement of 0.7 $MtCO_2e$: electricity grid connection (onshore gas, replacing gas oil) and gas recovery for sales - offshore oil/shale gas.

The progression to a higher cost cap from the core scenario to the further ambition scenario shows the implementation of an additional set of technologies, contributing further abatement. However, the abatement achieved by process upgrade technologies is reduced due to the lower amount of baseline fugitive emissions from pipeline leak of the further ambition scenario, due to partial gas grid closure and/or switchover to hydrogen in 2050.

In the speculative scenario, a large portion of the abatement is achieved through electricity fuel switching, as well as replacing a part of the CCS abatement produced in the further ambition scenario. As previously discussed in section 5.2.1, this is due to the marginally larger abatement potential of electricity fuel-switching compared to CCS and the lack of an abatement cost cap in the speculative scenario.

5.4 Projections of remaining emissions

The remaining emissions after the implementation of the available abatement technologies for each technology scenario and rollout profile are summarised in Figure 19.

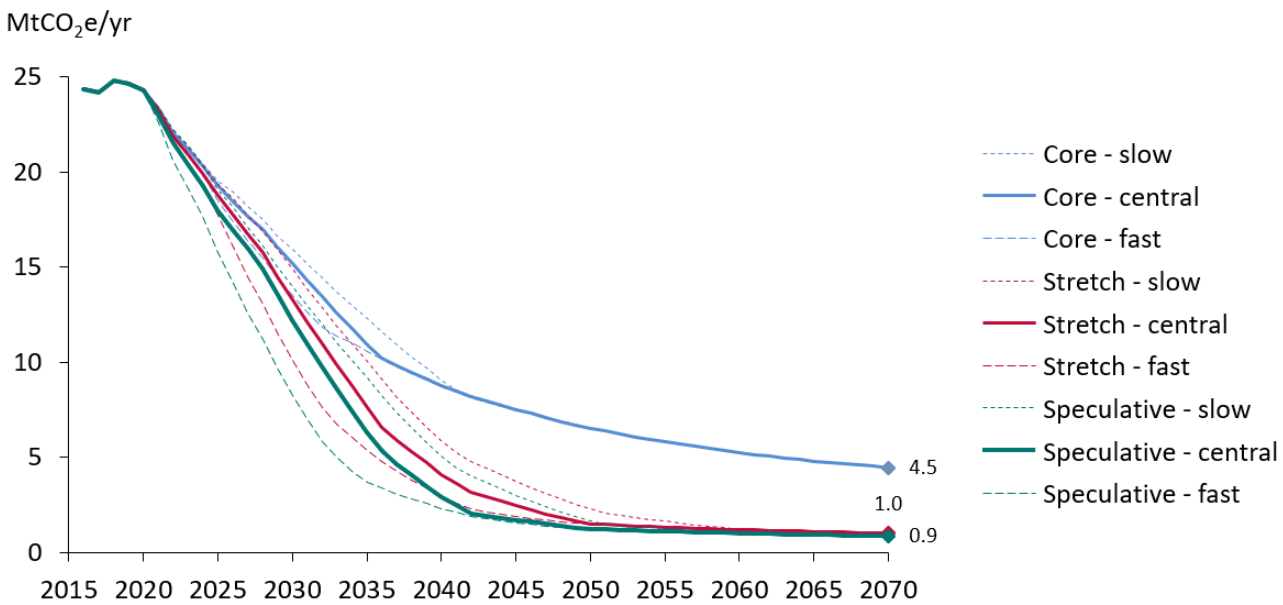


Figure 19: Remaining emissions for different technology scenarios and rollout profiles

Unabatable emissions are defined as the remaining emissions after the implementation of all available technologies delivering the highest abatement at any cost, with their earliest possible implementation. These correspond to the remaining emissions in the speculative scenario with fast rollout and are reported in Figure 20.

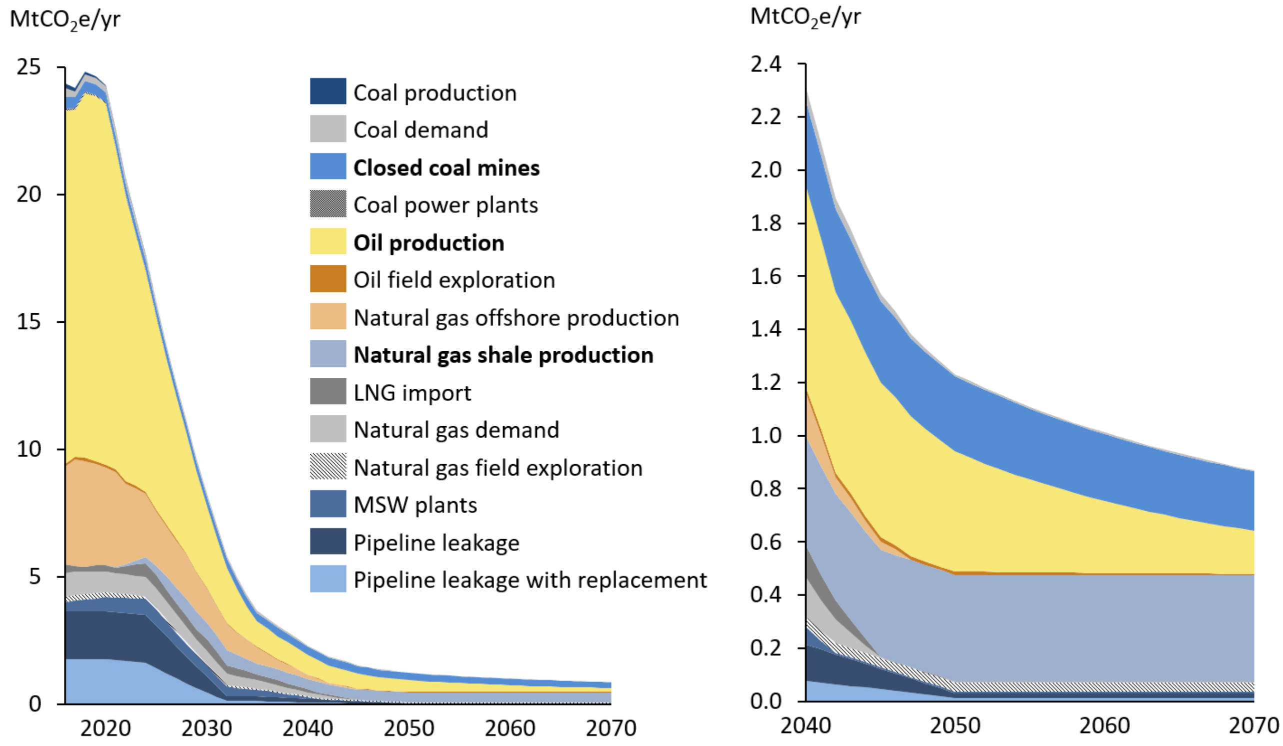


Figure 20: Unabatable emissions by trigger point (left: 2016-2070 projection, right: 2040-2070 closeup) - Speculative scenario, fast rollout

The remaining emissions amount to 2.3MtCO2e in 2040 and 0.9MtCO2e in 2070, corresponding to a reduction in emissions of 81% of total baseline emissions in 2040 and 84% of total baseline emissions in 2070. Compared to 2016 values, this would correspond to a total abatement of emissions of 90% in 2040 and 96% in 2070.

The main contributors to remaining emissions after 2040 are sources associated with natural gas shale production, closed coal mines and oil production. About two thirds of all remaining emissions expected in 2040 are produced by only six of the main sources in our scope, as reported in Table 10. Remaining emissions in 2070 would stem almost exclusively from fugitive emissions, while emissions from combustion processes could be abated almost entirely. In fact, some of the abatement technologies considered for fugitive emissions associated with natural gas shale production and oil production, such as gas recovery for sales and flaring, are capable of reducing 2016 emissions only by 50% and 40% respectively at their maximum deployment. No abatement technology was identified to further reduce fugitive emissions from closed coal mines.

Table 10: Main technically unabatable emissions in 2040 and 2070 - speculative scenario, fast rollout

NAEI / IPCC code	NAEI Source	NAEI Activity	GHG	Emissions 2040		Emissions 2070	
				$ktCO_2e$	Cumulative[63] %	$ktCO_2e$	Cumulative[63] %
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CO_2	603	26%	129	15%
1B1a1iii	Closed Coal Mines	Non-fuel combustion	CH_4	317	40%	224	41%
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion	CH_4	169	47%	169	60%
1A1ciii	Gas production - Transmission and storage (72%)	Natural gas	CO_2	148	54%	0	60%
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CO_2	146	60%	146	77%
1B2b5	Gas leakage - M+R stations (50%)	Natural gas supply	CH_4	124	65%	18	79%
1A1ciii	Gas production - Regasification (28%)	Natural gas	CO_2	116	70%	0	79%
1A1cii	Upstream Gas Production - Fuel combustion	Natural gas	CO_2	114	75%	0	79%
1B2b5	Gas leakage - Pipeline leaks (50%)	Natural gas supply	CH_4	78	79%	11	80%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CH_4	68	81%	15	82%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CO_2	57	84%	5	82%
1B2c1i	Upstream Oil Production - Venting	Non-fuel combustion	CH_4	57	86%	12	84%
1B1b	Solid smokeless fuel production	Coal	CO_2	31	88%	0	84%
1B2b4	Upstream Shale Gas leakage - production and processing - Compressor stations (80%)	Non-fuel combustion	CH_4	20	89%	20	86%
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	19	89%	19	88%
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	17	90%	15	90%
Others (complete list: see appendix, section 7.12)							100%

[63] Cumulative emissions are calculated here by subsequent addition of the emissions share of each entry in the list.

