



"Modelling of hydrogen supply chains for Germany in the E3-database"



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20 November 2006

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1 Acronyms

CCGT	Combined Cycle Gas Turbine
CCS	CO ₂ Capture and Storage
CGH ₂	Compressed Gaseous Hydrogen
CHP	Combined Heat and Power
FC	Fuel Cell
GHG	Green House Gas
ICE	Internal Combustion Engine
LH ₂	Liquefied Hydrogen
LNG	Liquefied Natural Gas
NG	Natural gas
PEMFC	Proton Exchange Membrane Fuel Cell
PR	Progress Ratio
PSA	Pressure Swing Adsorption
SMR	Steam Methane Reforming
WTT	Well-to-Tank
TTW	Tank-to-Wheel
WTW	Well-to-Wheel
WtStU	Well-to-Stationary Use

2 Methodology

The GHG emissions, the energy requirements and the costs of the supply of transportation fuel, electricity and heat have been carried out for a number of hydrogen energy chains using the E3 database tool. Initially as time horizon the year 2020 has been selected because it can be expected that in 2020 fuel cell vehicles as well as most of the hydrogen generation technologies are commercially available. Additionally the time horizon 2030 has been considered in order to take into account long term hydrogen production processes

Once the data were accepted they were incorporated in the E3 database.

The processes used in E3 database for the calculation of the hydrogen energy pathways also have been presented in the technology fact sheets (based on EXCEL: FACT_SHEETS_LBST_31Oct2006.xls). Additionally the different hydrogen related technologies are presented in a template for MARKAL (also based on EXCEL: Template_MARKAL_13-09-2006.xls) which is used as input for the calculations in MARKAL.

2.1 General

All calculations are based on the lower heating value (LHV).

Most of the processes already have been used in the CONCAWE/EUCAR/JRC study. Newly introduced processes are processes where CO₂ capture and storage is embodied, processes that describe stationary hydrogen fueled fuel cells, gas engines and gas turbines, and Norwegian specific processes (e.g. Norwegian NG supply). For the German pathways the following new processes have been introduced:

- Power Station / Wind / on-shore / Enercon E-66 / 20.70 (Germany)
- Power Station / Wind / off-shore (water depth 30 m)
- Electricity / Provision Mix D / PRIMES
- GH₂ / Electrolysis / Hydrogen Systems (small and large)
- GH₂ / DeOxo dryer (purity: 99.995%)
- GH₂ / NG / Steam Reforming / FW / CO₂-sequestration
- GH₂ / coal gasification / FW / CO₂ sequestration (hard coal)
- GH₂ / By-Product (Reference = NG)
- LH₂ / Tankstelle, Linde (small and large)
- FC / H₂ PEMFC / IRD w peak boiler
- Power Station / GH₂ / CCGT / ECN (CHP)
- Heat / NG / Hoval TopGas M condens (12)
- Heat+Electricity / Micro CHP System Single Family House

Furthermore different electrolyzers have been used (Stuart Energy instead of GHW). In the CONCAWE/EUCAR/JRC study only passenger vehicles have been considered. In HyWays also buses are taken into account.

Table 2-1: Selected pathways

No.	PE	Production	1 st Conversion	Transport Distribution	2 nd Conversion	End-use
1	NG	onsite SMR	-	-	CGH ₂ FS	FC/ICE car, (FC)
		central SMR(*)	- liquefaction **	pipeline LH ₂ truck	CGH ₂ FS LH ₂ FS	FC/ICE car, (FC/GT) FC/ICE car
2	WW/FW ¹	gasification	-	pipeline	CGH ₂ FS	FC/ICE car, (FC/GT)
3	offshore wind(EI-mix)	central electr.	-	pipeline	CGH ₂ FS	FC/ICE car, (FC/GT)
4	onshore wind(EI-mix)	onsite electr.	-	micro grid	CGH ₂ FS	FC/ICE car. (FC)
5	hard coal*	gasification	-	pipeline	CGH ₂ FS	FC/ICE car, (FC/GT)
			liquefaction ***	LH ₂ truck	LH ₂ FS	FC/ICE car
6	by-product	-	-	pipeline	CGH ₂ FS	FC/ICE car, (FC/GT)

¹ WW - waste wood, FW - farmed wood

* without and with CCS

** H₂ liquefaction with NG fueled CCGT

*** H₂ liquefaction with German electricity mix 2020

2.2 Conversion factors for Greenhouse Gas Equivalents

For the conversion of the different greenhouse gases (GHG) to CO₂ equivalents the following conversion factors have been used:

Table 2-2: Conversion factors [IPCC 2001]

	g CO ₂ equivalent per g
CO ₂	1
CH ₄	23
N ₂ O	296

2.3 Learning curves

Economic learning curves have been applied for technologies which will be produced at large numbers of units e.g. hydrogen filling stations, onsite electrolyzers and onsite steam reformers. The learning curve is defined by the following formula:

$$I = a \cdot N^{-b}$$

where

I = Investment of the Nth unit

a = Investment of the 1st unit

N = Number of units

b = Parameter

b ranges between 0.1 and 0.3. In some literature the so-called progress ratio (PR) is indicated. The progress ratio is used to express the progress of cost reductions for different technologies. The cost reduction is (1-PR) for each doubling of cumulative production. The progress ratio can be calculated by

$$PR = 2^{-b}$$

If the progress ratio (PR) is given the investment of the Nth unit can be calculated by

$$I = a \cdot N^{\frac{\ln(PR)}{\ln(2)}}$$

For the calculation of the fuel supply costs for the average investment per unit has to be considered. This means that e.g. if 10,000 hydrogen filling stations will be installed the investment of the 1st filling station as well as the investment of the last filling stations influences the fuel supply costs. Therefore for the cost calculation in E3 database the average investment has been used. The average investment can be calculated by integration of the formula for the learning curve:

$$A = \frac{a}{N} \cdot \int_1^N N^{-b} dN = \frac{a}{N} \cdot \left[\frac{1}{1-b} \cdot (N^{1-b} - 1) + 1 \right]$$

where A = average investment of one unit.

As a result the average investment is always higher than the investment of the Nth unit.

2.4 Scaling by size

The investment for volume related technologies (in contrast to surface related technologies e.g. photovoltaics) like coal power stations but also steam reforming plants and hydrogen liquefaction plants do not increase linearly with the size of the plants. The investment of a plant with a size required here can be calculated by

$$I_2 = I_1 \cdot \left(\frac{C_2}{C_1} \right)^{0.7}$$

where

I₁ = Investment of the plant with capacity C₁

I₂ = Investment of the plant with capacity C₂

C_1 = Capacity of plant 1

C_2 = Capacity of plant 2

3 Well-to-Tank (WTT) analysis

3.1 Chain 1: CGH₂ and LH₂ from NG SMR

Five variants has been investigated:

- a) CGH₂ from onsite steam methane reforming (SMR) without CO₂ capture and storage
- b) CGH₂ from large scale steam methane reforming (SMR) without CO₂ capture and storage (CCS)
- c) LH₂ from large scale steam methane reforming (SMR) without CO₂ capture and storage (CCS)
- d) CGH₂ from large scale steam methane reforming (SMR) with CO₂ capture and storage
- e) LH₂ from large scale steam methane reforming (SMR) with CO₂ capture and storage (CCS)

3.1.1 Chain 1 a): CGH₂ from onsite SMR

Natural gas (NG) from the EU natural gas mix is distributed via the regional and local natural gas pipeline grid to the filling station where the NG is converted to hydrogen via steam methane reforming (SMR).

Table 3-1: Input and output data for NG extraction and processing [Shell 2002], [ETSU 1996], [GEMIS]

	Input	Output
Natural gas [kWh/kWh]	1.024	1.000
CO ₂ [g/kWh]	-	4.1
CH ₄ [g/kWh]	-	0.3

The data for the high pressure (HP) natural gas distribution has been derived from [GEMIS 2002]. The costs for the supply of natural gas has been assumed to be 0.0284 € per kWh of natural gas in 2020 and 0.0373 € per kWh of natural gas in 2030 without distribution based on the WETO scenarios (45.1 US\$/bbl of oil equivalent in 2020 and 59.3 US\$/bbl of oil equivalent in 2030; LHV (crude oil) = 1590 kWh/bbl; 1 US\$ = 1 €).

Table 3-2: Input and output data for NG distribution (high pressure pipeline) over 250 km

	Input	Output
Mechanical work [kWh/kWh]	0.0015	-
NG [kWh/kWh]	1.000	1.000
CH ₄ emissions [g/kWh]	-	0.0011

The mechanical work is supplied by a gas turbine (efficiency: 30%). The costs for NG distribution via high pressure pipeline has been assumed to be 0.0004 EUR per kWh of natural gas as indicated in [CONCAWE 2006]¹. For the local NG distribution no energy requirements and no GHG emissions occur. But the local NG distribution leads to additional costs. The costs for the local natural gas distribution to the filling stations has assumed to be 0.0002 EUR per kWh of natural gas as indicated in [CONCAWE 2006].

Table 3-3 shows the technical and economic data of the onsite SMR for the 120 t/yr filling station. The technical data are derived from [Haldor Topsoe 1998] and the investment has been derived from [HyGear 2006]. The investment has been derived from a 500 Nm³/h plant by down and up scaling (scaling exponent: 0.7). The specific investment of a 500 Nm³/h plant is about 3000 €/(Nm³/h) and the specific investment of a 50 Nm³/h plant is about 6000 €/(Nm³/h).

Table 3-3: Onsite SMR for the 120 t/yr filling station [Haldor Topsoe 1998] [HyGear 2006]

	1998	2020	2030
Capacity [Nm ³ H ₂ /h]	222	222	222
NG consumption [kWh/kWh _{H2}]	1.441	1.441	1.441
Electricity consumption [kWh/kWh _{H2}]	0.016	0.016	0.016
CO ₂ emissions [g/kWh _{H2}]	292	292	292
CH ₄ emissions [g/kWh _{H2}]	0.075	0.075	0.075
Pressure (H ₂) [MPa]	1.5	1.5	1.5
Investment [EUR]	850,000	376,000 ¹⁾	339,000 ²⁾
Maintenance coefficient [% of investment]	1.0	1.0	1.0
Useful lifetime [yr]	15	15	15
Equivalent full load period [h/yr]	6,000	6,000	6,000

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

¹ in [CONCAWE 2006] only maintenance costs has been considered

Table 3-4: Technical and economic data for the 120 t/yr CGH₂ filling station for onsite SMR (suction pressure: 1.5 MPa)

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	120	120	120
Electricity consumption [kWh/kWh _{H₂}]	0.077	0.077	0.077
Investment [EUR]	591,000	273,000 ¹⁾	249,000 ²⁾
Maintenance [% of investment]	3.9	4.7	4.8
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

It has been assumed that in 2020 only small (120 t/yr) filling stations have been installed. In 2020 the cumulative number of filling stations is 10,000. In 2030 in the EU the cumulative number both of small (120 t/yr) and large (480 t/yr) filling stations in the EU is 28,000 (total: 56,000). The share of fuel output which comes from the larger filling station will be about 80% in 2030.

Table 3-5: Onsite SMR for the 480 t/yr filling station [Haldor Topsoe 1998], [HyGear 2006]

	1998	2030
Capacity [Nm ³ H ₂ /h]	889	889
NG consumption [kWh/kWh _{H₂}]	1.441	1.441
Electricity consumption [kWh/kWh _{H₂}]	0.016	0.016
CO ₂ emissions [g/kWh _{H₂}]	292	292
CH ₄ emissions [g/kWh _{H₂}]	0.075	0.075
Pressure (H ₂) [MPa]	1.5	1.5
Investment [€]	2243,000	895,000 ¹⁾
Maintenance coefficient [% of investment]	1.0	1.0
Useful lifetime [yr]	15	15
Equivalent full load period [h/yr]	6,000	6,000

¹⁾ average investment per unit when 28,000 units are installed

Table 3-6: Technical and economic data for the 480 t/yr CGH₂ filling station (suction pressure: 1.5 MPa)

	2004	2030
Annual fuel output [t H ₂ /yr]	480	480
Electricity consumption [kWh/kWh _{H₂}]	0.077	0.077
Investment [€]	2,272,000	955,000
Maintenance [% of investment]	3.9	4.7
Useful lifetime [yr]	20	20

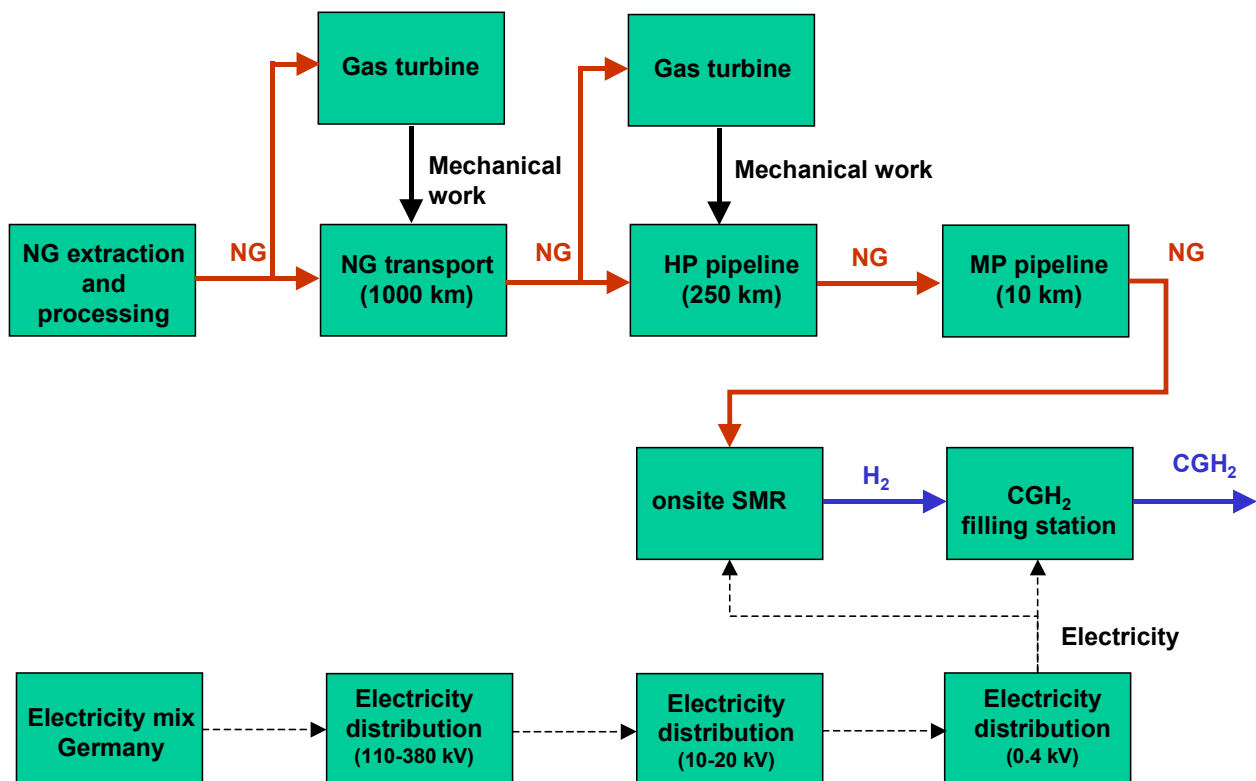
¹⁾ average investment per unit when 280,000 units are installed

The electricity requirement for the onsite steam reformer and the hydrogen compression at the filling station is met by the German electricity mix. The electricity mix has been derived from [PRIMES 2003]. The GHG emissions from the Germany electricity mix ex power plants amount to some 534 g/kWh in 2020 and 509 g/kWh in 2030.

Table 3-7: Costs of the electricity from German electricity mix in 2020 and for 2030 (0.4 kV) [RWE 1999]

	Efficiency distribution [%]	[EUR/kWh _e]
Electricity generation	-	0.030
Distribution (110-380 kV)	99.0	0.004
Distribution (10-20 kV)	99.3	0.020
Distribution (0.4 kV)	98.8	0.007
Total	97.1	0.061

Figure 3-1: CGH₂ from onsite steam reforming of NG



3.1.2 Chain 1 b): CGH₂ from central SMR

Natural gas (NG) from the EU natural gas mix is distributed via the regional natural gas pipeline grid to the SMR.

The costs for the supply of natural gas has been assumed to be 0.0284 € per kWh of natural gas in 2020 and 0.0373 € per kWh of natural gas in 2030 without distribution based on the WETO scenarios (45.1 US\$/bbl of oil equivalent in 2020 and 59.3 US\$/bbl of oil equivalent in 2030; LHV (crude oil) = 1590 kWh/bbl; 1 US\$ = 1 €). The costs for NG distribution via high pressure pipeline has been assumed to be 0.0004 EUR per kWh of natural gas as discussed above.

A large steam methane reformer with a capacity of 100,000 Nm³/h as described in [Linde 1992] has been used. The excess steam of this reformer is used for electricity generation. As a result the steam reformer generates excess electricity which replaces electricity from the German electricity mix.

Table 3-8: Technical and economic data of the SMR without CO₂ capture and storage [Linde 1992]

Capacity [Nm ³ H ₂ /h]	100,000
NG consumption [kWh/kWh _{H₂}]	1.417
Output excess electricity [kWh/kWh _{H₂}]	0.050
CO ₂ emissions [g/kWh _{H₂}]	288
CH ₄ emissions [g/kWh _{H₂}]	0.057
Investment [EUR]	78,000,000
Maintenance coefficient [% of investment]	3
Labor [EUR/yr]	600,000
Useful lifetime [yr]	20
Equivalent full load period [h/yr]	8,000

For the supply of CGH₂ the hydrogen is distributed via a hydrogen pipeline grid. The large steam methane reforming plant should most suitably be located close to large agglomerations e.g. large cities like Munich, Berlin or Hamburg. It has been assumed that the hydrogen grid consists of 10 larger pipelines with a throughput of 240 GWh H₂ per year and pipeline and some smaller pipelines with a throughput of 8 GWh H₂ per year and pipeline. (Figure 3-2).

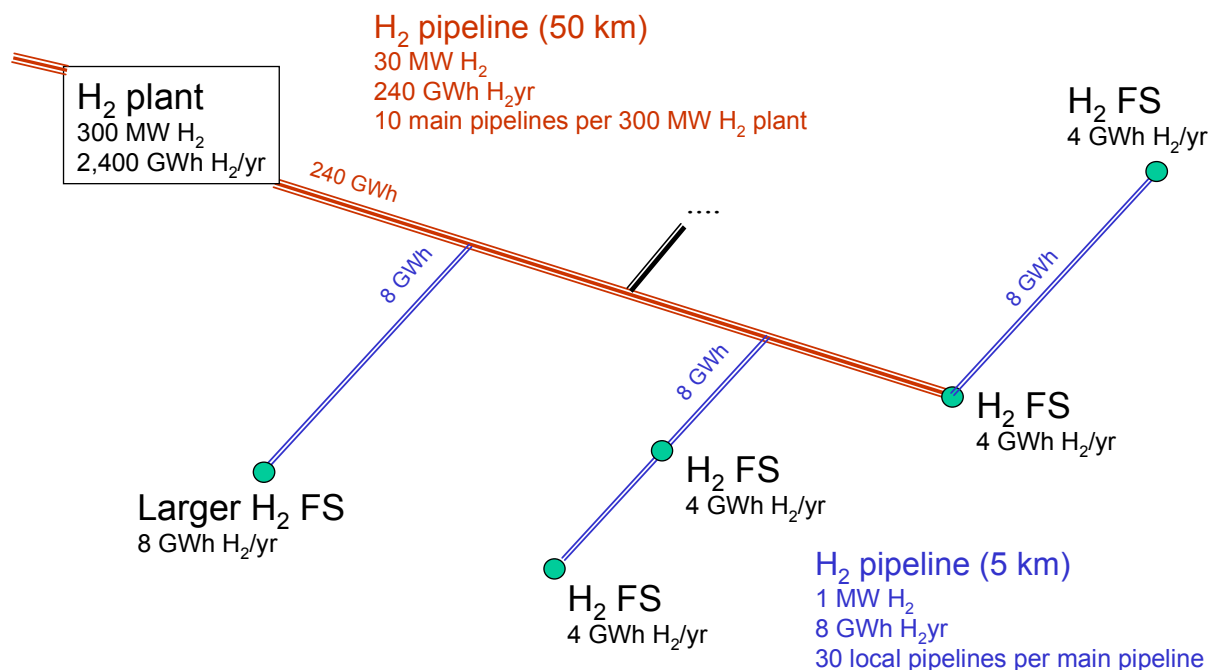
Figure 3-2: Pipeline grid for the large SMR plant without CO₂ capture and storage (CCS)

Table 3-9: Technical and economic data for a 50 km H₂ pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H ₂ /yr]	240
Diameter [mm]	150
Investment [EUR]	8,950,000
Labor, maintenance etc. [EUR/yr]	261,000
Useful lifetime [yr]	30

Table 3-10: Technical and economic data for a 5 km H₂ pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H ₂ /yr]	8
Diameter [mm]	100
Investment [EUR]	895,000
Labor, maintenance etc. [EUR/yr]	21,000
Useful lifetime [yr]	30

For the calculation it has been assumed that the annual fuel output per CGH₂ filling station amounts to some 4 million kWh per year (120 t H₂/yr). The larger filling station (480 t/yr) would need two 8 GWh/yr pipelines. The technical and economic data of the 120 t/yr CGH₂ filling station are shown in Table 3-11.

Table 3-11: Technical and economic data for the 120 t/yr CGH₂ filling station (suction pressure: 2.0 MPa)

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	120	120	120
Electricity consumption [kWh/kWh _{H2}]	0.070	0.070	0.070
Investment [EUR]	496,000	231,000 ¹⁾	211,000 ²⁾
Maintenance [% of investment]	2.7	3.7	3.7
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

Table 3-12: Technical and economic data for the 480 t/yr CGH₂ filling station (suction pressure: 2.0 MPa)

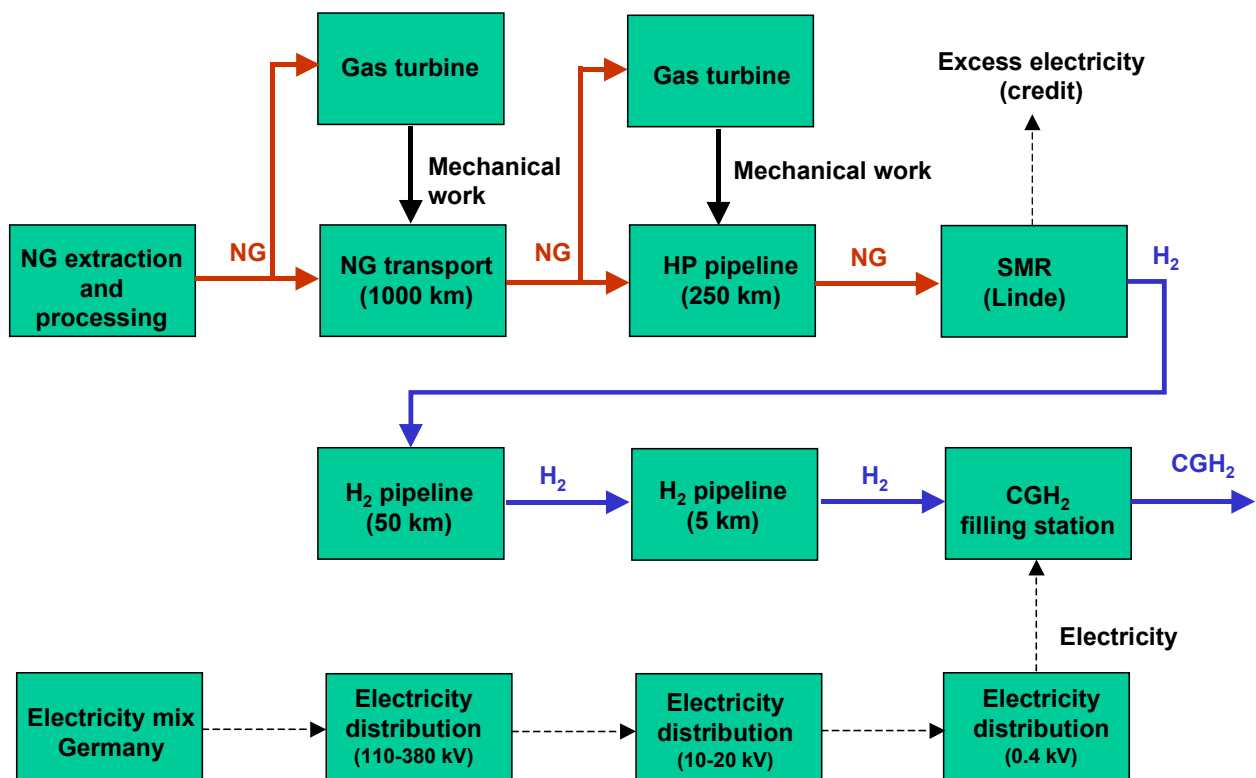
	2004	2030
Annual fuel output [t H ₂ /yr]	480	480
Electricity consumption [kWh/kWh _{H₂}]	0.070	0.070
Investment [EUR]	2,272,000	955,000 ¹⁾
Maintenance [% of investment]	3.6	4.6
Useful lifetime [yr]	20	20

¹⁾ average investment per unit when 28,000 units are installed

It has been assumed that in 2020 only small (120 t/yr) filling stations have been installed. In 2020 the cumulative number of filling stations is 10,000. In 2030 in the EU the cumulative number both of small (120 t/yr) and large (480 t/yr) filling stations in the EU is 28,000 (total: 56,000).

The electricity requirements for the CGH₂ filling station is met by the German electricity mix.

Figure 3-3: CGH₂ from large scale steam methane reforming (SMR) without CO₂ capture and storage (CCS)



3.1.3 Chain 1 c): LH₂ from central SMR

The same central steam methane reformer (SMR) as for the supply of CGH₂ from central steam methane reforming without CO₂ capture and storage has been used (see subchapter 3.1.2).

The electricity consumption for the hydrogen liquefaction has been assumed to be 0.3 kWh per kWh of LH₂ (LHV) for large hydrogen liquefaction plants in the near future as discussed within the CONCAWE/JRC/EUCAR study. The investment and the maintenance and labor costs has been derived from [NHEG 1992] via up scaling and has been agreed by [Linde 2004].

Table 3-13: H₂ liquefaction in 2020 [NHEG 1992], [TotalFinaElf 2002], [Linde 2004]

Capacity [MW _{LH2}]	300
H ₂ consumption [kWh/kWh _{LH2}]	1.0
Electricity consumption [kWh/kWh _{LH2}]	0.3
Investment [EUR]	239,000,000
Maintenance [% of investment]	2.5
Labor [EUR/yr]	1,230,000
Equivalent full load period [h/yr]	8,000
Useful lifetime [yr]	30

The electricity requirements for the hydrogen liquefaction is met by a natural gas fueled combined cycle gas turbine (CCGT) power plant (Table 3-14).

Table 3-14: Combined cycle gas turbine (CCGT) power plant [GEMIS 2002]

Fuel	NG
Capacity [MW _e]	450
Efficiency [%]	55
Investment [EUR]	196,000,000
Maintenance [% of investment]	3
Equivalent full load period [h/yr]	6,000
Useful lifetime [yr]	15
CO ₂ emissions [g/kWh _e]	361
CH ₄ emissions [g/kWh _e]	0.027
N ₂ O emissions [g/kWh _e]	0.016

The LH₂ has been distributed via truck (average distance in Germany: 150 km). The transport capacity of the LH₂ trailer is 3.5 t LH₂. Including the LH₂ tank the payload is

about 27 t and the gross weight is 40 t. The fuel consumption of the 40 t truck is about 3.5 kWh/km or 35 l diesel per 100 km.

The energy requirement and the GHG emissions for the supply of the diesel has been derived from [CONCAWE 2006]. The energy requirements for diesel supply are about 1.16 kWh per kWh of diesel. The GHG emissions amount to about 51.5 g/kWh of diesel (incl. combustion: 315.5 g/kWh of diesel).

In [Linde 2001] a scenario for the installation of 343 hydrogen filling stations at Germany motorways has been investigated. One variant was a filling station which is capable to refuel CGH₂ and LH₂ vehicles. The filling station in [Linde 2001] has two dispensers, one for LH₂ and one for CGH₂. For HyWays the technical and economic data for the LH₂ part has been used to calculate the investment for a LH₂ filling station with one dispenser and a fuel output of 115 t LH₂ per year.

For the stationary LH₂ storage at the filling station the half of the investment of the LH₂ storage of the combined LH₂/LCGH₂ filling station (270,000 EUR for 343 filling stations) has been used. The LH₂ filling station consists of a LH₂ tank (135,000 EUR), a LH₂ pump (51,000 EUR) and a LH₂ dispenser (37,000 EUR). Further other investment e.g. for installation, engineering etc. has been added (50,000 EUR). As a result the total investment for the LH₂ part is 273,000 EUR for the case when 343 filling stations would be installed. Then a learning curve has been applied to trace back the investment from the 343 filling stations to the 1st filling station and to calculate the average investment for the LH₂ filling stations for 10,000 installed units. The result is shown in Table 3-15.

Table 3-15: Technical and economic data for the 120 t/yr LH₂ filling station [Linde 2001]

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	115	115	115
Electricity consumption [kWh/kWh _{H₂}]	0.0007	0.0007	0.0007
Investment [EUR]	440,700	194,900 ¹⁾	175,900 ²⁾
Maintenance [% of investment]	2.0	2.0	2.0
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

It has been assumed that in 2030 also larger filling stations will be installed. The larger LH₂ filling station consist of one LH₂ tank, 4 LH₂ pumps and 4 LH₂ dispensers and has a fuel output of 460 t LH₂ per year. The number of 460 t/yr filling stations is also 28,000.

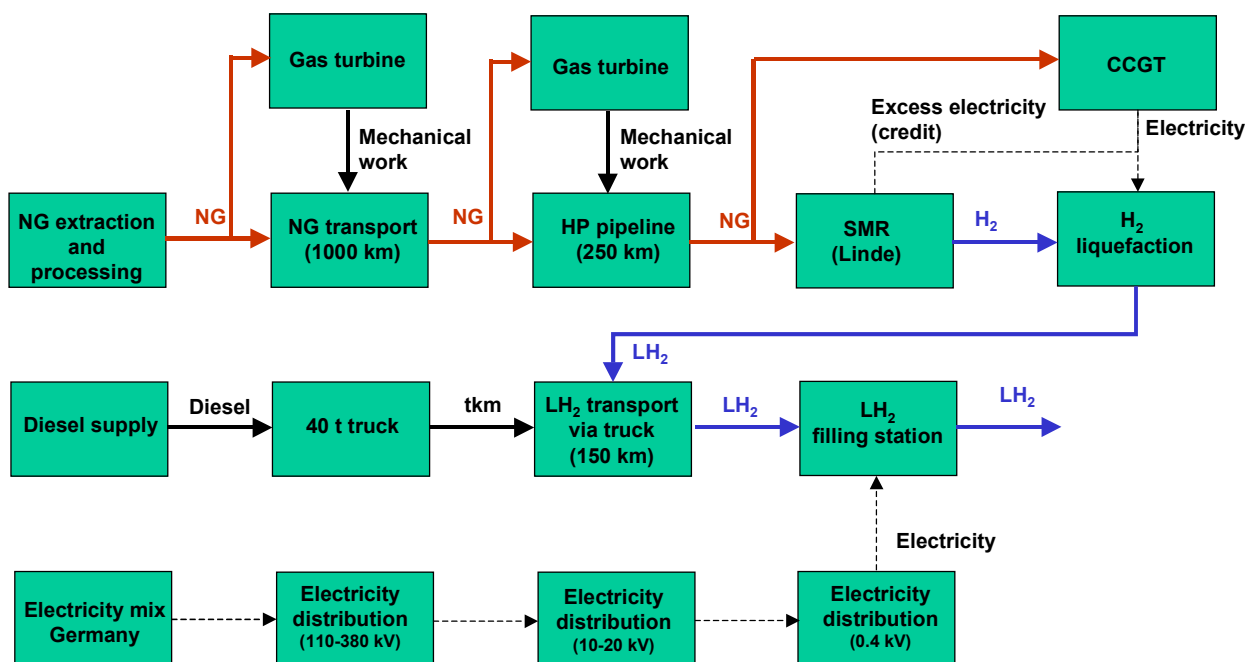
Table 3-16: Technical and economic data for the 460 t/yr LH₂ filling station [Linde 2001]

	2004	2030
Annual fuel output [t H ₂ /yr]	460	460
Electricity consumption [kWh/kWh _{H₂}]	0.0007	0.0007
Investment [€]	1,327,000	529,600 ¹⁾
Maintenance [% of investment]	2.0	2.0
Useful lifetime [yr]	20	20

¹⁾ average investment per unit when 28,000 units are installed

The electricity consumption of the CGH₂ filling station in Germany is met by the German electricity mix in 2020.

