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A comparison of electricity and hydrogen production systems with CO_2 capture and storage—Part B: Chain analysis of promising CCS options

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Abstract

Promising electricity and hydrogen production chains with CO_2 capture, transport and storage (CCS) and energy carrier transmission, distribution and end-use are analysed to assess (avoided) CO_2 emissions, energy production costs and CO_2 mitigation costs. For electricity chains, the performance is dominated by the impact of CO_2 capture, increasing electricity production costs with 10–40% up to 4.5–6.5 €ct/kWh. CO_2 transport and storage in depleted gas fields or aquifers typically add another 0.1–1 €ct/kWh for transport distances between 0 and 200 km. The impact of CCS on hydrogen costs is small. Production and supply costs range from circa 8 €/GJ for the minimal infrastructure variant in which hydrogen is delivered to CHP units, up to 20 €/GJ for supply to households. Hydrogen costs for the transport sector are between 14 and 16 €/GJ for advanced large-scale coal gasification units and reformers, and over 20 €/GJ for decentralised membrane reformers. Although the CO_2 price required to induce CCS in hydrogen production is low in comparison to most electricity production options, electricity production with CCS generally deserves preference as CO_2 mitigation option. Replacing natural gas or gasoline for hydrogen produced with CCS results in mitigation costs over 100 €/t CO_2, whereas CO_2 in the power sector could be reduced for costs below 60 €/t CO_2 avoided.

Keywords: Chain analysis; CO_2 capture; CO_2 transport; CO_2 storage; Hydrogen; Infrastructure

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1. Introduction

In recent years, carbon dioxide capture and storage (CCS) has received much attention for its potential to achieve major CO_2 reductions in a carbon constrained world. In part A, we made an inventory and techno-economic comparison of electricity and hydrogen production technologies

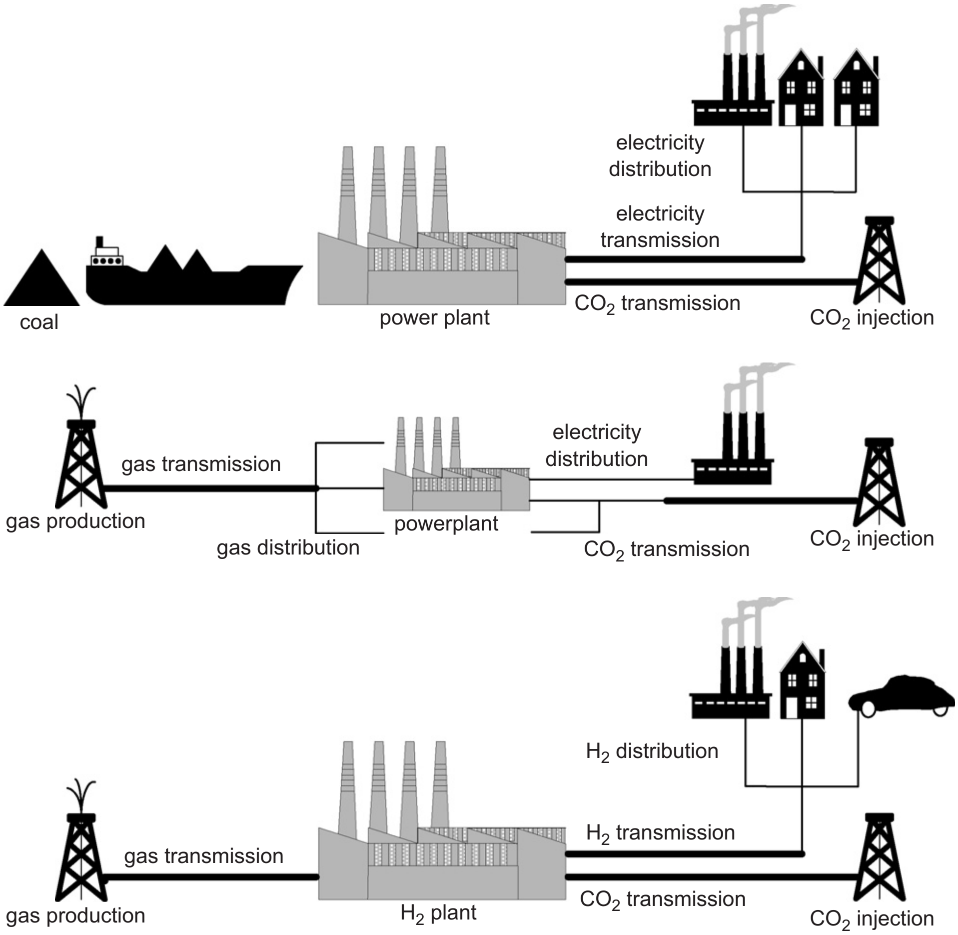


Fig. 1. Different electricity and hydrogen production chains with CCS (from top to bottom: central power production, decentralised power production, central hydrogen production).