6 Conclusions

Baseline emissions

- **Baseline emissions are estimated to reduce over the investigated timeframe leading to 2070, before accounting for mitigation measures.** The main reason for the progressive reduction of baseline emissions is the reduction of domestic production of fossil fuels, which is not matched by an equal reduction in demand, therefore resulting in 'offshoring' of a part of these avoided emissions. For instance, emissions related to natural gas offshore production and oil field exploration are expected to reduce significantly and constitute a very small contribution to overall emissions after 2040. Total direct emissions are expected to reduce by 67% between 2016 and 2070, going from about 24MtCO_2e/yr in 2016 to 8MtCO_2e/yr in 2070. Furthermore, if partial gas grid closure and/or switchover to hydrogen in considered, the reduction in emissions is more substantial, leading to 5.3MtCO_2e/yr baseline emissions in 2070 and 78% of reduction compared to 2016.
- **Baseline GHG emissions between 2040 and 2070 are expected to stem mainly from pipeline leakage, shale gas production and oil production.** However, the future relevance of the first two sectors has a high level of uncertainty. Emissions from pipeline leakage would be strongly affected if the natural gas delivered by the grid were substituted with hydrogen, as is presented in section 3.2 with additional baseline forecasts assuming 90% gas grid closure and/or switchover to hydrogen. Similarly, the future role of shale gas production in the UK is still unclear, as future political and techno-economical decisions would likely result in either large-scale investments or no investment in the sector.

Abatement of fossil fuel production and fugitive emissions in the UK

- **A variety of abatement options applicable to the sources in the scope of this study were identified.** These include fuel switching, CCS and equipment/process-specific options such as gas recovery for sales, continuous monitoring, LDAR, RECs and vent reduction. Some technologies, such as continuous monitoring, CCS and hydrogen fuel switching, are currently associated with a low TRL and their abatement potential will be limited during the early years of the timeframe considered in this analysis. The abatement potential of more mature technologies will also be restricted where their current share of deployment in the UK is already substantial.

  Abatement costs vary considerably from -£104 to £1,180, with electricity supply to offshore via either the grid or local wind power with battery storage resulting in the highest mitigation costs. The lowest cost abatement options identified is gas recovery to sales, offering negative abatement costs.

- **High costs and the technical difficulty of implementation for some of the abatement technologies might bring about unintended consequences.** For instance, while the uptake of GHG abatement technologies could be responsible for the creation of a new industry or the prolonged lifespan of the UK fossil fuel industry, there is also a risk that oil and gas operators may prefer to decommission their fields earlier instead of investing in decarbonisation measures.

- **When mitigation options are implemented, baseline direct emissions can be abated by up to 88% in 2040 and by up to 96% in 2070, when compared to 2016 levels.** However, the costs associated with the different abatement potentials are highly variable and depend mainly on the technology utilised and often also on the year of implementation. The implementation of cheap mitigation options with a cost-effectiveness of abatement smaller than £100/tCO_2e enables mitigation of 64% of emissions in 2040 and 82% in 2070, compared to 2016 levels. The high mitigation costs estimated in this study for some of the mitigation options may decrease over time, but nevertheless represent a significant barrier to decarbonisation.

Relevance of results for the Fifth Carbon Budget and for net zero emissions

- **Abatement of emissions in the scope of this study will contribute to meeting current targets UK GHG emissions targets for 2050.** Total UK GHG emissions in 2016 amounted to 59% the emissions of 1990[64]. In order to achieve the legally binding target of carbon emissions reduction of at least 80% by 2050 relative to 1990 levels, a further reduction in overall UK GHG emissions by at least 66% of 2016 emissions is required. Our forecast suggests that direct emissions from all sources in the scope of fossil fuel production and fugitive emissions can be abated by up to 73% in 2050 compared to 2016 values in the core scenario with central rollout profile. Higher abatement potentials are achievable by 2050 with up to 94% abatement in the further ambition scenario and with up to 95% abatement in the speculative scenario, considering central rollout profiles. Similarly, achievable rates of abatement of baseline direct emissions in 2040 compared to 2016 levels are expected to amount to 64% in the core scenario, 83% in the further ambition scenario and 88% in the speculative scenario. The increase in indirect emissions resulting from a larger use of electricity and hydrogen would not be significant in the core scenario. In the further ambition and speculative scenarios indirect emissions account to only a few percentages of the baseline emissions.
- **Significant emissions abatement can be achieved by implementing technologies from the lower costing bracket.** The calculated abatement estimate figures suggest that the implementation of a set of abatement technologies associated with abatement costs below £100/tCO_2e, even in the case of no gas grid closure and/or switchover to hydrogen, are more than sufficient for reducing the GHG emissions contribution from the UK fossil fuel production and fugitive emissions sector in line with the existing 2050 emissions reduction target. Furthermore, the direct emissions abatement potential achieved by the technologies considered in the core scenario allows for a reduction in emissions by 66% compared to 2016 levels as early as in 2042, corresponding to the overall UK GHG emissions reduction required to meet the current 2050 target.
- **Net zero abatement from the fossil fuel production and fugitive emissions scope is not achievable alone through the implementation of the investigated abatement technologies in the timeframe considered**, due to remaining emissions from some sources in the scope of this study that cannot be fully abated (see section 5.4). Direct emissions abatement achievable in the core scenario compared to 2016 increases progressively from 73% in 2050 to 78% in 2060 and 82% in 2070. When considering partial closure of the gas grid and/or switchover to hydrogen and higher cost of abatement technologies, the maximum level of direct abatement in 2070 that can be obtained is 96% in both further ambition and speculative scenarios.

  The target of net zero emissions from the sources in the scope of this study can only be attained through the implementation of the investigated abatement technologies, together with the utilisation of additional GHG removal options delivering a negative emissions contribution. A future analysis of the cost-effectiveness of the available GHG removal technologies will be necessary, in order to determine the portion of total budget that would be allocated to the abatement of emissions and the portion allocated to GHG removal, selecting the overall most cost-effective combination of abatement and removal options to produce net zero emissions.

Recommendations for further work

Further investigations will be required in order to complete and refine the spectrum of information that was utilised in this study and to further the accuracy of the results.

- A bottom-up assessment of the abatement potential and cost effectiveness of the identified abatement options will be necessary to refine the estimates of this study, analysing the individual installations on a case-by-case basis.

- Further work on the applicability and effectiveness of some of the less mature technologies can also be completed. A few examples of the aspects worth analysing are offshore small-scale CCS, use of

[64] Provisional UK greenhouse gas emissions national statistics 2017 https://www.gov.uk/government/statistics/provisional-uk-greenhouse-gas-emissions-national-statistics-2017

hydrogen for various application, use of hydrogen with CCUS for heating to reduce indirect emissions and increasing the capture rate of CCS. Using a less technical approach, the relevance of unintended consequences could also be assessed through engagement with relevant industries, government bodies and relevant stakeholders.

- Finally, future work should also address the uncertainty of emissions. The impact of emissions uncertainty for each source on total emissions can then be assessed. For instance, Figure 21 shows a sensitivity analysis of the contribution in emissions due to leakage from the gas grid in the core scenario (not considering gas grid closure and/or switchover to hydrogen). Assuming the emissions contribution from pipe leakage doubles, the total remaining emissions show a significant increase during the first years of our analysis, with an increase of 15% in 2020. The increase is much smaller in the following years, thanks to the successful implementation of continuous monitoring as an abatement technology capable of reducing emissions by 90%, resulting in an increase in total remaining emissions by only 3% in 2040 and 7% in 2070.

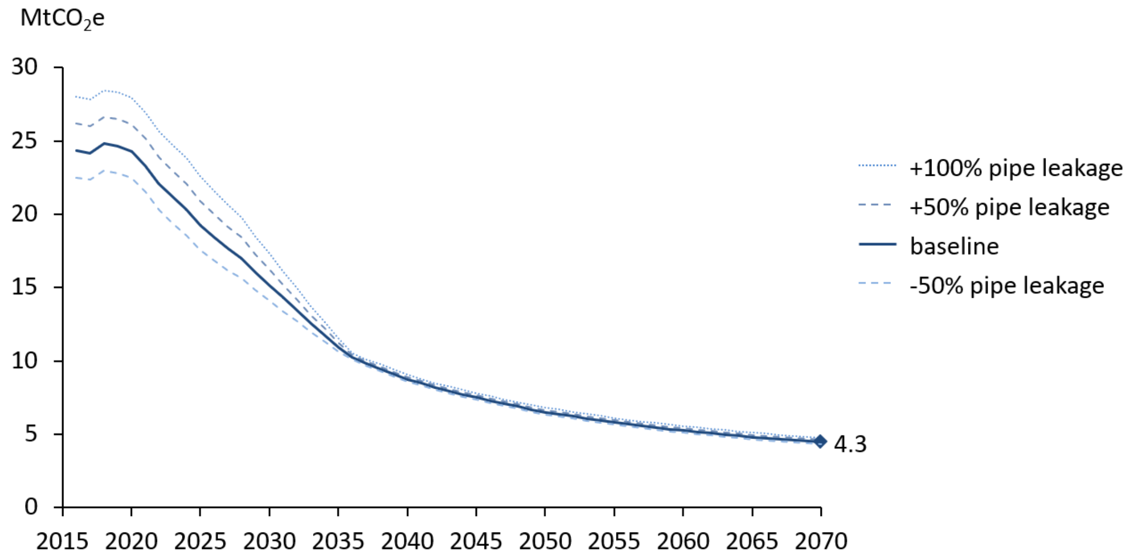


Figure 21: Remaining emissions in core scenario, central rollout – Pipe leakage sensitivity

