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Guidance

# Emerging techniques for hydrogen production with carbon capture

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This publication is available at [https://www.gov.uk/government/publications/emerging-techniques-for-hydrogen-production-with-carbon-capture/emerging-techniques-for-hydrogen-p...](https://www.gov.uk/government/publications/emerging-techniques-for-hydrogen-production-with-carbon-capture/emerging-techniques-for-hydrogen-production-with-carbon-capture)

You can produce hydrogen from methane or refinery fuel gas and capture the carbon dioxide (CO<sub>2</sub>) which is also produced in this process.

The hydrogen can be:

- used within the installation
- exported as a product

The CO<sub>2</sub> can be:

- transported by pipeline or other means and stored in permanent underground geological storage facilities
- used as a product (not covered in this guidance)

These environmental regulators (referred to as ‘the regulators’) worked with industry stakeholders to develop a [review of emerging techniques](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) (<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>)’ on which this guidance is based:

- Environment Agency
- Natural Resources Wales
- Northern Ireland Environment Agency (an executive agency of the Department of Agriculture, Environment and Rural Affairs)
- Scottish Environment Protection Agency

Except where existing regulations apply, this guidance on emerging techniques is not a regulatory requirement but identifies best practice to address important environmental issues.

The regulators expect operators to follow this guidance, or to propose an alternative approach to provide the same (or greater) level of protection for the environment.

## 1. Who this guidance is for

This guidance is for:

- operators when designing their plants and preparing their application for an environmental permit
- regulatory staff when determining environmental permit applications
- any other organisation or members of the public who want to understand how the environmental regulations and standards are being applied

This guidance covers large-scale industrial plants:

- producing hydrogen using methane (for example, from natural gas) or refinery fuel gas
- capturing the CO<sub>2</sub> produced within the process, carbon capture (CC), or using post-combustion carbon capture (PCC) to make it ready for permanent geological storage – this is known as carbon capture and storage or sequestration (CCS)

The guidance covers both new plants and retrofits to existing plants.

It does not cover downstream permanent geological storage or using the captured CO<sub>2</sub>.

Large-scale means typically greater than 100 tonnes a day of hydrogen which is around 140MW of hydrogen energy at its lower heating value.

Smaller plant should use this guidance until further guidance is available.

When you apply for an environmental permit for this activity, you must tell your regulator whether you are going to follow this guidance. If not, you must propose an alternative approach which will provide the same or greater level of protection for the environment.

In the UK, these installations are permitted under the:

- Environmental Permitting (England and Wales) Regulations 2016
- Pollution Prevention and Control (Scotland) Regulations 2012
- Pollution Prevention and Control (Industrial Emissions) Regulations (NI) 2013

For environmental permitting purposes, the hydrogen production plant is a Part A (1) 4.2 (a)(i) inorganic chemicals activity.

A CC or PCC plant is a Part A (1) 6.10 (a) carbon capture and storage activity when the CO<sub>2</sub> is being captured from an installation for geological storage.

The existing best available techniques (BAT) reference documents (BREFs) for [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) (<https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers>) and [Refining of Mineral Oil and Gas](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0) (<https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0>) do not include hydrogen production with CC, other than as an intermediate product for ammonia production.

The [large combustion plant BREF](https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) (<https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0>) identifies carbon capture as an emerging technique but does not address all the potential environmental effects of carbon capture.

Where BAT is not covered in existing BREFs or where all the potential environmental effects are not addressed, the regulator must follow [Article 14\(6\) of the Industrial](#)

[Emissions Directive \(IED\) \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075#d1e1666-17-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075#d1e1666-17-1).

This means that your regulator must set permit conditions covering emission limit values (ELVs), together with other permit conditions. These conditions must be based on the regulator's own assessment of emerging techniques using the criteria listed in [Annex III of the IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-57-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-57-1). They should also consult with operators before setting these conditions. The regulators consulted potential technology providers and operators when developing the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) on which this guidance is based.

Permits must protect the environment by setting conditions to make sure operators do not breach any environmental quality standards ([Article 18 of the IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1918-17-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1918-17-1)).

Your regulator may grant a [temporary derogation \(https://www.gov.uk/guidance/best-available-techniques-environmental-permits\)](https://www.gov.uk/guidance/best-available-techniques-environmental-permits) of BAT- associated emission levels (BAT AELs) for up to 9 months, on the basis that hydrogen production with carbon capture for permanent storage is testing and using an emerging technique (see [Article 15\(5\) of IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1802-17-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1802-17-1)). You should discuss this with your regulator if this is likely to apply.

Your regulator will make a decision on the emission limits and other permit conditions that will apply on a case-by-case basis. They will do this based on the elements outlined in this guidance and the most appropriate source of reference.

The [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) summarises the available evidence to support this guidance. We refer to the relevant sections of the review in this guidance.