Nomenclature

ATR	autothermal reforming
AZEP	advanced zero emission power plant
BF	blast furnace
BOF	basic oxygen furnace
CCS	CO_2 capture and storage
CG	coal gasification
CHP	combined heat and power production
CLC	chemical looping combustion
COE	cost of electricity
COH	cost of hydrogen
GT	gas turbine
DR	direct reduction
EAF	electric arc furnace
EOR	enhanced oil recovery
FCV	fuel cell vehicle
GHG	greenhouse gas
HMCM	hydrogen mixed conducting membrane
HSD	hydrogen separation device
ICEV	internal combustion engine vehicle
IGCC	integrated gasification combined cycle
LHV	lower heating value
LS	liquid steel
MEA	monoethanolamine
MOB	transport sector
MR	membrane reformer
NGCC	natural gas combined cycle
O&M	operating and maintenance
PC	pulverised coal-fired power plant
PEMFC	proton exchange membrane fuel cell
RES	residential sector
ROW	right of way
SMR	steam methane reforming
SOFC	solid oxide fuel cell
ST	steam turbine
STL	steel production
TCR	total capital requirement

with CO_2 capture to identify promising options [1]. The system boundary of this analysis was set at the production plant, i.e. only energy conversion, CO_2 capture and compression were considered. The complete CCS chain also encompasses fuel extraction and transport, CO_2 transport and storage and energy carrier transmission, distribution and end-use, causing additional CO_2 emissions and costs and thereby affecting the overall chain performance. As the technologies studied in [1] differ in fuel type, the amount of CO_2 captured and in scale, the impact of the chain elements outside the plant boundary may affect the performance of the technologies differently (see Fig. 1). For this reason, the complete chain has to be considered to compare (bituminous) coal with natural gas-fired options, oxyfuel with post-combustion capture options, and central with decentralised technologies. A comparison of electricity production with CCS versus hydrogen production with CCS as competing CO_2 reduction options cannot be performed on plant level only. It requires the assessment of CO_2 mitigation costs versus a reference system, such as gasoline or natural gas in case of hydrogen. Since the distribution and end-use of hydrogen is different with respect to the fuels it substitutes, these elements have to be incorporated.

Relatively few studies have been performed in which the entire chain is analysed. Most of these studies focus on large-scale combustion or gasification systems and include only a number of chain elements. CCS at decentralised units is generally considered incompatible due to economies of scale. Hendriks et al. performed a generic chain analysis for several central electricity and hydrogen chains with CCS to assess additional costs and avoided emissions versus the average park and natural gas [2]. Costs and energy use of CO_2 and energy transmission (excluding distribution to end-use markets) for central power and hydrogen plants have been studied in [3]. Fuel supply chains and associated costs for different hydrogen production and supply technologies have been assessed in [4]. Ogden studied large-scale hydrogen production and supply chains for the transport sector in the USA, including CCS [5]. Also various Dutch CCS chains have been analysed, in which existing electricity and industrial plants were linked to possible storage sites [6].

However, no study could be identified in which the aspects of *time* (short versus long term), *scale* (central versus decentralised units), *energy transmission and distribution* for different end-users and choice of the *reference system* are explicitly and consistently dealt with for both electricity and hydrogen systems with CCS. Therefore, in this study, promising technologies identified in part A are further assessed in a chain analysis that accounts for these factors. Overall CO_2 emissions, electricity and hydrogen production costs and CO_2 mitigation costs of various technologies are assessed for different technological and infrastructural settings, and various reference systems. This allows us to consistently compare a wide range of CCS technologies in different contexts. By including different hydrogen end-users, the performance of hydrogen in different sectors can be compared. The chain analysis also provides insight into the economic trade-off between CO_2 and energy transmission. This knowledge is of importance in site selection of new plants, for the construction of new infrastructure involves large investments. Finally, the CO_2 emissions over the entire chain give an indication of the 'climate neutrality' of decarbonised electricity and hydrogen versus its reference as applied in [2].

The geographical focus is on the Netherlands, representing a densely populated industrialised country, where CCS would typically be deployed. CCS may play a significant role in the Netherlands in the coming decades, as this country is characterised by numerous large CO_2 sources and potential sinks. The Dutch CO_2 emission in 2003 was circa 177 Mt CO_2, of which approximately 100 Mt emitted by the energy and manufacturing industry [7]. Power and heat production accounted for 55 Mt CO_2. Large point sources (>0.1 Mt CO_2/yr) at which CO_2 capture is feasible represented circa 96 Mt CO_2 [8]. The estimated technical storage capacity of Dutch on- and offshore aquifers and gas fields exceeds 11 Gt CO_2 [8], implying CCS could potentially be deployed for many decades to come.