7 Appendix

7.1 Sources

Table 11: Fuel combustion activities (1A)

NAEI / IPCC code	NAEI Source	NAEI Activity
1A1ai	Miscellaneous industrial/commercial combustion	MSW
1A1cii	Upstream gas production - Fuel combustion	Gas oil
1A1cii	Upstream gas production - Fuel combustion	Natural gas
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	LPG
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	OPG
1A1cii	Upstream Oil Production - Fuel combustion	Gas oil
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas
1A1ciii	Collieries - combustion	Colliery methane
1A1ciii	Collieries - combustion	Natural gas
1A1ciii	Gas production	Natural gas

Table 12: Fugitive emissions from fuels (1B)

NAEI / IPCC code	NAEI Source	NAEI Activity
1B1a1i	Deep-mined coal	Coal produced
1B1a1ii	Coal storage and transport	Deep mined coal production
1B1a1iii	Closed Coal Mines	Non-fuel combustion
1B1a2i	Open-cast coal	Coal produced
1B1b	Charcoal production	Charcoal produced
1B1b	Coke production	Coke produced
1B1b	Iron and steel - Flaring	Coke oven gas
1B1b	Solid smokeless fuel production	Coal
1B1b	Solid smokeless fuel production	Petroleum coke
1B1b	Solid smokeless fuel production	SSF produced
1B2a1	Upstream Oil Production - Offshore Well Testing	Exploration drilling: amount of gas flared
1B2a2	Petroleum processes	Oil production
1B2a2	Upstream Oil Production - Process emissions	Non-fuel combustion
1B2a3	Upstream Oil Production - Offshore Oil Loading	Crude oil
1B2a4	Upstream Oil Production - Oil terminal storage	Non-fuel combustion
1B2b1	Upstream Gas Production - Offshore Well Testing	Exploration drilling: amount of gas flared
1B2b3	Upstream Gas Production - Process emissions	Non-fuel combustion
1B2b4	Gas leakage	Natural Gas (transmission leakage)
1B2b4	Upstream Gas Production - Gas terminal storage	Non-fuel combustion

1B2b5	Gas leakage	Natural Gas (leakage at point of use)
1B2b5	Gas leakage	Natural gas supply
1B2c1i	Upstream Oil Production - Venting	Non-fuel combustion
1B2c1ii	Upstream Gas Production - Venting	Non-fuel combustion
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion
1B2c2ii	Upstream Gas Production - Flaring	Non-fuel combustion

Table 13: Mineral products (2A)

NAEI / IPCC code	NAEI Source	NAEI Activity
2A4d	Power stations - FGD	Gypsum produced

Table 14: Shale gas - additional sources

NAEI / IPCC code	NAEI Source	NAEI Activity
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Gas oil
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas
1B2b1	Upstream Gas Production - Shale Gas Well Testing	Exploration drilling: amount of gas flared
1B2b3	Upstream Gas Production - Shale Gas Well Testing	Exploration drilling: amount of gas flared
1B2b4	Upstream Gas Production - Process emissions (shale gas)	Non-fuel combustion
1B2b4	Upstream Shale Gas leakage- Production and processing	Non-fuel combustion
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion

7.2 Supply chain mapping diagrams

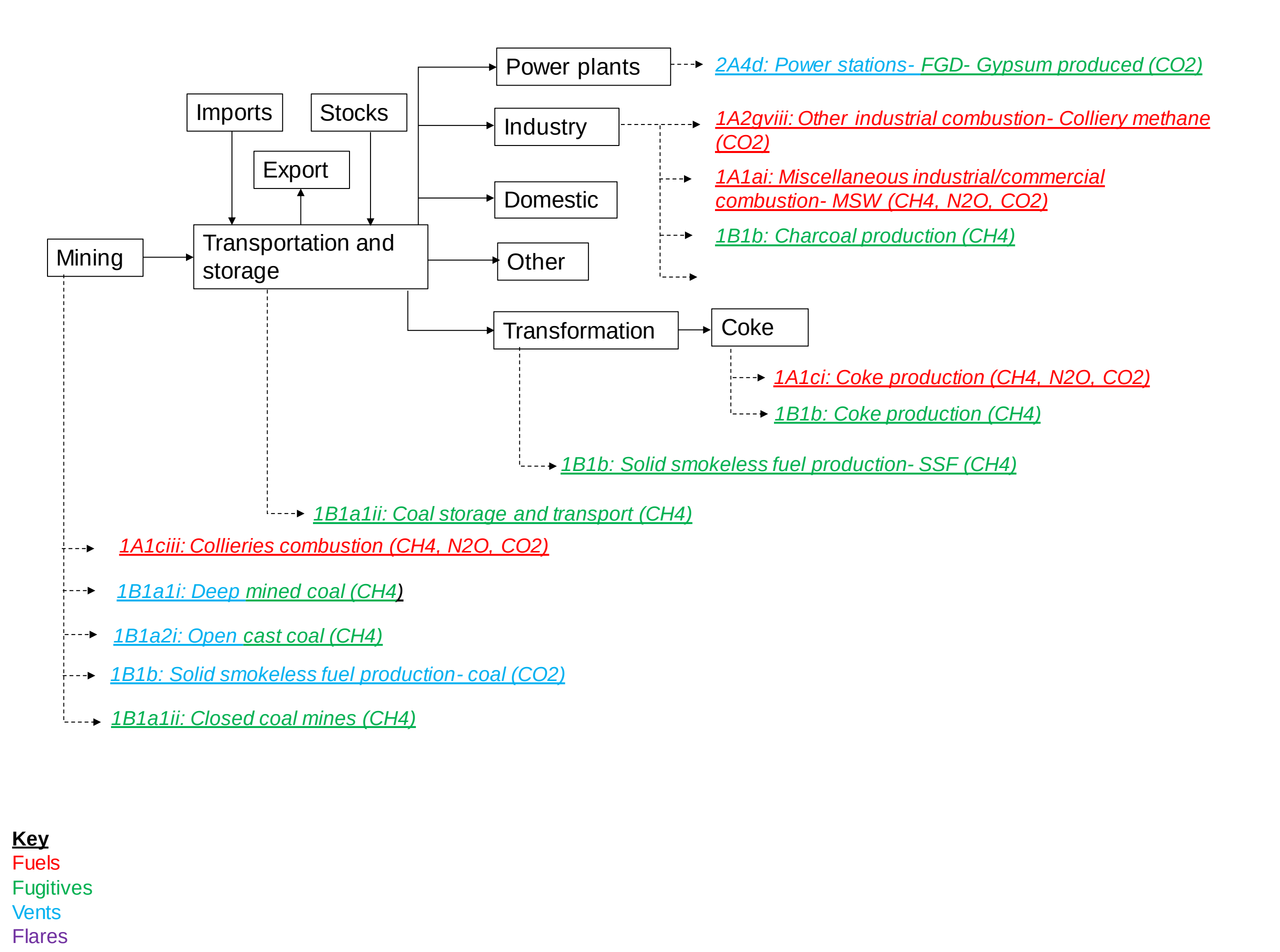


Figure 22: The coal supply chain and emissions categories

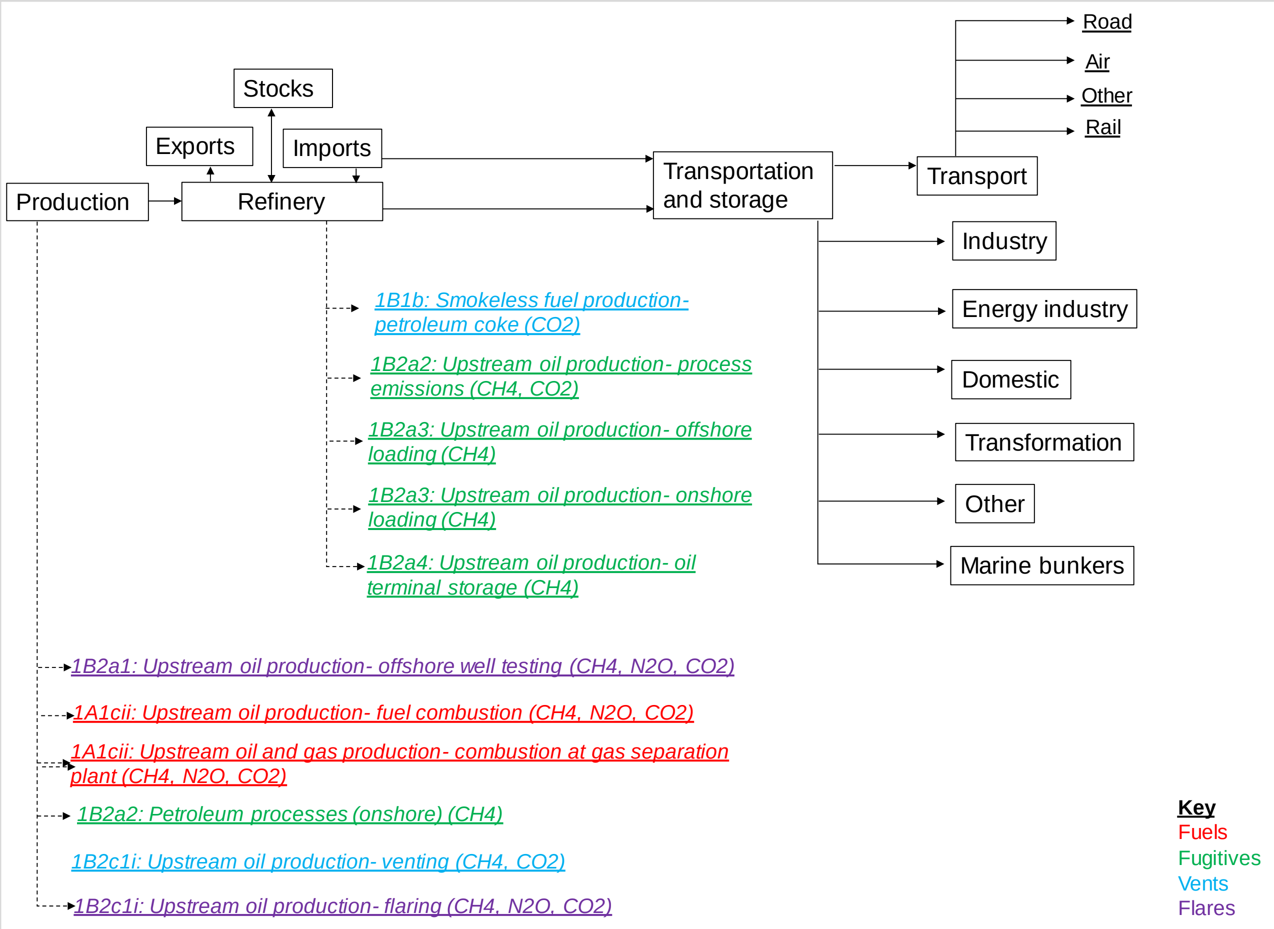


Figure 23: The oil supply chain and emissions categories

7.3 Key assumptions on emission sources

A number of assumptions were made during the emission source identification process to simplify and characterise emissions mitigation options, described below. One key assumption is that when a single equipment type was found to be the dominant source of emissions (>80%), 100% allocation was assumed for that source. Examples of this assumption are ‘1A1cii: Upstream gas/oil production, fuel combustion (gas oil)’, for which it was assumed that gas oil is used for power generation. For ‘1A1cii: Upstream gas/oil production, fuel combustion (natural gas)’, we assume that natural gas is used for compression.

For emissions entries from multiple sources, emissions were allocated based on the data available. For example, ‘1A1ciii: Gas production’, emissions were partly assigned to LNG regasification fuel usage (72% pipeline gas, 28% LNG), based on fuel usage from LNG regasification equating to 1.5% of total LNG imports. The remaining emissions were allocated to transmission and storage fuel usage. The emission source ‘1B2b5: Gas leakage (natural gas supply)’ accounts for fugitive leaks of methane across the distribution system. We assume that these emissions were split 50:50 between pipeline leaks and metering and regulation stations.

As part of this project, emission factors associated with the potential UK shale gas industry were developed. However, the UK currently has no commercially active shale gas wells and only one active exploration well. Combining emission factors derived from UK offshore production with previous work by the Sustainable Gas

Institute[65] and other literature[66], emission factors were estimated for UK shale. Table 15 indicates the emission factors developed for this project compared to the emission factors of offshore gas included in the UK inventory. For fuel usage emissions and CO_2 venting in the processing stage, the same emission factors were assumed, due to a lack of information on average raw gas compositions. For venting, flaring and fugitive emissions at pre-production and production stages, emission factors were developed from Laurenzi et al. [67] and Balcombe et al. [68]. Note that emissions from UK shale production may differ significantly from that of US facilities, which is the basis of much of the previous literature, and that the emission factors listed here are unabated emissions. Many emissions mitigation options (as described in section 4.1) were assumed to be put in place as soon as shale gas is developed, reducing the emission factor concurrently.

Table 15: Estimated emission factors for UK shale gas versus UK offshore gas production

Emission source	$ktCO_2e$/bcm of gas produced	
	Offshore gas	Shale gas
1A1cii Upstream gas production, fuel combustion, natural gas (CO_2)	75.91	
1A1cii Upstream gas production, fuel combustion, natural gas (N_2O)	2.02	
1A1cii Upstream gas production, fuel combustion, natural gas (CH_4)	0.83	
1A1cii Upstream gas production, fuel combustion, gas oil (CO_2)	5.24	
1A1cii Upstream gas production, fuel combustion, gas oil (N_2O)	0.28	
1A1cii Upstream gas production, fuel combustion (CH_4)	0.83	
1B2b1 Upstream Gas Production - Gas Well Testing (CO_2)	3.8	4.8
1B2b1 Upstream Gas Production - Gas Well Testing (CH_4)	1.5	3.1
1B2b4 Upstream Gas Production - Gas, process emissions (CO_2)	5.5	
1B2b4 Upstream Gas Production - Gas, production and processing (CH_4)	1.6	15.9
1B2c1ii Upstream Gas Production, gas - venting (CH_4)	9.2	17.7
1B2c2ii Upstream Gas Production, gas - flaring (CO_2)	7.6	18.3
1B2c2ii Upstream Gas Production, gas - flaring (CH_4)	0.6	1.4

65 Balcombe, P., Brandon, N. P. & Hawkes, A. D. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. Journal of Cleaner Production, 172, 2019-2032.
66 Laurenzi, I. J. & Jersey, G. R. 2013. Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas. Environmental Science & Technology, 47, 4896-4903.
67 Laurenzi, I. J. & Jersey, G. R. 2013. Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas. Environmental Science & Technology, 47, 4896-4903.
68 Balcombe, P., Brandon, N. P. & Hawkes, A. D. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. Journal of Cleaner Production, 172, 2019-2032.

7.4 Trigger forecasts

Figure 24 to Figure 34 show the forecasts used for each trigger. Blue: historical data and projections from literature; Orange: extrapolation.

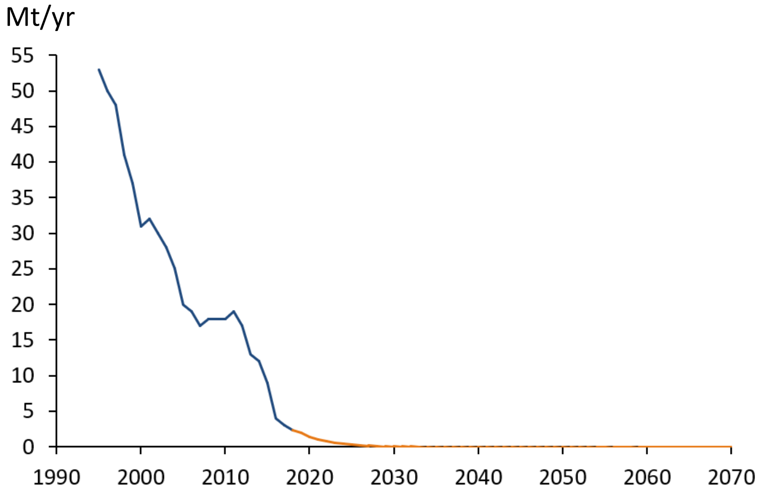


Figure 24: Coal production

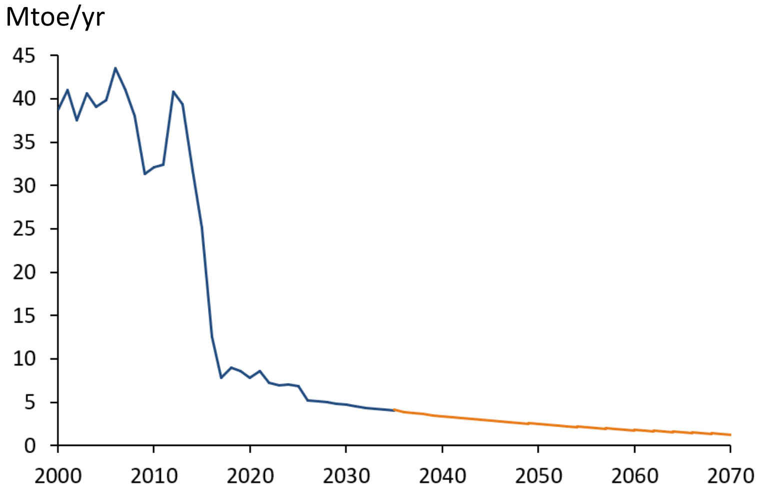


Figure 25: Coal demand (Mtoe/yr)