You may [request advice before applying for your permit \(https://www.gov.uk/guidance/get-advice-before-you-apply-for-an-environmental-permit\)](https://www.gov.uk/guidance/get-advice-before-you-apply-for-an-environmental-permit).

For further advice from your regulator, in:

- England, contact the Environment Agency: [enquiries@environment-agency.gov.uk](mailto:enquiries@environment-agency.gov.uk)
- Scotland, contact the Scottish Environment Protection Agency: [ppc@sepa.org.uk](mailto:ppc@sepa.org.uk)
- Wales, contact Natural Resources Wales: [enquiries@naturalresourceswales.gov.uk](mailto:enquiries@naturalresourceswales.gov.uk)
- Northern Ireland, contact the Northern Ireland Environment Agency: [IPRI@daera-ni.gov.uk](mailto:IPRI@daera-ni.gov.uk)

## 2. Technique selection

When choosing hydrogen production and CC plant configuration, you should consider its overall environmental performance, including:

- energy efficiency
- resource efficiency
- CO<sub>2</sub> capture efficiency
- emissions to the environment

These are the hydrogen production methods the regulators considered when producing this guidance:

- steam methane reforming (SMR)
- autothermal reforming (ATR)
- gas heated reforming (GHR)
- partial oxidation (POX)

They also considered combinations of these such as GHR plus ATR and GHR plus SMR.

All of these methods will need to separate out, capture and prepare hydrogen and CO<sub>2</sub> ready for:

- using hydrogen product within the installation
- transporting hydrogen product for use off-site
- transporting CO<sub>2</sub> for permanent geological storage off site

These activities are outside the scope of this guidance.

## 3. Plant design and operation

### 3.1 Flexible operation

You must consider whether your hydrogen production plant may need to operate on a flexible basis to balance variations in demand from hydrogen users.

You should consider whether this need for flexibility will affect the design, operation and maintenance of the plant.

You should identify flexible operating scenarios where environmental performance could be affected, or where additional emissions are expected. For example, these could be as a result of rapid changes in capacity, or start-up following enforced shutdown.

You should describe measures you would take to minimise the environmental impact of these scenarios, which could result in, for example:

- reduced CO<sub>2</sub> capture rates
- reduced energy efficiency
- increased emissions to air, venting and flaring
- increased effluent or wastes produced
- increased risk of accidents in non-steady state conditions

### **3.2 Reliability and availability**

You will need to identify equipment and systems that are critical in avoiding emissions. You will need to design, operate and maintain these to make sure they are reliable and available, including providing installed back-up equipment, where necessary.

You should implement a risk-based other than normal operating conditions (OTNOC) management plan, which identifies potential scenarios, mitigation measures, monitoring and periodic assessment.

### **3.3 Overall CO<sub>2</sub> capture efficiency**

You should design plant to maximise the carbon capture efficiency. As a minimum, you should achieve an overall CO<sub>2</sub> capture rate of at least 95%, although this may vary depending on the operation of the plant. You can base this on average performance over an extended period (for example, a year).

Overall carbon capture rate or efficiency is defined as ‘the mass of CO<sub>2</sub> equivalent captured for storage as a percentage of the mass of CO<sub>2</sub> equivalent in all feed gas, including methane or refinery fuel gas (or both) used in combustion plant’.

For clarity, this is the same as ‘the mass of carbon captured as a percentage of the mass of carbon in all feed gas’.

This should be achievable for the hydrogen production and CO<sub>2</sub> capture routes considered for new plant.

You will need to provide justification if you are proposing a design CO<sub>2</sub> capture rate of less than 95%.

You should consider how you would comply with future requirements for increased CO<sub>2</sub> capture efficiency by making your plant decarbonisation ready.

You should plan to allow for space and technical retrofit within the design for additional carbon capture plant. This will allow for the capture of residual emissions of CO<sub>2</sub>, for example, from combustion of any hydrogen purification residual gas.

This is to future-proof the plant so you can comply with any future requirements for carbon capture ready for emissions of CO<sub>2</sub> and the likely changes to CO<sub>2</sub> capture efficiency required.

You should note that any carbon-containing compounds as allowed by the hydrogen product specification will be emitted to the environment in downstream uses, such as combustion. You should aim to minimise these where feasible.

For more detail, see the [review of emerging techniques](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) (<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>):

- section 5.7 Carbon capture efficiency
- section 6.3, Table 22: Carbon capture key performance parameters

### 3.4 Process CO<sub>2</sub> capture from hydrogen product

Technology for CO<sub>2</sub> capture from hydrogen product will typically be through absorption in a circulating solvent, with regeneration of the solvent through reducing pressure and heating to liberate CO<sub>2</sub>.

You should select the solvent, process design and operating conditions that maximise energy efficiency, capture performance, and minimise the waste and effluent treatment required. Where you have considered various options, you should provide the reasoning behind this to demonstrate that your chosen option uses overall BAT.