After the discussion of the main methodological issues in Section 2, the electricity and hydrogen chains are described in Section 3. These chains are inspired by the future 'energetic and geological map' of the Netherlands, which gives an overview of CO_2 sources, hydrogen end-use markets and CO_2 storage reservoirs. Section 4 presents the results of the chain analysis, including a sensitivity analysis for several crucial parameters, followed by discussion and conclusions in Section 5.

2. Chain analysis

Fig. 2 shows the different elements of the CCS chains. In the analysis, greenhouse gas (GHG) emissions of fossil fuel extraction, transport and distribution are accounted for. In order to capture CO_2, additional fuel is required, which results in additional GHG emissions due to coal mining and natural gas extraction, as well as transport and distribution of these fuels. Electricity and hydrogen transmission and distribution is accounted for as significant energy losses and/or additional costs can occur depending on the system layout [3,5]. Hydrogen end-use is accounted for because specific hydrogen conversion technologies (fuel cells) can be fundamentally different from reference end-use technologies for conversion of hydrocarbons (turbines, boilers, internal combustion engines).

For each chain, we set up an energy and CO_2 balance and calculate levelised production costs of electricity and hydrogen (COE and COH for electricity and hydrogen, respectively) and CO_2 mitigation costs. COE and COH are calculated by dividing the sum of annual capital and O&M costs of the conversion system and infrastructure, fuel costs and CO_2 storage costs by the annual energy production. Costs are converted to €$_{2003}$ using GDP deflators [9] and annual currency exchange rates [10]. CO_2 mitigation costs for electricity production with CCS are calculated using the following formula:

$$CO_2\text{ mitigation costs} = \frac{\text{COE}_{\text{CCS}} - \text{COE}_{\text{ref}}}{m_{CO_2,\text{ref}} - m_{CO_2,\text{CCS}}}, \quad (1)$$

in which COE is the cost of electricity (€/kWh) and m the CO_2 emission factor (kg/kWh) of the CCS chain and reference chain.

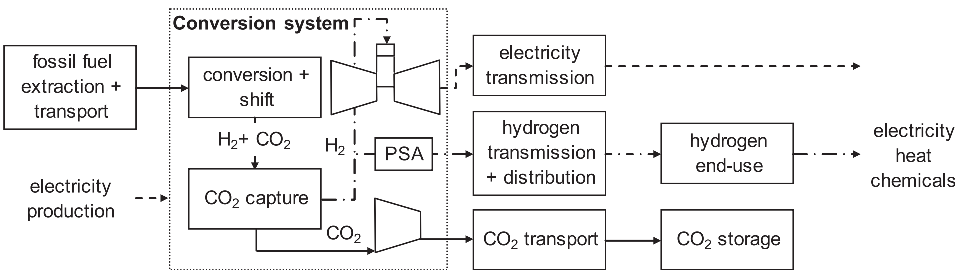


Fig. 2. Elements in electricity and hydrogen production chains with CCS.

The choice of the reference system has a significant impact on calculated CO_2 mitigation costs. In this analysis, the impact of the various reference systems will be assessed. In the most common approach as applied in part A, identical plants with and without CO_2 capture are compared (i.e. the baseline varies per technology). This method gives a good indication which technology inherently enables low-cost CO_2 capture. However, a plant with CO_2 capture does not necessarily replace an identical plant without capture, as the construction of a new power plant is determined by market forces and policies. In addition, the plant with low capture costs can be expensive as such. In the Netherlands, the fuel mix for power generation consists primarily of coal and natural gas, so it can be argued to consider a PC and NGCC as reference system. Hendriks et al. [2] make a distinction between a project independent approach using generic emission and cost figures, and a project specific approach, using project specific data as reference. In the former approach, the reference system could be the current Dutch power generation mix, resulting in more generalised CO_2 mitigation costs.

Hydrogen produced with CO_2 capture should be compared to the fuel it substitutes: gasoline or diesel in the transport sector, natural gas in households and industry, or hydrogen (produced without CO_2 capture), e.g. for chemical purposes. In the long term, hydrogen might replace cokes as reducing agent in steel production [11]. When hydrogen produced with CO_2 capture replaces conventionally produced hydrogen, the common formula to calculate CO_2 mitigation costs can be applied (Eq. (1)). For the cases where it substitutes gasoline, natural gas or cokes, the end-use technology should be accounted for as well (Eq. (2)):

$$\mathrm{CO_2\ mitigation\ costs} = \frac{(\mathrm{COH}/\eta + \mathrm{C} + \mathrm{O\&M})_{\mathrm{H_2}} - (\mathrm{COF}/\eta + \mathrm{C} + \mathrm{O\&M})_{\mathrm{ref}}}{(m_{\mathrm{CO_2}}/\eta)_{\mathrm{ref}} - (m_{\mathrm{CO_2}}/\eta)_{\mathrm{H_2}}}, \qquad (2)$$

in which COH is the hydrogen cost (€/GJ on LHV basis); COF the reference fuel costs (€/GJ); η the end-use efficiency (functional unit/GJ); C the capital cost of end-use (€/functional unit); O&M the operating and maintenance costs (€/functional unit); and m the CO_2 emission factor (kg/GJ).

