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Hydrogen technologies — Methodology for determining the greenhouse gas emissions associated with the production, conditioning and transport of hydrogen to consumption gate

Annex B

Hydrogen Production Pathway – Steam Methane Reforming (with Carbon Capture and Storage - CCS)

Contents

Annex B
(informative)

Hydrogen Production Pathway – Steam Methane Reforming (with Carbon Capture and Storage - CCS)

B.1 SMR/CCS process description and overview

Sections B.1.1 and B.1.2 provide a description and an overview for hydrogen produced from steam methane reforming with carbon capture and storage.

B.1.1 Description

Currently, the steam methane reformer (SMR) is the leading technology for hydrogen production from natural gas or light hydrocarbons.

An SMR production plant is typically composed of the following sub processes:

- A gas pre-treatment / Sulfur removal unit
- A reformer (optionally a pre reformer if the feed contains higher hydrocarbons) where the feedstock is reformed into syngas composed of hydrogen and CO. The main chemical reaction is $CH_4 + H_2O \rightarrow CO + 3H_2$
- A cold box separating CO in case CO is co-produced (optional)
- A Water Gas Shift where the CO in the Syngas is "Shifted" to CO_2 and hydrogen through the following chemical reaction: $CO + H_2O \rightarrow CO_2 + H_2$
- A Pressure Swing Adsorption unit (PSA) to purify the hydrogen
- A Carbon Capture Unit (optional)

In an SMR facility, GHG emissions are produced via combustion of fossil fuels for heat and steam, and via the water gas shift reaction. Modern SMR based hydrogen production facilities have achieved efficiencies that could reduce CO_2 emissions down to nearly 10% above its theoretical minimum. Further reduction of CO_2 emissions from hydrogen production would only be possible by the integration of CCS.

The current industry standard for capturing CO_2 from an SMR based hydrogen plant is the capture of CO_2 from the shifted syngas using MDEA solvent. Other CO_2 capture options are considered as the use of hydrogen rich burner in conjunction with capture of CO_2 from shifted syngas using MDEA; the capture of CO_2 from PSA's tail gas using MDEA (or similar), or the use of Cryogenic and Membrane Separation; and the capture of CO_2 from flue gas using MEA or the use of adsorption and cryogenic separation.

B.1.2 Overview

The main simplified block flow diagram for a SMR with CO_2 capture on the PSA tail Gas is described in in Figure B.1 —.

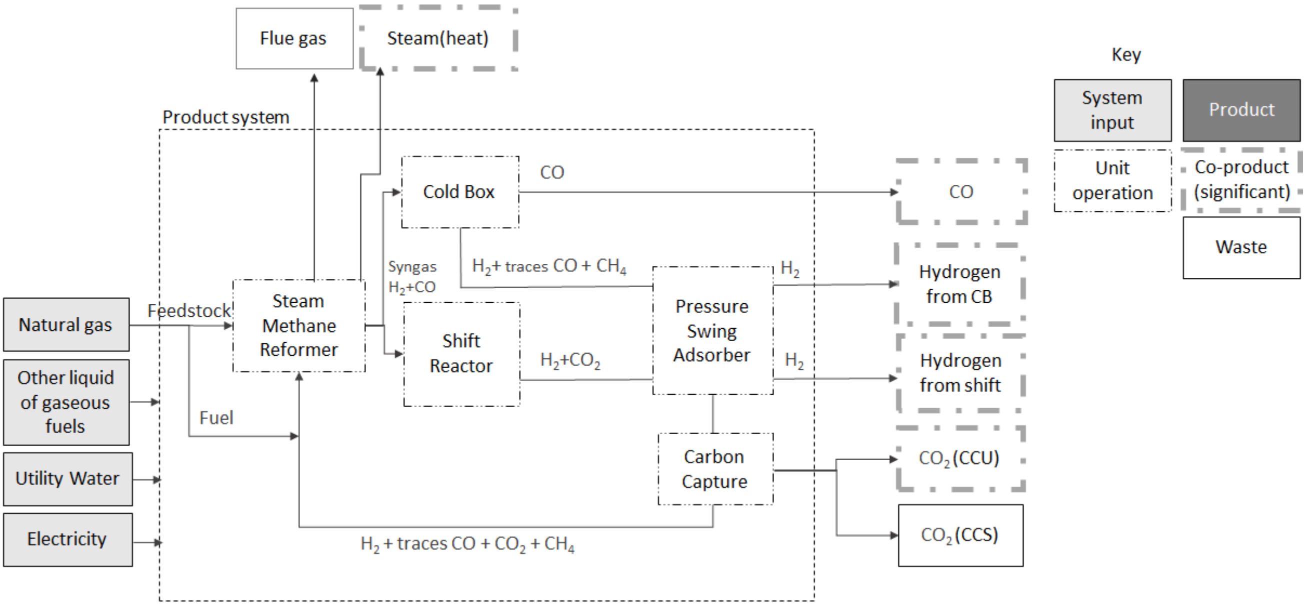

Figure B.1 — Example of a simplified SMR plant block diagram

B.2 Emission sources and inventory

Sections B.2.1, B.2.2 and B.2.3 provide the emissions sources and inventory in case of attributional approach and consequential approach for hydrogen produced from steam methane reforming with carbon capture and storage.