Figure 3-4: LH₂ from large scale steam methane reforming (SMR) without CO₂ capture and storage (CCS)



3.1.4 Chain 1 d): CGH₂ from central SMR with CO₂ capture and storage

In this pathway the supply of CGH₂ from central steam methane reforming of natural gas with CO₂ capture and storage has been investigated. The steam methane reformer (SMR) with CO₂ capture and storage (CCS) has been derived from a study carried out by Foster Wheeler [Foster Wheeler 1996]. The CO₂ capture, extraction and compression is included. The CO₂ capture is carried out via scrubbing process using aMDEA (activated methyl diethanol amine) The CO₂ is compressed to a pressure of approximately 11 MPa which leads to liquefaction. The CO₂ is transported via pipeline in liquid state. The CO₂ is injected into depleted natural gas and oil fields. The SMR plant is located at the coast. The plant consists of 3 single

units (each 94,000 Nm³ H₂/h). In contrast to the Linde SMR the Foster Wheeler plant has no electricity export.

Table 3-17: Technical and economic data of the SMR with CO₂ capture and storage [Foster Wheeler 1996]

Capacity [Nm ³ H ₂ /h]	281,300
NG consumption [kWh/kWh _{H2}]	1.365
CO ₂ emissions [g/kWh _{H2}]	42.7
CH ₄ emissions [g/kWh _{H2}]	0.057
Investment [EUR]	453,090,000
Maintenance coefficient [% of investment]	1.5
Labor [EUR/yr]	546,400
Overhead [% of investment]	0.1
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

A part of the hydrogen is exported and another part is used in the region. It has been assumed that the hydrogen grid consists of a larger pipeline with a throughput of 240 GWh H₂ per year and some smaller pipelines with a throughput of 8 GWh H₂ per year.

Figure 3-5: Pipeline grid for the large SMR plant with CO₂ capture and storage (CCS)

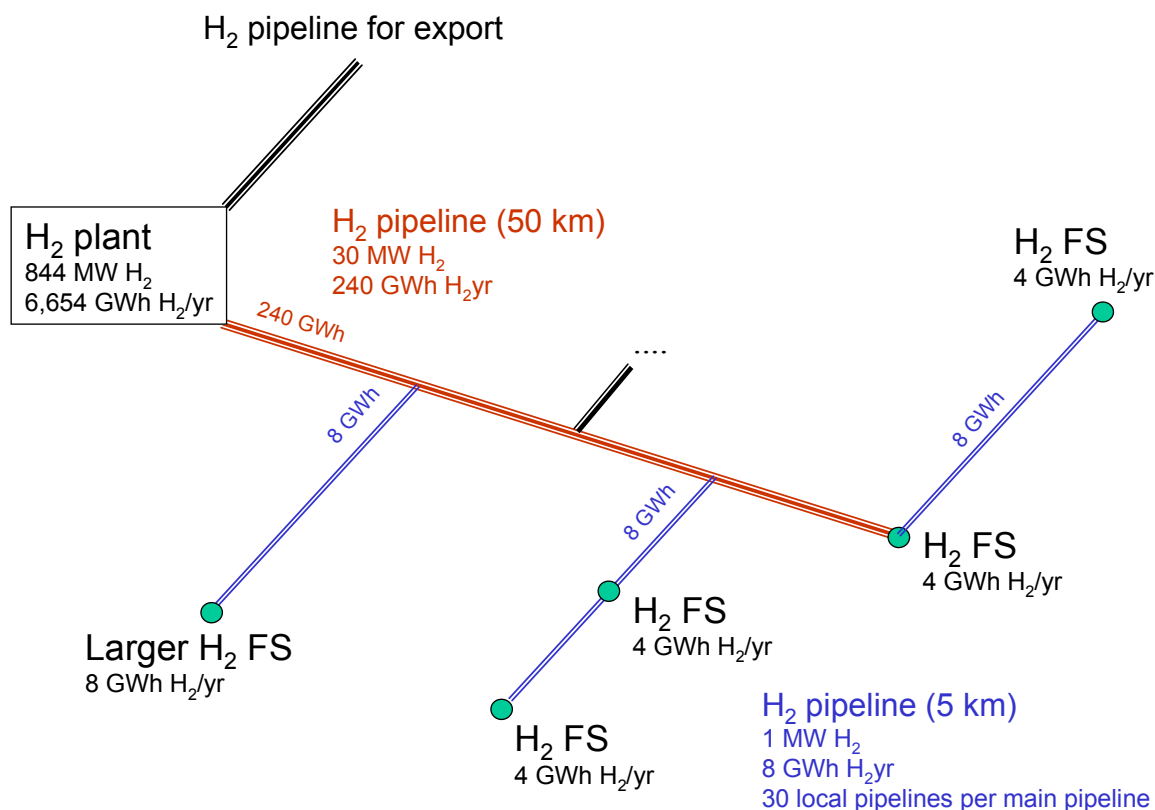


Table 3-18: Technical and economic data for a 50 km H₂ pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H ₂ /yr]	240
Diameter [mm]	150
Investment [EUR]	8,950,000
Labor, maintenance etc. [EUR/yr]	261,000
Useful lifetime [yr]	30

Table 3-19: Technical and economic data for a 5 km H₂ pipeline [Tschauder 1998]

Annual hydrogen throughput [GWh H ₂ /yr]	8
Diameter [mm]	100
Investment [EUR]	895,000
Labor, maintenance etc. [EUR/yr]	21,000
Useful lifetime [yr]	30

The technical and economic data of the 120 t/yr CGH₂ filling station are shown in Table 3-20.

Table 3-20: Technical and economic data for the CGH₂ filling station (suction pressure: 2.0 MPa)

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	120	120	120
Electricity consumption [kWh/kWh _{H₂}]	0.070	0.070	0.070
Investment [EUR]	496,000	231,000 ¹⁾	211,000 ²⁾
Maintenance [% of investment]	2.7	3.7	3.7
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000

A significant number of larger filling stations (480 t H₂/yr) will be installed in 2030.

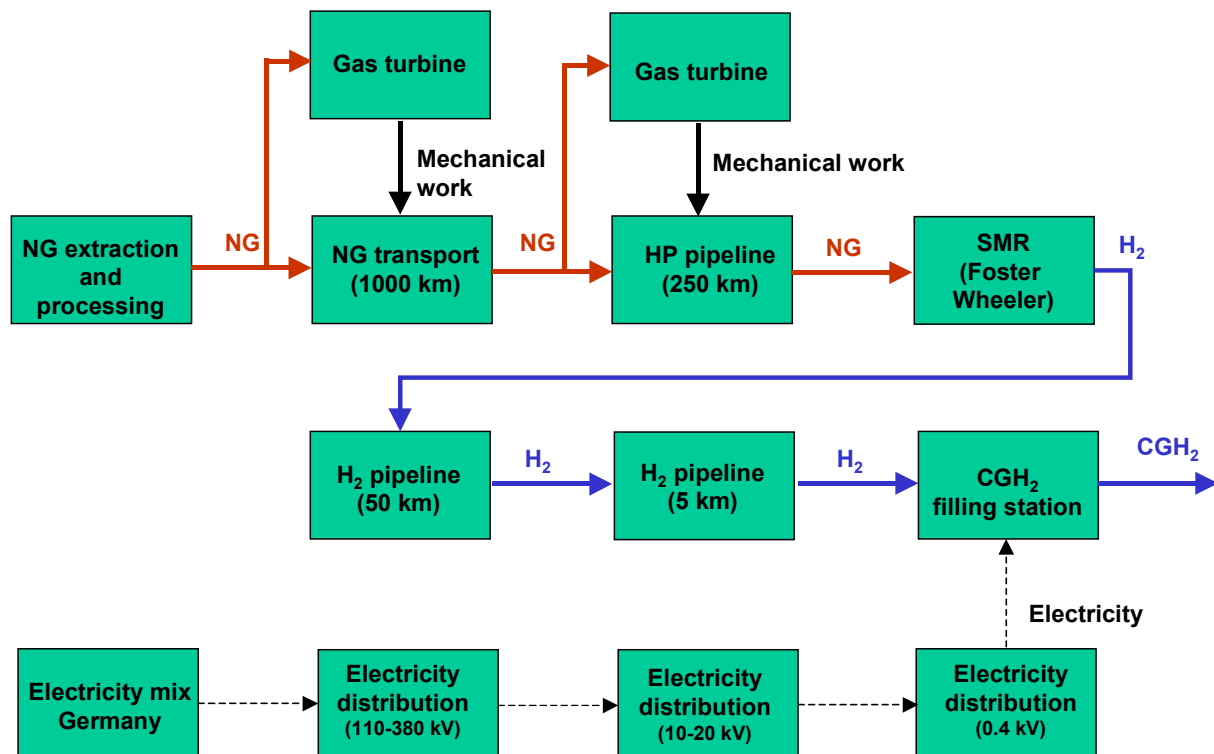
Table 3-21: Technical and economic data for the 480 t/yr CGH₂ filling station (suction pressure: 2.0 MPa)

	2004	2030
Annual fuel output [t H ₂ /yr]	480	480
Electricity consumption [kWh/kWh _{H₂}]	0.070	0.070
Investment [EUR]	2,272,000	955,000 ¹⁾
Maintenance [% of investment]	3.6	4.6
Useful lifetime [yr]	20	20

¹⁾ average investment per unit when 28,000 units are installed

The electricity requirements for the CGH₂ filling station is met by the German electricity mix.

Figure 3-6: CGH₂ from large scale steam methane reforming (SMR) with CO₂ capture and storage (CCS)



3.1.5 Chain 1 e): LH₂ from central SMR with CO₂ capture and storage

The same steam methane reformer as for the supply of CGH₂ from central steam reforming with CO₂ capture and storage has been used (see subchapter 3.1.4).

The electricity consumption for the hydrogen liquefaction has been assumed to be 0.3 kWh per kWh of LH₂ (LHV) for large hydrogen liquefaction plants in the near future as discussed within the CONCAWE/JRC/EUCAR study. The investment and the maintenance and labor costs has been derived from [NHEG 1992] via up scaling and has been agreed by [Linde 2004].

Table 3-22: H₂ liquefaction in 2020 [NHEG 1992], [TotalFinaElf 2002], [Linde 2004]

Capacity [MW _{LH₂}]	300
H ₂ consumption [kWh/kWh _{LH₂}]	1.0
Electricity consumption [kWh/kWh _{LH₂}]	0.3
Investment [EUR]	239,000,000
Maintenance [% of investment]	2.5
Labor [EUR/yr]	1,230,000
Equivalent full load period [h/yr]	8,000
Useful lifetime [yr]	30

The electricity requirements for the hydrogen liquefaction is met by a natural gas fueled combined cycle gas turbine (CCGT) power plant (Table 3-23).

Table 3-23: Combined cycle gas turbine (CCGT) power plant [GEMIS 2002]

Fuel	NG
Capacity [MW_e]	450
Efficiency [%]	55
Investment [EUR]	196,000,000
Maintenance [% of investment]	3
Equivalent full load period [h/yr]	6,000
Useful lifetime [yr]	15
CO_2 emissions [g/ kWh_e]	361
CH_4 emissions [g/ kWh_e]	0.027
N_2O emissions [g/ kWh_e]	0.016

The LH_2 has been distributed via truck (average distance in Germany: 150 km). The transport capacity of the LH_2 trailer is 3.5 t LH_2 . Including the LH_2 tank the payload is about 27 t and the gross weight is 40 t. The fuel consumption of the 40 t truck is about 3.5 kWh/km or 35 l diesel per 100 km.

The energy requirement and the GHG emissions for the supply of the diesel has been derived from [CONCAWE 2006]. The energy requirements for diesel supply are about 1.16 kWh per kWh of diesel. The GHG emissions amount to about 51.5 g/kWh of diesel (incl. combustion: 315.5 g/kWh of diesel).

In [Linde 2001] a scenario for the installation of 343 hydrogen filling stations at Germany motorways has been investigated. One variant was a filling station which is capable to refuel CGH_2 and LH_2 vehicles. The filling station in [Linde 2001] has two dispensers, one for LH_2 and one for CGH_2 . For HyWays the technical and economic data for the LH_2 part has been used to calculate the investment for a LH_2 filling station with one dispenser and a fuel output of 115 t LH_2 per year.

For the stationary LH_2 storage at the filling station the half of the investment of the LH_2 storage of the combined $\text{LH}_2/\text{LCGH}_2$ filling station (270,000 EUR for 343 filling stations) has been used. The LH_2 filling station consists of a LH_2 tank (135,000 EUR), a LH_2 pump (51,000 EUR) and a LH_2 dispenser (37,000 EUR). Further other investment e.g. for installation, engineering etc. has been added (50,000 EUR). As a result the total investment for the LH_2 part is 273,000 EUR for the case when 343 filling stations would be installed. Then a learning curve has been applied to trace back the investment from the 343 filling stations to the 1st filling station and to calculate the average investment for the LH_2 filling stations for 10,000 installed units. The result is shown in Table 3-24.

Table 3-24: Technical and economic data for the 120 t/yr LH₂ filling station [Linde 2001]

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	115	115	115
Electricity consumption [kWh/kWh _{H2}]	0.0007	0.0007	0.0007
Investment [EUR]	440,700	194,900 ¹⁾	175,900 ²⁾
Maintenance [% of investment]	2.0	2.0	2.0
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

It has been assumed that in 2030 also larger filling stations will be installed. The larger LH₂ filling station consist of one LH₂ tank, 4 LH₂ pumps and 4 LH₂ dispensers and has a fuel output of 460 t LH₂ per year. The number of 460 t/yr filling stations is also 28,000.

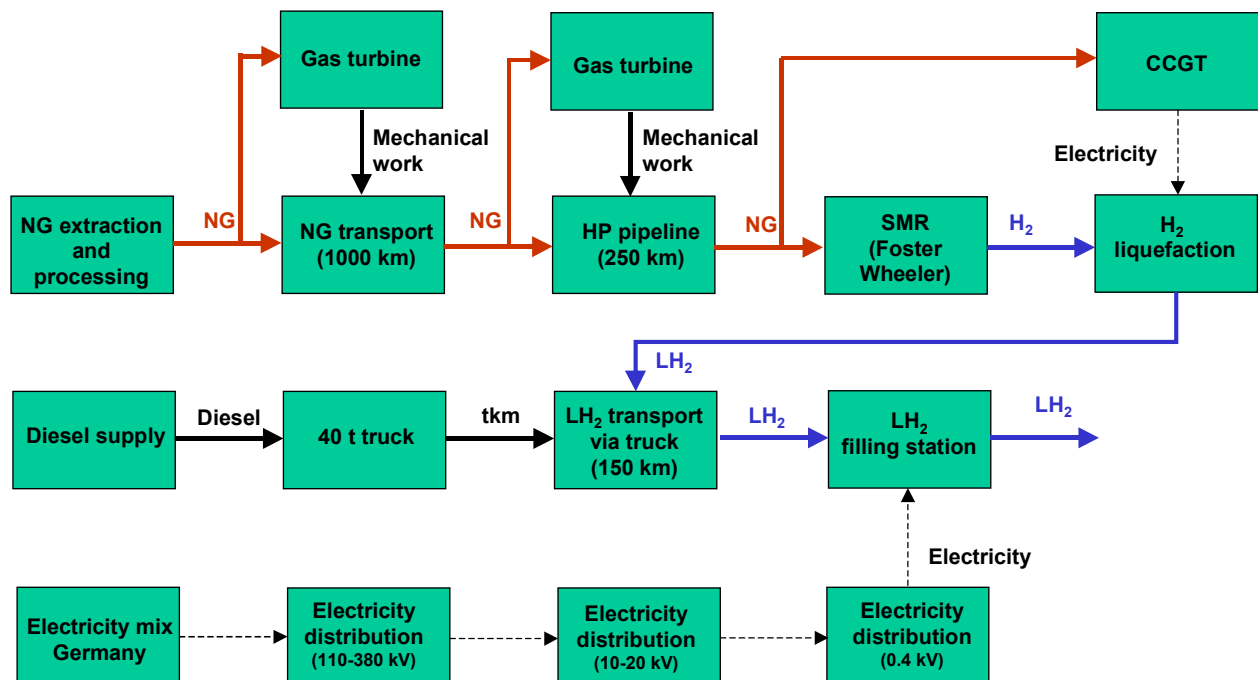
Table 3-25: Technical and economic data for the 460 t/yr LH₂ filling station [Linde 2001]

	2004	2030
Annual fuel output [t H ₂ /yr]	460	460
Electricity consumption [kWh/kWh _{H2}]	0.0007	0.0007
Investment [€]	1,327,000	529,600 ¹⁾
Maintenance [% of investment]	2.0	2.0
Useful lifetime [yr]	20	20

¹⁾ average investment per unit when 28,000 units are installed

The electricity consumption of the LH₂ filling station in Germany is met by the German electricity mix in 2020.

Figure 3-7: LH₂ from large scale steam methane reforming (SMR) with CO₂ capture and storage (CCS)



3.2 Chain 2: CGH₂ from woody biomass

In this pathway woody biomass is used as feed-stock. Two variants have been considered:

- CGH₂ from residual wood
- CGH₂ from wood plantation

3.2.1 Residual wood

Wood residues are generated in the process of timber harvesting and of thinning after reforestation, in the timber processing industry (carpentry shops, furniture producers etc.) and as wood waste e.g. from used furniture. The wood is chipped at the source and then transported to the gasification plant by truck. The average transport distance for the transport of the wood chips is assumed to be 50 km.

The diesel consumption for wood chipping is indicated with 0.3 to 0.5% of the energy content (LHV) of the wood [Hartmann 1995].

3.2.2 Wood plantation

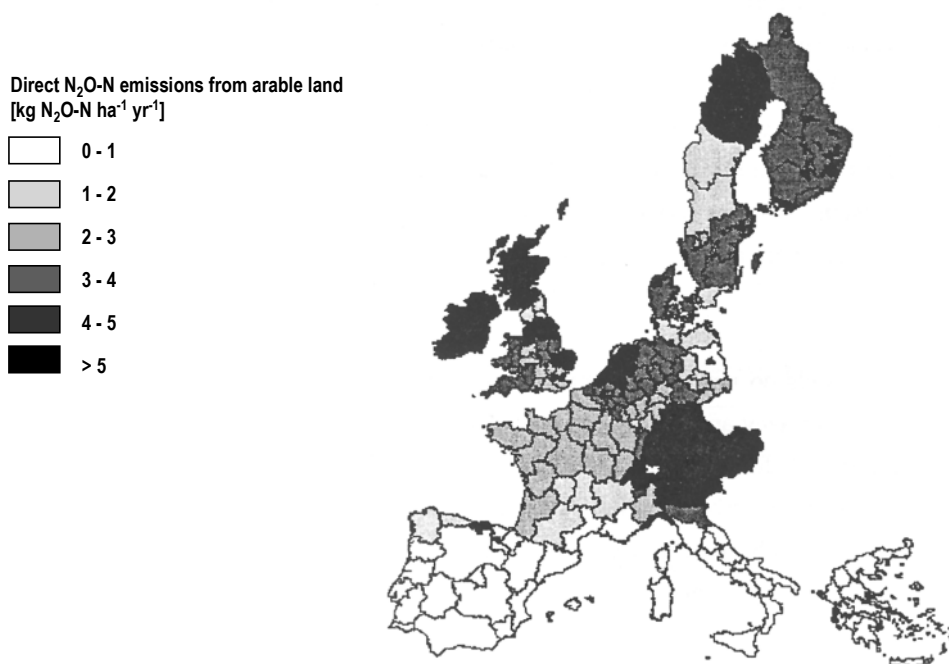
In contrast to the previous chapter (CGH₂ from residual biomass) woody biomass from plantation of poplar or willow is used here. The harvested woody biomass is chipped at the plantation site. Subsequently, the wood chips are transported to the gasification plant by truck (average distance: 50 km).

Besides the N₂O emissions from the production of synthetic nitrogen (N) fertilizer the plantation of crops causes direct N₂O emissions at the field. According to IPCC [IPCC 1/1996], [IPCC 2/1996] all kinds of fertilizers have to be considered for the calculation of the direct emissions of N₂O: the synthetic fertilizer-N as well as N-input by the crop residues and the N-input by N-fixing crops.

The formation and decomposition of N₂O in soils depend on various controlling parameters. The main factors are aeration, water content and availability of N and organic material. Apart from that the amount of N₂O emitted from soils is influenced by their physical characteristics. Measurements lead to the conclusion that there is a strong relationship between the soil texture and the de-nitrification activity. Fine-textured soils (clay soils and silty soils) can maintain a higher water content for a longer time than coarse textured soils (sandy soils). Clay soils have a higher potential for N₂O formation. On the other hand N₂O formed within the soil can also be reduced to N₂ when diffusion is slow due to high water content in fine textured soils. Fine-textured soils seem to emit more N₂O than sandy soils, but this tendency can be masked or reversed by other factors, especially climate and soil management practices.

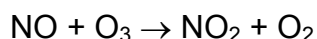
Other factors which influence the N₂O emissions from soils are freezing and thawing, drying and rewetting [Kamp 2000].

Figure 3-8: Direct N₂O emissions from arable land



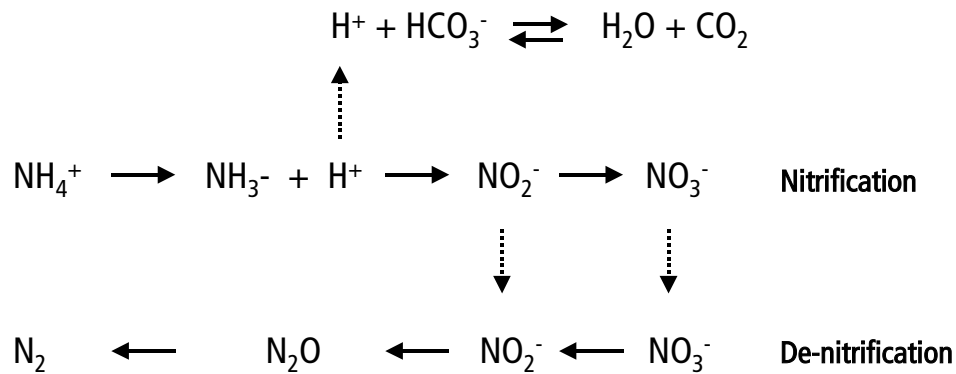
Source: Freibauer, A., Kaltschmitt, Institut für rationelle Energieanwendungen (IER), Stuttgart: Biogenic Greenhouse Gas Emissions from Agriculture in Europe, European Summary Report of the EU Concerted Action FAIR3-CT96-1877, financed by EU DG VI, February 2001

But the direct emissions of N₂O are only one part of the total emissions of N₂O from agricultural land. The indirectly emitted N₂O is also considered here. A part of the fertilizer-N is emitted as NH₃ and NO_x and is leached e.g. as NO₃ which is subsequently deposited on soils and surface waters. Atmospheric deposition of nitrogen compounds such as NO_x and NH₃ fertilizes soils and surface waters and as such enhances the biogenic N₂O formation. In soils and waters bacteria oxidize the NH₄⁺ (which is formed from the NH₃ in the soil) to nitrate (NO₃⁻) (nitrification) while some amounts of N₂O are formed. The NO_x (consisting of NO and NO₂) emitted from soils is converted to HNO₃ in the atmosphere according to the following reactions:





The HNO_3 is then deposited on soil and surface waters by rainfall ("acid rain"). In soils and water the HNO_3 is dissolved into H^+ and NO_3^- . Then the NO_3^- which is also formed by the nitrification of NH_4^+ is partly reduced to N_2O (de-nitrification). The conversion in the soil occurs in several stages according to the following reactions:



The same reactions occur with NO_x emitted by fuel combustion e.g. in truck engines. This source of N_2O is neglected here for the fuel supply processes such as the transport of wood chips. Here only the NO_x from fertilizer use is considered.

In contrast to the direct N_2O emissions only the input of synthetic fertilizer-N and the input of N from manure (N excreted by animals) has to be considered for the calculation of the indirect amount of N_2O (from N leaching and N from NH_3 and NO_x emitted). There are no emissions of NO_x and NH_3 from N of N-fixing crops or from N derived from the use of crop residues here.

The plantation of poplar is more similar to forestry than to agriculture. The behavior of soils in forests might be different to agricultural soils. For the calculation of the hydrogen supply from gasification of woody biomass from poplar plantation the energy requirements have been derived from [GEMIS 2002].

If the biomass yield were assumed to be 10 t of dry matter the amount of N-fertilizer (expressed as kg N) is indicated with 20 to 30 kg per ha and year [Murach 2003]. In [CONCAWE 1/2003] the fertilizer requirement has assumed to be 25 kg per ha and year. The direct N_2O emissions has been derived from [Flesse 1998] and the indirect N_2O emissions has been calculated according to the guidelines described in [IPCC 1/1996].

Table 3-26: Poplar plantation

	Input	Output
Woody Biomass [kWh/kWh _{wood}]	1.0000	1.0000
Mechanical work [kWh/kWh _{wood}]	0.0015	-
N fertilizer [kg/kWh _{wood}]	0.00049	-
N ₂ O [g/kWh _{wood}]	-	0.0123

The mechanical work is supplied by a diesel engine (efficiency: 30%).

Table 3-27: Energy requirements for the supply of N-fertilizer [Kaltschmitt 1997]

Hard coal	1.097 kWh/kg _N
Diesel oil	0.239 kWh/kg _N
Electricity (10-20 kV level)	0.174 kWh/kg _N
Heavy fuel oil	1.217 kWh/kg _N
NG	9.167 kWh/kg _N

Table 3-28: Emissions from the supply of N-fertilizer [Kaltschmitt 1997]

CO ₂	2468 g/kg _N
CH ₄	0.45 g/kg _N
N ₂ O	9.63 g/kg _N

The electricity requirements are met by the German electricity mix (110 kV). For the natural gas requirement the EU natural gas mix and the requirement of hard coal the EU hard coal mix has been used.

3.2.3 Wood chipping

In case of residual woody biomass from forestry the wood is chipped nearby the forest via mobile wood chipper. In case of wood plantation the wood is chipped during harvesting.

Table 3-29: Wood chipping

	Input	Output
Woody Biomass [kWh/kWh _{wood}]	1.025	1.000
Diesel [kWh/kWh _{wood}]	0.004	-
CO ₂ [g/kWh _{wood}]	-	1.06

The costs of biomass supply both from residual wood and wood from short rotation forestry without transport has been assumed to be 30 US\$ per barrel of oil equivalent leading to about 0.0189 €/kWh of biomass in 2020. In 2030 the biomass costs are assumed to be 35 US\$ per barrel oil equivalent leading to about 0.0220 €/kWh of biomass.

3.2.4 Transport of wood chips

The wood chips are transported to the gasification plant via a 40 t truck. The maximum payload ranges between 80 and 100 m³ and between 22 and 27 t [Kaltschmitt 2001]. A manufacturer of trailers for the transport of biomass indicates a maximum payload of 90 to 92 m³ [Fahrzeugbau Langendorf 2001]. The water content of the wood chips is assumed to be 30%. The bulk density of wood ranges between 0.24 and 0.33 t/m³. For the calculation of this pathway a payload of 26 t wood chips has been assumed.

3.2.5 Hydrogen generation

For the gasification an indirectly heated gasifier based on the so-called „staged reforming“ with a biomass input of 10 MW_{th} has been assumed. The data has been derived from DM2 [DM2 2001]. To provide pure hydrogen a CO-shift stage and a PSA plant has been added. The tail gas of the PSA is used for electricity generation via a gas engine.

Table 3-30: Syngas generation via gasification (10 MW_{th}) [DM2 2001]

	Input	Output
Wood chips [MW]	10.03	-
Electricity [MW]	0.19	-
Syngas [MW]	-	7.67
Heat [MW]	-	0.50
CH ₄ [g/kWh _{syngas}]	-	0.028
N ₂ O [g/kWh _{syngas}]	-	0.008

The investment for the gasifier is indicated with about 6,490,000 €. After 500 installed units the investment will be about 3,500,000 €. The average investment of the 500

units is 3,900,000 €. The 3,900,000 € have been used as average investment in 2030.

The lifetime is assumed to be 20 years. The maintenance is about 3% of the investment per year. The labor costs amount to about 179,000 € per year.

The gasifier is operated at about 0.1 MPa (ambient pressure). After dust removal the syngas (a mixture of H₂, CO, CO₂ and small amounts of CH₄) is compressed to about 2 MPa before it is fed into the CO shift stage.

Table 3-31: Syngas compression and CO shift

	Input	Output
Syngas [kWh/kWh _{H2}]	1.036	-
Electricity [kWh/kWh _{H2}]	0.072	-
H ₂ [kWh/kWh _{H2}]	-	1.000

The investment for the CO shift including syngas compression is indicated with about 1,453,000 EUR. The lifetime is assumed to be 20 years.

The gas at the outlet of the CO shift stage consists of H₂, CO₂ and small amounts of CH₄ and non-reacted CO. The generation of pure hydrogen is carried out via pressure swing adsorption (PSA).

Table 3-32: Pressure Swing Adsorption (PSA)

	Input	Output
H ₂ (diluted) [kWh/kWh _{H2}]	1.424	-
H ₂ (pure) [kWh/kWh _{H2}]	-	1.000
Tail gas (syngas) [kWh/kWh _{H2}]	-	0.424

The investment for the PSA is about 445,000 EUR [QuestAir 2003]. The lifetime is assumed to be 20 years.

The tail gas is fed into a gas engine for heat and electricity generation (efficiency electricity generation: 34%). The hydrogen recovery rate of the pressure swing adsorption plant depends on the composition of the feed gas and the pressure. The pressure drop of the PSA is below 0.1 MPa. Furthermore, the larger the specific volume of adsorbent (volume per Nm³ of hydrogen throughput) the larger is the hydrogen recovery rate, and the higher is the investment.

Table 3-33: Gas engine [GEMIS 2002], [Jenbacher 2002]

Capacity [kW_e]	588
Tailgas (syngas) input [kWh/kWh_e]	2.941
Heat output [kWh/kWh_e]	1.500
Investment [EUR]	588,000
Maintenance [% of investment]	10
Equivalent full load period [h/yr]	7,500
Useful lifetime [yr]	20

For the calculation of the credit for heat export the technical data of an existing wood chips fueled heating plant have been used. The plant is located in Hesse, Germany.

Table 3-34: Biomass fueled heating plant for credit calculation [GEMIS 2002]

	Input	Output
Wood chips [MW_{heat}]	2.059	-
Electricity [MW_e]	0.035	-
Heat [MW_{th}]	-	1.750

The pressure at the outlet of the PSA is about 2 MPa. The hydrogen is transported to the CGH_2 filling stations via a H_2 pipeline (distance: 5 km, throughput: 8 GWh/yr). The pressure drop during the pipeline transport can be neglected.