A functional unit can be a kilometre, a GJ electricity/heat or a tonne of steel.

3. Chain description

CCS chains, which combine specific electricity and hydrogen production technologies via specific infrastructure to specific CO_2 storage reservoirs and specific end-users, have both a *spatial* and *temporal* dimension. The *spatial* dimension encompasses the infrastructural design to connect energy extraction, conversion, and end-use markets and CO_2 sources with storage reservoirs. Therefore, insight into the transport costs of primary and secondary energy carriers and CO_2 is required, for which quite a variation exists in literature [3,5,12–16]. For a 500 MW_e NGCC, transmission costs of electricity (in €/kWh) over a certain distance are higher than for natural gas and CO_2 (onshore conditions) [3]. It may be more advantageous, however, to produce electricity nearby the CO_2 storage reservoir provided that this reservoir is closely located to the natural gas source. Such trade-offs also exist for hydrogen, natural gas and CO_2 transmission. It has been estimated that hydrogen will cost between 30% and 50% more to transport than an equivalent energetic quantity of natural gas [17]. Although hydrogen has a lower molecular weight and viscosity in comparison to gas, which makes hydrogen flow faster, the volumetric energy content of hydrogen is about one third of that of natural gas. The trade-off between CO_2 and H_2 transmission is amongst others depending on the fuel used to produce hydrogen and will be further studied here.

The *temporal* dimension is related to the timeframe considered for implementation. We distinguish chains that may be implemented on a relatively short term (2010–2015) from long-term chains (>2030), which differ in a number of aspects:

- *Extent of CCS*: In the short term, the construction of at most a few plants with CO_2 capture can be expected. In the longer term, a more significant contribution of CCS in the portfolio of CO_2 emission reduction options is presumed. As a guiding line, we assume 20 Mt CO_2 will be captured and stored annually by 2030.[1]

[1]The technical potential for CCS in 2030 has been estimated at 40–60 Mt CO_2 [18]. A recent update studying the potential of various GHG reduction options revealed that the expected contribution of CCS in 2020 is between 0 and 15 Mt CO_2 avoided, depending on the emission reduction target set [19]. In order to capture and store 20 Mt CO_2 annually in the electricity sector, the equivalent of at least six 500 MW_e state-of-the-art PC plants needs to be installed with a chemical absorption unit.

- *Technologies*: We consider state-of-the-art technologies for the short-term chains and more advanced technologies for the long-term chains [1]. Fuel cells for hydrogen end-use are expected to become available in the longer term. In the shorter term, hydrogen could technically be deployed for heat and power generation using boilers and turbines and for traction in internal combustion engines. However, forecasts of hydrogen demand for energy purposes in 2010–2015 appear too small to justify central hydrogen production with CCS [4,20–22].
- *Storage capacity:* The capacity of natural gas fields becomes gradually available in the coming decades with the depletion of these reservoirs.
- *Infrastructure:* In the short term, we consider dedicated CO_2 pipelines from power plants to storage reservoir(s). In the long term, the CO_2 infrastructure is likely to be expanded to a network connecting various point sources and reservoirs. Similarly, we consider a hydrogen network to connect a large plant with various end-use markets.

First, the electricity and hydrogen production technologies are discussed, followed by the CO_2 storage reservoirs and the different hydrogen end-use markets. Combining the information on CO_2 sources, CO_2 sinks and H_2 end-use markets then allows us to design the infrastructure required to connect these elements. The economic assumptions and emission factors applied in the analysis are given in Table 1.

Table 1
Economic parameters and emission factors used in this analysis

Parameter[a]	Value	Range
Interest rate	10%	5–15%
Capacity factor	85%	60–90%
Economic lifetime for production plants (yr)	20	15–25
Energy+material costs		
Steam coal (€/GJ)[b]	1.7	1–3
Natural gas for large industrial users (€/GJ)[b]	4.7	3–6
Natural gas for small industrial users (€/GJ)[b]	5.4	4–7
Natural gas for households (€/GJ)[b]	8.2	7–10
Electricity for large industrial users (€/MWh)[b] (= average Dutch electricity costs)	50	40–70
Electricity for small industrial users (€/MWh)[b]	80	70–100
Electricity for households (€/MWh)[b]	90	80–110
Gasoline (€/GJ)[c]	9	5–15
Coking coal (€/GJ)[d]	2.1	—
Steam (€/GJ)[d]	5	—
Iron ore (fine) (€/t)[d]	18	—
Iron ore (lump) (€/t)[d]	24	—
Iron ore pellets (€/t)[d]	36	—
Scrap (€/t)[d]	100	—
Electrodes (€/kg)[d]	2.4	—
GHG emission factors[e]		
Natural gas (kg CO_2-eq/GJ)	56 (57)	—
Coal (kg CO_2-eq/GJ)	95 (103)	—
Gasoline (kg CO_2-eq/GJ)	72 (87)	—
Average Dutch electricity 2020 (kg CO_2/MWh)	450	350–500