B.2.1 Emission sources

For steam methane reforming, the main source of GHG emissions is the combustion of fossil fuel to provide the reaction heat to convert natural gas into syngas and the conversion of CO to hydrogen and CO_2. Other significant emissions sources include the upstream emissions occurring during the life cycle related to the supply of inputs (feedstock and energy), including emissions of grid electricity, CO_2 removal, CO_2 compression for CCS.

Emissions sources of each process unit or stage in the SMR process are outlined in Table B.1 —Table B.1 —.

Table B.1 — Key life cycle GHG emission sources in hydrogen production for SMR /CCS

Process unit/stage	Key emissions sources	Other emissions sources
Natural gas production	• Electricity and/or fuel combustion for natural gas extraction and transport to a processing plant • Fugitive methane and/or carbon dioxide from natural gas extraction and transport	• Flaring and venting
Natural gas processing	• Electricity and/or fuel combustion for separating heavier components of recovered gas (e.g., natural gas liquid) or acid gases (e.g., CO_2) from pipeline-quality natural gas	• Flaring and venting

	• Fugitive methane and/or carbon dioxide from NG processing	
NG transport	• Electricity and/or fuel combustion for transport • Fugitive Methane emissions	
Heat recovery and electricity generation	• No significant emissions other than those covered under common emissions sources	
Auxiliary Heating Processes	• Electricity and/or fuel combustion to provide auxiliary heat, e.g. in pre-heaters	
CO_2 and hydrogen purification	• Electricity and/or heat for operation of the relevant purification units	• Exhaust CO_2 due to sulphur removal
Hydrogen enrichment	• Electricity and/or heat to supply water gas shift reactions occurring as part of hydrogen enrichment (if relevant)	
CO_2 capture and separation	• Electricity and/or heat for relevant separation units • Residual CO_2 which is not captured for permanent storage	
Compression and transport of CO_2	• Electricity for compression of CO_2 • Electricity and/or fuel combustion for pipeline transport • Liquid and/or fuel combustion for motive transport • Fugitive carbon dioxide emissions	
Storage of CO_2	• Electricity/fuel for compression and injection	• Fugitive CO_2 from permanent storage location
Hydrogen compression and storage	• Electricity for compression and storage maintenance	
Disposal of waste products (where not valorized)	• Electricity and fuel combustion for transport of waste products	

B.2.2 Inventory in case of Attributional Approach

The emission inventory is performed across the life cycle stages from cradle to gate.

<u>Upstream / Indirect emissions:</u>

Upstream indirect GHG emissions are evaluated based on relevant data available for the Natural Gas (and/or other Feed Gas / Fuel Gas) and electricity supplied in the considered geography.

They are taken into account from the well to the inlet meter of the production plant and are evaluated based on relevant data available for the Natural Gas (and/or other Feed Gas / Fuel Gas) supplied in the considered geography.

<u>Direct emissions at production:</u>

The quantity of CO_2 released into the atmosphere during the production lifecycle stage is determined by the carbon balance within the boundaries of the plant. The total carbon input is determined from the quantity and characteristic of the feedstock. It corresponds to the total carbon output which is the sum

of the carbon in the CO_2 emitted + the carbon in the CO_2 non-emitted (used or stored) + the Carbon in the CO produced + other possible carbon containing species, such as CH4, VOC, etc.

NOTE: in case of SMR, other possible carbon containing species in the emissions may be considered as negligible.

Emissions from capital goods:

As per Section 4.2.1 the quantification of CAPEX emissions shall be provided for information.

B.2.3 Inventory in case of Consequential Approach

In case of a consequential approach, the inventory may be performed across life cycle stages extending beyond the production unit. The goal of the LCA should define the boundaries to take into account for consideration of the consequential emissions.

For instance the goal of the LCA may include:

- the emissions occurring during the usage phase of hydrogen coproducts such as CO or CO_2;
- the emissions resulting from other means to produce the co-products (substitution methods).