This could include, for example:

- maximising absorption for CO<sub>2</sub> capture
- optimising solvent regeneration to provide CO<sub>2</sub> at high pressure, but avoiding excessive degradation of solvent
- maximising heat exchange between lean and rich solvent streams
- minimising solvent carryover to minimise the need for downstream removal
- minimising wastes and effluent streams, while removing contaminant build-up in solvent

For more detail, see the [review of emerging techniques](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) (<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>), section 5.4.



## 3.5 CO<sub>2</sub> capture for steam methane reforming

In SMR, heat for the reformer reaction is provided by external combustion in a furnace.

The fuel gas can be either:

- methane (usually from natural gas feed)
- refinery fuel gas
- hydrogen product
- a combination of these

All require post combustion capture to remove the CO<sub>2</sub> produced from the flue gas, except where pure hydrogen product is used as the fuel. Following consultation with industry, the regulators expect that more than 95% of CO<sub>2</sub> can be removed from the reformer flue gases.

The plant could be designed in such a way that no post combustion capture is needed if both of these apply:

- hydrogen is used as the fuel gas for the reformer
- there is in-process CO<sub>2</sub> removal prior to hydrogen purification

You will need to justify the best overall approach, considering all environmental impacts.

If post-combustion CO<sub>2</sub> capture is needed, you should use the guidance [Post-combustion carbon dioxide capture: best available techniques \(BAT\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat) (<https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat>) (referred to as PCC guidance).

You should take account of any differences between the flue gases considered in the PCC guidance and the flue gases from the SMR reformer furnace.

These differences could be, for example, oxygen and nitrogen content, potential for formation of nitrogen oxides (NO<sub>x</sub>) and impact of requirement for flexible operation.

When optimising for environmental performance, you should consider:

- selecting appropriate solvents
- emissions to air of solvent and associated degradation products
- energy requirements
- effluents and wastes
- cooling requirements
- pump and fan noise

- flue gas pre-treatment
- treated flue gas dispersion

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), sections 5.5 and 5.6.

### 3.6 CO<sub>2</sub> capture from residual gas from hydrogen purification

You should consider how to capture CO<sub>2</sub> produced by the combustion of residual gas, which results when hydrogen is purified.

You should aim to remove this CO<sub>2</sub> to maximise the overall carbon capture efficiency and to make sure you achieve at least 95%.

The residual gas may contain methane, carbon monoxide (CO) and CO<sub>2</sub> as well as hydrogen, nitrogen and argon. This is normally used as a fuel gas and any carbon containing compounds will be converted to CO<sub>2</sub>.

The amount of carbon-containing compounds depends on the efficiency of conversion and removal before the hydrogen purification stage.

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.9.

### 3.7 Energy efficiency, process efficiency, cooling

You should choose your hydrogen production process and design your plant to maximise:

- energy efficiency (minimise the energy needed to produce each tonne of hydrogen)
- process efficiency (minimise the raw materials, such as methane and water, needed to produce each tonne of hydrogen)

To decide on BAT, you will have to balance how you achieve these efficiencies in order to optimise the environmental and economic requirements.

You must explain how you have done this and what your considerations were.

This should take into account all of the chemical and physical processes within the installation boundary needed to produce hydrogen and capture carbon.

Main energy users will include:

- air separation unit (ASU) – for oxygen supply to ATR and POX

- hydrogen compressors
- CO<sub>2</sub> compressors
- hydrogen and CO<sub>2</sub> purification
- solvent recovery system
- pumping or fan systems

You should consider:

- electrical power needs and whether you will import or generate on site
- high pressure steam need and availability
- maximising any residual waste heat recovery
- cooling needs
- cooling type and medium

You should also consider heat integration optimisation, for example, heat recovery at:

- higher temperatures from compression systems including the ASU, CO<sub>2</sub> and hydrogen compression for power generation or drives
- medium temperatures for solvent recovery
- lower temperatures for boiler feed pre-heat

See also section 3.9 Water supply and use

You should reference the BREF documents:

- [Industrial Cooling Systems \(https://eippcb.jrc.ec.europa.eu/reference/industrial-cooling-systems\)](https://eippcb.jrc.ec.europa.eu/reference/industrial-cooling-systems)
- [Energy Efficiency \(https://eippcb.jrc.ec.europa.eu/reference/energy-efficiency\)](https://eippcb.jrc.ec.europa.eu/reference/energy-efficiency)

For further details, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture):

- section 5.10
- section 6.1 Table 20

## 3.8 Oxygen production

Oxygen is required for the ATR and POX processes. It is usually produced by an ASU, which is a relatively large energy user.

You must consider heat recovery from the heat generated by the air compression system and whether you can use it within the rest of the hydrogen production process

to maximise energy efficiency. We expect you to explore all opportunities for waste heat recovery as the ASU will be considered part of the installation.