[a]We consider fixed costs and emission factors to increase transparency in outcome. The uncertainty in developments in fuel costs is further accounted for in the sensitivity analysis.
[b]Forecasts for 2020 [23,24], including commodity, transmission and distribution costs, excluding taxes and VAT. Electricity prices are used for selling and buying.
[c]Rotterdam gasoline price (plus distribution costs, excluding taxes and VAT) in 2003/2004, during which oil prices were around 30–35 $/bbl [25].
[d][26].
[e]Values in parentheses include GHG emissions of fossil fuel extraction, transport and distribution (and refining in the case of gasoline) [2,27]. Note that indirect GHG emissions of coal and natural gas use may change in the longer term as a consequence of improved mining and transport practices, longer transport distances and switch to LNG. The average emission factor of Dutch electricity production is based on a scenario forecast given in [23].

3.1. CO_2 sources: electricity and hydrogen production technologies

Key techno-economic characteristics of the technologies have been discussed in [1] and are summarised in Tables 2 and 3. Decentralised electricity and hydrogen production is generally not considered due to the relatively high costs of CCS at such scales. Advanced concepts using fuel cells and membranes, however, offer the potential for low-cost CO_2 capture at relatively small scales [28]. Decentralised electricity production with CCS is of particular interest for the Netherlands given the large share of decentralised CHP units (circa 5 GW_e of total installed capacity near 20 GW_e in 2003) [29]. Small-scale H_2 production with CCS might play a role in the transition towards a hydrogen economy.

3.2. CO_2 sinks: geological reservoirs

Reservoirs suited for geological storage of CO_2 can be classified into (nearly) depleted oil and gas

Table 2
Key parameters of electricity production technologies with CO_2 capture and compression to 110 bar

Feedstock	Conversion technology	CO_2 capture technology	Net electric efficiency (%)	CO_2 capture efficiency (%)	TCR (€/kW)	O&M (%)
Reference technologies (600 MW_e)						
Bituminous coal	PC	—	44	—	1500	5.2
Natural gas	NGCC	—	56	—	540	3.7
State-of-the-art technologies (600 MW_e)						
Bituminous coal	PC	Post-comb (MEA)	35	88	2080	5.8
	IGCC	Pre-comb (Selexol)	32–35	85	1770–2170	4.8–5.2
Natural gas	NGCC	Post-comb (MEA)	47	85	920	4.3
Advanced technologies (600 MW_e except SOFC-GT)						
Bituminous coal	Advanced PC	Improved post-comb (MEA)	40	85	1520	6.5
	Advanced IGCC	Pre-comb (Selexol)	43	85	1500	5
	IG-Water	Oxyfuel (ASU)	41	100	1530	3.7
	IG-SOFC-GT	Various (membrane/ cat. combustor)	50	90	1760	3.3
Natural gas	Advanced NGCC	Improved post-comb (MEA)	55	85	650	4.8
	MR-CC	Pre-comb (HMCM)	53	100	940	4
	CLC	Oxyfuel (separate combustion)	51	100	900	4
	AZEP	Oxyfuel (oxygen membrane)	50	100	900	4
	SOFC-GT (20 MW_e)	Oxyfuel (afterburner)	59	80	1530	3

Table 3
Key parameters of hydrogen production technologies with CO_2 capture and compression to 110 bar

Conversion technology	CO_2 capture technology	Fuel + feed input (GJ/GJ_{H_2})	Electricity input (GJ_e/GJ_{H_2})	Conversion efficiency (%)	CO_2 capture efficiency (%)	TCR (€/kW_{H_2})	O&M (%)
Advanced ATR (1000 MW_{H_2})[a]	MDEA	1.28	0.03	74	90	280	4
Advanced CG (1000 MW_{H_2})[a]	Selexol	1.35	0.05	69	90	600	4
MR (2 MW_{H_2})[b]	Pd membrane	1.26	0.13	65	70	610	9

[a]Including H_2 compression to 60 bar.
[b]Estimated capacity to supply a future hydrogen refuelling station, including H_2 compression to 480 bar [28].

fields, deep saline aquifers and unminable coal seams.[2] In the Netherlands, gas fields offer a large storage potential of circa 10 Gt CO_2, of which 7.5 Gt is represented by the Groningen gas field. Most of the reservoirs provide less than 30 Mt CO_2 storage capacity,[3] although nearly 30 reservoirs provide a storage potential between 30 and 300 Mt CO_2 [31]. In the coming decade various small and

[2]Storage in the deep ocean is not considered. Injection depths are at least 1000 m [30], which would require transport by ship over large distances as the North Sea is not deep enough.