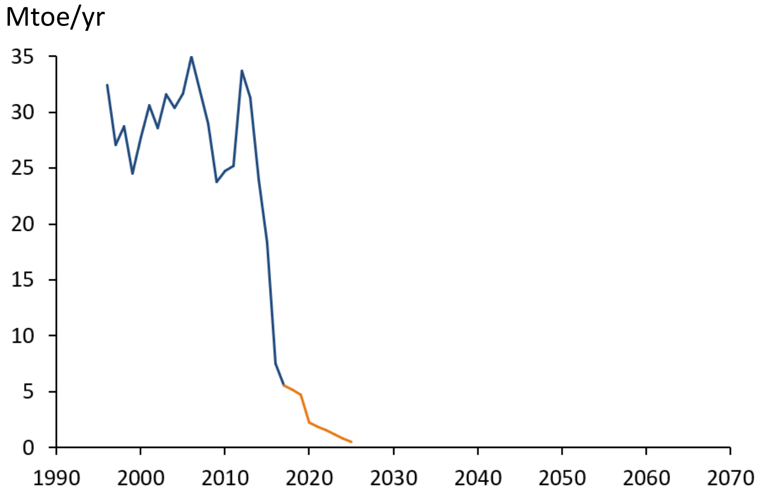


Figure 26: Coal power plants

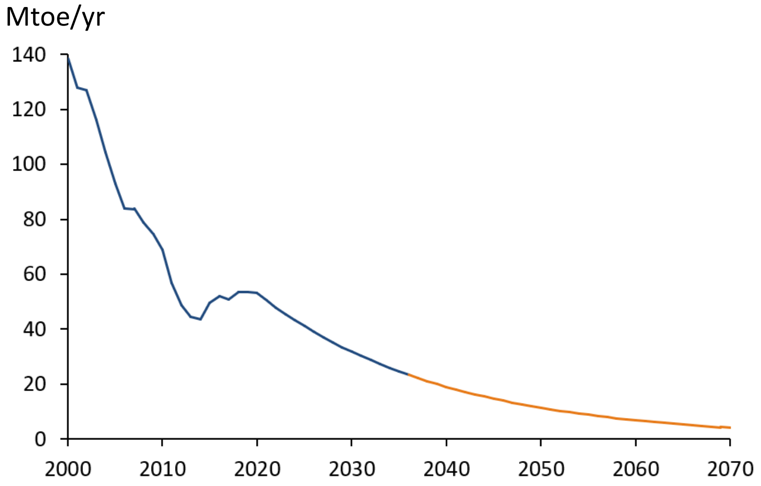


Figure 27: Oil production

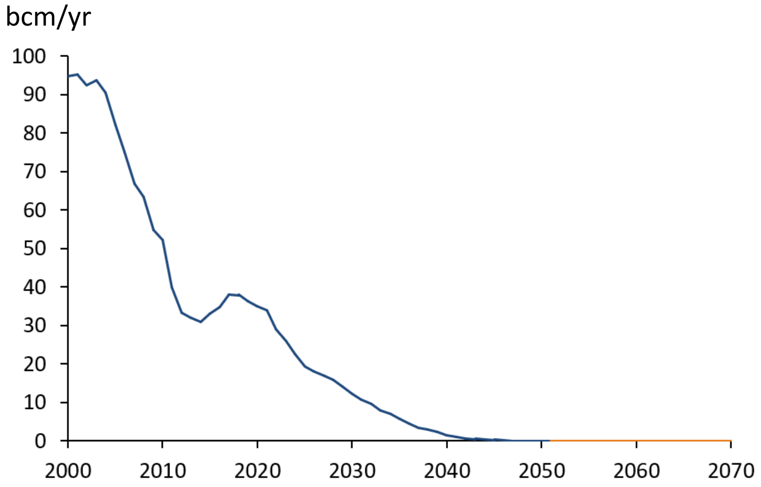


Figure 28: Natural gas offshore production

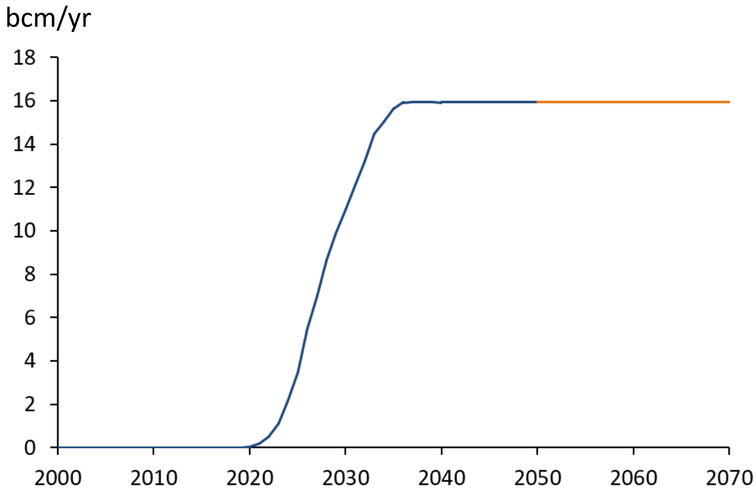


Figure 29: Natural gas shale production

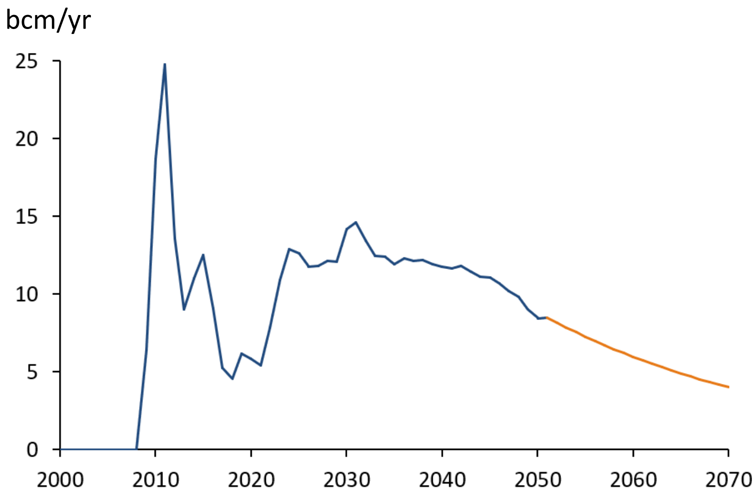


Figure 30: LNG import

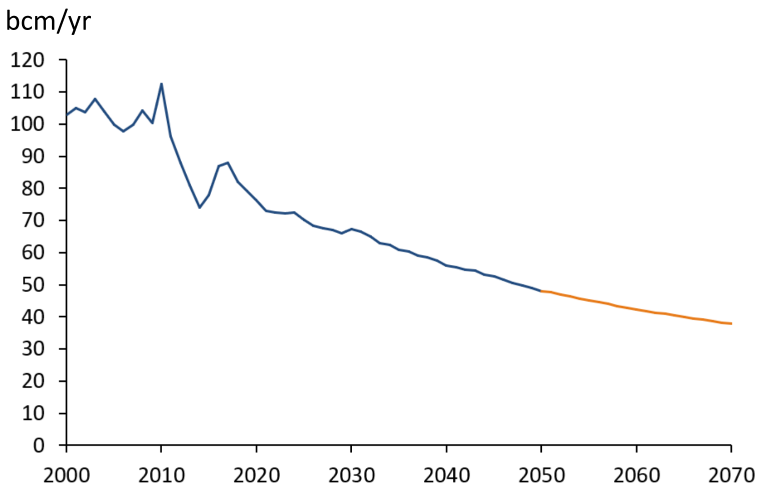


Figure 31: Natural gas demand

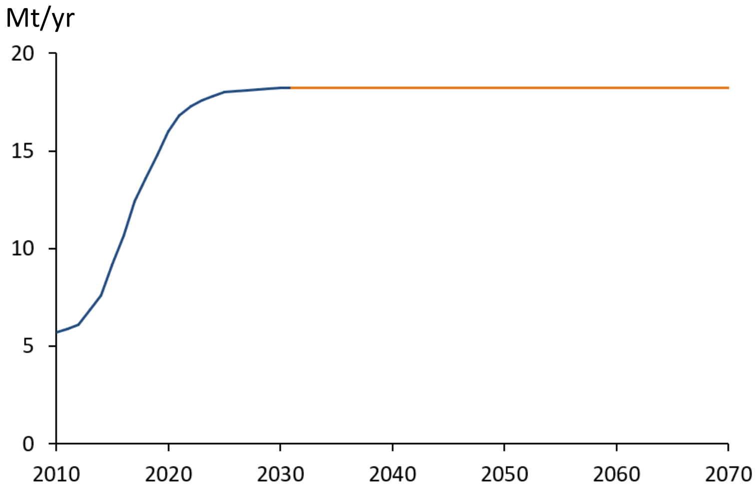


Figure 32: MSW plants

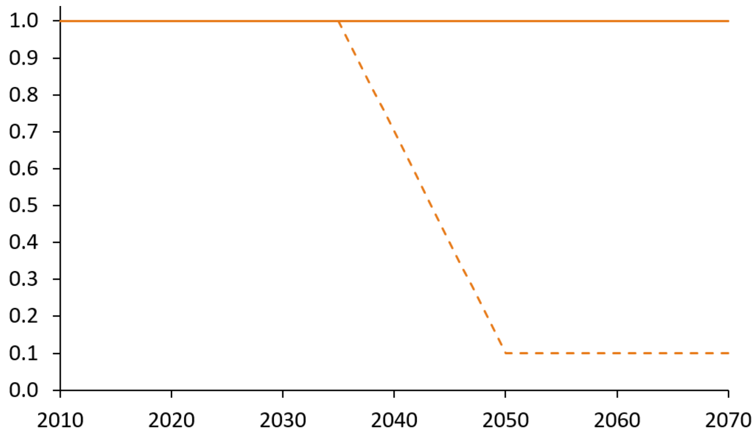


Figure 33: Pipeline leakage (% 2016 emissions) – dashed line with partial gas grid closure and/or switchover to hydrogen

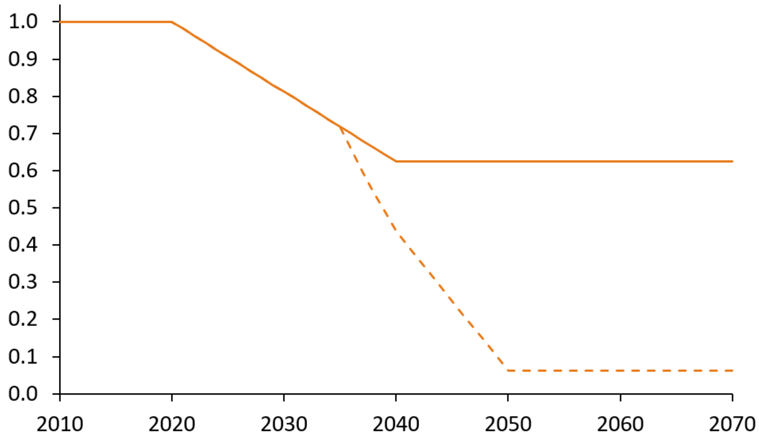


Figure 34: Pipeline leakage with replacement (% 2016 emissions) – dashed line with partial gas grid closure and/or switchover to hydrogen