You should take the following into account when designing the oxygen production plant and optimise to show you are using BAT:

- overall energy consumption depends on the design of the ASU and its air compressor
- energy required will be a balance between oxygen purity, oxygen pressure needed to supply the hydrogen production process and energy needed to purify the hydrogen
- higher oxygen purity will increase the energy required for oxygen production, but reduce the amount needed for hydrogen purification to remove residual argon and nitrogen
- co-production of argon and nitrogen can be used for export or on site
- heat energy needed to dry and purify the compressed air
- options to increase the compressor exit temperature to improve options for heat recovery should be explored, balanced with compressor design and higher power requirement.
- safe and reliable operation of both the ASU and hydrogen production plant where heat integration is used
- high availability of oxygen supply and backup supply or liquid storage is important to avoid potential environmental impacts of emergency or frequent shutdown and start-up of the plant

For further details, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.12.

### 3.9 Water supply and use

Water supply and its efficient use is an important aspect of BAT in hydrogen production plant.

The quality of the water supply will determine the pre-treatment needed before it can be used as a:

- raw material in hydrogen production
- heat transfer medium
- cooling medium

Water is consumed in the process as part of the hydrogen product.

Your choice of hydrogen production method will determine the ratio of hydrogen product that comes from water compared with that which comes from methane, or

refinery fuel gas, or both.

For further details see Water consumption (process) in Table 20 of the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture).

You should:

- minimise the amount of water you use
- segregate, treat and reuse water where possible
- choose a cooling method that takes account of the temperature impact on process performance, energy efficiency and environmental impact on the receiving medium

For refineries, you should also comply with BAT conclusion 11 emissions to water from the [BAT conclusions \(BATC\) for refining of mineral oil and gas \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL\\_2014\\_307\\_R\\_0009\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

### 3.10 Water treatment

Water and steam are used in the process.

Water is condensed both from steam systems and from process cooling. In most cases, this water can be reused without being treated. However, some water will need to be removed to avoid the build-up of contaminants. You will need to treat it in an effluent treatment system before releasing it into the environment.

You should decide how much water to treat and how to treat it before it is:

- reused
- released to surface water or sewage undertaker
- disposed of

You should identify how much contaminant, such as methanol and ammonia, needs to be removed and design the treatment process accordingly.

You should identify any emissions to air or wastes that may result from the water treatment process, for example, emission of CO<sub>2</sub> from deaeration of boiler feed water.

You should use the following references to choose the most appropriate treatments:

- [BREF and BATC for common waste water and waste gas treatment/management systems in the chemical sector \(https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0\)](https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)
- [BREF and BATC for refining of mineral oil and gas \(https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0\)](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)

For discharges to water, you should refer to the guidance [Surface water pollution: risk assessment for your environmental permit \(https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit\)](https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit).

For further details on water treatment for re-use, see the emerging techniques review, section 5.13.

### 3.11 Feed gas quality and treatment

Your choice of supply of methane-containing feed gas will determine the type of gas treatment processes you will need prior to the main conversion reactions., It will also determine whether you will need to remove inert gases at the hydrogen purification stage.

If you use refinery fuel gas as your feed gas supply, where possible, you should remove contaminants such as sulphur and mercury in existing upstream refinery processes, taking account of BAT across the refinery installation.

You will need to take account of the possible range of gas composition so that you can design your processes to minimise the overall environmental impact, including substances such as:

- sulphur (S), typically as H<sub>2</sub>S
- nitrogen (N<sub>2</sub>)
- CO<sub>2</sub>
- mercury
- other hydrocarbons

You will need to design your gas treatment and downstream processes in order to:

- minimise solid wastes (for example, catalyst) for recycling or disposal
- minimise sulphur dioxide (SO<sub>2</sub>) emissions to air where feed gas is combusted
- maximise overall process reaction and energy efficiency
- minimise emissions to air associated with the removal of nitrogen or other inerts

You should consider removing sulphur compounds by hydrogenation and using catalyst adsorbent to avoid SO<sub>2</sub> emissions from combustion and catalyst poisoning.

You should consider removing other hydrocarbons by pre-reforming to avoid carbon deposition on catalysts.

You should consider the impact a pre-reforming step will have on the downstream reforming stage for an SMR. You may be able to optimise the energy efficiency and minimise NO<sub>x</sub> emissions to air due to reduced gas fired reformer furnace duty. You will need to consider the impact on steam balance for the plant.

You should remove mercury to avoid catalyst poisoning and other downstream contamination.

Any CO<sub>2</sub> in the feed gas will be removed along with the CO<sub>2</sub> produced in the process. You should include this in the overall CO<sub>2</sub> balance and capture efficiency monitoring and reporting.

### 3.12 Reforming and CO shift

Hydrogen is produced in the reforming and CO shift stages of the plant.