[3]Reservoirs should preferably offer sufficient potential to store the captured CO_2 of one plant over its lifetime. A 500 MW_e NGCC equipped with amines captures circa 1.5 Mt CO_2/yr, corresponding to 30 Mt to be stored in a 20-year lifetime. For a PC plant of equal capacity, the capture rate is more than twice as large.

Table 4
CO_2 storage costs as derived from [6]

Reservoir type	Depth (m)	Storage rate (Mt/year)	Storage cost (€/t CO_2)
Aquifer onshore	1000–2500	1–2	3
		2–4	2
Aquifer offshore	1500–2500	1–2	8
		2–4	5
Gas field onshore	2500–3500	1–2	3
		2–4	2
Gas field offshore	3000–4000	1–2	10
		2–4	6

medium-sized gas fields become available, whereas the Groningen gas field is not expected to become available before 2050 [32]. The Dutch oil fields are less interesting for CO_2 storage as they represent a relatively low storage potential. The interest in enhanced oil recovery (EOR) by injecting CO_2 into oil fields in the North Sea [33] might offer short-term opportunities for CCS. Aquifers and coal seams are not that well studied and characterised as hydrocarbon structures, which causes a relatively large uncertainty in the storage potential. Storage in coal seams is still in an experimental phase and needs considerable testing before it might be applied commercially. In this analysis, we will therefore focus on gas fields and aquifer traps as potential CO_2 storage reservoirs.

There is significant variation in storage cost estimates due to differences in CO_2 injection rate, storage capacity, reservoir type, features (pressure, thickness, permeability and depth) and location (onshore-offshore). Relations between storage costs, injection rate, reservoir type and capacity are applied to generalise storage costs (see Table 4). We distinguish storage rates between 1 and 2 Mt/yr (typical capture rate for 600 MW_e NGCC or 1000 MW_{H_2}SMR) and between 2 and 4 Mt/yr (typical capture rate 600 MW_e PC/IGCC or 1000 MW_{H_2}CG). In some specific source-sink combinations, more than one trap may be required to store all CO_2 in a 20-year lifetime. Storage costs may increase with a factor 2 when three gas fields are required instead of one to store 1 Mt CO_2/yr [6].

3.3. Hydrogen end-use markets

In order to set up a basic design of hydrogen infrastructure, we need an indication of potentials, demand profiles and spatial distribution of future hydrogen end-use markets. In this analysis, the transport, residential and industrial sector are considered (see Textbox 1 for details).

In the transport sector, hydrogen can be used as an alternative for gasoline and diesel in conventional vehicles with internal combustion engines (ICEV) and fuel cell vehicles (FCV). Various well-to-wheel analyses indicate that use in ICEV has no advantages from an energetic point of view [27,34], so use in ICEV is not further considered. Although FCV prototypes have been introduced into the market, significant market penetration is not expected before 2020 [4,20–22].

In the residential sector, hydrogen could gradually take over the function of natural gas and could simultaneously reduce electricity demand from the grid. It could technically be deployed in modified boilers. In the longer term, proton exchange membrane fuel cells (PEMFC) enable electricity and heat production on the level of a house/building (block) at a somewhat longer term. Hydrogen application is primarily foreseen for new build projects where an entire new infrastructure needs to be constructed.[4] In the short term, hydrogen demand in the residential sector is likely to be very limited [20,22].

The manufacturing industry is an another interesting sector to realise large CO_2 emission reductions by means of CCS due to the large amount of energy consumed and its clustered nature. Hydrogen could play an important role in the decarbonisation of industrial energy use. Nowadays, hydrogen is produced and consumed in industry on a large scale, mainly for fuel upgrading and desulphurisation at refineries, and ammonia production. In the future, the hydrogen market can be further extended by replacing fossil fuels applied in industrial CHP units, boilers and heaters.[5] At

[4]The question is whether pure hydrogen can be distributed through the local natural gas grid to existing households, considering the lower energy density and material issues. Much of the distribution grid consists of polyethylene, which might be susceptible to hydrogen leakage [35].

[5]Hydrogen can generally not be combusted in existing boilers and turbo-machinery. However, industrial burners using hydrogen are available [36]. Gas turbines need to be retrofitted to enable combustion of hydrogen-rich fuels [37]. In our analysis, we assume the thermal efficiency of hydrogen combustion is unchanged, although there could be improvements in efficiency [38].

Textbox 1

Estimating hydrogen demand for the Netherlands

In estimating hydrogen demand, we focus on the Randstad, a large urban conglomeration in the Midwestern part of the Netherlands, where major cities (accommodating over 7 million people) and industries are located.