Figure 3-9: CGH₂ from gasification of residual wood

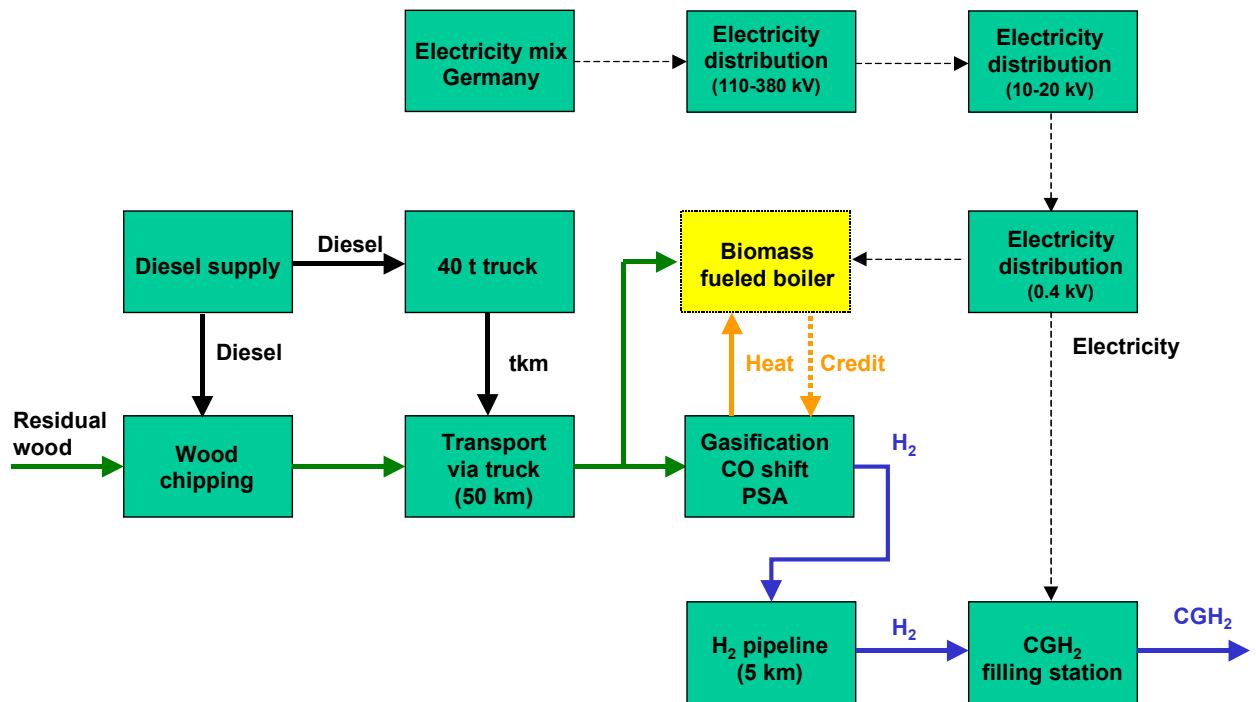
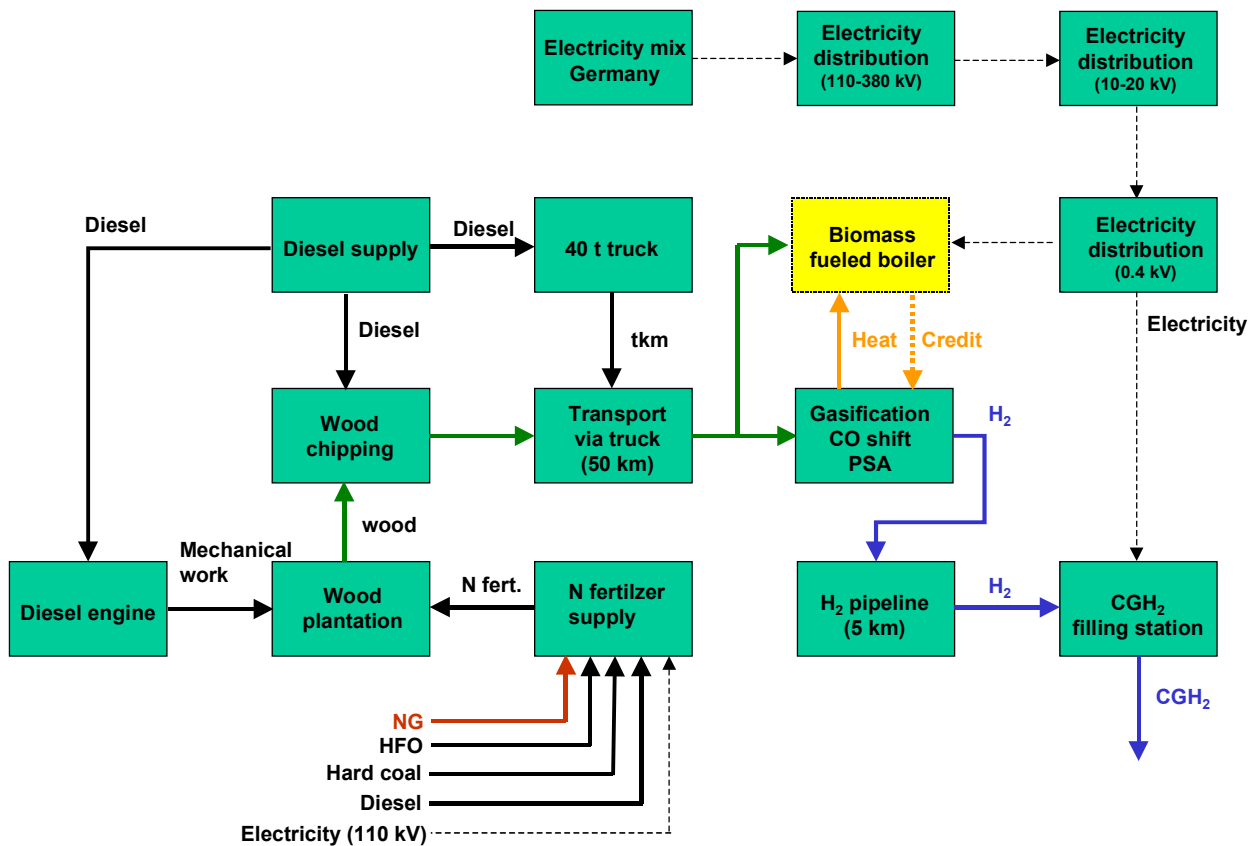


Figure 3-10: CGH₂ from gasification of wood chips from wood plantation



3.3 Chain 3: CGH₂ via central electrolysis

In this pathway hydrogen is generated in a large central electrolysis plant and then distributed via a hydrogen pipeline grid.

Two variants has been considered

- a) Electricity from offshore wind power
- b) Electricity from the German electricity mix

3.3.1 Offshore wind power

An offshore wind installation typically consists of 100 to 1,000 single wind turbines. The water depth can be up to 40 m.

The investment of the offshore wind power installation in Middelgrunden in Denmark which has a total capacity of 40 MW and which is already in operation has been indicated with 49,000,000 € leading to 1,250 €/kW. But the wind turbines are rather close to the coast (2-3 km) and as a result the water depth in Middelgrunden is low (2-6 m). The investment of the offshore wind power installation at Horns Rev (160 MW; water depth: 6.5-13.5 m; distance from coast: more than 17 km) is indicated with about 280 million € or about 1,700 €/kW including grid connection [Renewable Energy World 2002]. Table 3-35 shows the technical and economic data of existing offshore wind farms.

Table 3-35: Technical and economic data of existing offshore wind farms

	Unit	Blyth	Middlegrunden	Horns Rev	Kentish Flats	Scroby sands
Country		UK	Denmark	Denmark	UK	UK
Location		North Sea	Baltic Sea	North Sea	North Sea	North Sea
Capacity per unit	MW	2	2	2	3	2
Number of wind converters		2	20	80	30	30
Capacity	MW	4	40	160	90	60
Distance from coast up to	km		2	20	10	2.5
Water depth up to	m		5	14	5	12
In operation since year		2000	2001	2002	2005	2005
Electricity generation	GWh/yr	10.5	89	600	285	
Equivalent full load period	h/yr	2625	2225	3750	3167	
Investment	G€	6	49	270	158	113
Specific investment	EUR/kW	1500	1225	1688	1750	1875

According to the Department of Trade and Industry in UK the investment can be expected to be about 1,200 € per kW of installed capacity in 2010. In [NREL 2004] the investment for offshore wind power is expected to be about 800 €/kW. For wind farms not close to the coast an investment of 1200 €/kW for 2010 seems to be too low.

As a rough estimate it has been assumed that the investment for large offshore wind power installations at a water depth of 30 m is assumed to be 1,200 €/kW in 2020 and about 800 €/kW in 2030.

Table 3-36: Technical and economic data for offshore wind power in 2020 and 2030

	2020	2030
Capacity per wind turbine [MW]	4.5	4.5
Water depth [m]	30	30
Investment [EUR]	5,400,000 ¹⁾	3,600,000 ¹⁾
Maintenance [% of investment]	4	4
Useful lifetime [yr]	25	25
Equivalent full load period [h/yr]	3,000	3,000

¹⁾ incl. additional costs (foundation, grid connection etc.)

The electricity is distributed to the central electrolysis plant via the high voltage (110-380 kV) grid.

3.3.2 German electricity mix 2020 and 2030

Table 3-37: Input and output data for the German electricity mix without transport and distribution in 2020 and 2030 [PRIMES 2003]

	I/O	Unit	2020	2030
Biomass	Input	kWh/kWh	0.060	0.075
Lignite	input	kWh/kWh	0.569	0.535
Coal hard	Input	kWh/kWh	0.569	0.535
Crude oil	Input	kWh/kWh	0.005	0.004
Hydro	Input	kWh/kWh	0.038	0.035
NG	Input	kWh/kWh	0.662	0.657
Nuclear	Input	kWh/kWh	0.146	0.000
Wind power	Input	kWh/kWh	0.107	0.130
Electricity	Output	kWh	1.000	1.000
CO ₂ emissions	Output	g/kWh	534	509

The electricity is transported to the central electrolysis plant via the high voltage (110-380 kV) grid.

Table 3-38: Costs of the electricity from German electricity mix in 2020 (110-380 kV) [RWE 1999]

	Efficiency distribution [%]	[EUR/kWh _e]
Electricity generation	-	0.030
Distribution (110-380 kV)	99.0	0.004
Total	99.0	0.034

3.3.3 Hydrogen generation, distribution and dispensing

The central electrolysis plant consist of a large number of electrolyzer units with a capacity of 800 Nm³/h each. If the total hydrogen generation capacity of the central electrolysis plant were 100,000 Nm³/h the number of 800 Nm³/h units would be 125. As a first approach for the central electrolysis no learning curve has been applied for the investment.

Table 3-39: Technical and economic data for the electrolyzer used for central hydrogen generation [Stuart Energy 2004]

Capacity [Nm ³ H ₂ /h]	800
Electricity consumption [kWh/kWh _{H₂}]	1.433
Pressure [MPa]	3.0
Investment [EUR]	2,200,000
Maintenance [% of investment]	0.9
Useful lifetime [yr]	20
Equivalent full load period [h/yr]	8,000

The hydrogen is distributed via a hydrogen pipeline grid similar to the CGH₂ supply via central large steam methane reforming without CO₂ capture and storage (main pipeline: 50 km, small pipeline: 5 km. Further the same CGH₂ filling station has been used (suction pressure: 2. MPa). The electricity requirement for the filling station is met by the German electricity mix (0.4 kV) both for hydrogen from wind power and from the German electricity mix.

Figure 3-11: CGH₂ from offshore windpower (offshore) via central water electrolysis

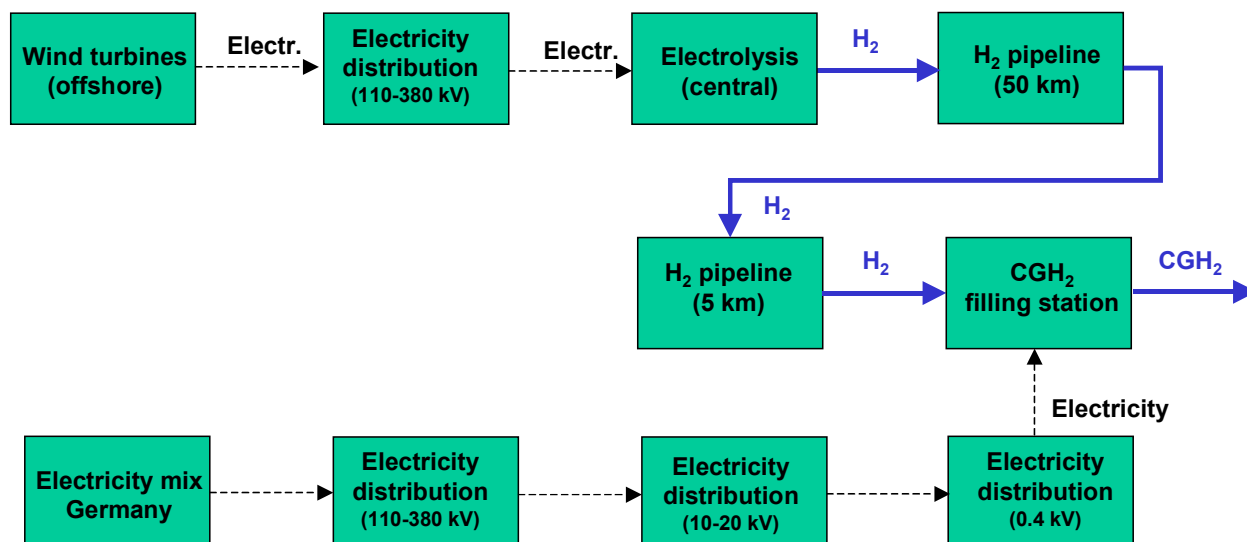
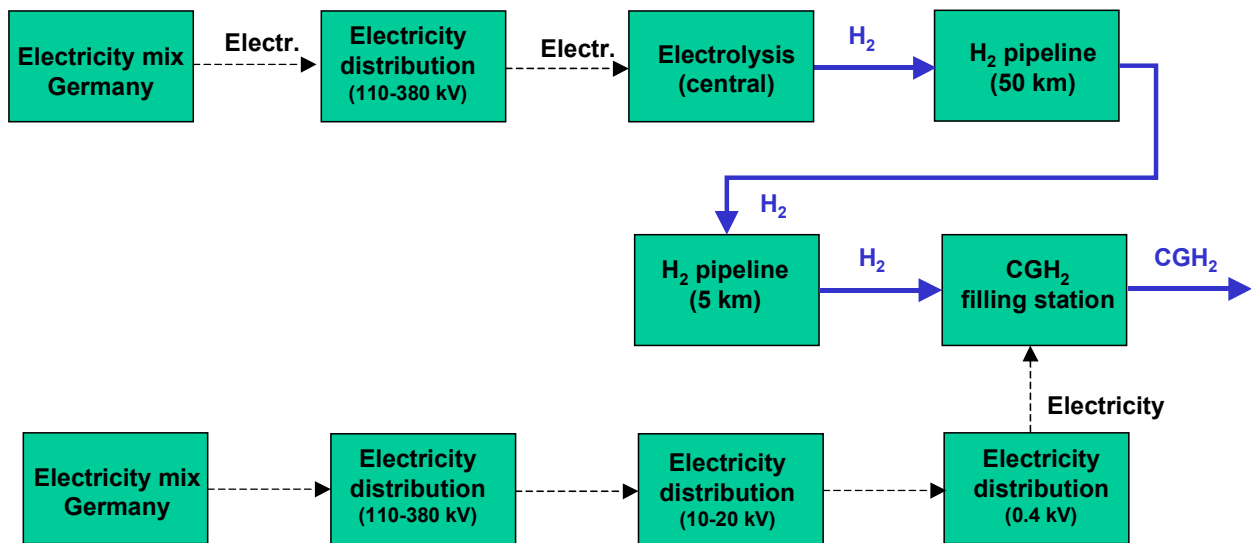


Figure 3-12: CGH₂ from German electricity mix via central water electrolysis

3.4 Chain 4: CGH₂ via onsite electrolysis

The electric power is distributed via the high voltage (110 kV and above) and the medium high voltage (10 kV to 20 kV) to the filling stations. The electrolysis plant is located onsite the filling station. In case of the 120 t/yr filling station the hydrogen is compressed from 2.6 MPa (pressure at the outlet of the electrolyzer) to 88 MPa for refueling of 70 MPa vehicle tanks. In case of the 480 t/yr filling station the suction pressure is 3.0 MPa.

Three variants has been considered:

- Electricity from wind power (onshore)
- Electricity from German electricity grid

3.4.1 Electricity from wind power

The cost data of the wind turbine for 2004 has been derived from an Enercon model E-66 / 20.70. The investment in Table 3-36 includes the additional investment which has been assumed to be 28% of the investment for the wind turbine alone. The investment for the Enercon wind turbine with a tower height of 84 m is indicated with 1,785,000 EUR [Windenergie 2004].

For 2020 a learning curve has been assumed based on the EWEA target for the installed capacity in 2020 in the EU (180 GW). In 2004 about 30 GW already has been installed in the EU 25. The progress ratio for wind power installations is indicated with 0.80 to 0.85. For the calculation a progress ratio of 0.85 has been assumed until 2020 and a progress ratio of 0.90 has been assumed between 2020 and 2030. The cumulative installed capacity in 2020 in the EU has been assumed to be 180 GW in 2020 and 300 GW in 2030.

Table 3-40: Technical and economic data of the wind turbine (onshore) installed in Germany [Windenergie 2004]

	2004	2020	2030
Capacity [MW]	2	2	2
Investment [EUR]	2,284,800 ¹⁾	1,501,062 ¹⁾	1,400,000 ¹⁾
Maintenance [% of investment]	1.5	1.5	1.5
Overhead [% of investment]	3.5	3.5	3.5
Useful lifetime [yr]	25	25	25
Equivalent full load period [h/yr]	1,800	1,800	1,800

¹⁾ incl. additional costs (foundation, grid connection etc.)

It has to be noted that the latest models of wind turbines have a higher equivalent full load period than the previous ones because of better aerodynamic and higher towers. The electricity generated by the wind turbines is distributed via the German electricity grid. The CGH₂ filling station is connected to the medium high voltage (10-20 kV) grid.

3.4.2 Electricity from German electricity mix

Variant b) and c) used electricity from the German electricity mix. The costs of electricity for variant b) are shown in Table 3-41.

Table 3-41: Costs of the electricity from German electricity mix in 2020 and in 2030 (10-20 kV) [RWE 1999]

	Efficiency distribution [%]	[EUR/kWh _e]
Electricity generation	-	0.030
Distribution (110-380 kV)	99.0	0.004
Distribution (10-20 kV)	99.3	0.020
Total	98.3	0.054

In 2006 the electricity price was significantly higher (about 0.05 €/kWh). Therefore it can be expected that the electricity price in 2020 and 2030 might be higher than the electricity price assumed in HyWays.

3.4.3 Hydrogen generation and dispensing

For the small filling station (120 t H₂/yr) two 120 Nm³/h electrolyzer units are used. For the larger filling station (480 t H₂/yt) one 800 Nm³/h electrolyzer is used.

Table 3-42: Technical and economic data for the electrolyzer used for onsite hydrogen generation for the 120 t/yr CGH₂ filling station [Stuart Energy 2004]

	2004	2020	2030
Capacity [Nm ³ H ₂ /h]	120	120	120
Electricity consumption [kWh/kWh _{H₂}]	1.600	1.600	1.600
Pressure [MPa]	2.6	2.6	2.6
Investment [EUR]	614,500	271,800 ¹⁾	228,800 ²⁾
Maintenance [% of investment]	0.9	0.9	0.9
Useful lifetime [yr]	20	20	20
Equivalent full load period [h/yr]	6,000	6,000	6,000

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 56,000 units are installed (28,000 small fillings stations, 2 electrolyzer units per 120 t/yr filling station)

Table 3-43: Technical and economic data for the CGH₂ filling station (suction pressure: 2.6 MPa)

	2004	2020	2030
Annual fuel output [t H ₂ /yr]	120	120	120
Electricity consumption [kWh/kWh _{H₂}]	0.065	0.065	0.065
Investment [EUR]	496,000	231,000 ¹⁾	211,000 ²⁾
Maintenance [% of investment]	2.7	3.7	3.9
Useful lifetime [yr]	20	20	20

¹⁾ average investment per unit when 10,000 units are installed; ²⁾ average investment per unit when 28,000 units are installed

It has been assumed that in 2020 only small filling stations have been installed. In 2030 in the EU the cumulative number both of small and large filling stations is 28,000 (total: 56,000).

Table 3-44: Technical and economic data for the electrolyzer used for onsite hydrogen generation for the 480 t/yr CGH₂ filling station [Stuart Energy 2004]

	2004	2030
Capacity [Nm ³ H ₂ /h]	800	800
Electricity consumption [kWh/kWh _{H₂}]	1.433	1.433
Pressure [MPa]	3.0	3.0
Investment [€]	2,200,000	878,000 ¹⁾
Maintenance [% of investment]	0.9	0.9
Useful lifetime [yr]	20	20
Equivalent full load period [h/yr]	6,000	6,000

¹⁾ average investment per unit when 28,000 units are installed

Table 3-45: Technical and economic data for the 480 t/yr CGH₂ filling station (suction pressure: 3.0 MPa)

	2004	2030
Annual fuel output [t H ₂ /yr]	480	480
Electricity consumption [kWh/kWh _{H₂}]	0.062	0.062
Investment [€]	2,272,000	955,000 ¹⁾
Maintenance [% of investment]	3.6	4.6
Useful lifetime [yr]	20	20

¹⁾ average investment per unit when 28,000 units are installed

In contrast to the small filling station the larger filling station has a separate primary compressor. Therefore the investment of the larger filling station is more than 4 times of that of the smaller one. For the smaller filling station it has been assumed that the booster compressor also is used for the recharging of the stationary hydrogen storage. This layout is possible if the number of cars to be refueled is low e.g. at the introduction phase.

Figure 3-13: CGH₂ from wind power (onshore) via onsite water electrolysis

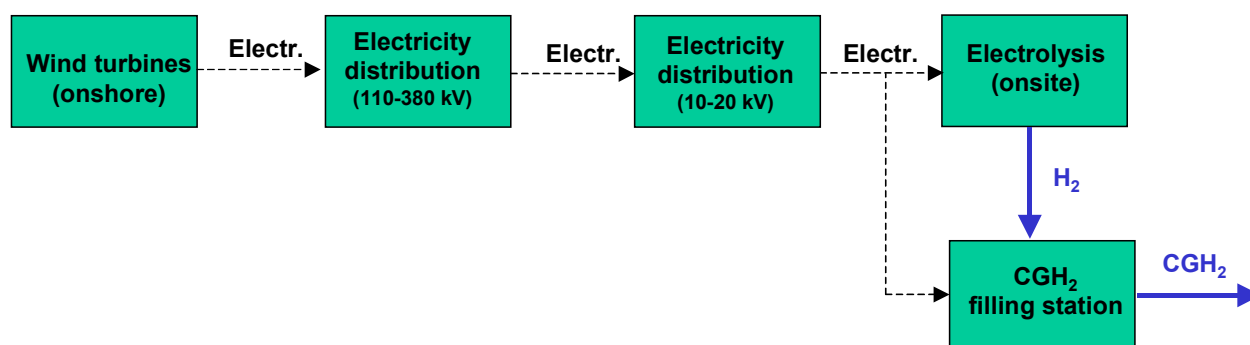
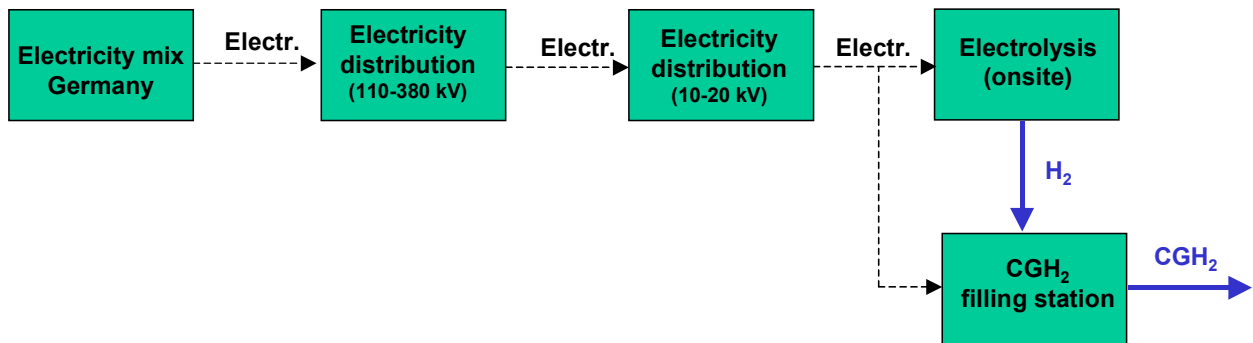


Figure 3-14: CGH₂ from German electricity mix via onsite water electrolysis

3.5 Chain 5: CGH₂ and LH₂ from hard coal via gasification

In this pathway hydrogen is generated via large scale gasification of hard coal with CO₂ capture and sequestration. The hard coal is derived from the EU hard coal mix. The hard coal price is assumed to be 0.0091 €/kWh of coal (14.5 US\$ per barrel of oil equivalent) for 2020 and 0.0106 €/kWh of coal (16.9 US\$ per barrel of oil equivalent) for 2030.

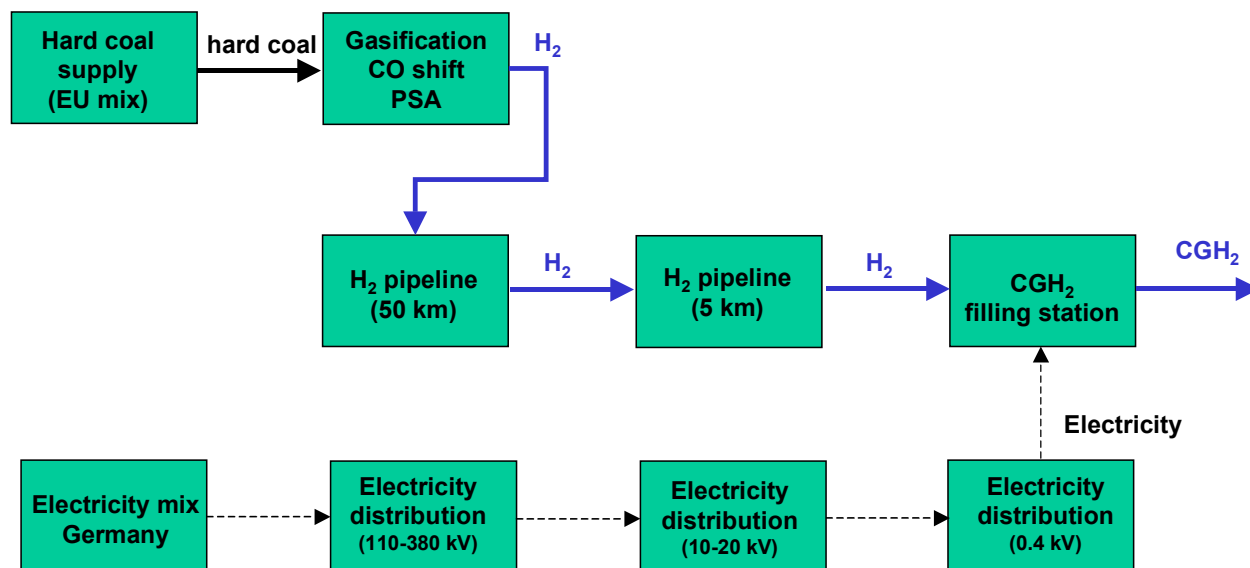
The plant is located nearby empty natural gas field (e.g. in Northern Germany) where the CO₂ is stored.

Table 3-46: Technical and economic data of hydrogen generation via coal gasification with CO₂ capture and storage [Foster Wheeler 1996]

Capacity [Nm ³ H ₂ /h]	281,600
Hard coal consumption [kWh/kWh _{H2}]	2.303
CO ₂ emissions [g/kWh _{H2}]	20.3
Investment [EUR]	1,168,100,000
Maintenance coefficient [% of investment]	3.57
Labor [EUR/yr]	1090,000
Overhead [% of investment]	0.07
Useful lifetime [yr]	25
Equivalent full load period [h/yr]	7,884

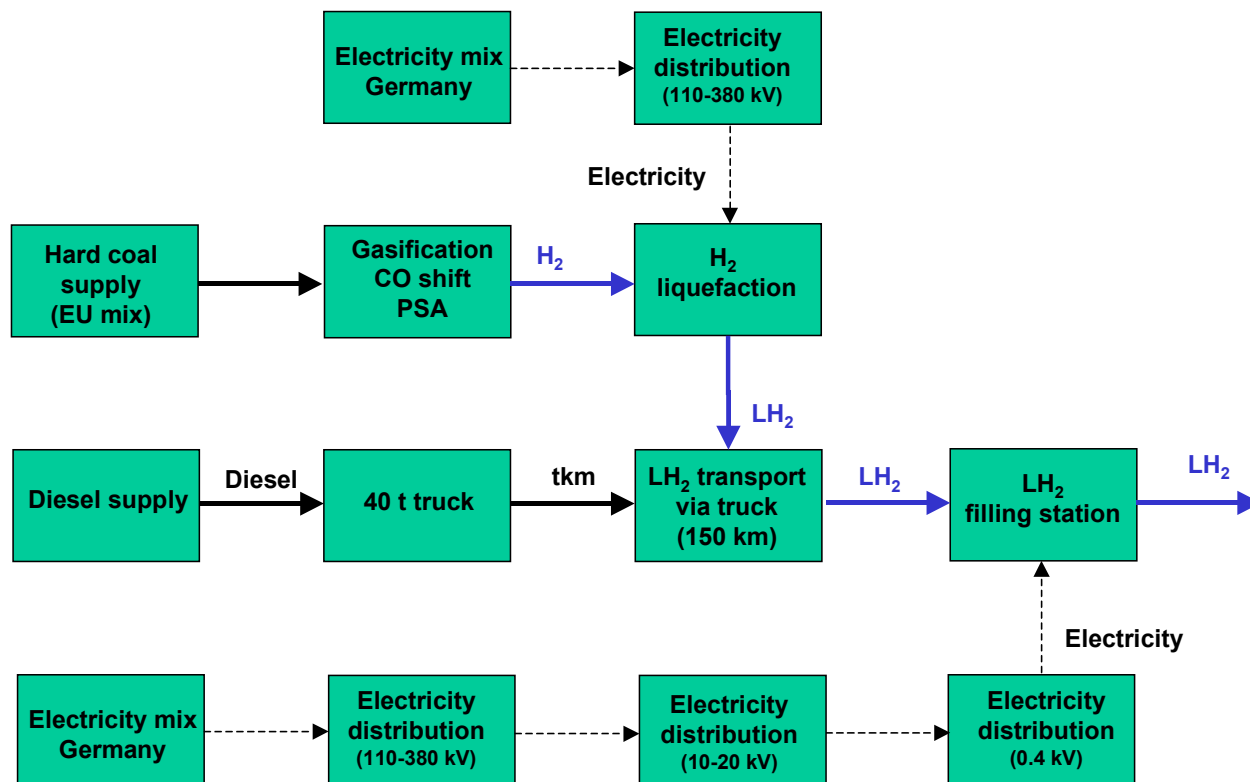
For the supply of CGH₂ the hydrogen is distributed via a hydrogen pipeline grid. At the CGH₂ filling station the hydrogen pressure is 2.0 MPa.

Figure 3-15: CGH₂ from hard coal gasification with CO₂ capture and storage



For the supply of LH₂ the hydrogen is liquefied in a large hydrogen liquefaction plant (electricity consumption: 0.3 kWh per kWh of LH₂). The electricity for the hydrogen liquefaction is derived from the German electricity mix in 2020 (110-380 kV). Then the LH₂ is distributed via truck (average distance: 150 km) and dispensed at a LH₂ filling station.

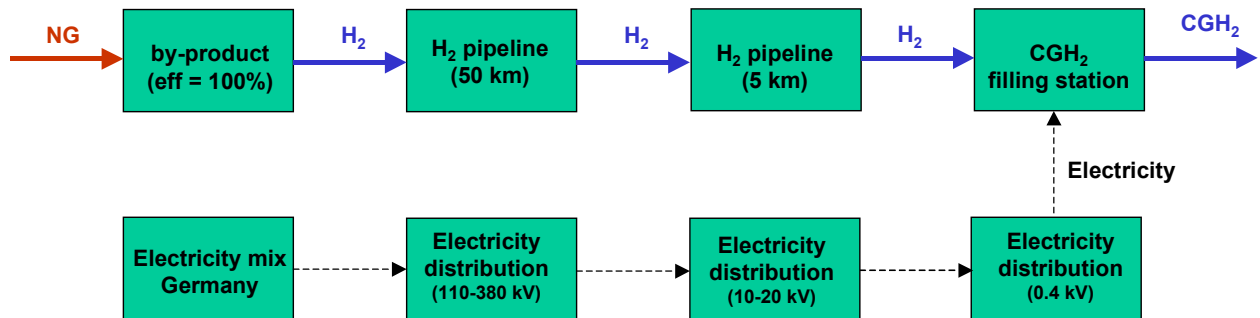
Figure 3-16: LH₂ from hard coal gasification with CO₂ capture and storage



3.6 Chain 6: CGH₂ from byproduct H₂

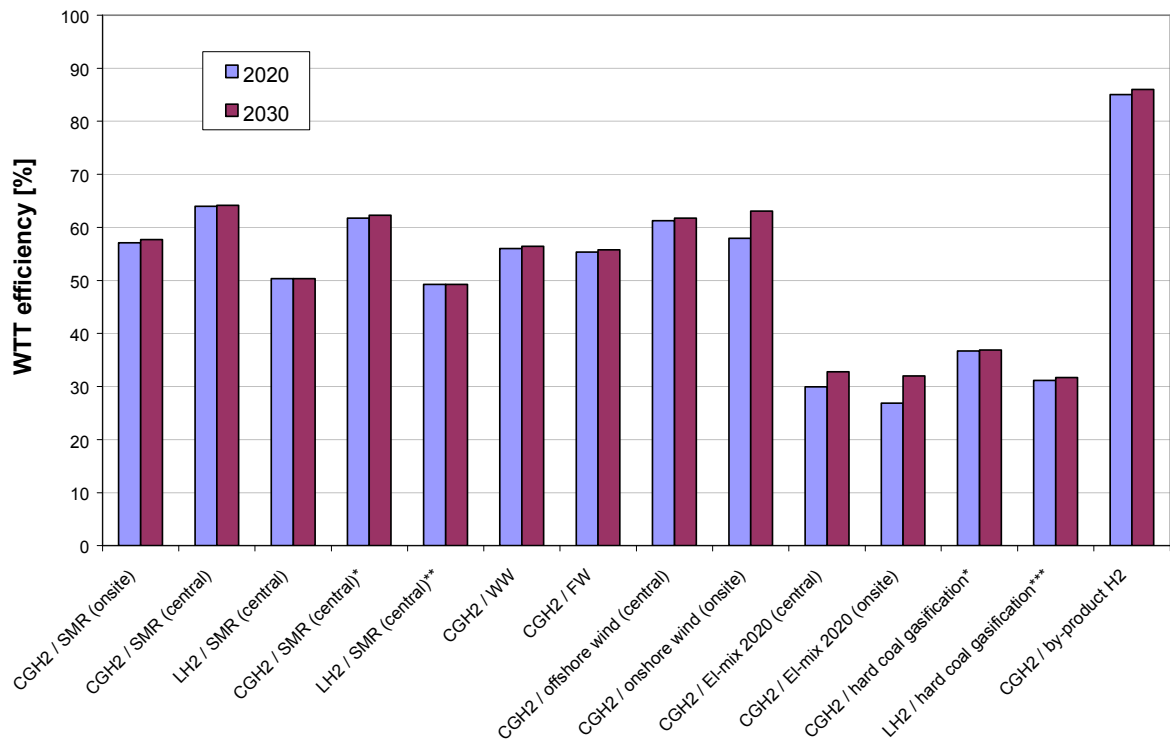
By-product hydrogen is generated by various types of industrial processes e.g. in refineries. Today the by-product hydrogen is used as fuel for the supply of process heat within the industry. If the by-product is exported as product e.g. for hydrogen vehicles within the industry additional natural gas will be required for the supply of process heat. Therefore the generation of by-product hydrogen can be considered as a process with natural gas as input and hydrogen as output and a conversion efficiency of 100%.