You should convert methane to hydrogen, CO and CO<sub>2</sub> in the reforming stage, while minimising unreacted methane.

You should optimise CO conversion to CO<sub>2</sub> considering the overall CO<sub>2</sub> capture requirement and the impact on downstream processing stages to meet the hydrogen product specification.

### 3.13. Reforming

You should select, design and operate the reformer reaction in order to:

- reduce the risk of carbon deposition on catalyst, which would result in reduced reaction efficiency
- minimise catalyst change frequency and the need for recycling or waste disposal

If you choose ATR or POX technologies, carbon formation may be more likely due to the reducing atmosphere. You should choose operating parameters to minimise this risk.

### 3.14 CO shift

You should select, design and operate CO shift reaction in order to:

- maximise energy efficiency through, for example, heat integration with the overall hydrogen production and CO<sub>2</sub> capture processes
- minimise the duration of start-up operations and associated emissions to air from flaring
- minimise the production of wastes for recycling or disposal

You should consider a single step CO shift process rather than a more conventional high temperature or low temperature shift process, with isothermal conditions achieved through reactor cooling with recovery of heat.

By using this option, it may allow you to:

- increase overall heat integration and efficient use of recovered heat, as long as sufficient conversion of CO to CO<sub>2</sub> is achieved
- avoid using chromium catalyst needed for high temperature shift, therefore minimising hazardous waste
- reduce the potential for catalyst damage, methanation reactions, and Fischer-Tropsch reactions
- reduce the potential for the production of methanol which would condense out with water downstream and need to be treated by effluent treatment
- consider the cost and environmental benefits of an isothermal reactor against a more complex multi-tube boiling water-cooled reactor

Refer to [BREF for large volume inorganic chemicals – ammonia, acids and fertilisers \(https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers\)](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) – section 2.4.14 Isothermal Shift Conversion.

### 3.15 Catalyst selection

When you choose which catalysts to use, you should consider the overall environmental performance, including, for example:

- any required pre-treatment to avoid poisoning, to minimise waste and associated treatment
- preventing any dust emissions, where applicable
- the ability to recover or recycle the solids or metals from the spent catalyst waste
- handling spent catalyst for environmentally safe recovery, recycling or disposal

### 3.16 Hydrogen product

You will need to purify and compress hydrogen so that it is fit for purpose after it is separated from the CO<sub>2</sub> in the CO<sub>2</sub> capture stage.

You should take account of hydrogen purification requirements. These will depend on:

- the hydrogen product quality specification
- impurities in the hydrogen following reforming, CO shift and CO<sub>2</sub> capture steps

The impurities may include:

- CO, which is not converted to CO<sub>2</sub> in the reforming or CO shift sections
- CO<sub>2</sub>, which is not removed in the CO<sub>2</sub> capture section
- methane, which is not converted to CO in the reforming section
- nitrogen and argon – inert gases present in feed gas or oxygen supply



- water – the hydrogen is saturated with water following CO<sub>2</sub> capture

You should consider pressure swing adsorption (PSA) to remove impurities from the hydrogen. Treating residual gas containing the impurities is considered in section 3.6 CO<sub>2</sub> capture from residual gas from hydrogen purification.

You should consider whether methanation to convert CO into methane is appropriate, depending on the specification of hydrogen, to make sure hydrogen is fit for purpose.

You should consider the impact on overall energy efficiency and the need for further treatment of hydrogen purification off-gas streams.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. See section 3.7 energy efficiency, process efficiency, cooling.

### **3.17 CO<sub>2</sub> product**

You should design the process to meet the required CO<sub>2</sub> quality specification, temperature and pressure as required for transport to permanent geological storage.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. You should maximise recovery of waste heat from compression. See section 3.7 energy efficiency, process efficiency, cooling.

## **4. Emissions to air**

You should eliminate, minimise or reduce any emissions to air that could cause pollution.

You should make sure that your process emissions can comply with all ELVs which are required under the relevant BATC.

You should carry out a risk assessment, including detailed air quality modelling, to assess the impact of these emissions.

### **4.1 Combustion processes**

You should maximise energy efficiency and heat integration so you minimise the need for combustion processes, resultant CO<sub>2</sub> and other combustion products.

You should maximise the capture of CO<sub>2</sub> from combustion processes, taking account of the overall carbon capture requirement.

If you decide that carbon capture from a combustion process is not appropriate, you must justify your decision based on BAT. You must identify and minimise the continuous and periodic emissions of combustion products to air.