7.5 Trigger association

Table 16: Disaggregated GHG emission sources in the project's scope and associated triggers

NAEI / IPCC code	NAEI Source	NAEI Activity	Associated trigger
1A1ai	Miscellaneous industrial/commercial combustion	MSW	MSW plants
1A1cii	Upstream gas production - Fuel combustion	Gas oil	Natural gas offshore production
1A1cii	Upstream gas production - Fuel combustion	Natural gas	Natural gas offshore production
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	LPG	Oil production
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	OPG	Oil production
1A1cii	Upstream Oil Production - Fuel combustion	Gas oil	Oil production
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas	Oil production
1A1ciii	Collieries - combustion	Colliery methane	Coal production
1A1ciii	Collieries - combustion	Natural gas	Coal production
1A1ciii	Gas production - Regasification	Natural gas	LNG import
1A1ciii	Gas production - Transmission and storage	Natural gas	Natural gas demand
1B1a1i	Deep-mined coal	Coal produced	Coal production
1B1a1ii	Coal storage and transport	Deep mined coal production	Coal production
1B1a1iii	Closed Coal Mines	Non-fuel combustion	Closed coal mines
1B1a2i	Open-cast coal	Coal produced	Coal production
1B1b	Charcoal production	Charcoal produced	Coal demand
1B1b	Coke production	Coke produced	Coal demand
1B1b	Iron and steel - Flaring	Coke oven gas	Coal demand
1B1b	Solid smokeless fuel production	Coal	Coal demand
1B1b	Solid smokeless fuel production	Petroleum coke	Coal demand
1B1b	Solid smokeless fuel production	SSF produced	Coal demand
1B2a1	Upstream Oil Production - Offshore Well Testing	Exploration drilling: amount of gas flared	Oil field exploration
1B2a2	Petroleum processes	Oil production	Oil production
1B2a2	Upstream Oil Production - Process emissions	Non-fuel combustion	Oil production
1B2a3	Upstream Oil Production - Offshore Oil Loading	Crude oil	Oil production
1B2a3	Upstream Oil Production - Onshore Oil Loading	Crude oil	Oil production
1B2a4	Upstream Oil Production - Oil terminal storage	Non-fuel combustion	Oil production
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing	Exploration drilling: amount of gas flared	Natural gas field exploration
1B2b1	Upstream Gas Production - Offshore Well Testing - Well completions	Exploration drilling: amount of gas flared	Natural gas field exploration
1B2b3	Upstream Gas Production - Process emissions	Non-fuel combustion	Natural gas offshore production
1B2b4	Gas leakage - Compressor stations	Natural Gas (transmission leakage)	Pipeline leakage
1B2b4	Gas leakage - Pipeline leak	Natural Gas (transmission leakage)	Pipeline leakage

1B2b4	Gas leakage - Regasification terminals	Natural Gas (transmission leakage)	LNG import
1B2b4	Upstream Gas Production - Gas terminal storage	Non-fuel combustion	Pipeline leakage
1B2b5	Gas leakage	Natural Gas (leakage at point of use)	Pipeline leakage
1B2b5	Gas leakage - Pipeline leaks	Natural gas supply	Pipeline leakage with replacement
1B2b5	Gas leakage - M+R stations	Natural gas supply	Pipeline leakage
1B2c1i	Upstream Oil Production - Venting	Non-fuel combustion	Oil production
1B2c1ii	Upstream Gas Production - Venting	Non-fuel combustion	Natural gas offshore production
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	Oil production
1B2c2ii	Upstream Gas Production - Flaring	Non-fuel combustion	Natural gas offshore production
2A4d	Power stations - FGD	Gypsum produced	Coal power plants
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Gas oil	Natural gas shale production
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas	Natural gas shale production
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Flow testing	Exploration drilling: amount of gas flared	Natural gas shale production
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Well completion	Exploration drilling: amount of gas flared	Natural gas shale production
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Flow testing	Exploration drilling: amount of gas flared	Natural gas shale production
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Well completions	Exploration drilling: amount of gas flared	Natural gas shale production
1B2b4	Upstream Gas Production - Process emissions (shale gas)	Non-fuel combustion	Natural gas shale production
1B2b4	Upstream Shale Gas leakage- Production and processing - Compressor stations	Non-fuel combustion	Natural gas shale production
1B2b4	Upstream Shale Gas leakage - Production and processing - Processing vents and leaks	Non-fuel combustion	Natural gas shale production
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion	Natural gas shale production
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	Natural gas shale production

7.6 Relevant sources in scope

Table 17: Relevant sources in scope - projected emissions >10ktCO_2e in 2040, without gas grid closure and/or switchover to hydrogen

NAEI / IPCC code	NAEI Source	NAEI Activity	GHG	Emissions (ktCO_2e)		Cumulative emissions[69] (%)
				2016	2040	2040
1B2b5	Gas leakage	Natural gas supply	CH_4	3,555	2,888	22%
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas	CO_2	6,887	2,523	42%
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas	CO_2	0	1,211	52%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CO_2	3,293	1,206	61%
1A1cii	Upstream Oil Production - Fuel combustion	Gas oil	CO_2	1,726	632	66%
1A1ciii	Gas production - Transmission and storage (72%)	Natural gas	CO_2	921	593	70%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CO_2	308	527	74%
1A1ciii	Gas production - Regasification (28%)	Natural gas	CO_2	358	465	78%
1B1a1iii	Closed Coal Mines	Non-fuel combustion	CH_4	448	317	80%
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CO_2	0	292	83%
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion	CH_4	0	282	85%
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	OPG	CO_2	743	272	87%
1B2b4	Upstream Shale Gas leakage - production and processing - Compressor stations (80%)	Non-fuel combustion	CH_4	0	203	88%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CH_4	370	136	90%
1A1cii	Upstream Gas Production - Fuel combustion	Natural gas	CO_2	2,657	114	90%
1B2c1i	Upstream Oil Production - Venting	Non-fuel combustion	CH_4	261	96	91%
1B2b4	Upstream Gas Production - Process emissions (shale gas)	Non-fuel combustion	CO_2	0	88	92%
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Gas oil	CO_2	0	84	92%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CH_4	47	80	93%
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas	N_2O	172	63	94%
1B1b	Solid smokeless fuel production	Coal	CO_2	225	61	94%
1B2b5	Gas leakage	Natural Gas (leakage at point of use)	CH_4	59	59	95%
1B2b4	Upstream Shale Gas leakage - production and processing - Processing vents and leaks (20%)	Non-fuel combustion	CH_4	0	51	95%
1B2a2	Upstream Oil Production - Process emissions	Non-fuel combustion	CO_2	126	46	95%
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	0	38	96%

[69] Cumulative emissions are calculated here by subsequent addition of the emissions share of each entry in the list.

1B2b1	Upstream Gas Production - Shale Gas Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CO_2	0	38	96%
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	67	34	96%
1B2b1	Upstream Gas Production - Offshore Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CO_2	67	34	96%
1B2a1	Upstream Oil Production - Offshore Well Testing	Exploration drilling: amount of gas flared	CO_2	89	33	97%
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas	N_2O	0	32	97%
1B1b	Solid smokeless fuel production	Petroleum coke	CO_2	96	26	97%
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CH_4	0	25	97%
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CH_4	0	25	97%
1B2b4	Gas leakage - Regasification terminals (33%)	Natural Gas (transmission leakage)	CH_4	19	25	98%
1A1cii	Upstream Oil Production - Fuel combustion	Natural gas	CH_4	67	25	98%
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CH_4	0	23	98%
1B2b4	Gas leakage - Pipeline leak (34%)	Natural Gas (transmission leakage)	CH_4	20	20	98%
1B2b4	Gas leakage - Compressor stations (33%)	Natural Gas (transmission leakage)	CH_4	19	19	98%
1B2a2	Upstream Oil Production - Process emissions	Non-fuel combustion	CH_4	41	15	98%
1A1cii	Upstream Oil Production - Fuel combustion	Gas oil	N_2O	40	15	99%
1B2c1ii	Upstream Gas Production - Venting	Non-fuel combustion	CH_4	323	14	99%
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	LPG	CO_2	37	14	99%
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CH_4	27	13	99%
1B2b1	Upstream Gas Production - Offshore Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CH_4	27	13	99%
1A1cii	Upstream Gas production - Fuel combustion (shale gas)	Natural gas	CH_4	0	13	99%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	N_2O	7	13	99%
1B2c2ii	Upstream Gas Production - Flaring	Non-fuel combustion	CO_2	265	11	99%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	N_2O	31	11	99%
1B2a2	Petroleum processes	Oil production	CH_4	29	11	99%

7.7 Carbon intensity assumptions

Table 18: Carbon intensities of fuels and energy sources[70,71]

Fuel	Carbon intensity (g/kWh)
Electricity	Variable (see Figure 35)
Hydrogen	11.5
Natural gas	184
Gas oil	268
LPG	215
OPG	186

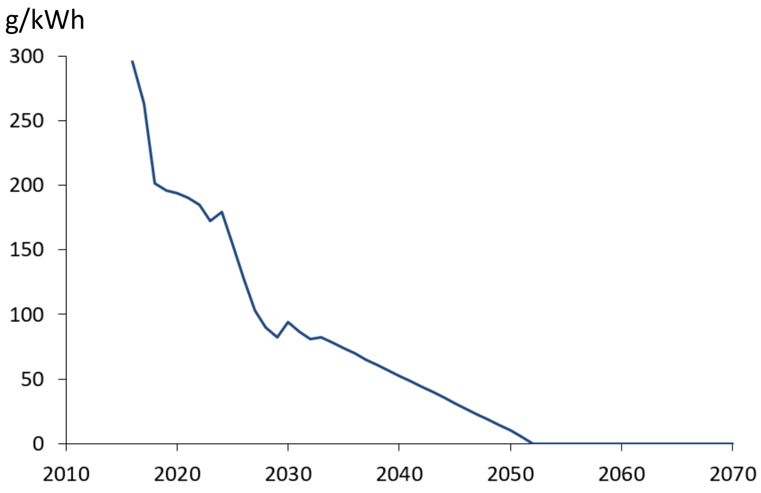


Figure 35: Projection of carbon intensity of electricity[70]