Figure 3-17: CGH₂ form by-product H₂



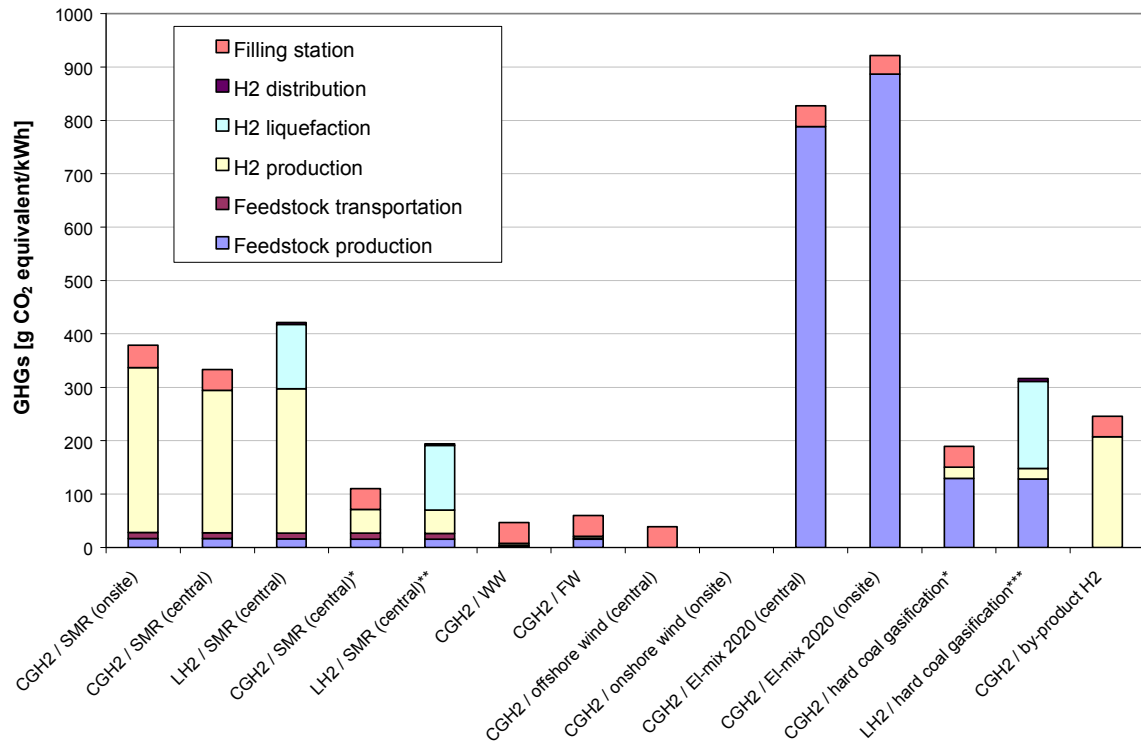
3.7 Results

Figure 3-18: WTT efficiency 2020 and 2030



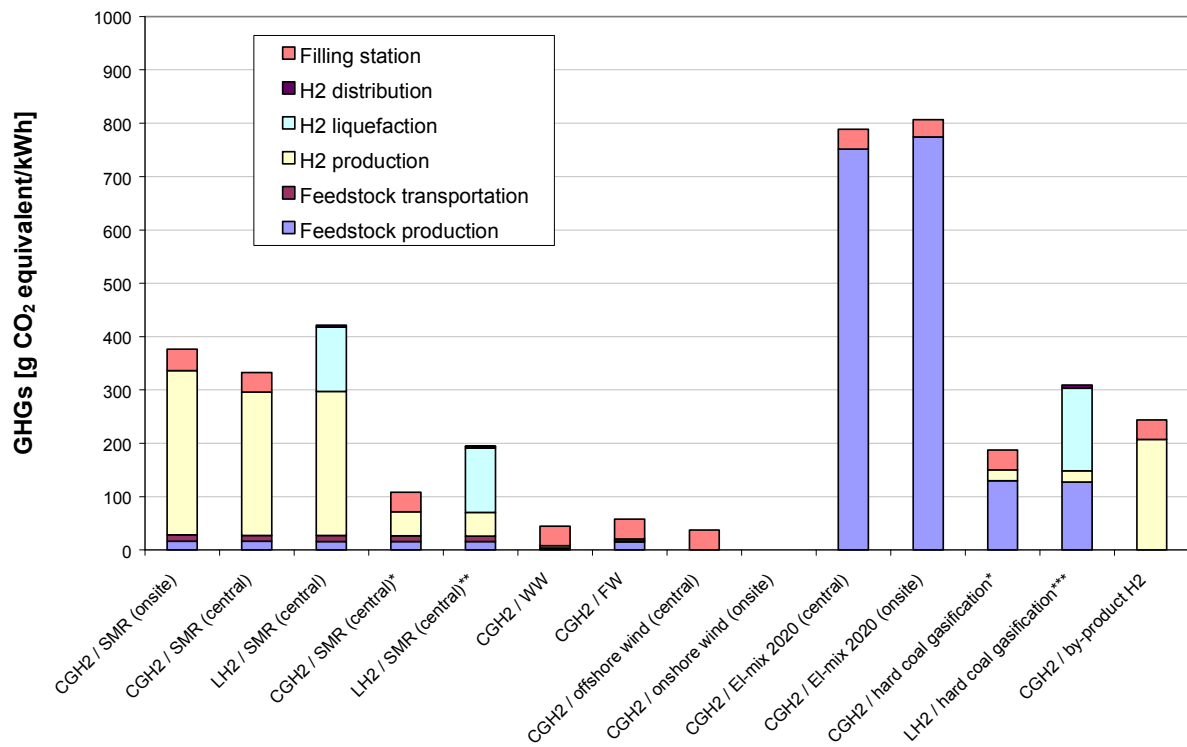
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 3-19: WTT GHG emissions 2020



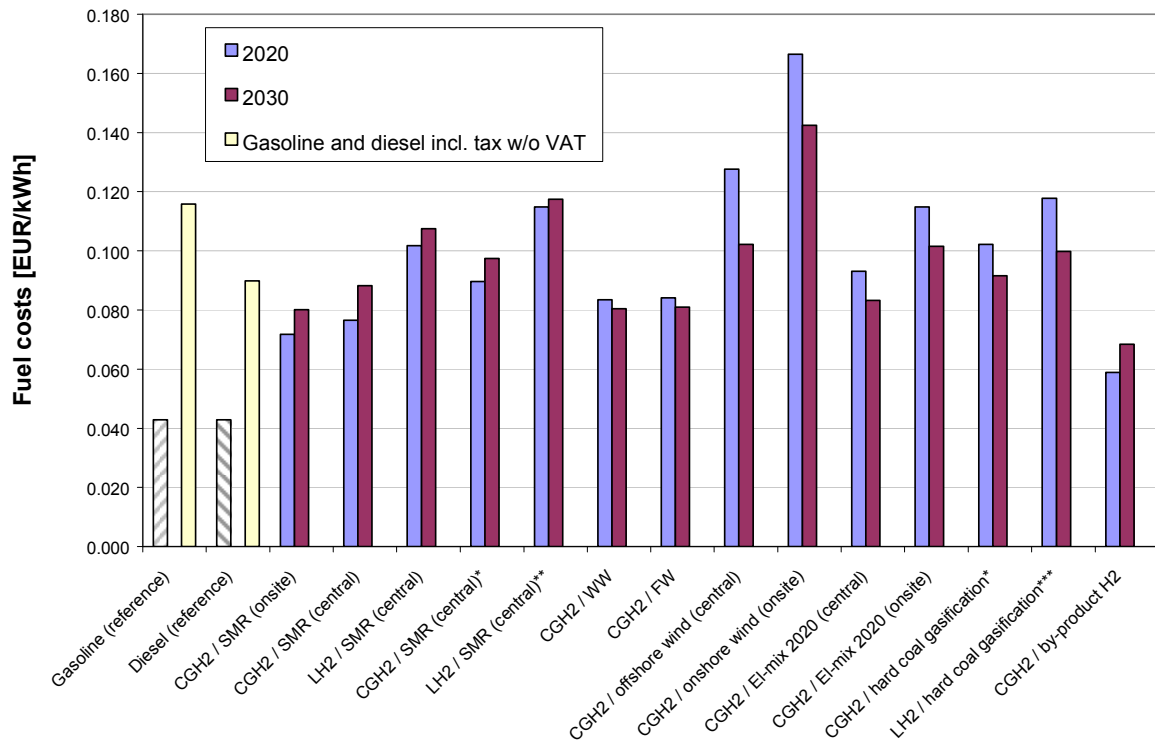
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 3-20: WTT GHG emissions 2030



* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 3-21: Fuel supply costs 2020 and 2030



* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

The costs for gasoline and diesel (reference) have been derived from [CONCAWE 2006] and are based on a crude oil price of 50 US\$/bbl.

4 Tank-to-Wheel (TTW)

The passenger vehicle data has been derived from the CONCAWE/EUCAR/JRC study [CONCAWE 2006]. The passenger vehicles are based on a VW Golf.

Table 4-1: Passenger vehicle data [CONCAWE 2006]

	Fuel consumption [kWh/km]	GHG emissions [g CO ₂ equivalent/km]
CGH ₂ FC vehicle	0.261	0
CGH ₂ FC vehicle hybrid	0.233	0
CGH ₂ ICE vehicle	0.465	0.5
CGH ₂ ICE vehicle hybrid	0.413	0.5
LH ₂ FC vehicle	0.261	0
LH ₂ FC vehicle hybrid	0.233	0
LH ₂ ICE vehicle	0.465	0.5
LH ₂ ICE vehicle hybrid	0.393	0.5
Gasoline ICE vehicle	0.529	140.3
Gasoline ICE vehicle hybrid	0.449	119.5
Diesel ICE vehicle	0.492	131.6
Diesel ICE vehicle hybrid	0.406	108.9

¹⁾ derived from [CONCAWE 2006]

The GHG emissions from the hydrogen fueled ICE vehicle are from the emissions of N₂O.

5 Well-to-Wheel (WTW)

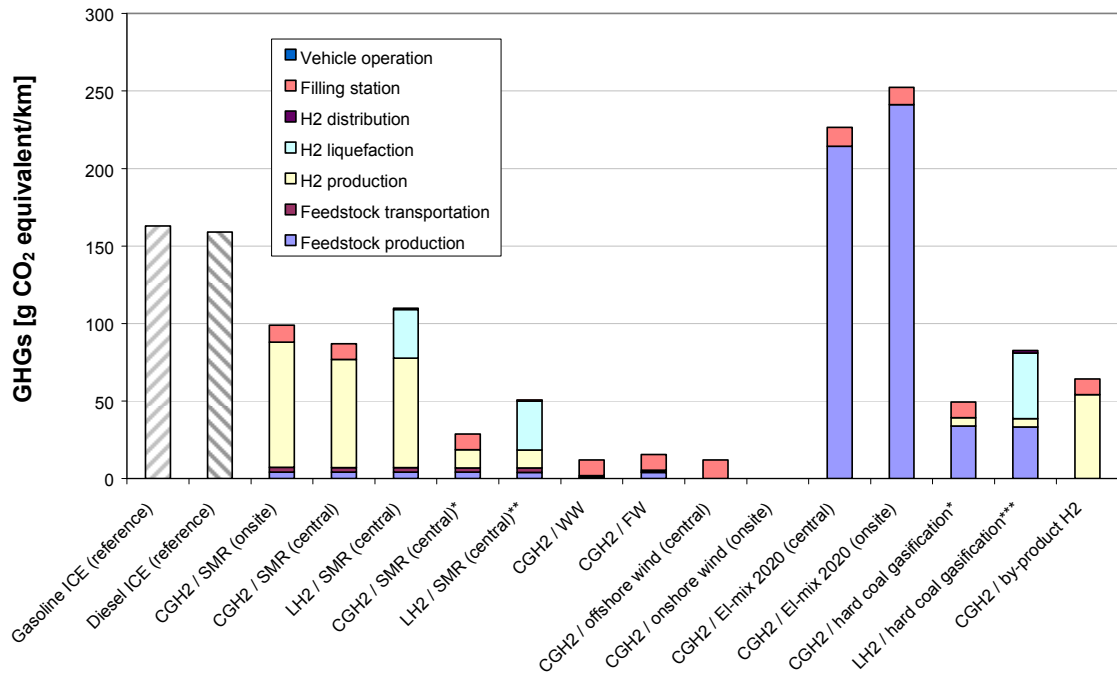
For CGH₂ fueled FC vehicles and hydrogen generated via electrolysis a deOxo dryer has been installed at the filling station to elevate the hydrogen purity from 99.95% to 99.995%. For CGH₂ fueled ICE vehicles no deOxo dryer is required.

Table 5-1: Technical and economic data for a deOxo dryer [Stuart Energy 2004]

Capacity [Nm ³ H ₂ /h]	120
Electricity consumption [kWh/kWh _{H2}]	0.0139
Investment [EUR]	94,500
Maintenance [% of investment]	0.24
Useful lifetime [yr]	20
Equivalent full load period [h/yr]	6,000

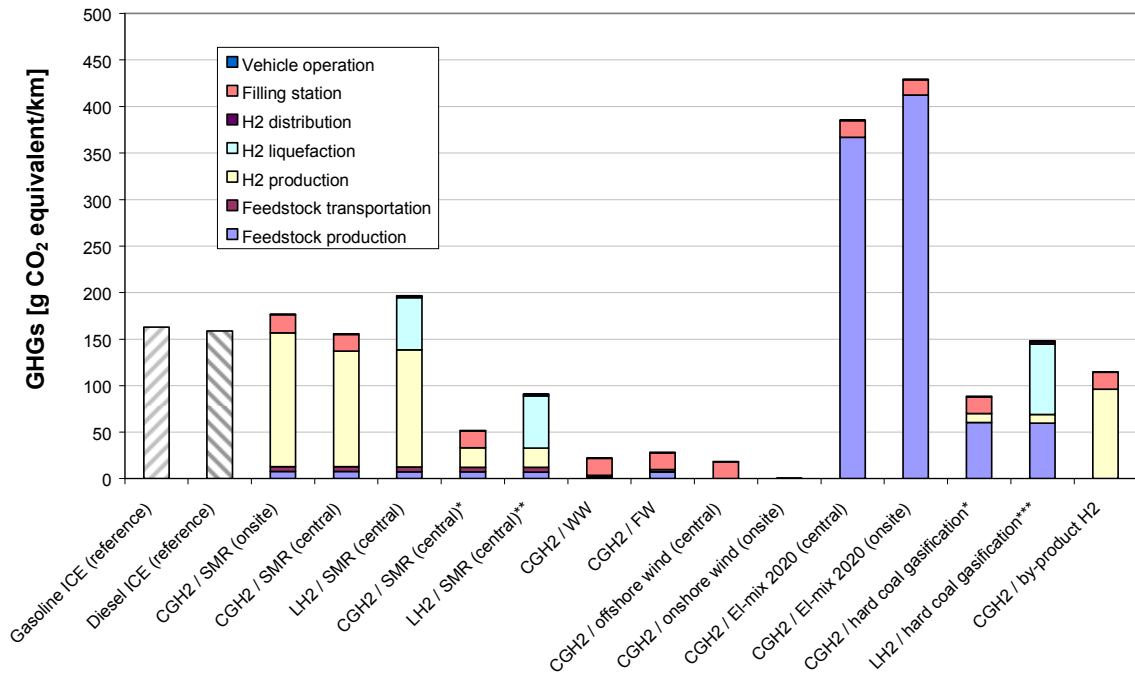
The purity of LH₂ is above 99.995% in any case.

Figure 5-1: WTW GHG emissions non-hybrid FC passenger vehicles 2020



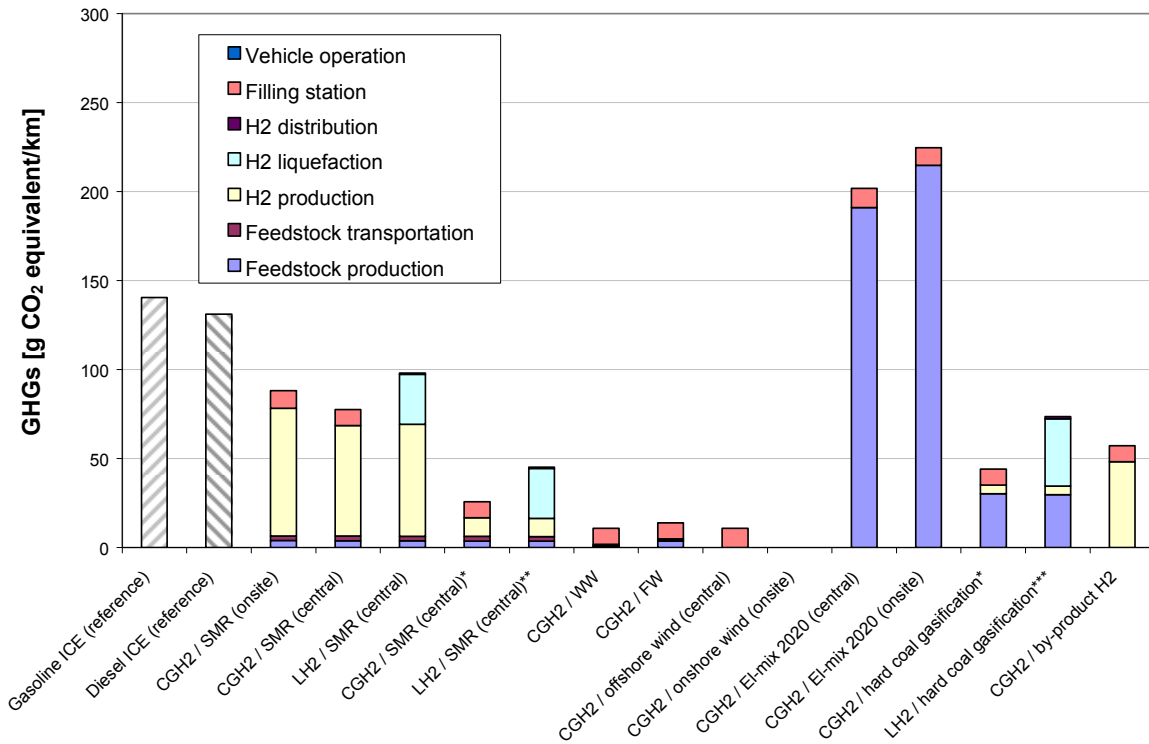
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-2: WTW GHG emissions non-hybrid ICE passenger vehicles 2020



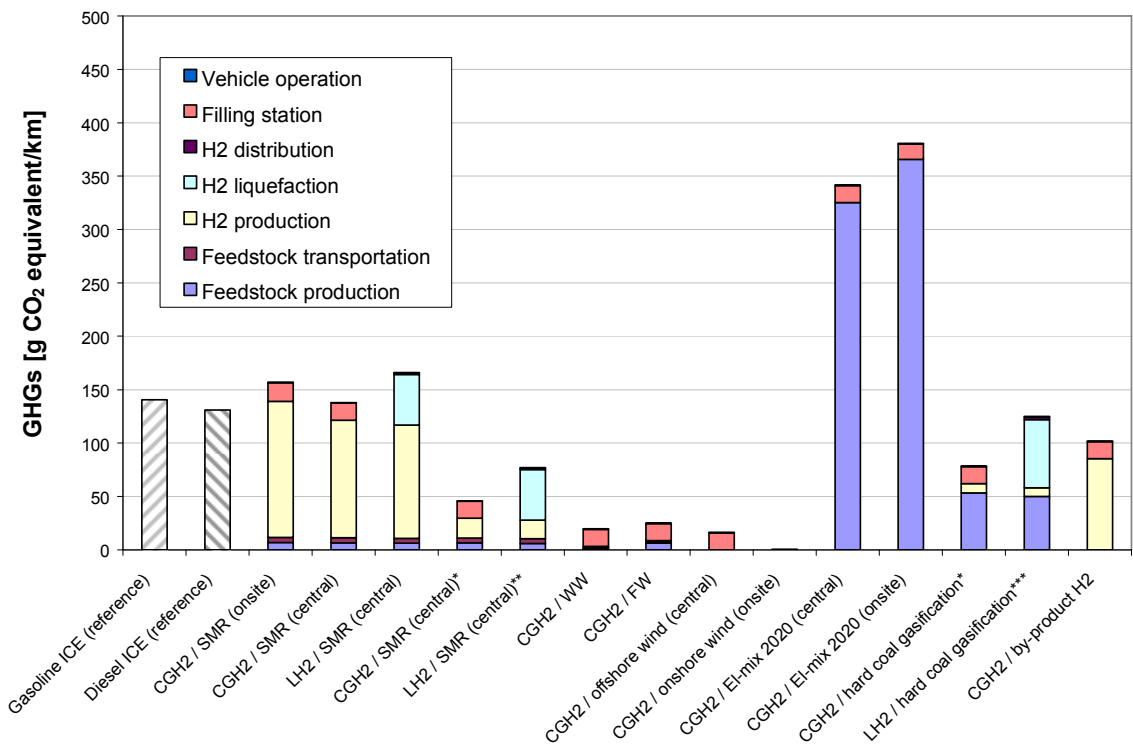
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-3: WTW GHG emissions hybrid FC passenger vehicles 2020



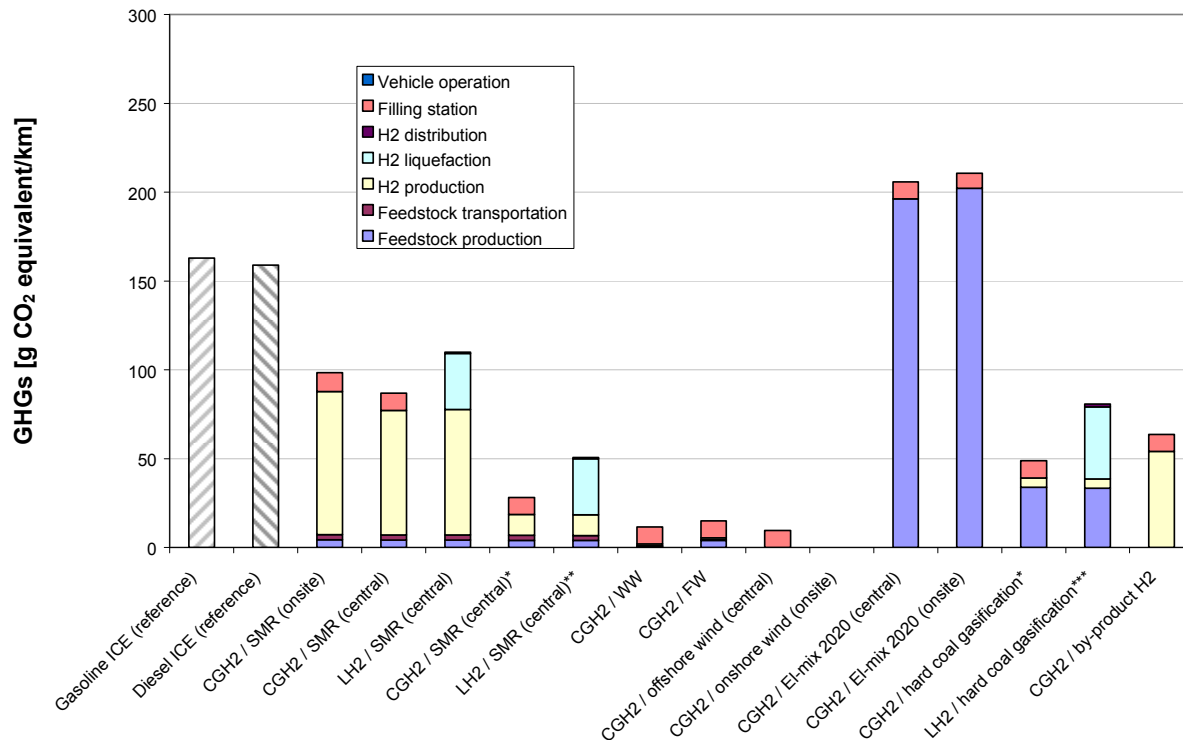
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-4: WTW GHG emissions hybrid ICE passenger vehicles 2020



* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-5: WTW GHG emissions non-hybrid FC passenger vehicles 2030



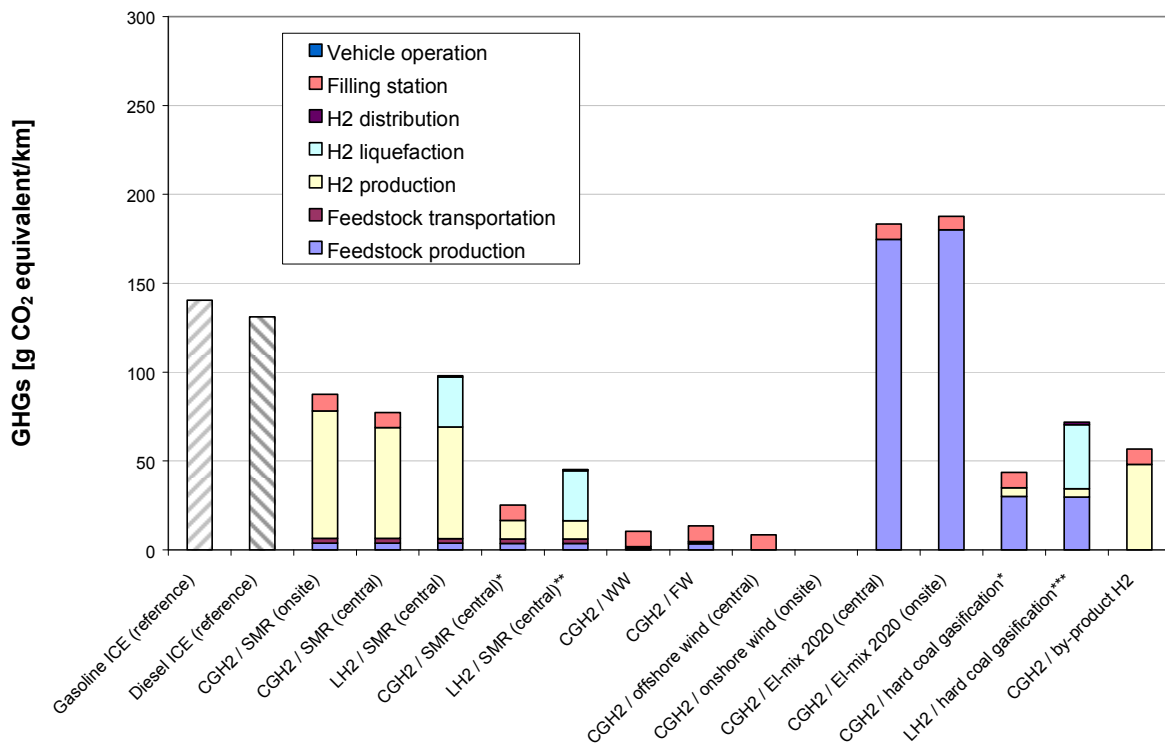
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-6: WTW GHG emissions non-hybrid ICE passenger vehicles 2030



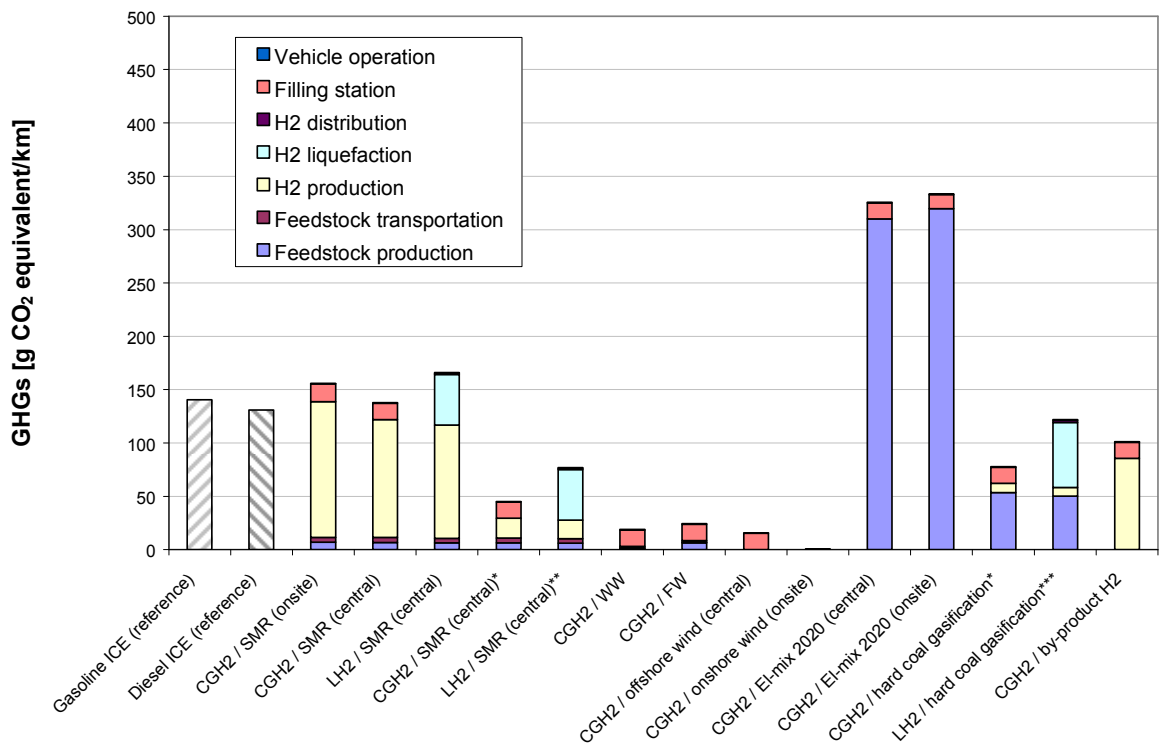
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-7: WTW GHG emissions hybrid FC passenger vehicles 2030



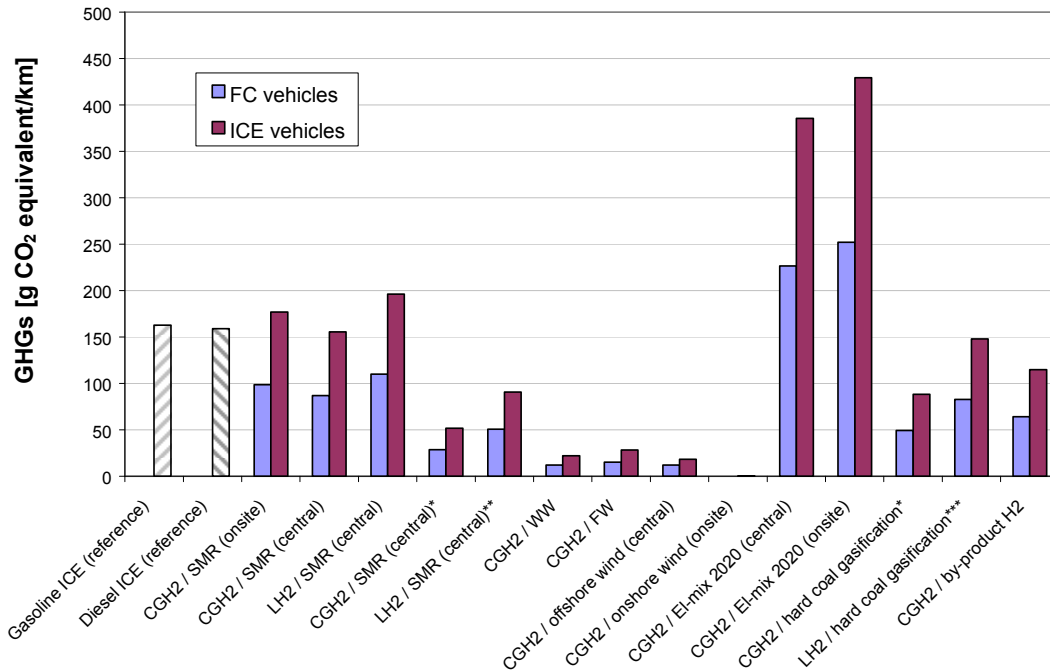
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-8: WTW GHG emissions hybrid ICE passenger vehicles 2030