You should consider NO<sub>x</sub> abatement techniques where the combustion of hydrogen-rich gas with the potential for higher flame temperatures will increase thermal NO<sub>x</sub> formation, including:

- burner design
- flue gas recirculation
- heat exchange with fuel or air

You should consider whether abatement of any of these emissions is required to comply with relevant BAT AELs or local air quality standards, for example, for NO<sub>x</sub>. Where relevant, you should consider the following abatement techniques:

- selective catalytic reduction (SCR)
- selective non-catalytic reduction (SNCR)

You should consider:

- the overall impact of using residual gas from the hydrogen purification process as a supplementary fuel for fired equipment to balance overall heat requirements, while considering the impact of the additional emissions of combustion products to air
- for SMR, the requirement for post-combustion carbon capture for the reformer furnace emissions to air and any pre-treatment of combustion gases needed see the [PCC guidance \(https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat)
- for ATR, whether the relatively smaller additional heat need can be supplied by combustion of hydrogen-rich residual gas or combustion of hydrogen product
- for POX, the process is usually energy-balanced or produces excess heat and so combustion processes may not be needed
- the impact on emissions to air due to variability in fuel gas composition or any need to switch between fuel gas sources, for example, at start-up when residual PSA gas for fuel is not available and some feed gas may need to be combusted

You could consider using excess oxygen, where available, to support oxy-combustion, in order to remove the source of nitrogen and therefore limit thermal NO<sub>x</sub> formation.

Fuel NO<sub>x</sub> may form from nitrogen in the residual gas from the PSA. There is limited experience of using oxygen, especially for hydrogen-rich gases and any such proposal would need to be fully justified with supporting data.

You should design combustion processes to comply with required emissions limit values (ELVs) from the existing sources of statutorily applicable emission limits and

BAT AELs, including the following:

- [Medium Combustion Plant Directive \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015L2193\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015L2193)
- [Industrial Emissions Directive Chapter III Annex V ELVs \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-59-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-59-1)
- BAT AELs identified in the [Large combustion plant BREF \(https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0\)](https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) and BATC
- [Refining of Mineral Oil and Gas \(https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0\)](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
- [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers \(https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers\)](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)
- [Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector \(https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0\)](https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)

You should consider the:

- type of combustion equipment
- fuels proposed to be combusted
- net rated thermal inputs
- BAT for control of emissions
- conclusions of an environmental risk assessment, considering the dispersion of pollutants into air and the sensitivity of the relevant receptors

## 4.2 Post combustion capture plant

Refer to the [PCC guidance \(https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat) – section 3.3 Features to control and minimise atmospheric and other emissions.

## 4.3 Flaring and venting

You must design and operate your plant to minimise the need for continuous or intermittent flaring or venting of gases, whether for operational or safety reasons, including:

- methane or refinery fuel gas
- hydrogen
- CO<sub>2</sub>

This should include:

- flaring rather than venting, where emissions cannot be eliminated and where practicable, to minimise emissions of higher global warming potential gases such as methane and hydrogen
- plant design to maximise equipment availability and reliability (see section 3.2 Reliability and availability)
- avoiding routine flaring for waste gas destruction
- managing production of off-gas and balance against requirements for fuel gas using advanced process control, for example
- using procedures to define operations, including start-up and shutdown, maintenance work and cleaning
- using commissioning and handover procedures to ensure that the plant is installed in line with the design requirements
- using return-to-service procedures to ensure that the plant is recommissioned and handed over in line with the operational requirements
- designing flaring devices to enable smokeless and reliable operations, and to ensure an efficient combustion of excess gases when flaring under other than normal operations
- monitoring and reporting of gas sent to flaring and associated parameters of combustion

You must minimise emissions under start-up, shutdown, and abnormal operations. This can be achieved by:

- using a flare gas recovery system with adequate capacity
- routing gas that would be flared to alternative users
- using high integrity relief valves
- other measures to limit flaring to abnormal operation

If your activity is part of a refineries installation, you should refer to BAT conclusions 55 and 56 in [BATC for the Refining of Mineral Oil and Gas \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL\\_2014\\_307\\_R\\_0009\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

You should quantify and assess harm from other routine venting and purging requirements, identifying any pollutants that are expected to be present, including, for example:

- CO<sub>2</sub>
- hydrogen
- CO
- methane
- ammonia vapour

- methanol vapour

Requirements for continuous venting during normal operations may include, for example:

- water vapour from CO<sub>2</sub> dehydration systems using circulating tri-ethylene glycol
- deaeration of steam condensate or boiler feed waters
- gases from processing waste water streams
- purge of tanks, vent or flare headers

Requirements for intermittent venting may include, for example:

- CO<sub>2</sub> vented in abnormal conditions, such as when the downstream transportation and storage system is not available, or if the CO<sub>2</sub> does not meet the export specification
- venting needed as part of purging equipment for maintenance activities

## 5. Emissions to water

You must identify and eliminate, minimise, recycle or treat any emissions to water that could cause pollution.

You should carry out a risk assessment, including detailed modelling, where appropriate, to assess the impact of these emissions.

For discharges to water, you should refer to the guidance [Surface water pollution: risk assessment for your environmental permit \(https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit\)](https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit).