[70] Source: CCC
[71] Source: Green book https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

7.8 Cost of fuel assumptions

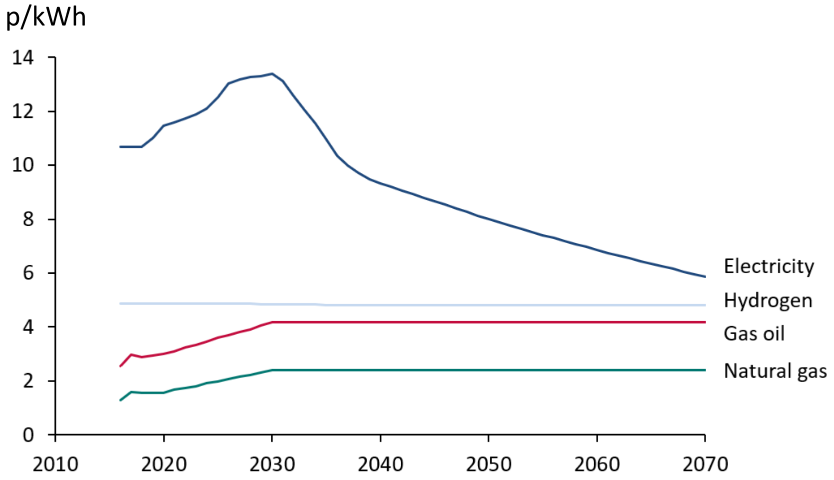


Figure 36: Projection of costs of fuels and energy sources[71]

7.9 Rollout scenario dates

Table 19: Slow rollout scenario dates

Abatement option	Year of 0% deployment	Year of 100% deployment
Small scale CCS	2029	2060
CCS (SSF oven, calcium looping)	2035	2073
CCS (SSF oven, amines)	2029	2060
Fuel switch to hydrogen	2030	2068
Fuel switch to electricity - connect to grid	2024	2051
Fuel switch to electricity - connect to onsite renewable generation (wind turbines with battery storage)	2025	2063
Electric heaters	2023	2048
Gas recovery for sales (as grid gas or as LNG)	2023	2041
Continuous monitoring	2026	2041
LDAR	2021	2027
RECs	2023	2041
Reduce venting and flaring where needed	2022	2034

Table 20: Central rollout scenario dates – All except hydrogen

Abatement option	Year of 0% deployment	Year of 20% deployment	Year of 100% deployment
Small scale CCS	2025	2033	2050
CCS (SSF oven, calcium looping)	2030	2040	2060
CCS (SSF oven, amines)	2025	2033	2050
Fuel switch to electricity - connect to grid	2020	2027	2042
Fuel switch to electricity - connect to onsite renewable generation (wind turbines with battery storage)	2020	2030	2050
Electric heaters	2020	2027	2040
Gas recovery for sales (as grid gas or as LNG)	2020	2025	2035
Continuous monitoring	2024	2028	2036
LDAR	2020	2022	2025
RECs	2020	2025	2035
Reduce venting and flaring where needed	2020	2023	2030

Table 21: Central rollout scenario dates - Hydrogen

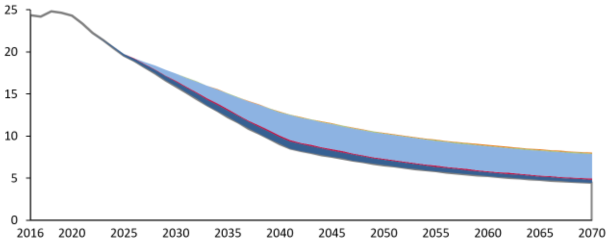
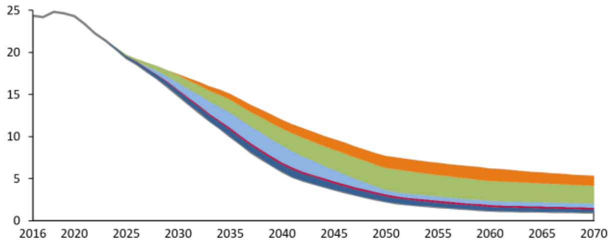
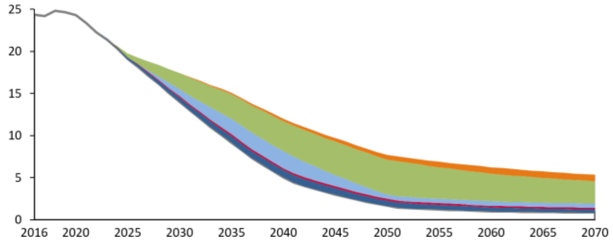
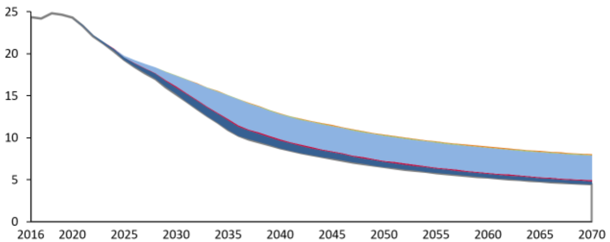
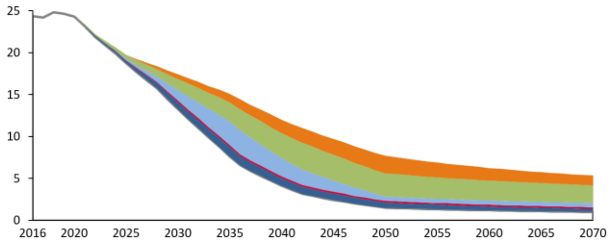
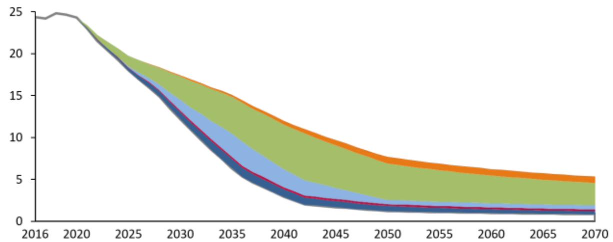
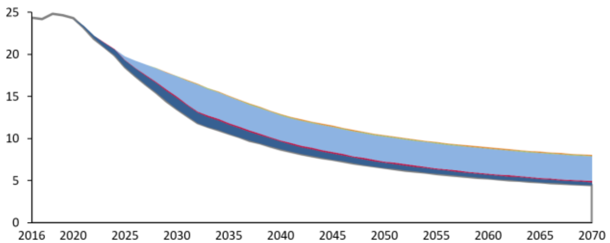
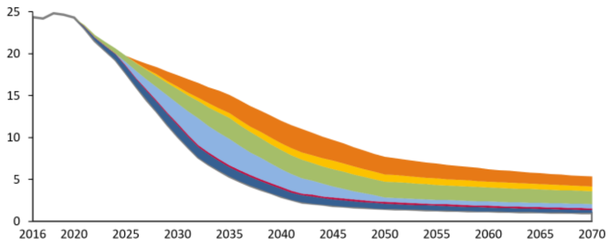
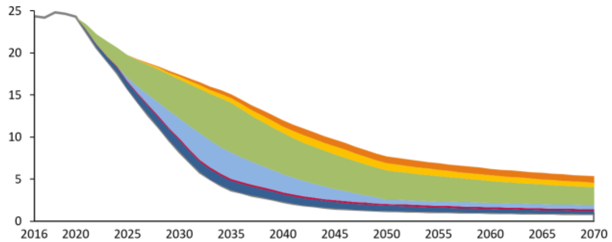
Abatement option	Year of 0% deployment	Year of 6.25% deployment	Year of 18.75% deployment	Year of 100% deployment
Fuel switch to hydrogen	2025	2030	2035	2051

Table 22: Fast rollout scenario dates

Abatement option	Year of 0% deployment	Year of 100% deployment
Small scale CCS	2025	2042
CCS (SSF oven, calcium looping)	2030	2050
CCS (SSF oven, amines)	2025	2042
Fuel switch to hydrogen	2025	2045
Fuel switch to electricity - connect to grid	2020	2035
Fuel switch to electricity - connect to onsite renewable generation (wind turbines with battery storage)	2020	2040
Electric heaters	2020	2033
Gas recovery for sales (as grid gas or as LNG)	2020	2030
Continuous monitoring	2024	2032
LDAR	2020	2023
RECs	2020	2030
Reduce venting and flaring where needed	2020	2027

7.10 Direct emissions abatement

Table 23: Direct emissions abatement by technology group, depending on technology scenario and rollout profile ($MtCO_2e/yr$)

	Core scenario	Further ambition scenario	Speculative scenario
Slow rollout			
Central rollout			
Fast rollout			

CCS
Hydrogen fuel-switching
Electricity fuel-switching
Process upgrade
Material upgrade
Gas recovery
Unabated