B.3 Emission Allocation

Several co-products may exist for a SMR/CCS system including hydrogen, Steam, CO, electricity, and CO_2. The exact coproducts depend on specific plant designs.

B.3.1 Allocation in case of Attributional Approach

Several co-products may exist for a SMR/CCS system including hydrogen, Steam, CO, electricity, and CO_2. The exact coproducts depend on specific plant designs.

a. Allocation in case of Attributional Approach

As described at para 4.3.2.8, the first step for the emission allocation is to subdivide the process.

- **1st Step: Process subdivision:**

The process is subdivided into 3 parts:

Given as an example in Figure B.2 — and below, the unit process is subdivided into 3 sub processes.

- Sub process 1 - The Steam Reformer reactor.
  This sub process has Natural Gas or other Hydrocarbon as inputs, Syngas and Steam as co products, and CO_2 emissions.
  The Syngas is mainly composed of H_2, CO, some traces of CO_2 and other impurities such as N_2 and unreacted methane.

The Syngas is then split in 2 parts, feeding the following 2 sub processes:

- Sub process 2 – H_2/CO production unit: This sub process has Syngas as input and H_2 and CO as co products, and CO_2 emissions.

  Note: The ratio between H_2 and CO in the Syngas is a process design characteristic for a given plant. It is typically in the range of 2.5 Nm^3 hydrogen for 1 Nm^3 CO. The actual design characteristic of the considered plant should be used to determine this ratio and derive the

quantity of hydrogen production considered as a co-product of CO.

- Sub process 3 - Water Gas Shift: This sub process has Syngas as input and hydrogen as output. In case of CCUS, it also has CO_2 as a coproduct (CCU) or waste (CCS).

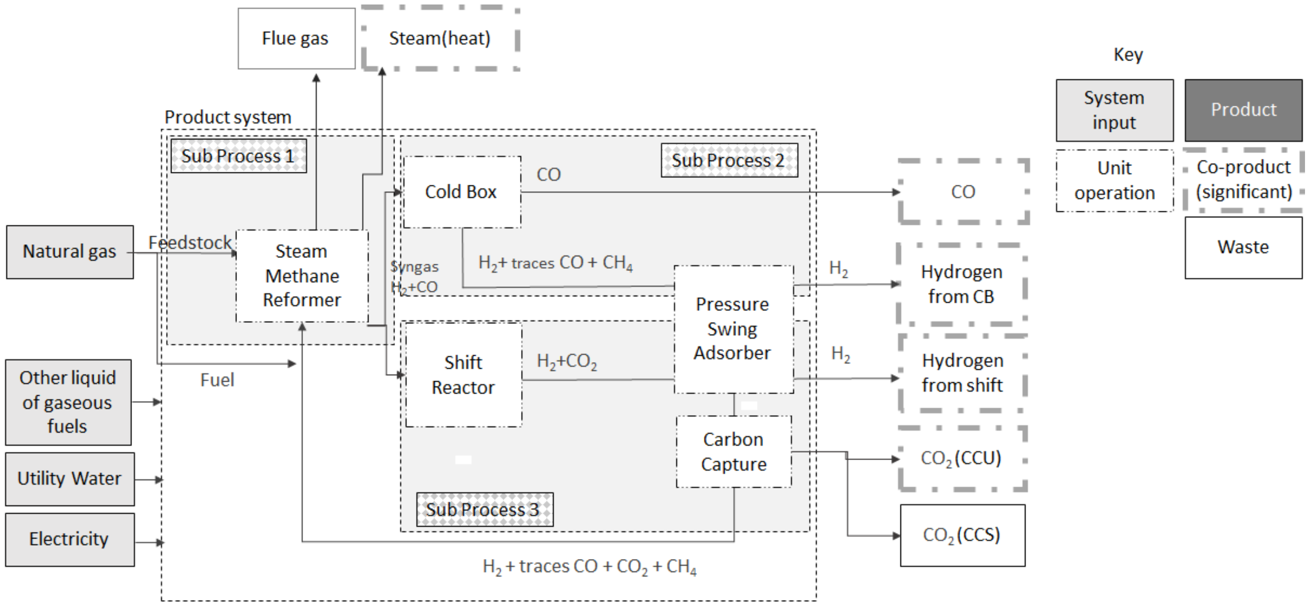

Figure B.2 — Example of a simplified SMR plant block diagram – Subdivision in sub processes

- **2nd Step: Allocations:**

<u>Sub Process 1 – SMR Reactor:</u>

The Feed (Natural Gas or other Hydrocarbon) is allocated to Syngas and Steam *prorata* their energy content (LHV[1] or, in case of the steam, the enthalpy difference between steam and the steam condensate). The steam Partial Carbon footprint results from the allocation of the combustion emissions of the NG allocated to it.