### 5.1 Effluent treatment discharges

You should identify continuous and periodic effluent streams from the process and determine whether effluent treatment is required. These streams may include process condensate containing contaminants, which may need treatment before discharge, for example:

- methanol
- ammonia
- CO<sub>2</sub>
- amines
- degradation products

You should treat water for reuse as far as possible. See section 3.10 Water treatment.

You should refer to the appropriate BREF and BATC (where available) if the installation is considered to be part of a refinery or a chemicals installation:

- [Refining of Mineral Oil and Gas \(https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0\)](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
- [Common Waste Gas Management and Treatment Systems in the Chemical Sector \(https://eippcb.jrc.ec.europa.eu/reference/common-waste-gas-treatment-chemical-sector\)](https://eippcb.jrc.ec.europa.eu/reference/common-waste-gas-treatment-chemical-sector)
- [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers \(https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers\)](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)

## 6. Waste

You must eliminate or minimise wastes and treat, where appropriate.

You should consider how to deal with the following wastes that may be generated.

### 6.1 Liquid wastes

Liquid wastes such as:

- demineralised water production reject stream
- amine solvent – for example, from bleed or feed replacement
- dehydration solvent – for example, in case of tri-ethylene glycol dehydration
- amine reclaimer residue

### 6.2 Solid wastes

Solid wastes such as:

- depleted catalyst material – hydrogenation, reforming, CO shift
- spent adsorbent materials – gas treatment, dehydration, hydrogen purification
- solids from amine filtration
- soot (POX process)

## 7. Monitoring

The main purpose of monitoring is to demonstrate compliance with the permit and show that emissions from the process are not causing harm to the environment.

You must also carry out monitoring to show that resources are being used efficiently. This includes:

- energy and resource efficiency
- carbon capture efficiency
- verifying that the CO<sub>2</sub> product is suitable for safe transport and storage
- hydrogen product quality
- verifying (when applicable) compliance with low carbon hydrogen standards

Your permit application should include a monitoring plan for both a commissioning phase and routine operation.

During the commissioning phase, you will need to assess monitoring results and optimise the operation of the process. You will need to report on your commissioning phase monitoring results, your assessment of them and any changes you want to make to the operation.

It's likely you will need to do more extensive monitoring during the commissioning phase than during routine operation. As these production techniques for hydrogen with CCS are emerging techniques, you will need to develop monitoring methods and standards. You should include proposals for this in your permit application.

Complying with ELVs in your permit will provide the necessary protection for the environment, by monitoring emissions at authorised release points. You must also show that you are managing the process to prevent (or minimise) the formation of solvent degradation products.

Where degradation products are formed (and may be released), you must reduce these and any solvent emissions to the appropriate level. This process control monitoring will also be part of the permit conditions.

## 7.1 Monitoring point source emissions to air

You should provide a monitoring plan for monitoring emissions to air, based on expected pollutants such as:

- ammonia
- amine compounds
- SO<sub>2</sub>
- NO<sub>x</sub>
- CO
- methane
- hydrogen

You should do this using appropriate methods and measuring techniques.

Emissions of methane and hydrogen should be eliminated or minimised due to their global warming potential.

Your monitoring should consider, for example:

- NO<sub>x</sub> and CO emissions from combustion
- SO<sub>2</sub> emissions from combustion where the fuel source contains sulphur
- ammonia emissions where SCR or SNCR is used
- amine or amine degradation products and other volatile solvent emissions, where relevant
- methane and hydrogen 'slip' from any combustion processes
- any other sources of methane or hydrogen emissions

For combustion plant, your monitoring plan should demonstrate compliance with the applicable emission limits described in section 4.1 Combustion processes.

Where you are using post-combustion CO<sub>2</sub> capture, for example, using amine solvent, your plan should include monitoring relevant emissions such as:

- ammonia
- volatile components of the capture solvent
- likely degradation products such as nitrosamines and nitramines

Specific pollutants arising from post-combustion capture may be monitored by continuous emissions monitors, if they are available, or by periodic extractive sampling. Where aerosol formation is expected, the sampling must be isokinetic.

## 7.2 Monitoring emissions to water

You must monitor emissions to water based on expected impurities (for example, ammonia, amine compounds, methanol, CO<sub>2</sub>) using appropriate methods and measuring techniques.

You should use monitoring standards for discharges to water following:

- [BATC for common waste water and waste gas treatment/management system in the chemical sector \(https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1579188127132&uri=CELEX%3A32016D0902\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1579188127132&uri=CELEX%3A32016D0902)
- [BATC for the refining of mineral oil and gas \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL\\_2014\\_307\\_R\\_0009\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009)

## 7.3 Monitoring standards



The person who carries out your monitoring must be competent and work to recognised standards such as the Environment Agency's [monitoring certification scheme \(MCERTS\)](https://www.gov.uk/government/collections/monitoring-emissions-to-air-land-and-water-mcerts) (<https://www.gov.uk/government/collections/monitoring-emissions-to-air-land-and-water-mcerts>).