7.11 Detailed technology assumptions

- Technology assumptions table
- Cost effectiveness calculations and assumptions

Abatement option	**Sub**	**Cost assumptions**	**2040 cost differences**	**Sources**
Small scale CCS	Offshore	- 0.1 Mtpa CO_2 capture plant - Capture plant capex ~£55m - Additional offshore cap cost ~£75m (e.g. additional rig) - O&M capture cost = 6% - Pipeline capex = £0.85m/ km, assume 25km pipeline - Compression capex = £3.75m - Transport opex = ~£300k/yr - Storage cost = £13/ t CO_2	-	- Irlam, Lawrence, 2017, *Global cost of carbon capture and storage- 2017 update*, CCS Institute. Available: https://hub.globalccsinstitute.com/sites/default/files/publications/201688/global-ccs-cost-updatev4.pdf - Budinis, Sara, 2016, *Can Technology Unlock Unburnable Carbon*, Sustainable Gas Institute, Imperial College London - DECC, 2013, *CCS Cost Reduction Taskforce,* Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf
	Onshore	- 0.1 Mtpa CO_2 capture plant - Capture plant capex ~£55m - O&M capture cost = 6% - Pipeline capex = £0.43m/ km, assume 10km pipeline - Compression capex = £3.75m - Transport opex = ~£200k/yr - Storage cost = £13/ tCO_2	-	
Fuel switch to electricity-connect to grid	Offshore	- 10.7 p/kWh current elec cost - 50km cable installation - 445 GBP/m subsea cable - £530k/ MW onshore converter/ transformer/ installation cap cost	- 9.3 p/kWh elec cost	- National Grid, 2013, *Electricity ten year statement (ETYS) 2013*- Appendix E- Technology. Available: https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys - Waide, P. and Brunner, C., Energy – Efficiency Policy Opportunities for Electric Motor-Driven Systems, International Energy Agency, 2011
	Onshore	- 10.7 p/kWh current elec cost - £530k/ MW onshore converter/ transformer/ installation cap cost	- 9.3 p/kWh elec cost	

Abatement option	Sub	Cost assumptions	2040 cost differences	Sources
Fuel switch to electricity- connect to onsite renewable generation (wind turbines with battery storage)		- Wind elec cost 5p/ kWh - Capacity to output 0.029 kW/MWh - Battery storage cap cost 1600 GBP/kW - Assume 1:1 battery storage on capacity basis	- Wind elec cost 3p/ kWh - battery cap costs 300 GBP/kW	- Schmidt, O. et al., 2017, *The future cost of electrical energy storage based on experience rates,* Nature Energy 2: 17110. Available: https://www.nature.com/articles/nenergy2017110 - 2015 cost of wind energy review, 2017, Christopher Mone, Maureen Hand, Mark Bolinger, Joseph Rand, Donna Heimiller and Jonathan Ho. National Renewable Energy Laboratory (NREL). Available: https://www.nrel.gov/docs/fy17osti/66861.pdf - US battery storage market trends, 2018. EIA, Available: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf - National Grid, 2013, Electricity ten year statement (ETYS) 2013- Appendix E- Technology. Available: https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys
Fuel switch to hydrogen		- 4.9 p/kWh hydrogen cost - 10km of pipework required at Assume this includes cost to tap into available infrastructure when ready	- 4.8 p/kWh hydrogen cost	- CCC internal
Gas recovery for sales (piped)	Onshore	- Pipeline cost ~£600k/ km - Compression capex ~£4m - pipeline distance 10km - Compression opex ~£150k - Gas sales 1.2 p/kWh	- Gas sales 2.4 p/kWh	- Sari Energy, Natural gas value chain: pipeline transportation. Available: https://sari-energy.org/oldsite/PageFiles/What_We_Do/activities/GEMTP/CEE_NATURAL_GAS_VALUE_CHAIN.pdf - Element internal - CCC internal
	Offshore	- Pipeline cost ~£1.2m/ km - Compression capex ~£4m - pipeline distance 10km - Compression opex ~£150k - Gas sales 1.2 p/kWh	- Gas sales 2.4 p/kWh	
LDAR		- 25.7 GBP/ t CO_2e based on Canadian ICF report - 1 additional campaign/ yr reduces fugitives by 40% - every additional 1 reduces by 20% (compound reduction)	-	- ICF, 2015, *Economic analysis of methane emissions reduction opportunities in the Canadian oil and gas industry*, EDF. Available: https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
RECs		- Capture equipment cost ~£400k - Additional pipeline and ancillary equipment cap cost £1m - Opex ~ £120k/ yr - Gas captured ~5,000 t/ completion	-	- US EPA, 2011, Lessons learned from natural gas STAR partners: Reduced emissions completion for hydraulically fractured natural gas wells, Available: https://www.epa.gov/natural-gas-star-program/reduced-emission-completions-hydraulically-fractured-natural-gas-wells

Abatement option	Sub	Cost assumptions	2040 cost differences	Sources
Replace iron and steel piping with plastic		- ~£65k/ km cost of mains replacement - 2600 km replacement per year - We are already 50% complete (2016)	-	- Energy Networks Association, 2018 *Gas Network innovation strategy at a glance*, Available: http://www.energynetworks.org/assets/files/Gas%20Network%20Innovation%20Strategy%20Final%202018.pdf
Reduce venting and flaring where needed		- ~£0.1/ kg gas flared levelised cost of capex and opex - 90% average flare efficiency	-	- US EPA, 2011, Lessons learned from natural gas STAR partners: Reduced emissions completion for hydraulically fractured natural gas wells, Available: https://www.epa.gov/natural-gas-star-program/reduced-emission-completions-hydraulically-fractured-natural-gas-wells
Continuous monitoring		- Target capital cost of ~£2.2k/ site/ yr - Enables reduction of 90%	-	- Willson, Brian, 2015, *Methane quantification & ARPA-E's MONITOR Program*. Available: https://www.epa.gov/sites/production/files/2016-04/documents/21willson.pdf

7.12 Unabatable emissions

Table 24: Main technically unabatable emissions in 2040 and 2070 - speculative scenario, fast rollout

NAEI / IPCC code	NAEI Source	NAEI Activity	GHG	Emissions 2040		Emissions 2070	
				$ktCO_2e$	Cumulative[72] %	$ktCO_2e$	Cumulative[72] %
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CO_2	603	26%	129	15%
1B1a1iii	Closed Coal Mines	Non-fuel combustion	CH_4	317	40%	224	41%
1B2c1ii	Upstream Gas Production - Venting (shale gas)	Non-fuel combustion	CH_4	169	47%	169	60%
1A1ciii	Gas production - Transmission and storage (72%)	Natural gas	CO_2	148	54%	0	60%
1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CO_2	146	60%	146	77%
1B2b5	Gas leakage - M+R stations (50%)	Natural gas supply	CH_4	124	65%	18	79%
1A1ciii	Gas production - Regasification (28%)	Natural gas	CO_2	116	70%	0	79%
1A1cii	Upstream Gas Production - Fuel combustion	Natural gas	CO_2	114	75%	0	79%
1B2b5	Gas leakage - Pipeline leaks (50%)	Natural gas supply	CH_4	78	79%	11	80%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	CH_4	68	81%	15	82%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CO_2	57	84%	5	82%
1B2c1i	Upstream Oil Production - Venting	Non-fuel combustion	CH_4	57	86%	12	84%
1B1b	Solid smokeless fuel production	Coal	CO_2	31	88%	0	84%
1B2b4	Upstream Shale Gas leakage - production and processing - Compressor stations (80%)	Non-fuel combustion	CH_4	20	89%	20	86%
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	19	89%	19	88%
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CO_2	17	90%	15	90%
1B2a1	Upstream Oil Production - Offshore Well Testing	Exploration drilling: amount of gas flared	CO_2	16	91%	4	91%
1B2c1ii	Upstream Gas Production - Venting	Non-fuel combustion	CH_4	14	91%	0	91%
1B1b	Solid smokeless fuel production	Petroleum coke	CO_2	13	92%	0	91%
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CH_4	12	93%	12	92%

[72] Cumulative emissions are calculated here by subsequent addition of the emissions share of each entry in the list.

1B2c2ii	Upstream Gas Production - Flaring (shale gas)	Non-fuel combustion	CH_4	11	93%	11	93%
1B2c2ii	Upstream Gas Production - Flaring	Non-fuel combustion	CO_2	11	94%	0	93%
1B2b1	Upstream Gas Production - Shale Gas Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CO_2	11	94%	11	95%
1B2b1	Upstream Gas Production - Offshore Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CO_2	10	94%	9	96%
1B2b4	Upstream Gas Production - Process emissions (shale gas)	Non-fuel combustion	CO_2	10	95%	1	96%
1A1ai	Miscellaneous industrial/commercial combustion	MSW	CH_4	9	95%	1	96%
1B2b3	Upstream Gas Production - Process emissions	Non-fuel combustion	CO_2	8	96%	0	96%
1A1cii	Upstream Gas Production - Fuel combustion	Gas oil	CO_2	8	96%	0	96%
1B1b	Iron and steel - Flaring	Coke oven gas	CO_2	8	96%	3	96%
1B2b3	Upstream Gas Production - Shale Gas Well Testing - Well completions (50%)	Exploration drilling: amount of gas flared	CH_4	7	97%	7	97%
1B2b1	Upstream Gas Production - Offshore Well Testing - Flow testing (50%)	Exploration drilling: amount of gas flared	CH_4	7	97%	6	98%
1A1cii	Upstream oil and gas production - Combustion at gas separation plant	OPG	N_2O	6	97%	1	98%
1B2c2i	Upstream Oil Production - Flaring	Non-fuel combustion	N_2O	6	97%	1	98%
1B2b4	Upstream Shale Gas leakage - production and processing - Processing vents and leaks (20%)	Non-fuel combustion	CH_4	5	98%	5	99%
1B2a2	Upstream Oil Production - Process emissions	Non-fuel combustion	CO_2	5	98%	0	99%