Transport sector: In 2003, the fuel consumption of road transportation in the Netherlands approximated 460 PJ, causing a CO_2 emission of 34 Mt [7]. Projections indicate that these emissions may reach circa 45 Mt by 2020 [23]. These emissions, along with local air pollutants, can be reduced by means of hydrogen. The hydrogen demand for the Randstad area in 2030 is estimated as a function of the number of FCVs (determined by penetration level, new car sales and average car lifetime), FCV fuel economy and travel distance. Considering a fleet of 4–5 million light duty vehicles and assuming 5–25% of the entire light duty vehicle fleet consists of FCVs in 2030 based on penetration scenarios presented in [4,20–22], between 0.2 and 1.25 million FCVs will be on the road by that time. Given the range in fuel economy as specified in Table 5, the total hydrogen demand for the Randstad area in 2030 varies between 3 and 40 PJ/yr. We consider an average scenario assuming 4.5 million cars on the road, a FCV fraction of 20% and a fuel economy of 0.92 MJ/km, which would require an annual hydrogen supply of 13.3 PJ. The size of the individual refuelling stations, ranging from 0.1 to 8 MW_{H_2} [40,41], is a function of the number of FCVs served by a refuelling station, fuel economy, travel distance and the refuelling pattern. In our analysis, we consider a uniform capacity of 2 MW_{H_2} (see Table 6). This would imply that circa 250 refuelling stations need to be installed to cover the demand of 13.3 PJ/yr, which corresponds to 0.05 hydrogen refuelling station per km^2 on average. The average gasoline refuelling station density is estimated at 0.31 per km^2 using national statistics on car density and number of cars served per gasoline station [42]. This implies a coverage factor of 16%.

Residential sector: In 2003, the Dutch residential sector consumed circa 360 PJ natural gas, producing 19 Mt CO_2 [7], and consumed 80 PJ electricity [47]. Considering 1,475,000 new dwellings to be constructed between 2011 and 2030 [48], we assume 200,000 dwellings constructed in this period in the Randstad area will be equipped with hydrogen infrastructure. This corresponds to circa 2.5% of the entire stock, which is within the range of estimates in other scenario studies (0.5–15% [20,22]). Based on heat and electricity demand of modern households and performance figures for micro-fuel cells for co-generation [49], we estimated hydrogen demand for 'hydrogen districts' comprising 5,000 households. We consider a configuration comprising a (heat) load following 1 kW_e PEMFC per household supplemented with a hydrogen burner and a heat buffer (see Table 7). In order to cover the specified energy demand, 10.53 MWh hydrogen is required and 1 MWh electricity is exported to the grid [49]. This would imply an annual hydrogen demand of 7.6 PJ to supply 200,000 households.

The service sector, consuming circa 200 PJ fuels causing a CO_2 emission of 11 Mt/yr [7], would also be appropriate to deploy hydrogen, but is not further considered here due to lack of data on heat and electricity demand patterns required to design a micro-CHP system.

Industrial sector: In 2003, total fuel consumption in the Dutch industrial sector was circa 430 PJ, corresponding to a CO_2 emission of circa 27 Mt (excluding joint-venture CHP units, refineries and feedstock use) [7]. The chemical industry is the main energy consumer, emitting 12 Mt CO_2/yr. Refineries emit another 11 Mt/yr from combustion of natural gas and oil products [7]. The fuel demand in the industry is projected to increase slightly the coming two decades [23].

Of the total industrial energy use, a significant share (circa 260 PJ) is represented by natural gas consumption in CHP units, boilers and heaters [47]. In 2003, the installed CHP capacity at refineries was about 400 MW_e [52], of which the majority steam and gas turbines in the range of 10–50 MW_e [53]. In the chemical industry, circa 1800 MW_e is installed, of which a few very large combined cycles [52]. The capacity of CHP is expected to grow the coming decades, especially at the chemical industry. We assume a part of this capacity will be fired with hydrogen: the excess of hydrogen (production 1000 MW minus demand transport and residential sector) equals nearly 6 PJ/yr, which is sufficient to fuel four 20 MW_e gas turbines with a net electric efficiency of 40%.

Table 5
Car characteristics [4,43–45]

Parameter	FCV	ICEV
Fuel economy (MJ/km)	0.5–1.3	1–2.8
Retail costs of drive train (€/kW_{peak})[a]	60	25
O&M costs (€/yr)	400	400
Lifetime (yr)	15	15
Annual travel distance (km)	16,000	16,000
Hydrogen stored onboard (kg)	4.76	—

[a]Including transmission, fuel storage tank and motor. ICEV and FCV have capacity of 100 and 74 kW, respectively.