MCERTS sets the monitoring standards you should meet. The Environment Agency recommends that you use the MCERTS scheme, where applicable. You can use another certified monitoring standard, but you must provide evidence that it is equivalent to the MCERTS standards.

There are no prescriptive BAT requirements for how to carry out monitoring. Monitoring methods need to be flexible to meet specific site or operational conditions.

You must use a laboratory accredited by the [United Kingdom Accreditation Service \(UKAS\)](https://www.ukas.com/) (<https://www.ukas.com/>) to carry out analysis for your monitoring.

You should also refer to the [JRC Reference Report on Monitoring for IED Installations](https://eippcb.jrc.ec.europa.eu/reference/monitoring-emissions-air-and-water-ied-installations-0) (<https://eippcb.jrc.ec.europa.eu/reference/monitoring-emissions-air-and-water-ied-installations-0>).

## 7.4 Monitoring CO<sub>2</sub> capture performance

You should clearly identify how you will monitor the CO<sub>2</sub> capture performance of the plant.

The regulators expect you to monitor CO<sub>2</sub> capture performance according to standards that are recognised under the UK ETS. Measurements required to monitor CO<sub>2</sub> emissions to atmosphere may, for example, include directly measuring the flow and composition of fuel gas to combustion systems.

This, together with measuring the following, will allow monitoring of the CO<sub>2</sub> capture rate and CO<sub>2</sub> quality (considering any impurities that could impact downstream systems):

- flow and composition of feed gas
- hydrogen product (including methane content where applicable)
- CO<sub>2</sub> product streams

You will need to include:

- CO<sub>2</sub> equivalent mass balance
- CO<sub>2</sub> equivalent in feed gas
- total capture efficiency (CO<sub>2</sub> equivalent captured as a mass percentage of CO<sub>2</sub> equivalent in feed gas)

- CO<sub>2</sub> equivalent released to the environment
- CO<sub>2</sub> quality

## 7.5 Monitoring process performance

You should identify the main requirements for monitoring process operations where these ultimately impact on environmental performance, including, for example, for the CO<sub>2</sub> capture system:

- amine system performance, including monitoring of amine solvent quality such as amine concentration
- pH and presence of degradation or corrosion products
- amine temperatures
- amine and wash water circulation rates
- rich and lean amine CO<sub>2</sub> loading
- stripper reboiler steam rates

You should monitor energy efficiency in the hydrogen production and CO<sub>2</sub> capture processes by measuring feed and product gas flows and electrical power consumption to calculate overall energy consumption.

You should monitor the quality of the hydrogen product to ensure it is fit for purpose.

Requirements for process performance monitoring, either online or offline, will also be a condition of the permit.

## 8 Unplanned emissions and accidents

You should propose a leak detection and repair (LDAR) programme that is appropriate for the fluids and their composition. This should use industry best practice to manage releases, including from joints, flanges, seals and glands.

You should include how you will use LDAR to eliminate or reduce fugitive emissions of methane and hydrogen due to their global warming potential.

Your hazard assessment and mitigation for the plant must consider the risks of accidental releases to the environment. This should also consider the actual composition of the liquids, gases and vapours that could be released from the plant after an extended period of operation.

## 9 Noise and odour

You need to consider sources that have high potential for noise and vibration. In particular, CO<sub>2</sub> and hydrogen compression, pumping and fan noise could be significant additional sources.

Once you've identified the main sources and transmission pathways, you should consider using common noise and vibration abatement techniques and mitigation at source, wherever possible. For example:

- embankments to screen the source of noise
- enclosure of noisy plant or components in sound-absorbing structures
- anti-vibration supports and interconnections for equipment
- orientation and location of noise-emitting machinery
- changing the frequency of the sound

Please refer to [Noise and vibration management: environmental permits](https://www.gov.uk/government/publications/noise-and-vibration-management-environmental-permits) (<https://www.gov.uk/government/publications/noise-and-vibration-management-environmental-permits>).

Handling, storing and using some amines may result in odour emissions, so you should always use best practice containment methods. Where there is increased risk that odour from activities will cause pollution beyond the site boundary, you will need to send an odour management plan with your permit application.

In England, Wales and Northern Ireland please refer to [Environmental permitting: H4 odour management](https://www.gov.uk/government/publications/environmental-permitting-h4-odour-management) (<https://www.gov.uk/government/publications/environmental-permitting-h4-odour-management>). In Scotland refer to [Odour guidance 2010](https://www.sepa.org.uk/media/154129/odour_guidance.pdf) ([https://www.sepa.org.uk/media/154129/odour\\_guidance.pdf](https://www.sepa.org.uk/media/154129/odour_guidance.pdf)).

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