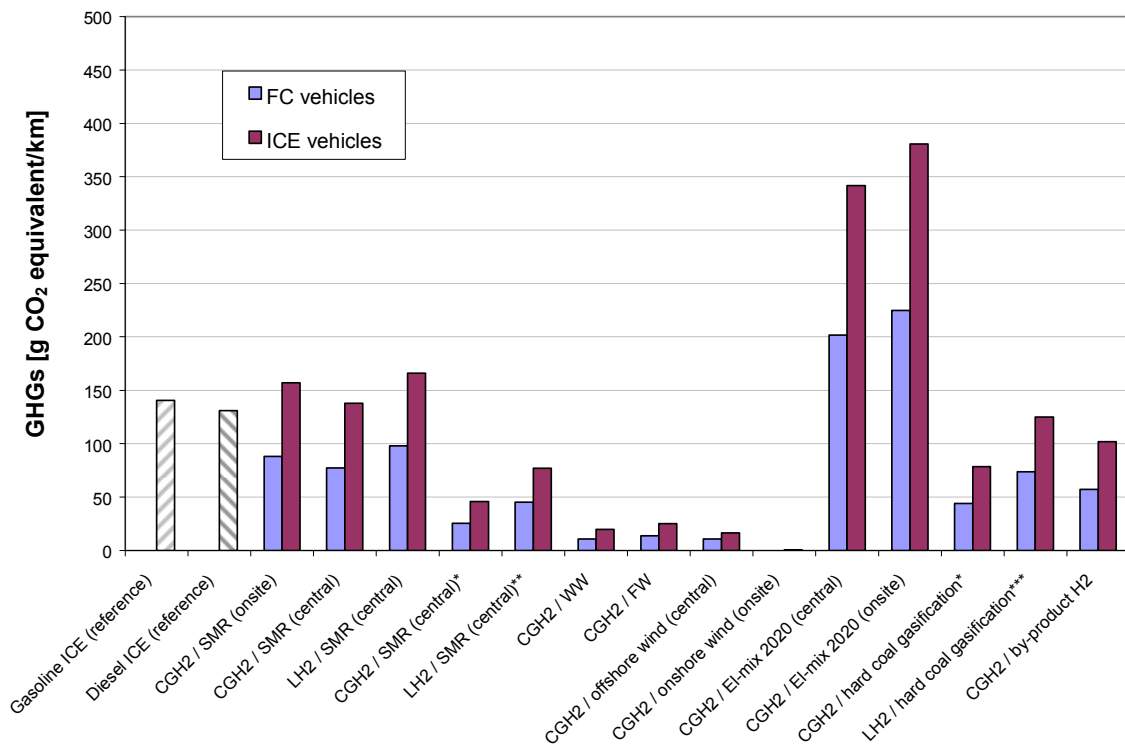
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-9: WTW GHG emissions non-hybrid FC and ICE passenger vehicles 2020



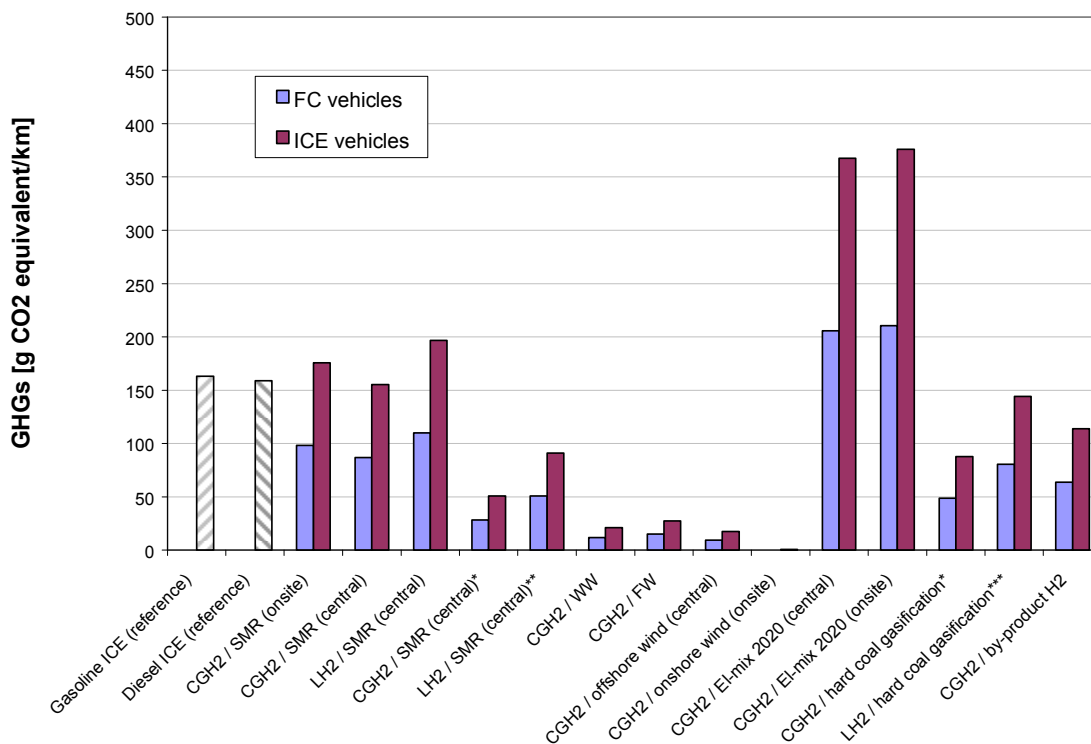
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-10: WTW GHG emissions hybrid FC and ICE passenger vehicles 2020



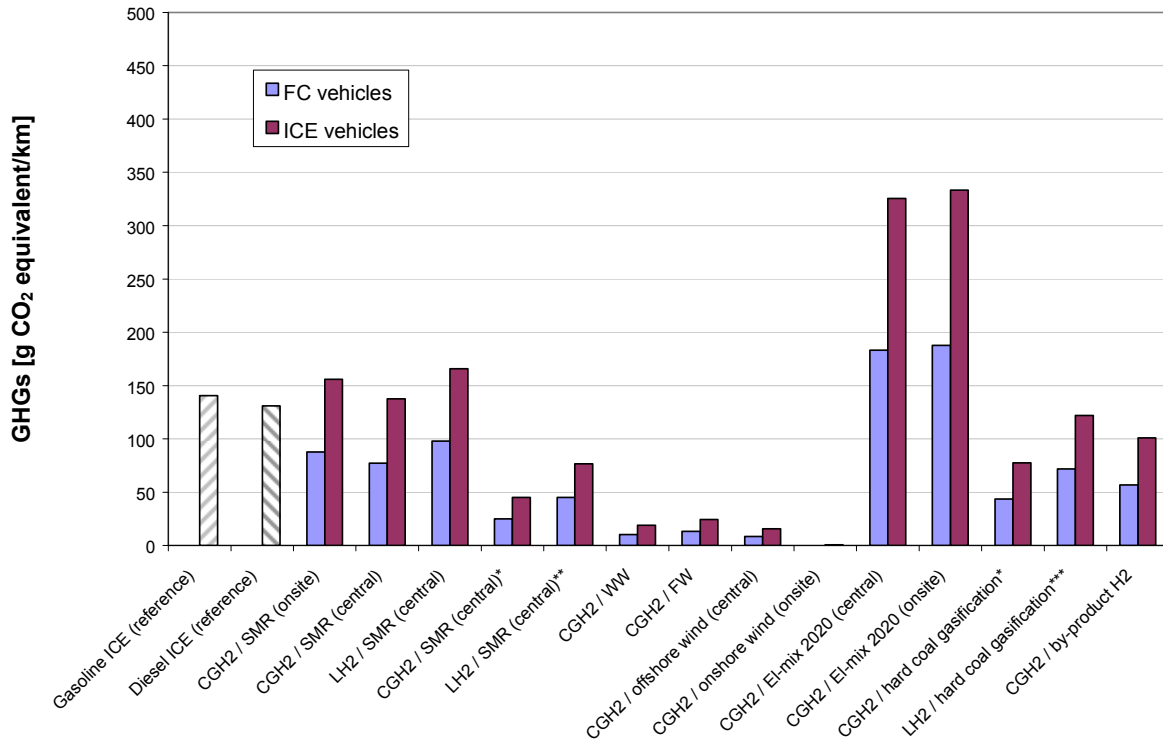
* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-11: WTW GHG emissions non-hybrid FC and ICE passenger vehicles 2030



* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

Figure 5-12: WTW GHG emissions hybrid FC and ICE passenger vehicles 2030



* with CO₂ capture and storage (CCS); ** with CO₂ capture and storage (CCS), H₂ liquefaction with NG fueled CCGT; *** with CO₂ capture and storage (CCS), H₂ liquefaction with German electricity mix

6 Well to stationary use (WtStU)

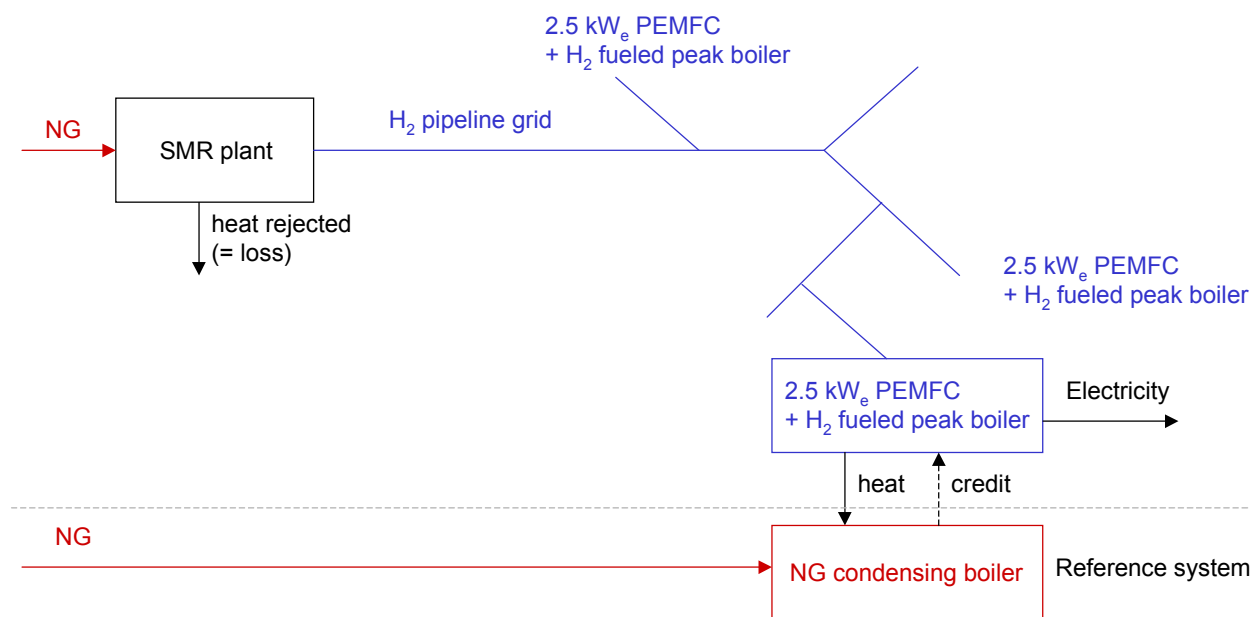
6.1 Methodology

In case of stationary applications WTT pathways without a filling station has been used for the supply of hydrogen. Further no LH₂ pathways has been considered because stationary fuel cell (FC) or combined cycle gas turbine (CCGT) combined heat and power (CHP) plants usually are connected to a hydrogen grid.

6.1.1 Households

CHP plants generate electricity and heat. For the calculation two different approaches have been considered. One approach is to calculate the GHG emissions, energy requirements and costs for the supply of electricity whereas the heat is considered as by-product. For the by-product a credit has been taken into account. It has been assumed that the heat from the CHP plants replaces heat from a conventional natural gas fueled condensing boiler.

Figure 6-1: Calculation CHP plants with heat credit



As a result the GHG emissions will be negative if the hydrogen is derived from renewable energy sources or from fossil plants employing CO₂ capture and storage.

Table 6-1: FC CHP plant with H₂ fueled peak boiler (2.5 kW_e)

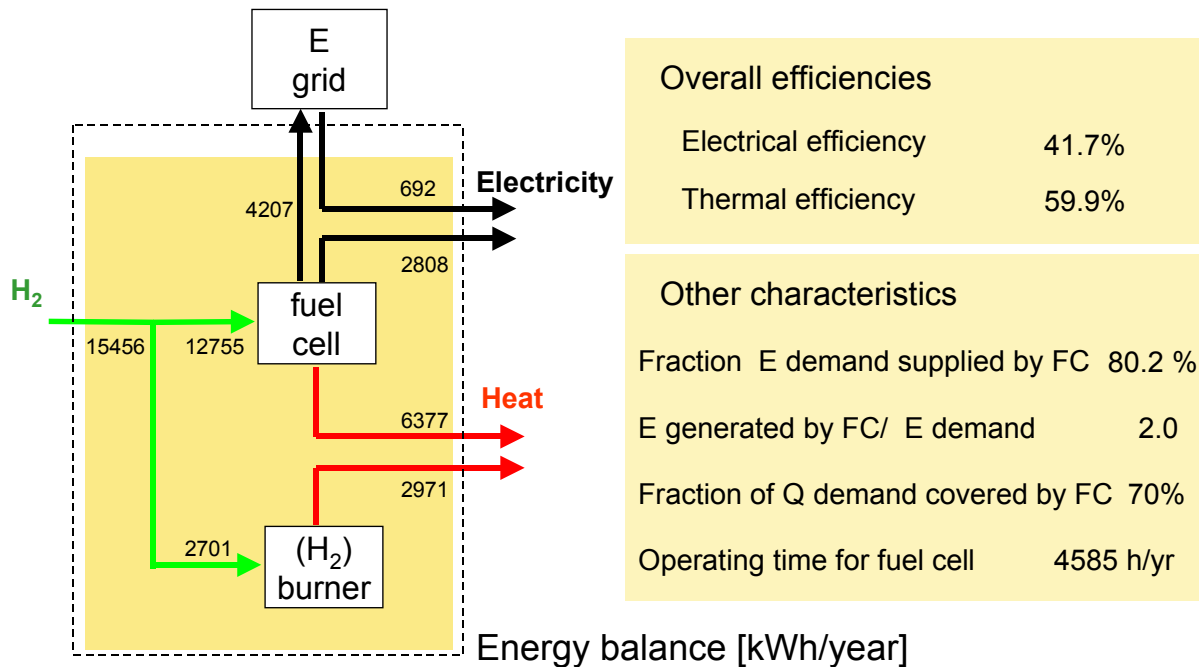
Capacity [kW _e]	2.5
H ₂ input [kWh/kWh _e]	3.39
Heat output [kWh/kWh _e]	1.71
Investment [EUR]	5500
Maintenance [% of investment]	9
Equivalent full load period [h/yr]	5,000
Useful lifetime [yr]	8

Table 6-2: FC CHP plant with H₂ fueled peak boiler (50 kW_e)

Capacity [kW _e]	50
H ₂ input [kWh/kWh _e]	2.67
Heat output [kWh/kWh _e]	1.71
Investment [EUR]	39,000
Maintenance [% of investment]	7
Equivalent full load period [h/yr]	5,000
Useful lifetime [yr]	8

The second approach is to look at the consumer e.g. a single family house. The single family house needs electricity and heat which is supplied by a FC CHP plant including a peak boiler.

Figure 6-2: Supply of electricity and heat for a single family house [ECN 2004]



The main output is „heat+electricity“ and the inputs are hydrogen and external electricity (from the German electricity). If the electricity generation of the FC CHP plant is higher than the demand then a net export of electricity occur. As a result an electricity credit has been taken into account. A natural gas fueled CCGT (efficiency: 55%) has been used as reference system.

Table 6-3: Supply of electricity and heat for a single family house

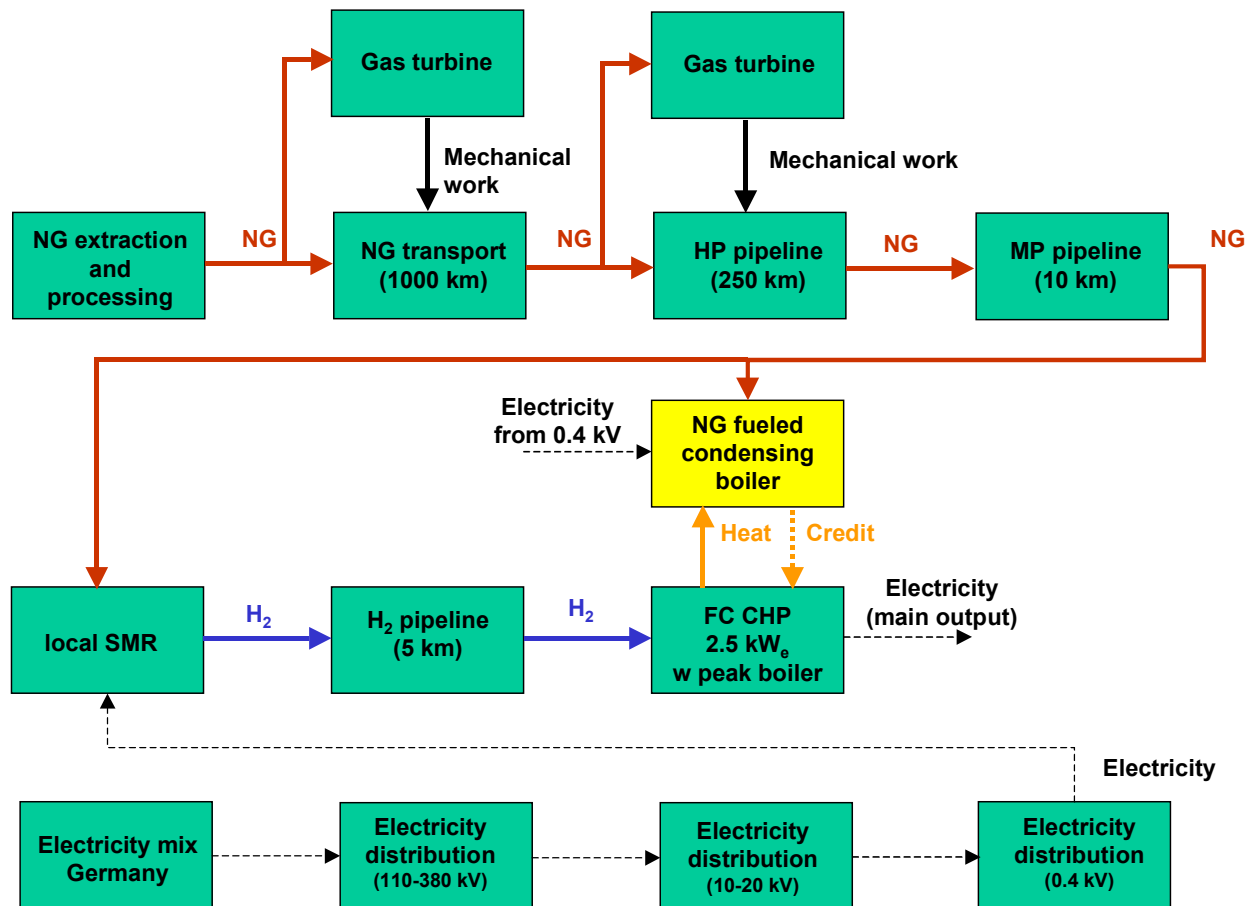
Capacity [kW heat and electricity]	2.8 ¹⁾
H ₂ input [kWh/kWh]	1.203
Electricity output [kWh/kWh]	0.274
Investment [EUR]	4,054
Maintenance [% of investment]	12
Equivalent full load period [h/yr]	4,585
Useful lifetime [yr]	20

¹⁾ average capacity: annual energy production (12,848) divided by the operating time (4,585 h/yr)

The investment includes the investment for a peak boiler. The investment for the peak boiler has been derived from the investment for a typical natural gas fueled condensing boiler for single family houses (3,000 EUR). The maintenance costs

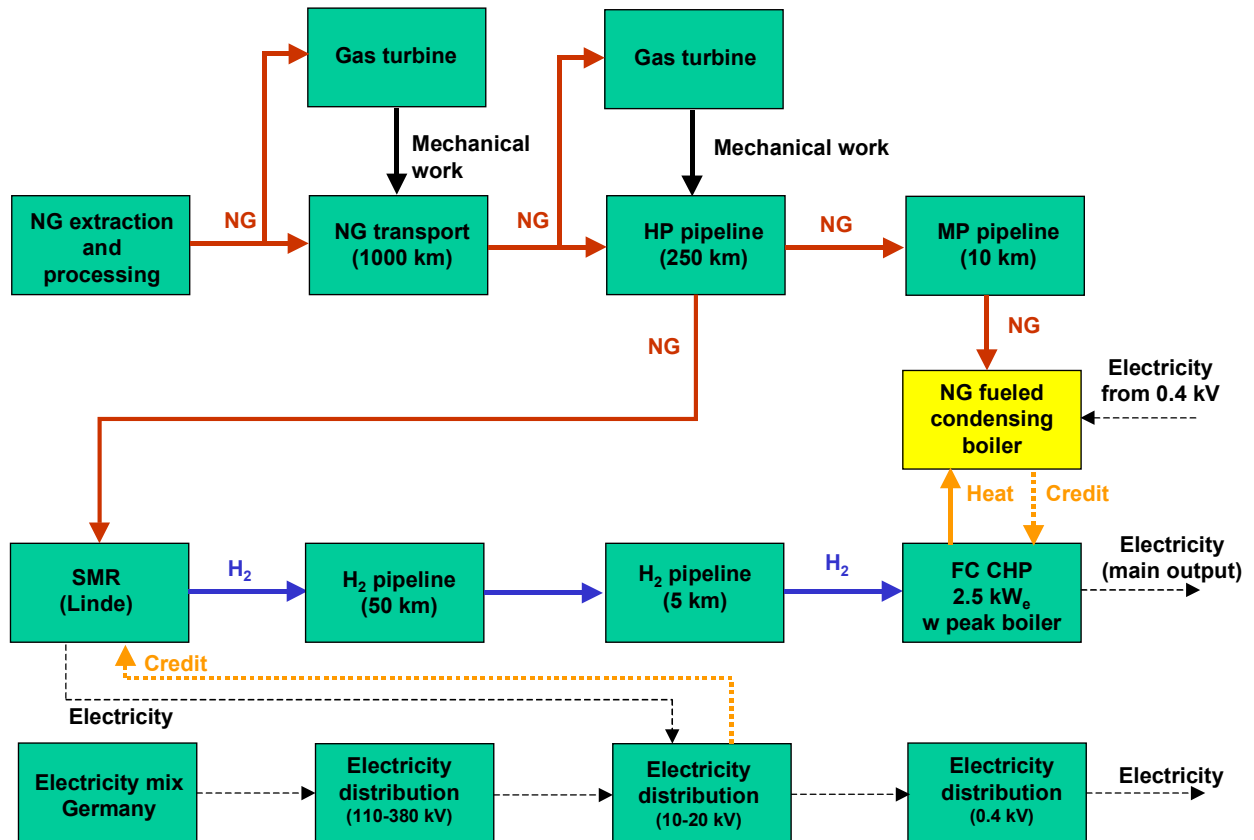
include stack replacement after every 5 years. The lifetime of the FC is indicated with 5 years [ECN 2004].

Figure 6-3: Chain 1a) H₂ from local SMR (Haldor Topsoe), stationary FC CHP plant (1st approach



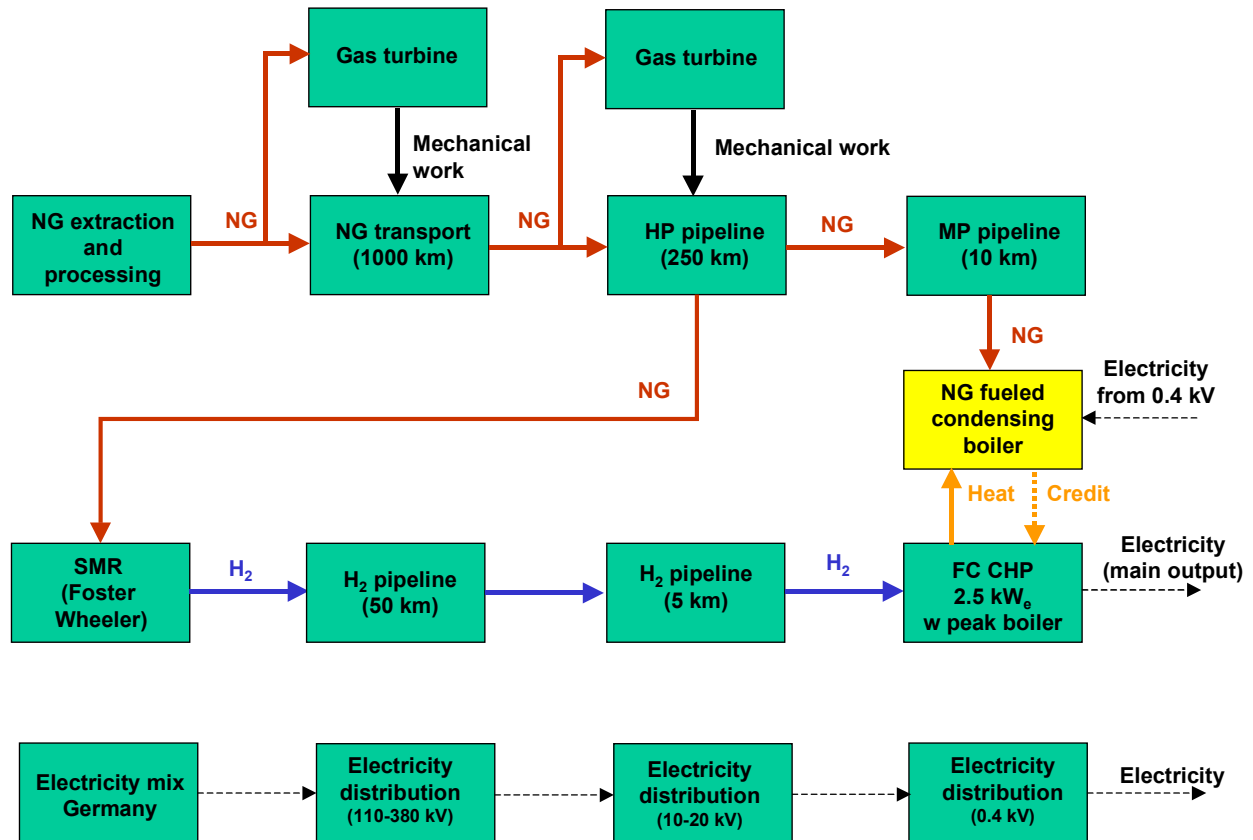
As mentioned above the heat of the hydrogen fueled CHP replaces heat from a natural gas fueled condensing boiler. Besides natural gas the natural gas fueled condensing boiler consumes small amounts of auxiliary electricity (approx. 0.016 kWh per kWh of heat).

Figure 6-4: Chain 1b) H₂ from central SMR (Linde), stationary FC CHP plant (1st approach)



The central steam reformer without CO₂ capture and storage (CCS) generates excess electricity which replaces electricity from the German electricity mix. Besides natural gas the natural gas fueled condensing boiler consumes small amounts of auxiliary electricity (approx. 0.016 kWh per kWh of heat).

Figure 6-5: Chain 1d) H₂ from central SMR (Foster Wheeler, with CO₂ capture and storage), stationary FC CHP (1st approach)



In contrast to the central steam reformer without CO₂ capture and storage (CCS) the large central steam reformer with CCS is self sufficient (no electricity import and no electricity export). Besides natural gas the natural gas fueled condensing boiler consumes small amounts of auxiliary electricity (approx. 0.016 kWh per kWh of heat).

Figure 6-6: Chain 2 a) H₂ from gasification of residual wood (waste wood [WW]), stationary FC CHP (1st approach)

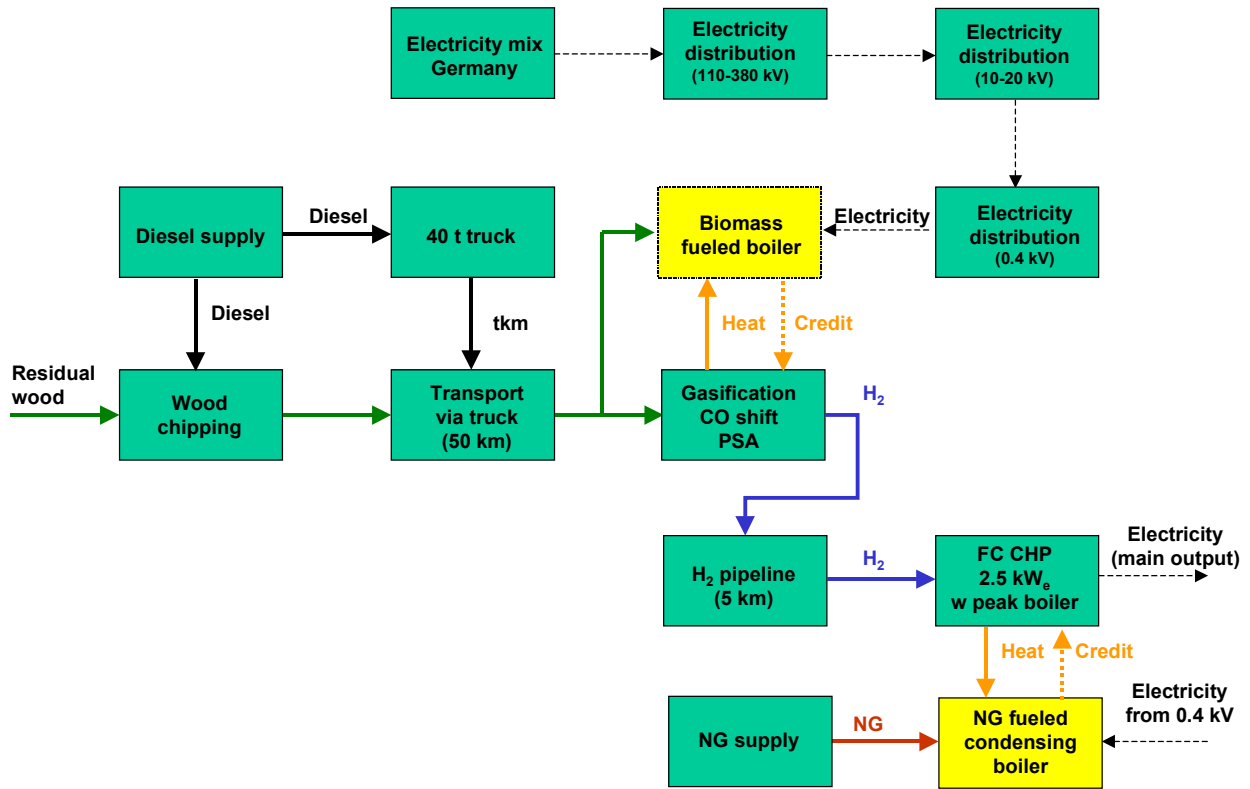


Figure 6-7: Chain 2 b) H₂ from gasification of wood from plantation (farmed wood [FW]), stationary FC CHP (1st approach)

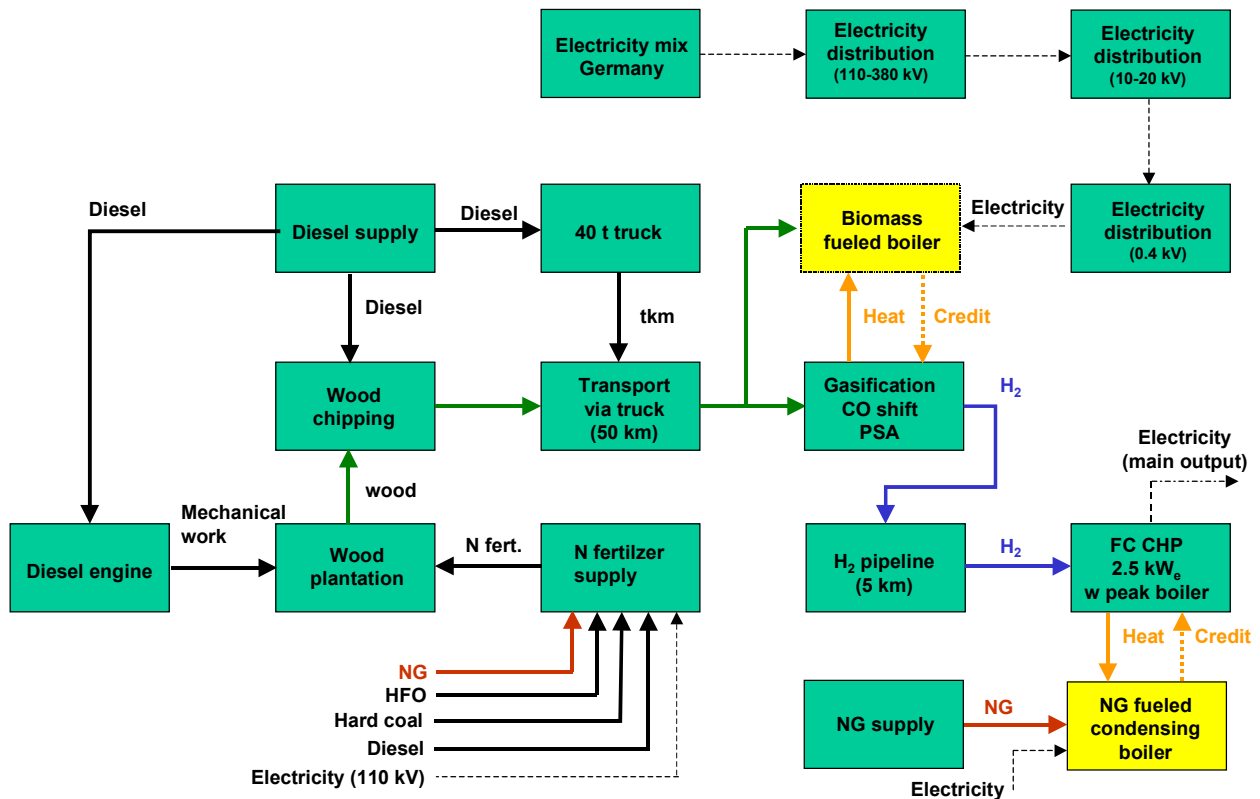
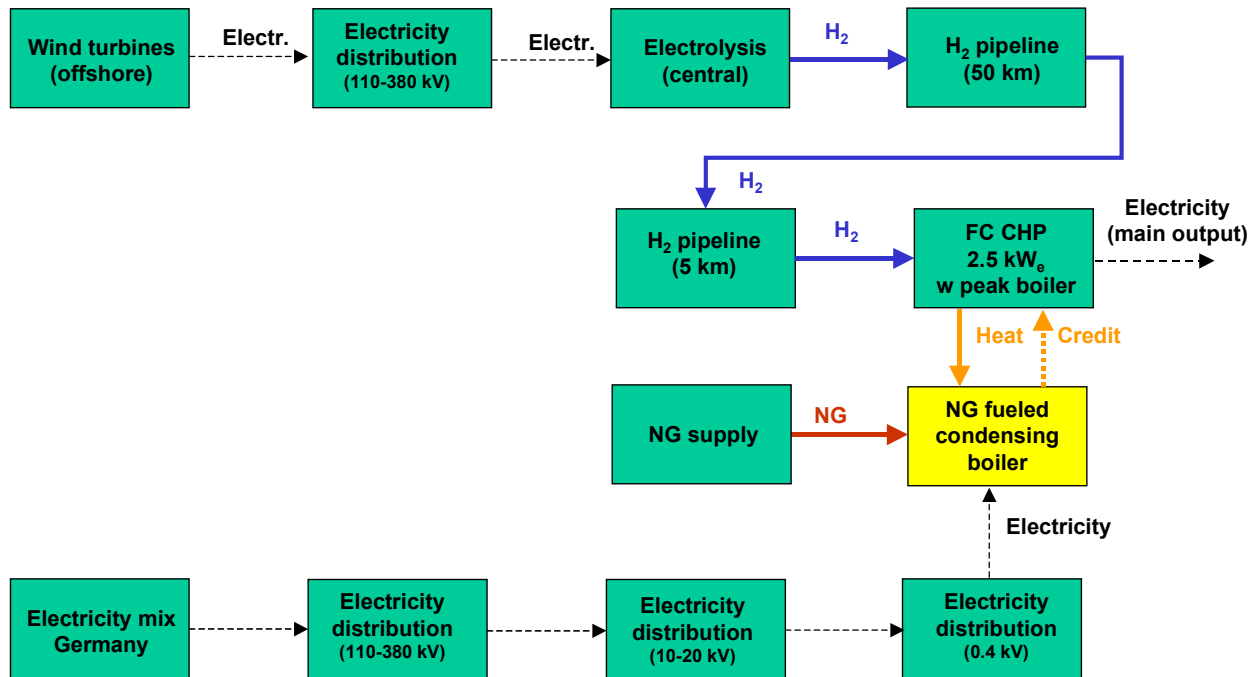


Figure 6-8: Chain 3 a) H₂ from offshore wind power (offshore) via central water electrolysis, stationary FC CHP (1st approach)



Chain 3b) is equivalent to chain 3a but with electricity from German electricity mix for the electrolysis instead of electricity from offshore wind power.