The Syngas is allocated to the sub processes 2 and 3 *prorata* the energy content (LHV) of their coproducts.

<u>Sub Process 2 – hydrogen CO Production:</u>

The emissions from Sub process 2 are determined as described at para B3, and allocated to Hydrogen from CB and CO as per their respective energy content (LHV).

<u>Sub Process 3 – Water Gas Shift:</u>

The emissions from Sub Process 3 are determined as described at para B3, and allocated to Hydrogen from WGS.

[1] LHV is more commonly used over HHV in situations where water vapour can't be recovered.

B.3.2 Allocation in case of Consequential Approach

In case of a consequential approach, the goal of the LCA should define the boundaries to take into account for consideration of the consequential emissions.

Under a consequential approach, the allocation of emission to coproducts may be avoided by applying substitution / system expansion with displacement as provided for at article 4.3.2.8.

B.4 Information to be reported

Table B.2 —shows the information to be reported for hydrogen produced from steam methane reforming with carbon capture and storage.

Table B.2 — Information to Be Reported for SMR /CCS

Category	**Matters to be identified**
Facility details	• Facility identity • Facility location • Facility capacity (Nm^3/h, t/h) • Capacity Factor (%) • Commencement of facility operation • Main climatic and meteorological data (Atmospheric pressure, average ambient temperature, average relative humidity)
Product specifications	• Production pathway • Hydrogen produced (kg) • Hydrogen temperature and pressure at the gate • Hydrogen purity level at the gate • Specification of contaminants
GHG emissions overview	• Emissions intensity of hydrogen batch [$kgCO_2e/kgH_2$]
Batch details	• Beginning and end of batch dates • Batch quantity [kg]
Electricity	Location based emissions accounting • Quantity of purchased grid electricity [kWh] • Location based emission factor used [gCO_2e/kWh] • Quantity of sold electricity [kWh] Market based emissions accounting • Quantity of purchased grid electricity [kWh] • Quantity of contracted electricity [kWh] and/or quantity of associated GOs or RECs • Residual electricity [kWh] • Residual mix emission factor [gCO_2e/kWh] • Type of GOs or RECs On-site electricity generation • Quantity of on-site generation [kWh] • Emission factor for on-site generation (as applicable) [gCO_2e/kWh]
Other utilities	• Source/s of water • Source/s of steam • Quantity of purchased water [kg] • Quantity of purchased steam [kg]

	• upstream emission factor for water [$kgCO_2e/kg$] • upstream emission factor for steam [$kgCO_2e/kg$]
Fuel feedstock	• Types of fuels combusted • Quantities of fuel combusted [L, kg] • Relevant emissions calculation or factors used [$kgCO_2e$/relevant unit of fuel] • Emissions intensity of fuel used, including all emissions associated with fuel extraction, transporting to a processing plant, and processing [e.g. gCO2e/MJ] • Credits claimed to evaluate emissions of fuel reformed
Process	• SMR reactor type • Air separation technology and capacity • Syngas purification technology and capacity • Sulphur waste gas processing technology (if applicable) • Quantity and type of vented GHG gases [kg] • Quantity and type of flared GHG gases [kg] • Technology for monitoring fugitives from CO_2 storage and capacity • CO_2 capture rate of the unit [%]
Air separation	• Electricity/fuel consumption
Cooling	• Electricity consumption [MWh]
Compression of gases throughout the facility	• Electricity consumption [MWh]
Natural gas feedstock	• Type of NG • NG composition • Quantity of NG used for SMR reactions [kg] • Quantity of NG used for heating [kg] • Quantity of NG used for producing steam [kg] • upstream emission factor for NG [$kgCO_2e/kg$] (derived from primary and secondary data, provided by supplier or sourced from relevant source i.e. NGA Factors)[2]
Carbon dioxide treatment	• Type of CO_2 storage and capacity • Location of CO_2 storage • Transport type of CO_2 to storage location (if applicable) and distance (in km) • Quantity of CO_2 captured [kg] • Quantity of CO_2 stored [kg] • Quantity of fugitive emissions created during injection of CO_2 into the storage location [kg] • Quantity of fugitive CO_2 emissions from storage [kg] (in line with period covered by the reporting)
Waste and other Co-products	• Quantity of steam produced [kg] • Quantity of steam sold [kg] • Emissions allocated to steam [$kgCO_2e/kg$] • Quantity of electricity sold (MWh) • Emissions allocated to electricity sold [gCO_2e/kWh]

[2] Note that where upstream emissions are derived using upstream data, there may be a requirement for additional information. This could include items such as coal source.