Figure 6-9: Chain 3 b) H₂ from German electricity mix via central water electrolysis, stationary FC CHP (1st approach)

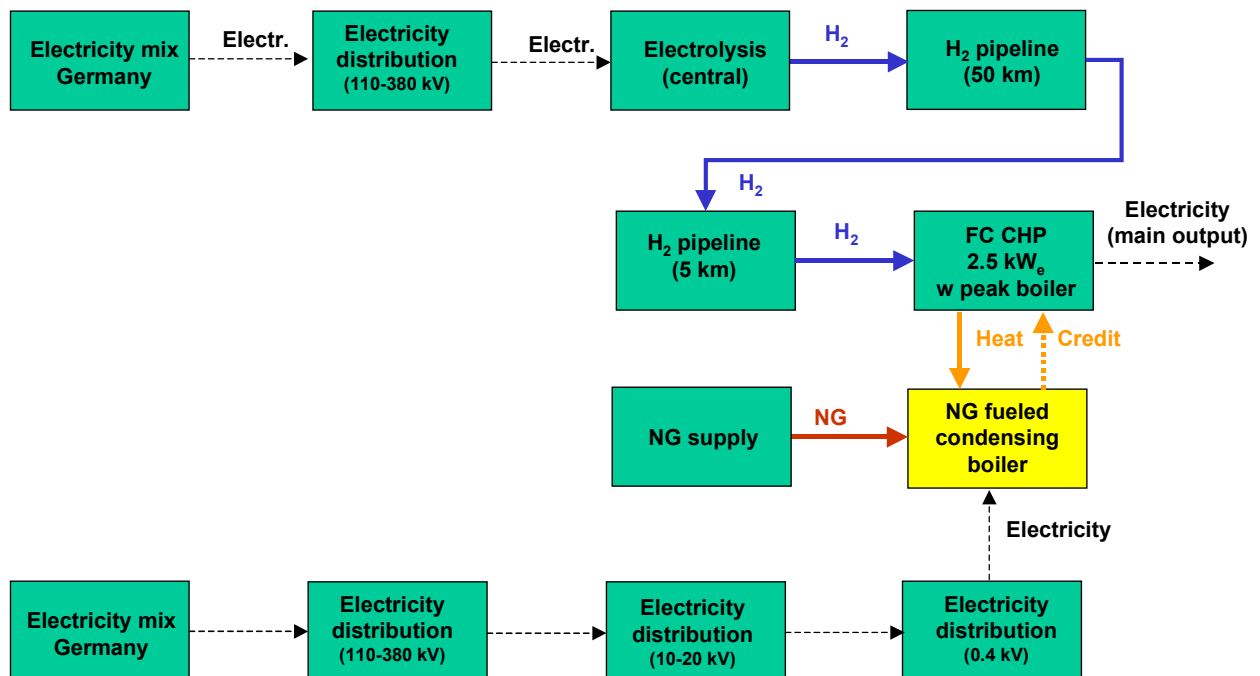


Figure 6-10: Chain 4 a) H₂ from wind power (onshore) via local water electrolysis, FC CHP (1st approach)

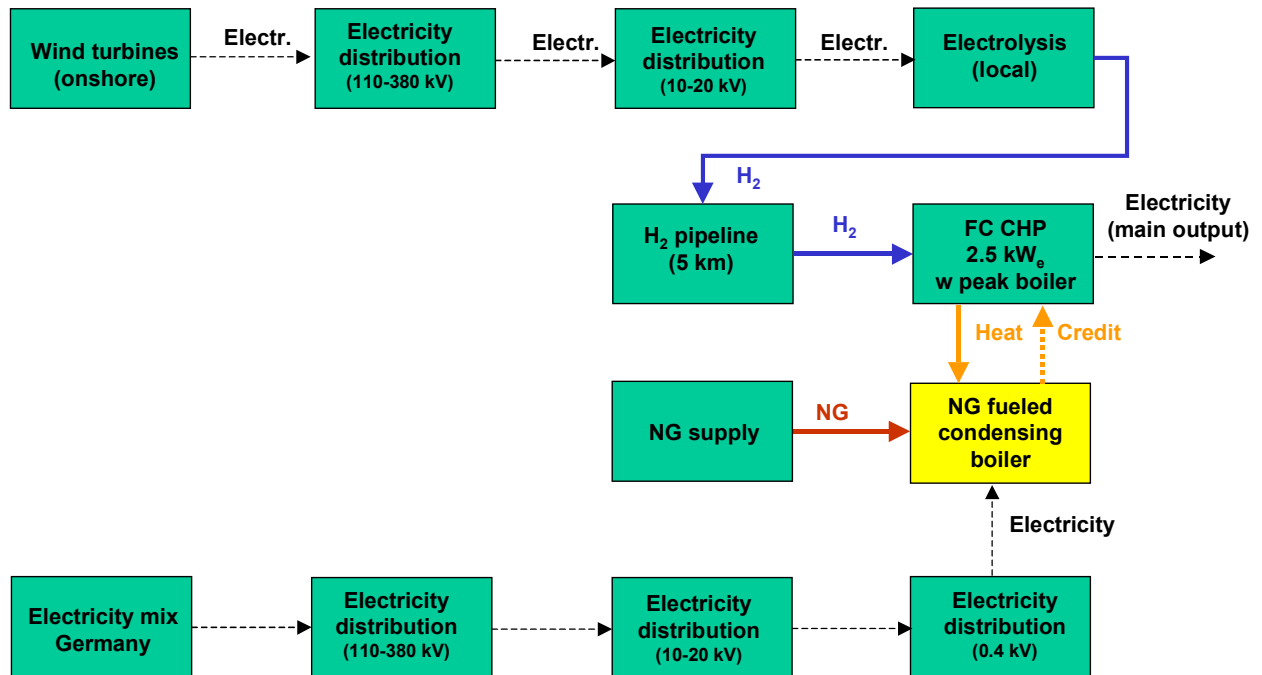


Figure 6-11: Chain 4 b) H₂ from German electricity mix via local water electrolysis, FC CHP (1st approach)

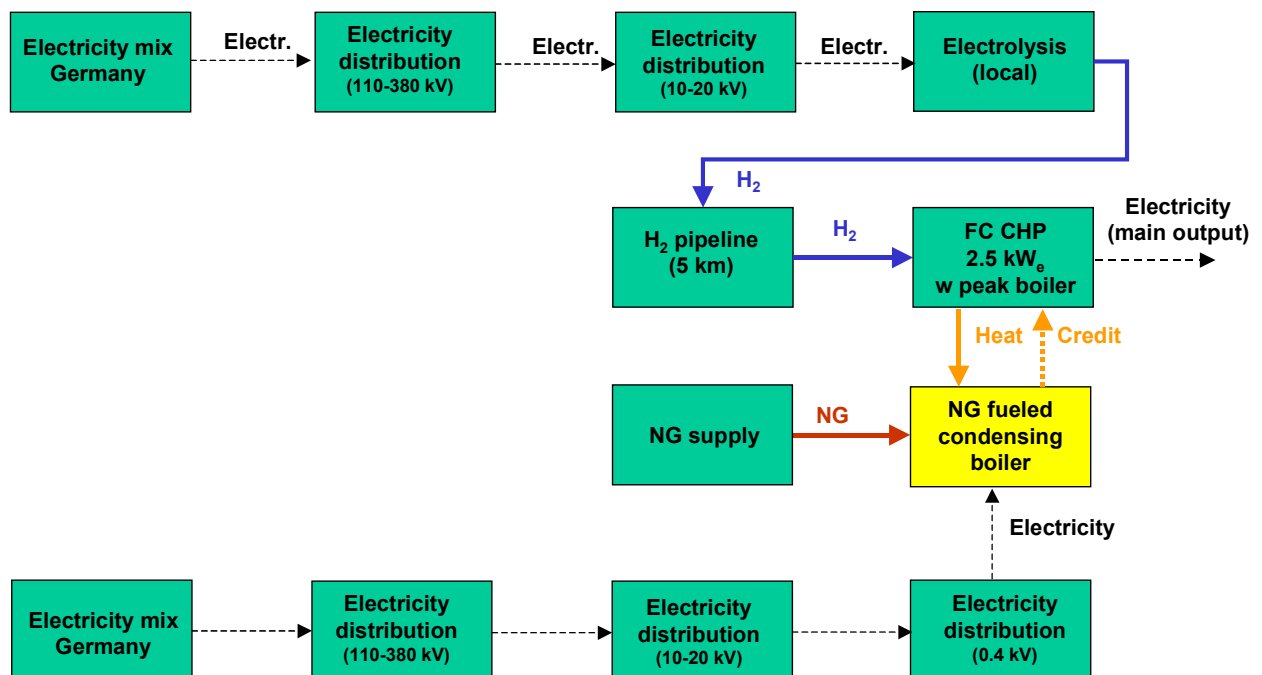


Figure 6-12: Chain 5 a) H₂ from hard coal gasification (Foster Wheeler, with CO₂ capture and storage), FC CHP (1st approach)

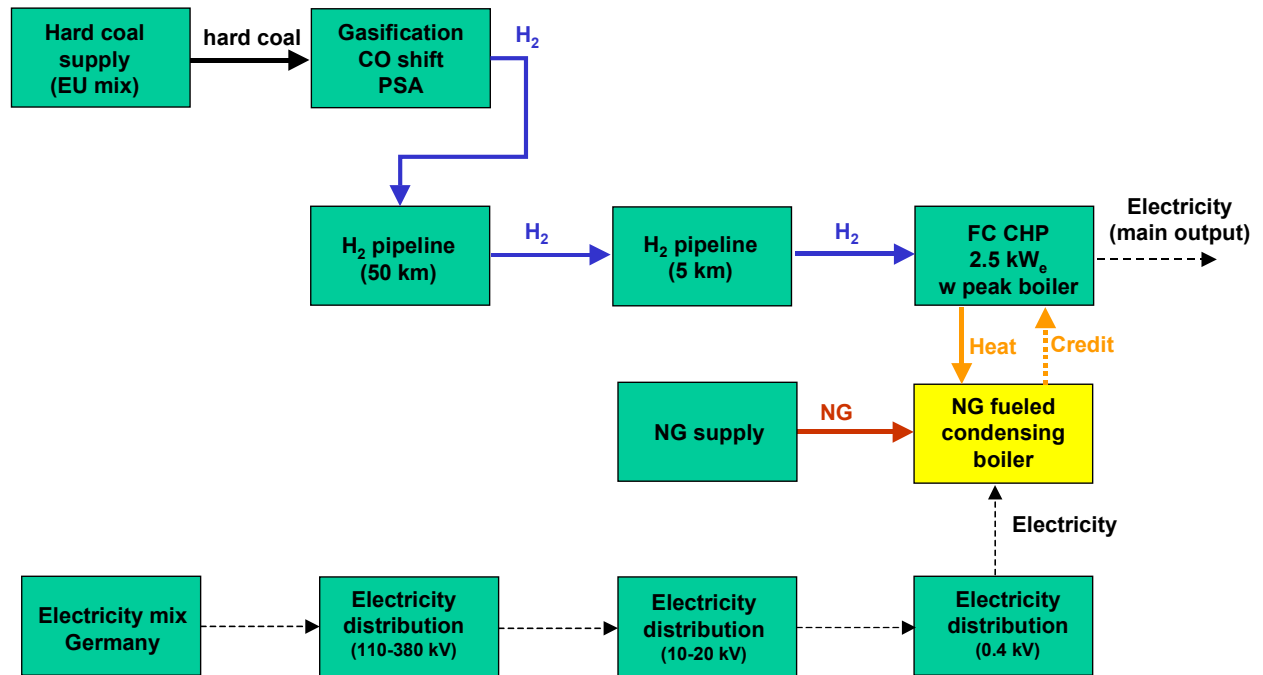


Figure 6-13: Chain 6 a) H₂ from by-product H₂: reference = NG (by-product H₂ is replaced by NG), FC CHP plant (1st approach)

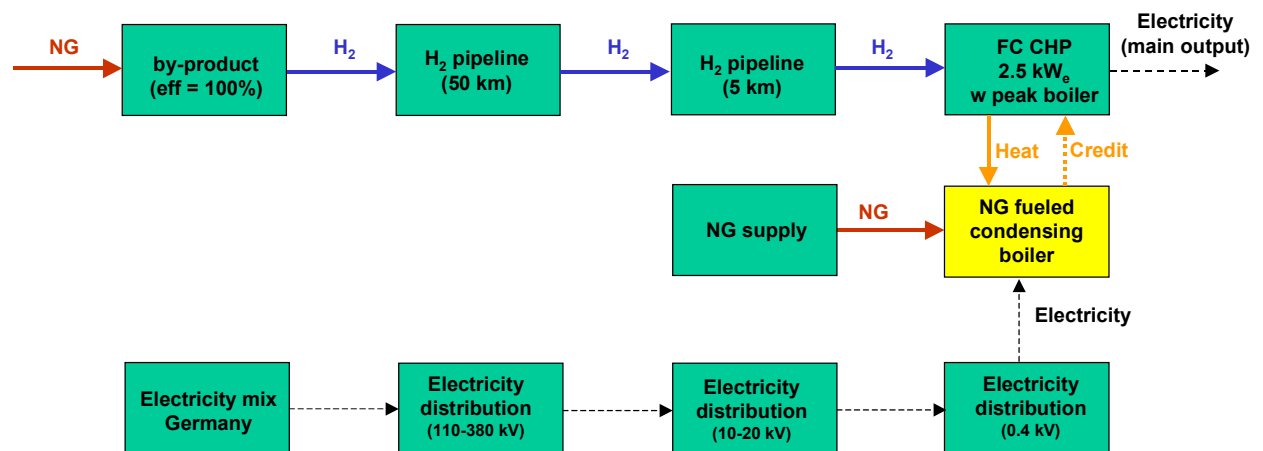


Figure 6-14: Chain 1a) H₂ from local SMR (Haldor Topsoe), stationary FC CHP plant (2nd approach)

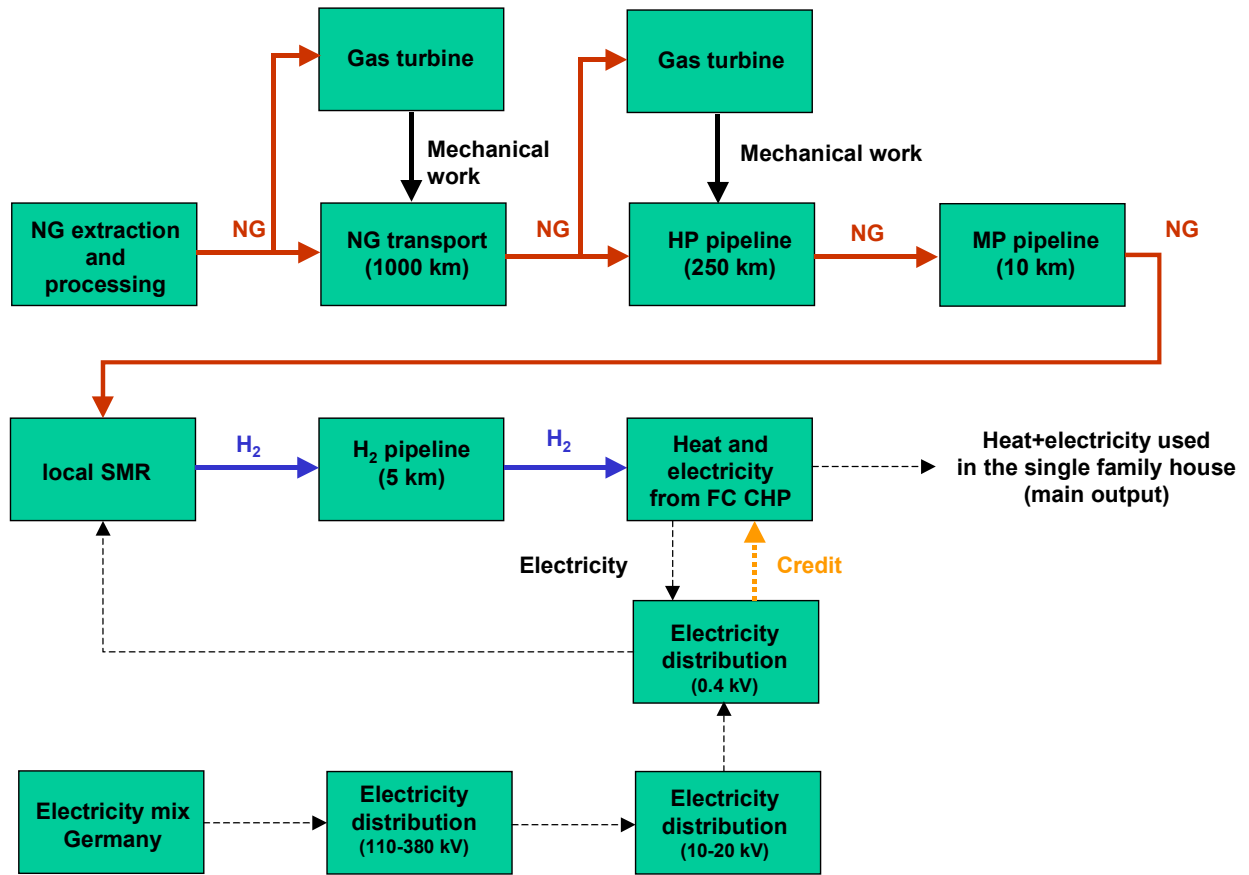


Figure 6-15: Chain 1b) H₂ from central SMR (Linde), stationary FC CHP plant (2nd approach)

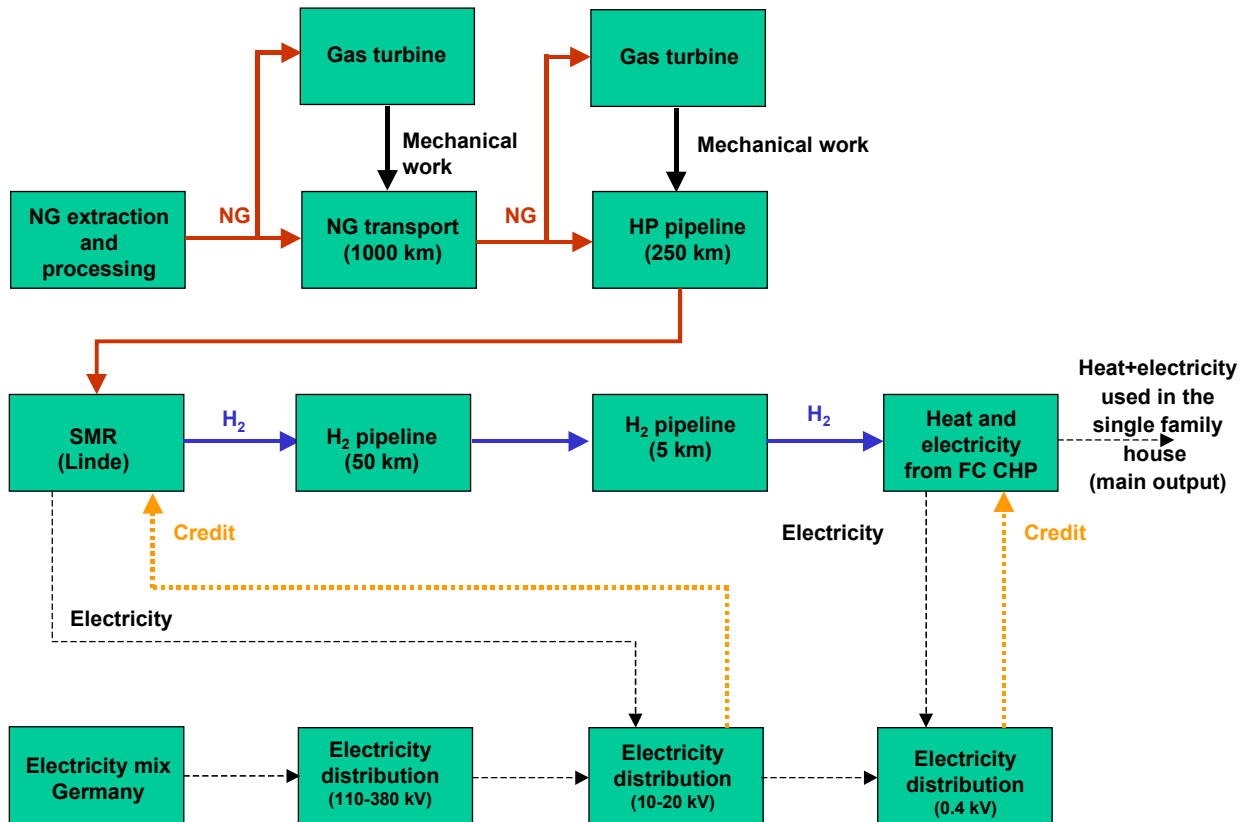


Figure 6-16: Chain 1d) H₂ from central SMR (Foster Wheeler, with CO₂ capture and storage), stationary FC CHP (2nd approach)

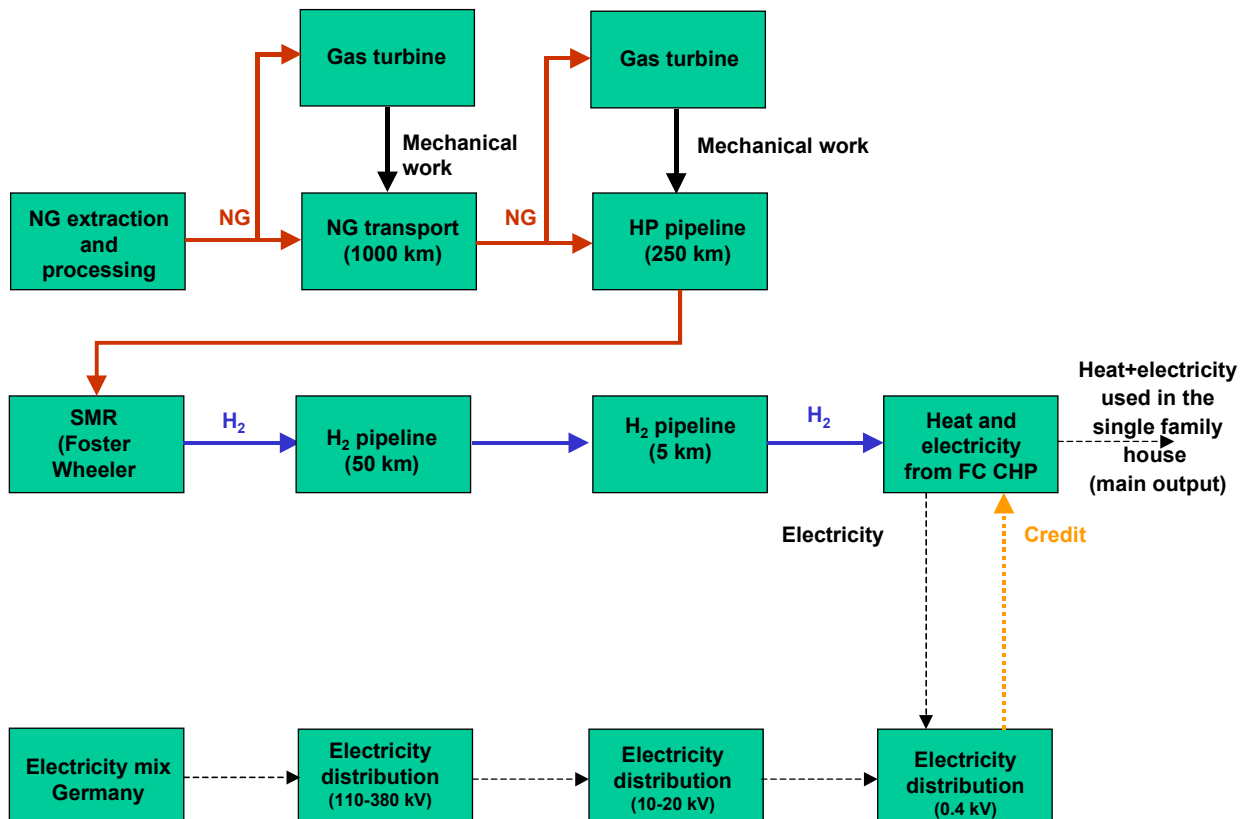


Figure 6-17: Chain 2 a) H₂ from gasification of residual wood (waste wood [WW]), stationary FC CHP (2nd approach)

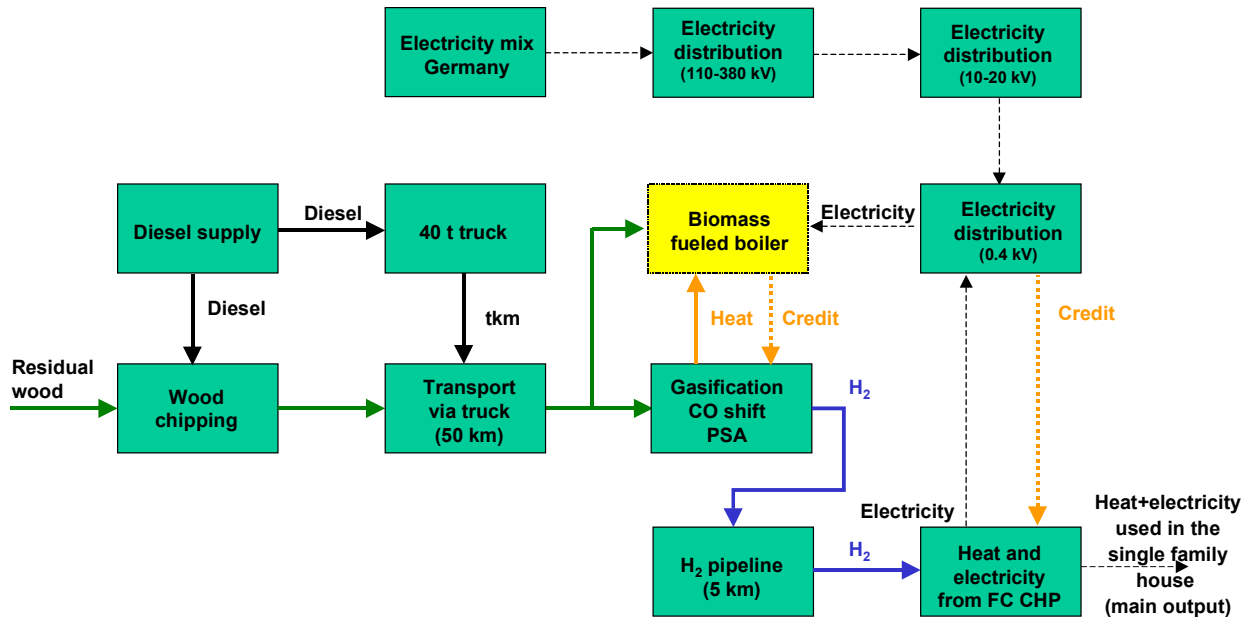


Figure 6-18: Chain 2 b) H₂ from gasification of wood from plantation (farmed wood [FW]), stationary FC CHP (2nd approach)

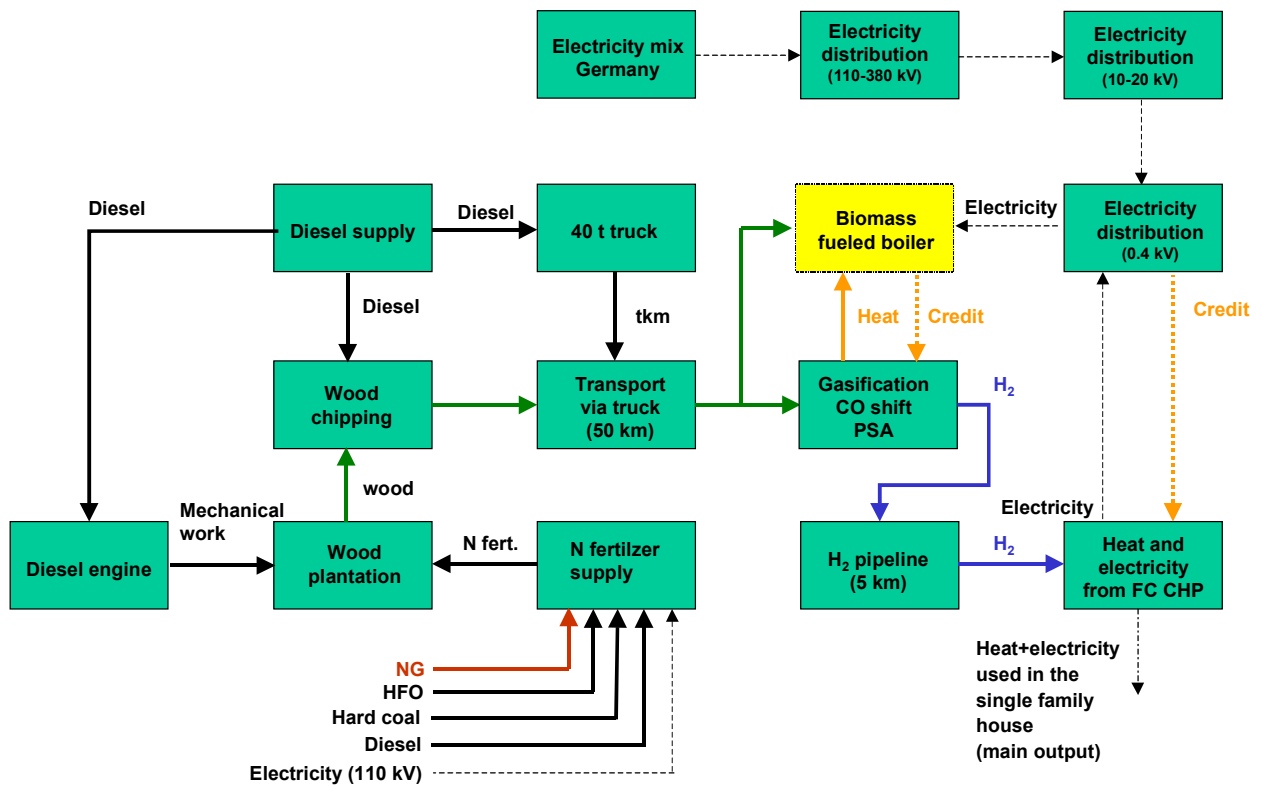
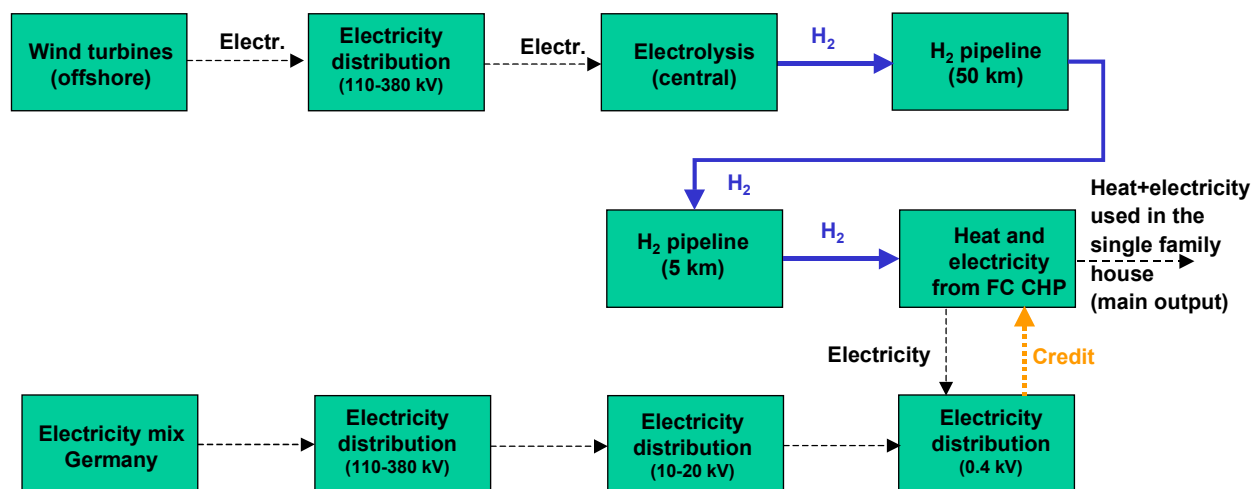


Figure 6-19: Chain 3 a) H₂ from offshore wind power (offshore) via central water electrolysis, stationary FC CHP (2nd approach)



Chain 3b) is equivalent to chain 3a but with electricity from German electricity mix for the electrolysis instead of electricity from offshore wind power.

Figure 6-20: Chain 3 b) H₂ from German electricity mix via central water electrolysis, stationary FC CHP (2nd approach)

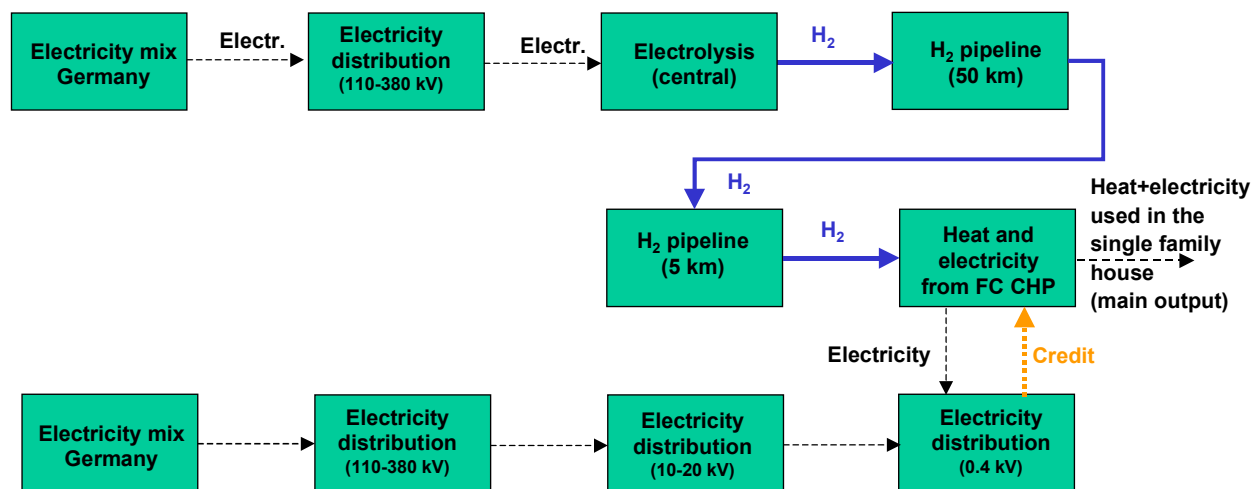


Figure 6-21: Chain 4 a) H₂ from wind power (onshore) via local water electrolysis, FC CHP (2nd approach)

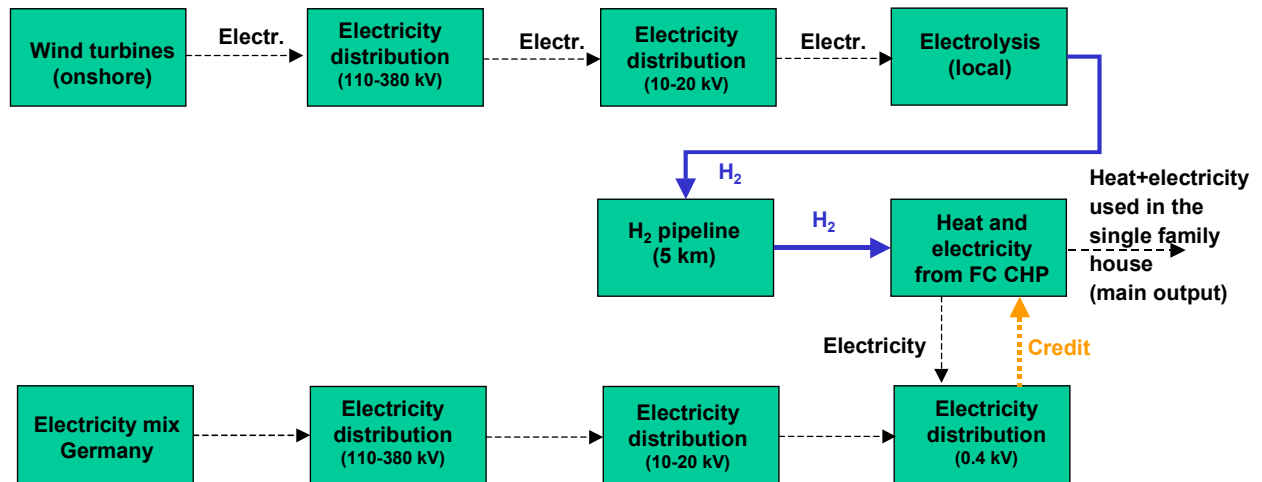


Figure 6-22: Chain 4 b) H₂ from German electricity mix via local water electrolysis, FC CHP (2nd approach)

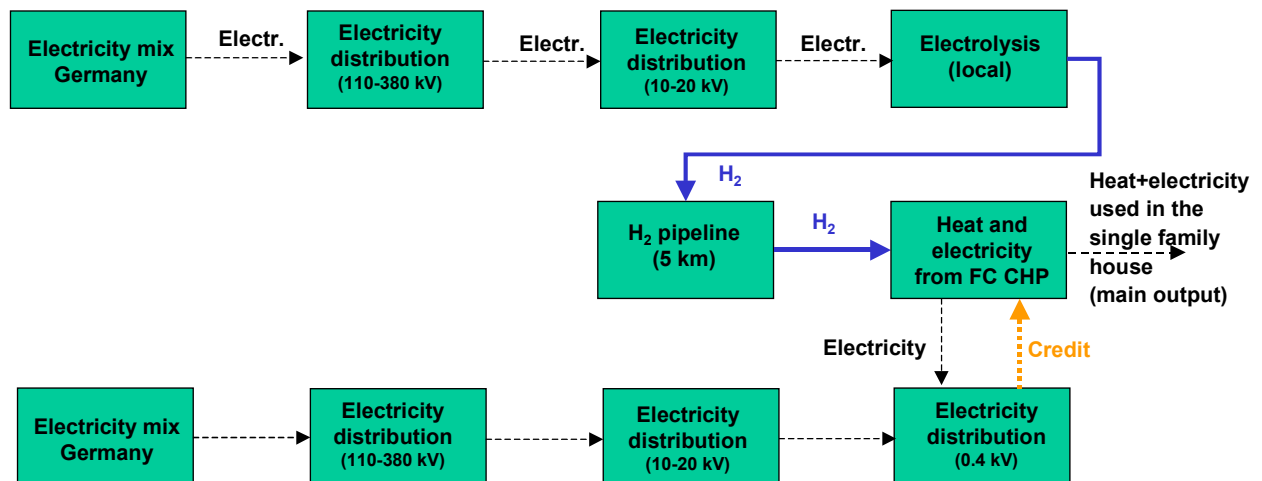


Figure 6-23: Chain 5 a) H₂ from hard coal gasification (Foster Wheeler, with CO₂ capture and storage), FC CHP (2nd approach)

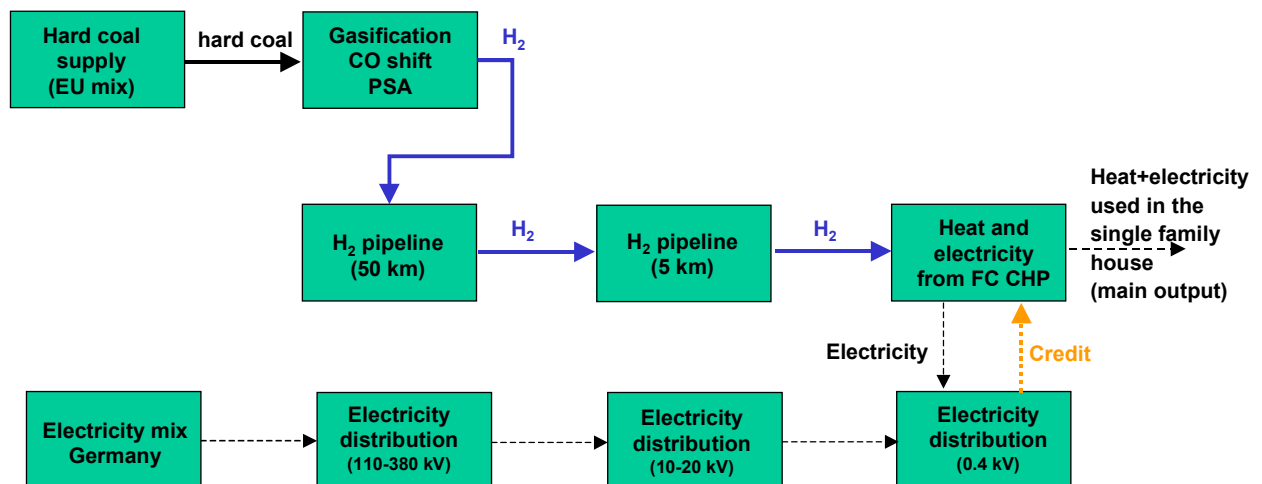
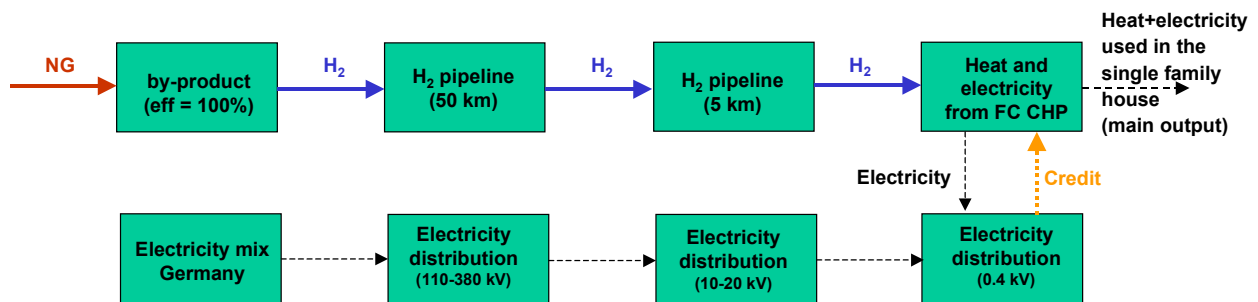


Figure 6-24: Chain 6 a) H₂ from by-product H₂: reference = NG (by-product H₂ is replaced by NG), FC CHP plant (2nd approach)



6.1.2 Industry

For stationary applications for large industry customers a CHP plant based on a combined cycle gas turbine (CCGT) power plant has been used. For the calculation the first approach has been used. The GHG emissions, energy requirements and costs for the supply of electricity have been calculated whereas the heat is considered as by-product. For the by-product a credit has been taken into account. It has been assumed that the heat from the CHP plants replaces heat from a conventional natural gas fueled industrial boiler (efficiency: 85%).

Table 6-4: CCGT CHP plant [LBST 1994]

Capacity [kW _e]	16,600
H ₂ input [kWh/kWh _e]	2.04
Heat output [kWh/kWh _e]	0.67
Investment [EUR]	19,920,000
Maintenance [% of investment]	3
Equivalent full load period [h/yr]	6,000
Useful lifetime [yr]	25

For industrial CHP plants no peak boiler has been considered. It has been assumed that for industrial applications the demand of electricity correlates with the heat demand.

Figure 6-25: Chain 1 b) H₂ from central SMR (Linde), CCGT CHP, industry

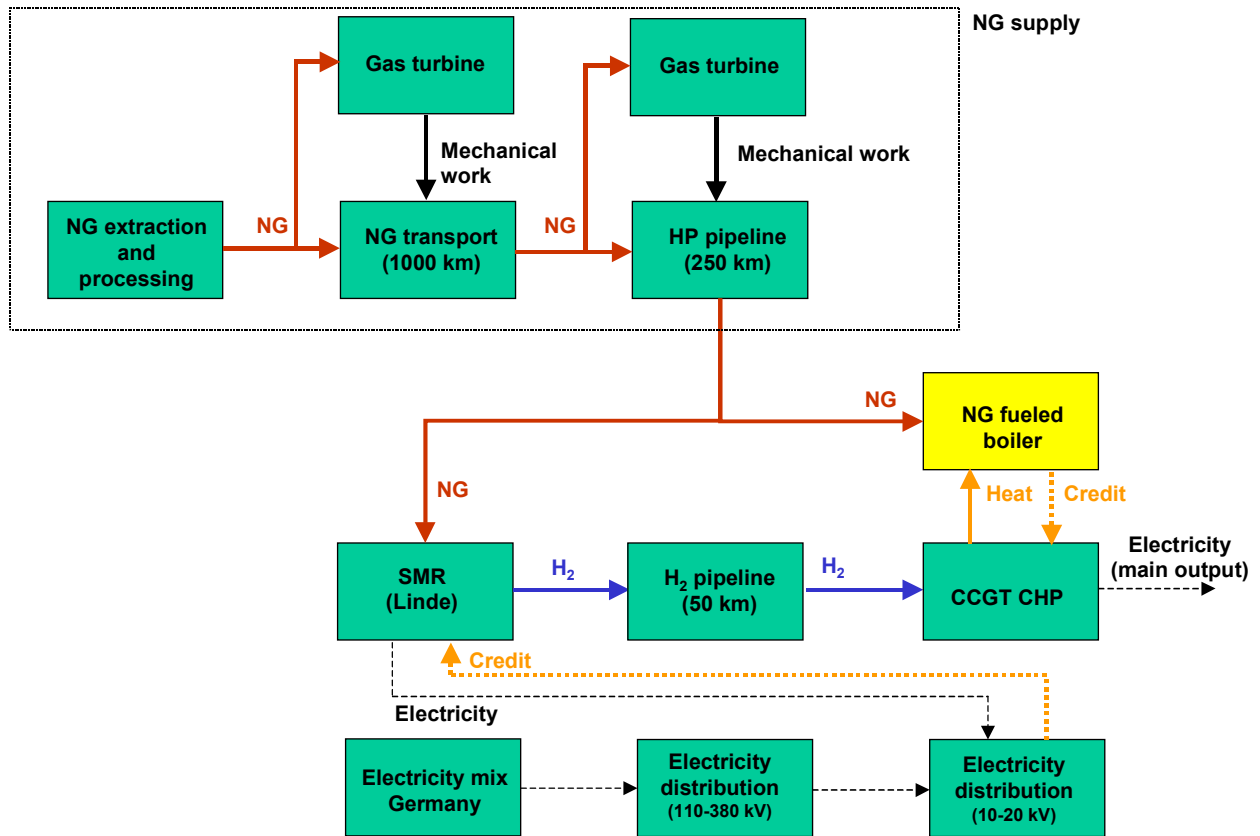


Figure 6-26: Chain 1 d) H₂ from central SMR (Foster Wheeler, with CO₂ capture and storage), CCGT CHP, industry

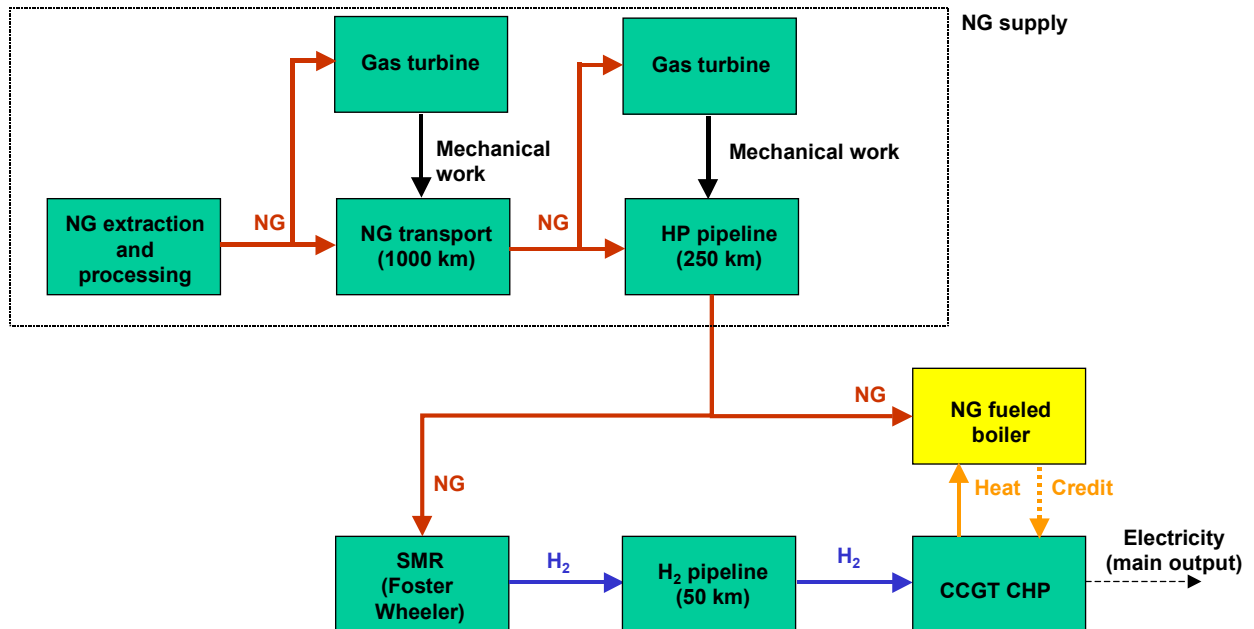


Figure 6-27: Chain 2 a) H₂ from gasification of residual wood (waste wood [WW]), CCGT CHP, industry

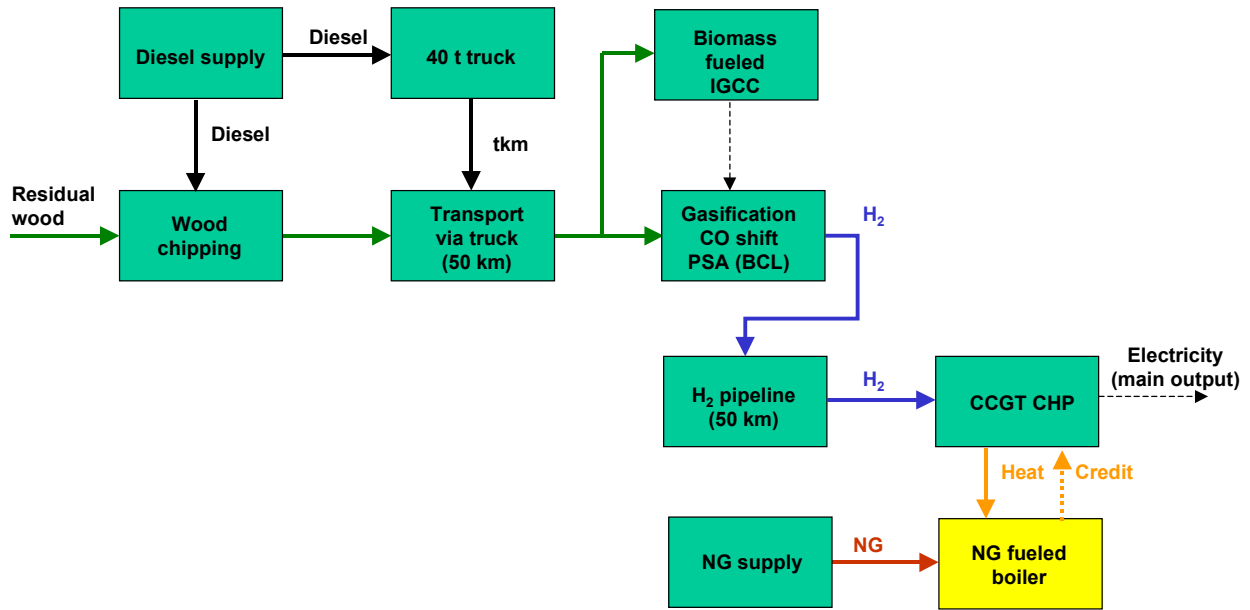


Figure 6-28: Chain 2 b) H₂ from gasification of wood from plantation (farmed wood [FW]), CCGT CHP, industry

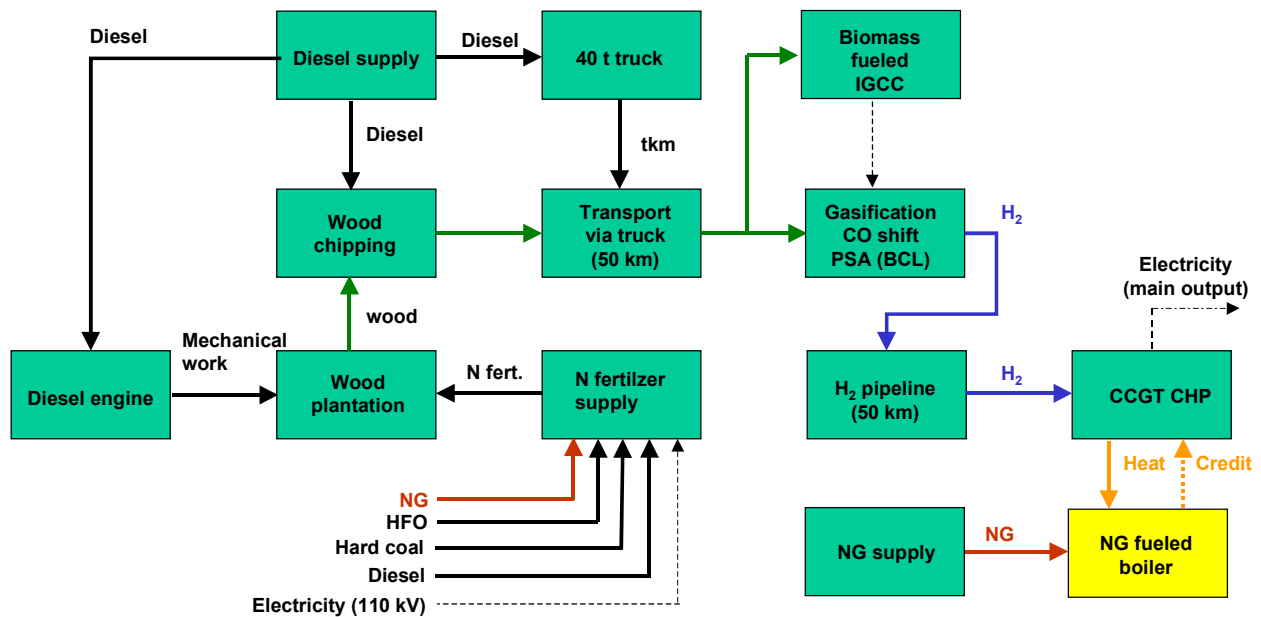


Figure 6-29: Chain 3 a) H₂ from offshore wind power (offshore) via central water electrolysis, CCGT CHP, industry

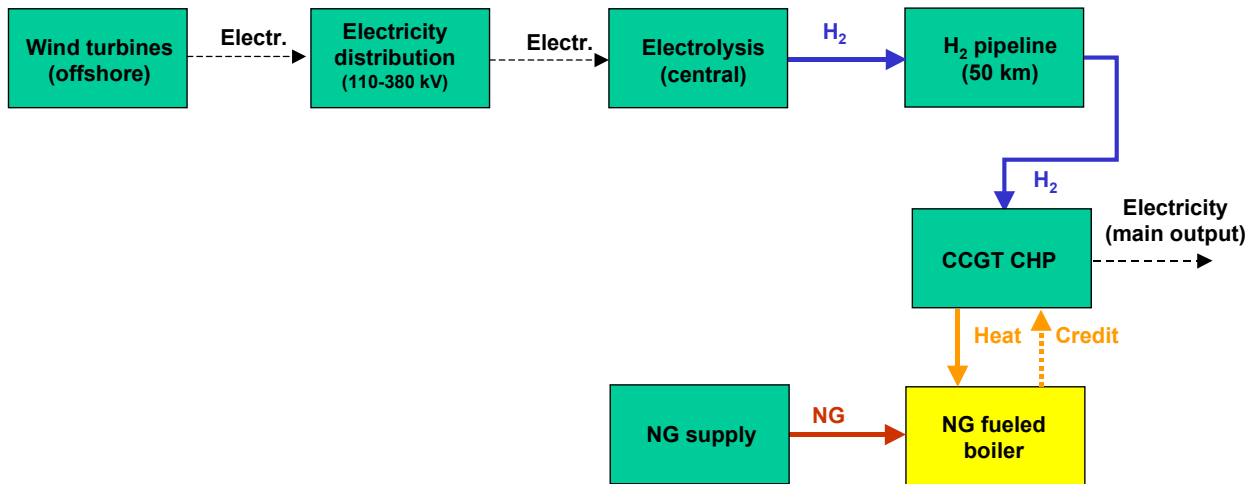


Figure 6-30: Chain 3 b) H₂ from German electricity mix via central water electrolysis, CCGT CHP, industry

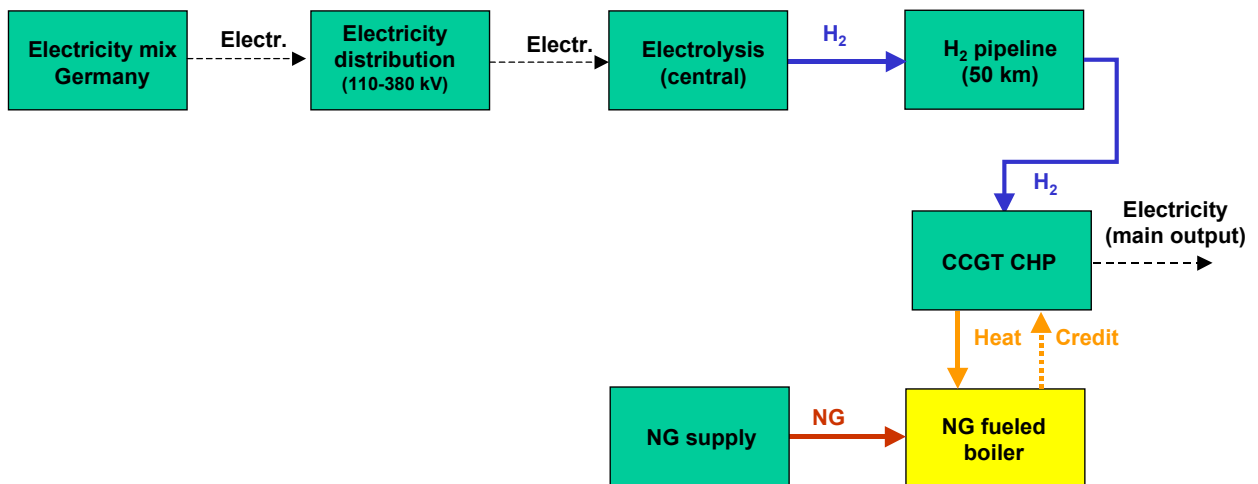


Figure 6-31: Chain 5 a) H₂ from hard coal gasification (Foster Wheeler, with CO₂ capture and storage), CCGT CHP, industry

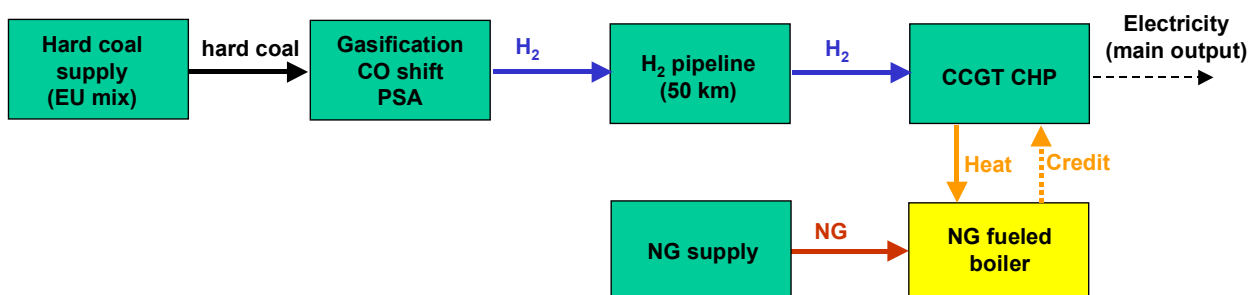
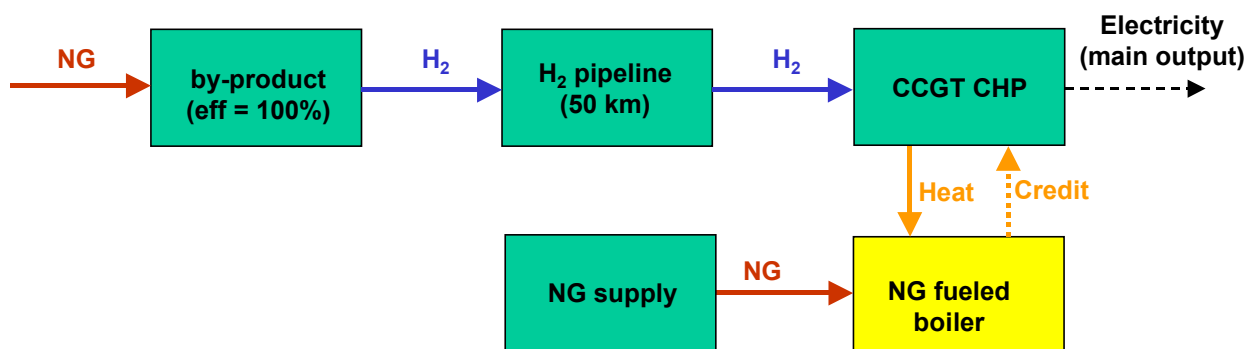


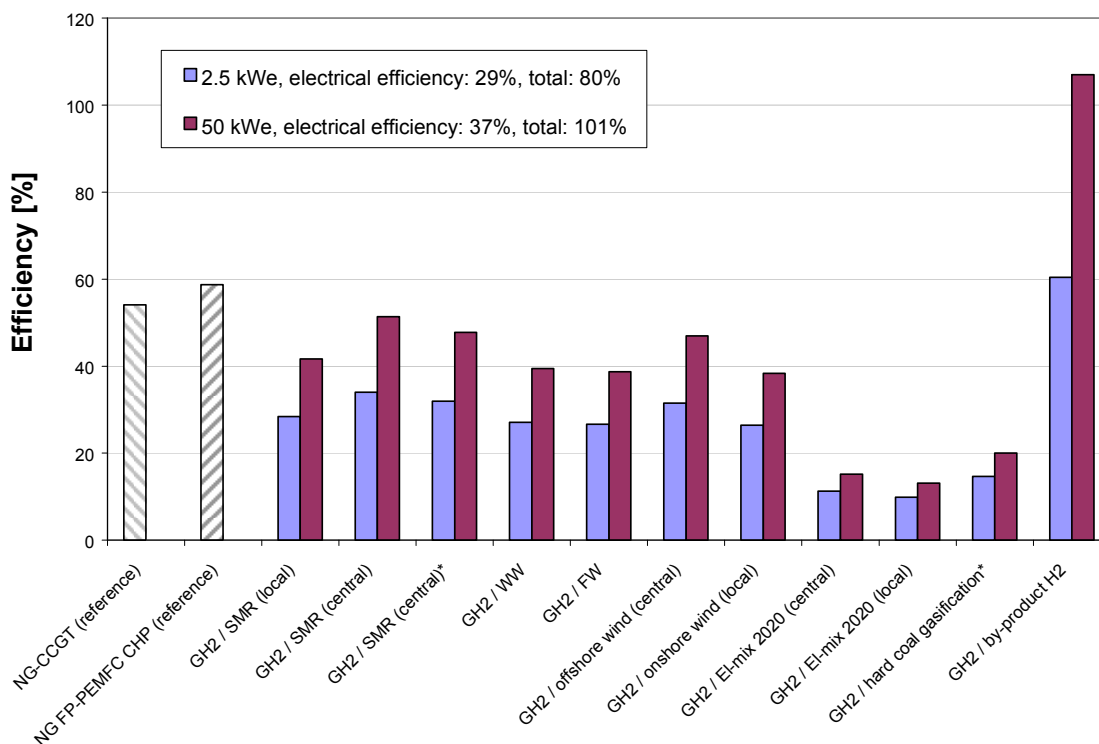
Figure 6-32: Chain 6 a) H₂ from by-product H₂: reference = NG (by-product H₂ is replaced by NG), CCGT CHP, industry



6.2 Results

6.2.1 Households (related to the electricity generation)

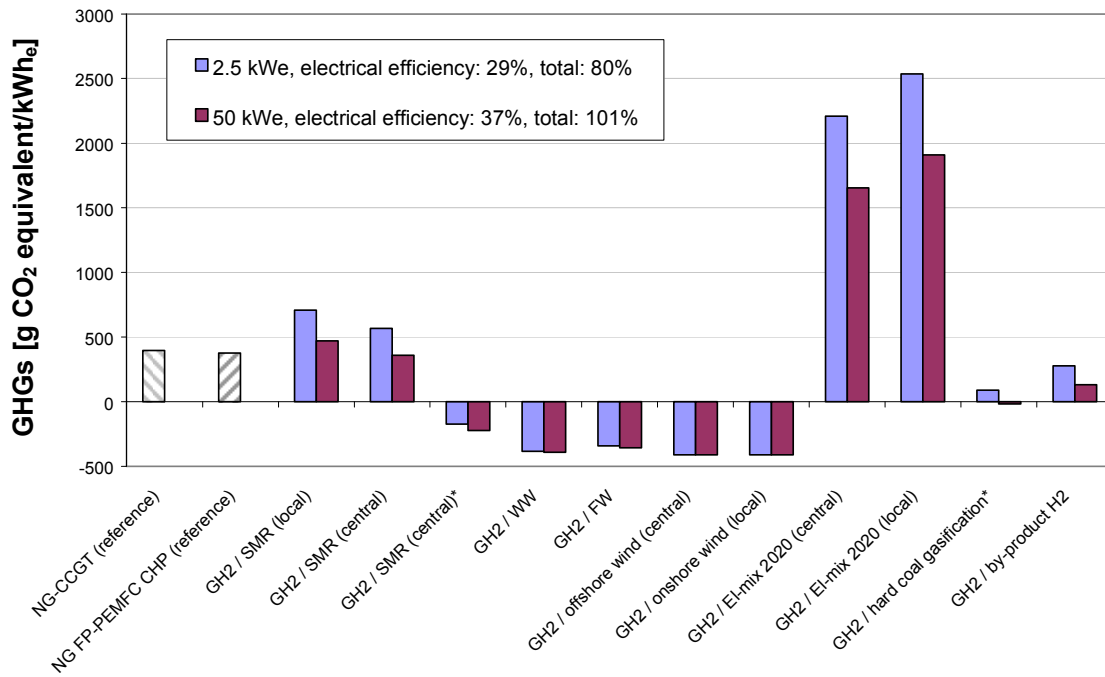
Figure 6-33: Well-to-Stationary Use (WtStU) efficiency 2020



* with CO₂ capture and storage

The efficiency is based on the lower heating value (LHV). Therefore the efficiency can be above 100% if the condensation heat is used.

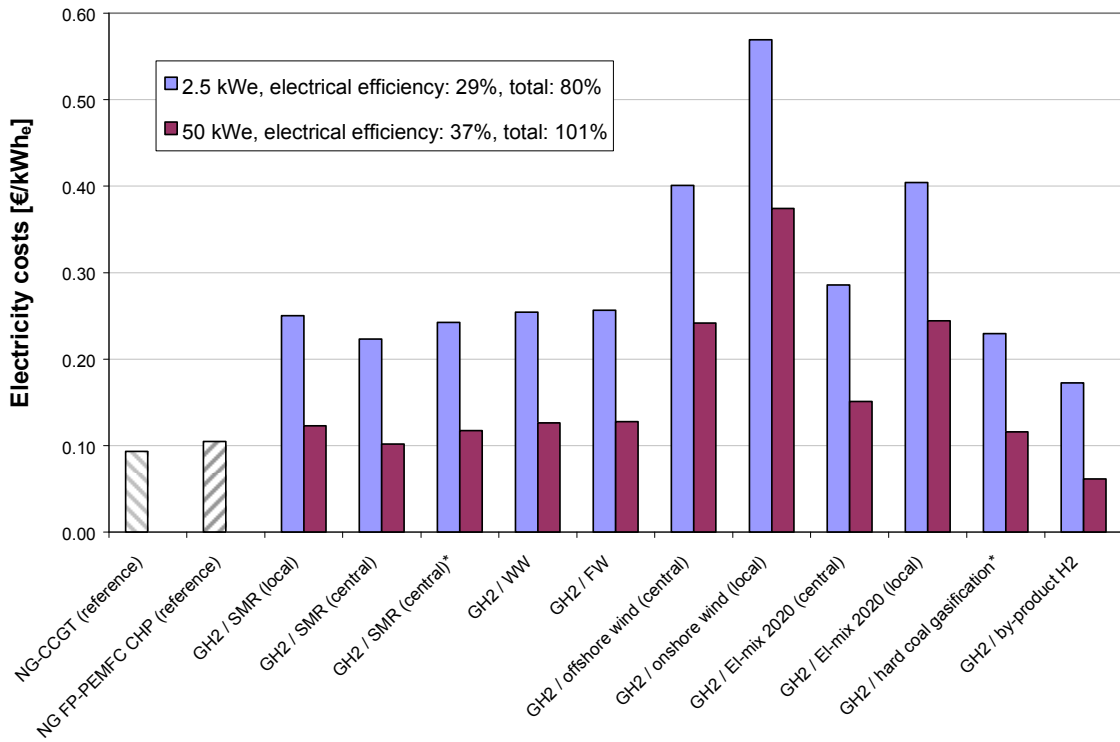
Figure 6-34: Well-to-Stationary Use (WtStU) GHG emissions 2020



* with CO₂ capture and storage

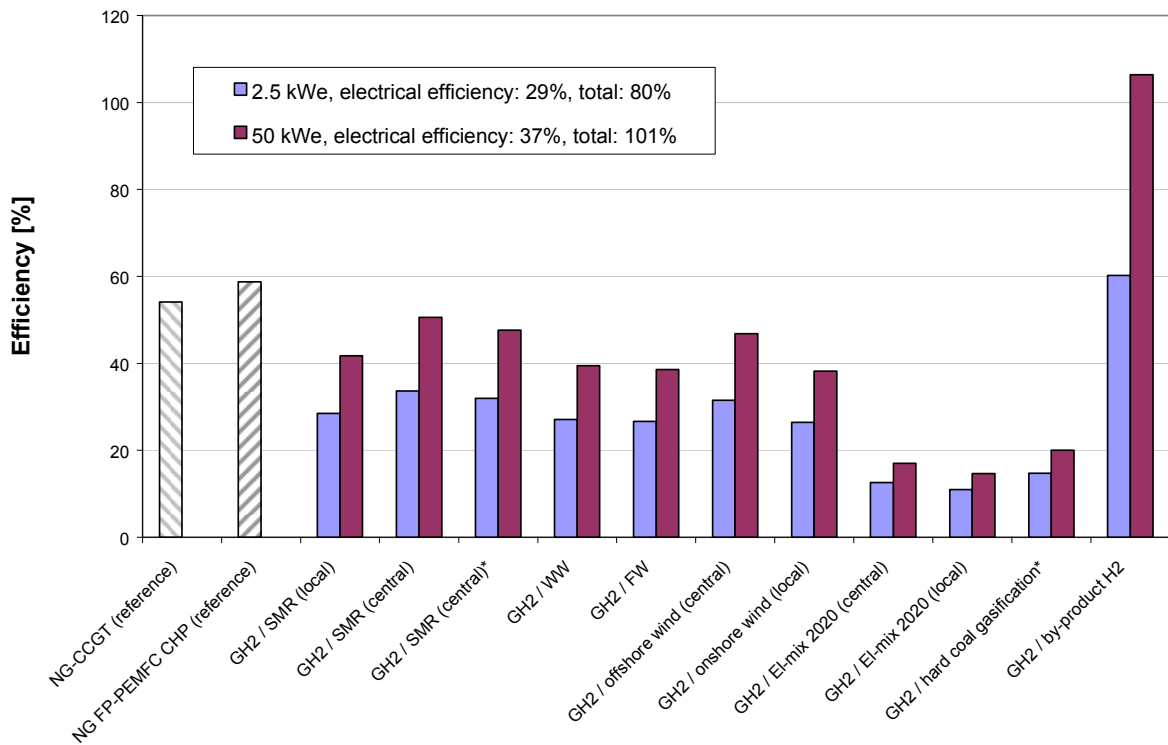
Negative GHG emissions are from the credit for replaced heat from a natural gas fueled heating boiler.

Figure 6-35: Well-to-Stationary Use (WtStU) costs 2020



* with CO₂ capture and storage

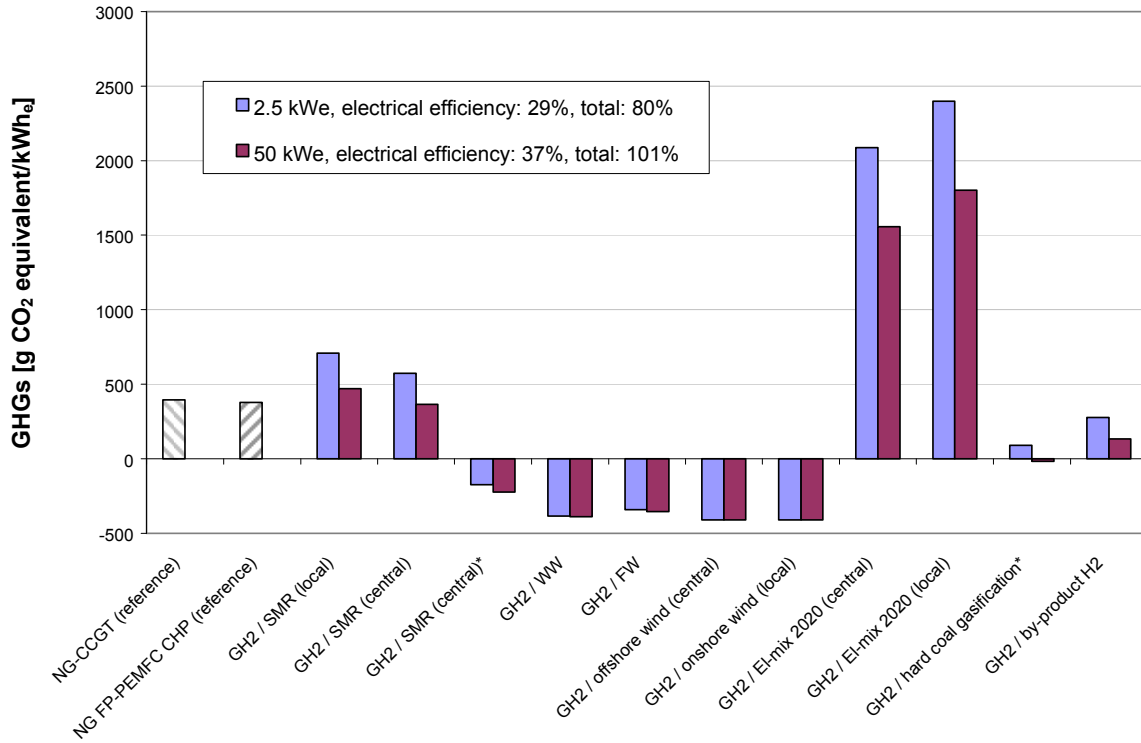
Figure 6-36: Well-to-Stationary Use (WtStU) efficiency 2030



* with CO₂ capture and storage

The efficiency is based on the lower heating value (LHV). Therefore the efficiency can be above 100% if the condensation heat is used.

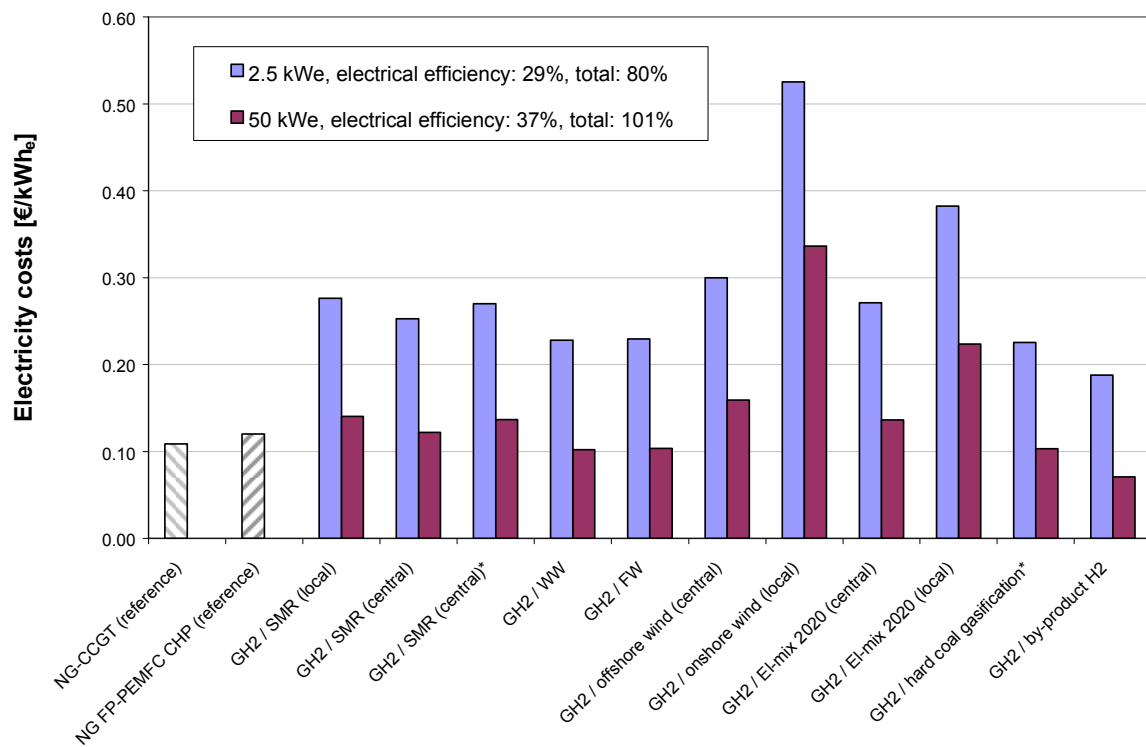
Figure 6-37: Well-to-Stationary Use (WtStU) GHG emissions 2030



* with CO₂ capture and storage

Negative GHG emissions are from the credit for replaced heat from a natural gas fueled heating boiler.

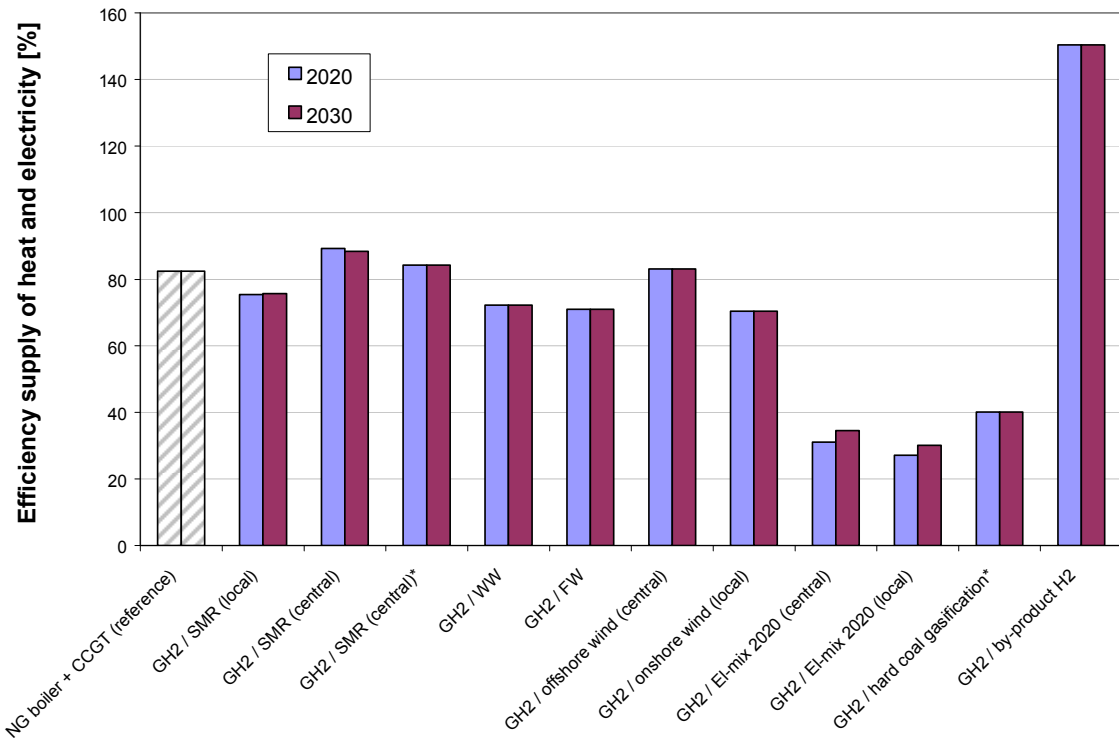
Figure 6-38: Well-to-Stationary Use (WtStU) costs 2030



* with CO₂ capture and storage

6.2.2 Households (related to the combined supply of electricity and heat)

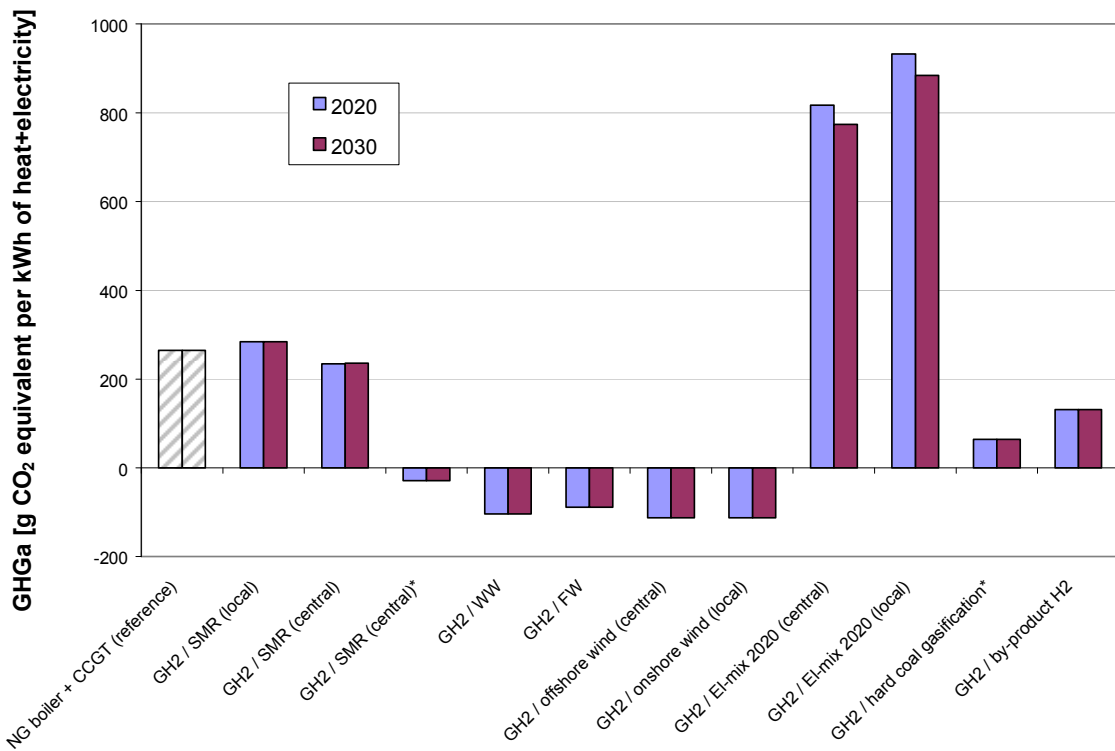
Figure 6-39: Well-to-Stationary Use (WtStU) efficiency 2020 and 2030



* with CO₂ capture and storage

Efficiencies higher than 100% are from credits for excess electricity. A natural gas fueled CCGT has been used as reference system to calculate the electricity credit.

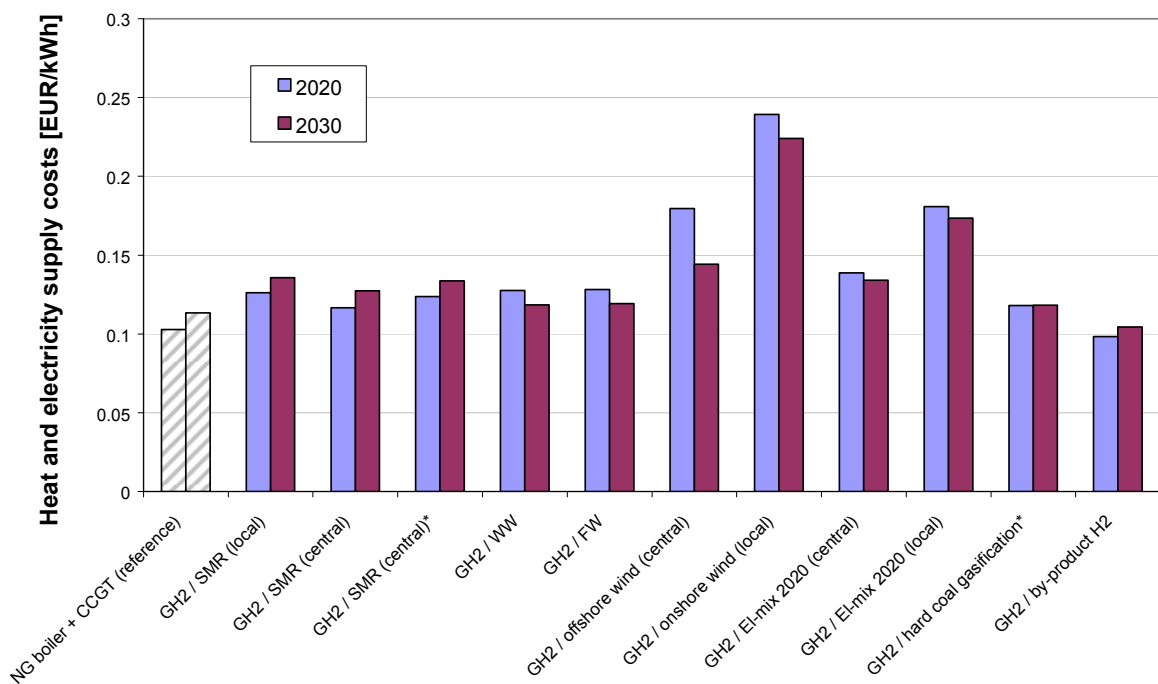
Figure 6-40: Well-to-Stationary Use (WtStU) GHG emissions 2020 and 2030



* with CO₂ capture and storage

Negative GHG emissions come from credits.

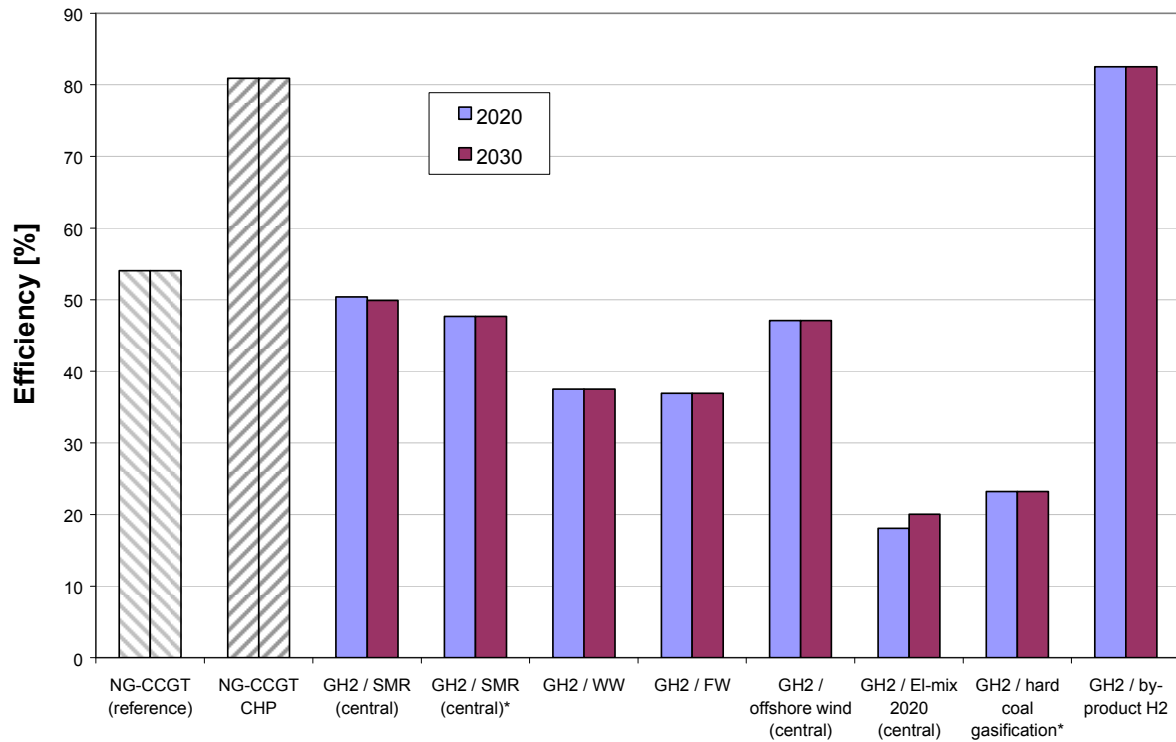
Figure 6-41: Well-to-Stationary Use (WtStU) costs 2020 and 2030



* with CO₂ capture and storage

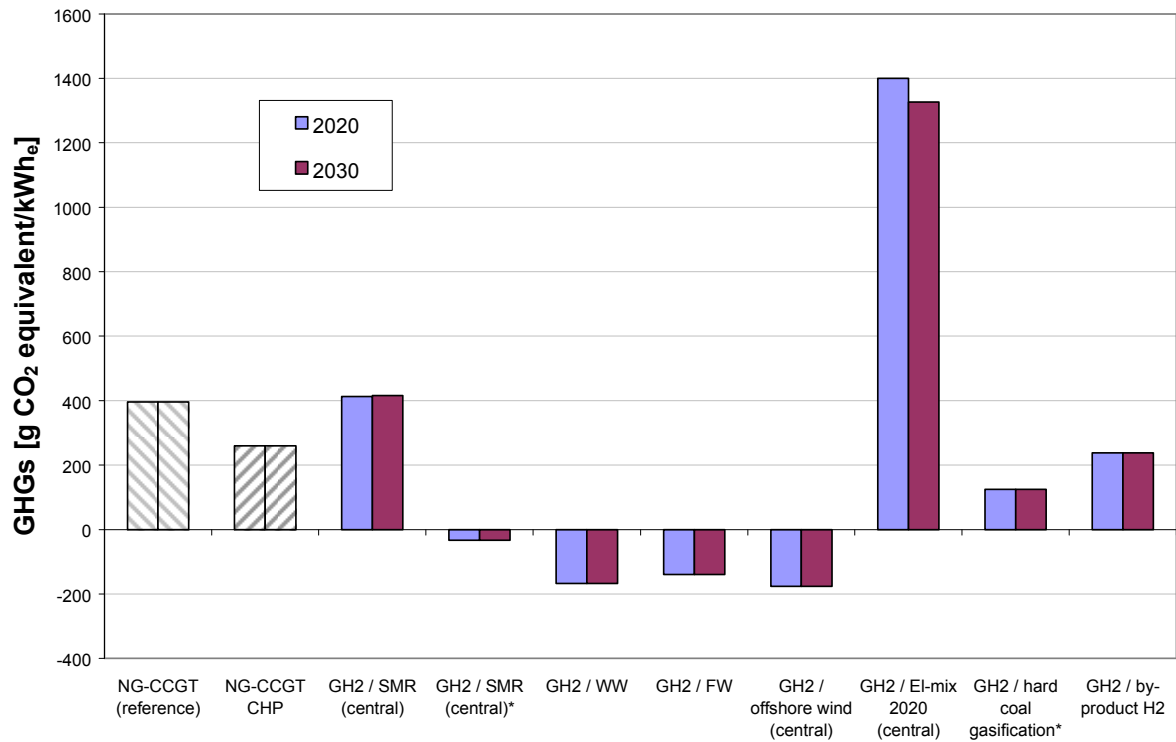
6.2.3 Industry

Figure 6-42: Well-to-Stationary Use (WtStU) efficiency (CCGT CHP, industry) 2020 and 2030



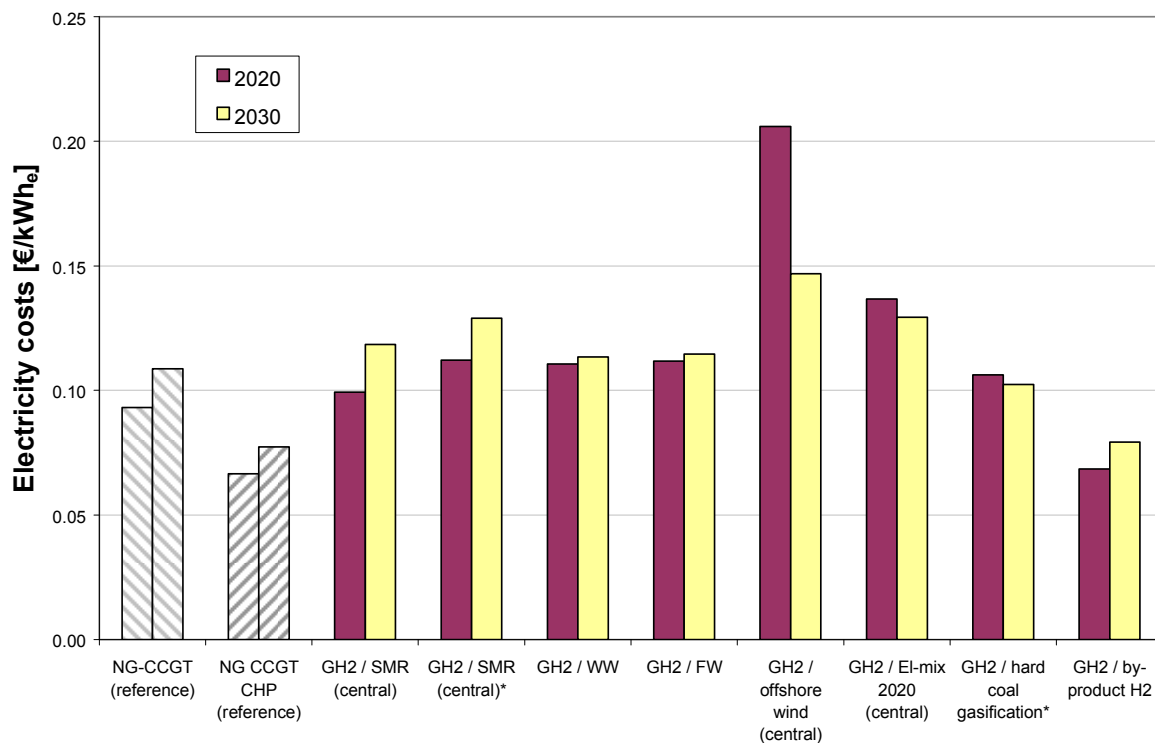
* with CO₂ capture and storage

Figure 6-43: Well-to-Stationary Use (WtStU) GHG emissions (CCGT, industry) 2020 and 2030



* with CO₂ capture and storage

Negative GHG emissions come from credits for replaced heat from a natural gas fueled boiler.

Figure 6-44: Well-to-Stationary Use (WtStU) costs (CCGT, industry 2020 and 2030)

* with CO₂ capture and storage

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8 Appendix