Table 6
Refuelling station features [4,40,43,46]

Parameter	Value
Station capacity (kg/d)	1440
Load factor	0.85
Peak production (kg/h)	153
Dispenser capacity (kg/h)	73
Tank refill (%)	80
# cars served (cars/day)	320
# cars served at peak hour (cars/h)	40
Maximum # cars per dispenser (cars/h)	10
# dispensers	4

Table 7
Cost and performance data for conventional and "hydrogen" households after [49]

Parameter	Value
Heat demand[a]	5.3 MWh/yr
Electricity demand	3.4 MWh/yr
η_{th} 10 kW_{th} heater (NG/H_2)	95%
η_e PEMFC	66%
η_{th} PEMFC	34%
Costs 10 kW_{th} heater (NG)	720 € + 2% O&M
Costs 1 $kW_{e,nominal}$ PEMFC[b]	1500 € + 2.5% O&M
Costs 8.2 kW_{th} heater (H_2)	630 € + 2% O&M
Costs 7.7 MJ_{th} heat buffer	340 € + 2% O&M

[a]State-of-the-art heat demand (space and water) for houses in new residential area. In the longer term, heat demand is expected to decrease further [23], but this is not accounted for in our calculations.

[b]Complete system costs. The value used here is an average of the USDOE target of 1500 $/kW [4], the EU target of 2000 €/kW for micro-CHP applications in 2020 [50] and a target of 1000–1500 $/kW for large volumes quoted in [51].

refineries, hydrogen production using coal or natural gas for combustion purposes is not the most obvious option, as refinery gas and heavy oil residues are often available. However, there are industries where no such energy carriers are available and natural gas is purchased for electricity and heat production. This might create some opportunities for decentralised CHP units fired with hydrogen. A recent study on decarbonisation strategies for a number of remotely located distributed gas turbines concluded that it would be more cost-effective to produce hydrogen centrally and distribute it to each turbine than scrubbing CO_2 from the collected flue gasses [39].

In the longer term, hydrogen might be applied as reducing agent in the steel industry. As the steel industry is a large CO_2 source in the Netherlands, emitting nearly 6 Mt in 2003 [7], we explore the opportunities for steel production using coal or natural gas with CCS. Direct reduction (DR) technology enables reduction of iron oxide with hydrogen or syngas, omitting the use of cokes in the blast furnace route to produce pig iron. Table 8 gives the basic characteristics of the reference route (blast furnace + basic oxygen furnace (BF + BOF)), and various DR routes (+ electric arc furnace (EAF)) with inherent CO_2 removal. A more detailed description of these technologies and their energy use can be found in [54–56].

3.4. Infrastructural requirements and costs

3.4.1. Electricity transmission and distribution

Central production units are connected to the high-voltage grid transporting electricity to the regional distribution networks. Decentralised power plants can be connected directly to the local distribution network, thereby avoiding transmission losses and costs. Typical electricity losses occurring during transmission and distribution to final consumers are estimated at 8%. Only 1% of these losses are caused by transmission, the other 7% by distribution on the medium and low-voltage grid [58]. Transmission and distribution tariffs for households are 40–60 €/MWh. Transmission tariffs for very large (50 MW_e) industrial users are approximately 5 €/MWh [59].[6]

3.4.2. CO_2 transmission

For large-scale CO_2 transport, pipelines are generally considered to be most suitable [14,16]. Textbox 2 discusses the CO_2 infrastructure for the Netherlands. Ship transport is an alternative when

[6]Transmission costs for a 500 MW_e NGCC have been estimated at 1–5 €/MWh for a distance of 50–500 km [3].

Table 8
Main inputs and outputs of different steel production routes [26,57]

Process	BF + BOF[a]	Circored + EAF[b]	Circofer + EAF[b]	Coal-based Midrex + EAF[b]
Input				
Fine ore (t)	1.2	1.4	1.4	—
Lump ore (t)	0.2	—	—	0.9
Pellets (t)	—	—	—	0.6
Scrap (t)	0.1	0.1	0.1	0.1
Coking coal (t)	0.4	—	—	—
Other coal (t)	0.1	—	0.4	0.4
Natural gas (GJ)	—	11.4	0.1	0.1
Electricity (GJ_e)	0 (0.77)	2.2	2.4	3.1
Electrodes	—	2.9	2.9	2.9
Output				
Liquid steel (t)	1	1	1	1
Electricity (GJ_e)[c]	−0.09 (0)	—	—	—
By-product (GJ)	−0.27	—	—	—
CO_2 emission (t)	1.7 (0.6)	0.4	0.5	0.5
CO_2 capture (t)	0 (1.1)	0.6	1.0	1.0
Costs (€/t liquid steel)				
Capital costs	32.0 (37.6)	28.0	27.1	34.3
O&M	48.2 (50.2)	49.5	52.4	46.6
Labour	27.1	17.9	19.4	17.9

[a]Values in parentheses refer to a configuration in which BF gas is compressed, shifted and CO_2 is captured and compressed.
[b]Including CO_2 capture and compression to 110 bar.
[c]We assume the excess BF, BOF and coke oven gas is converted into electricity to cover the internal electricity demand and eventually to export electricity to the grid.

Textbox 2
CO_2 infrastructure

Fig. 3 clearly illustrates the mismatch in CO_2 sources and gas fields in the Netherlands; the majority of the gas fields are located in the Northern part of the country and offshore, whereas the majority of CO_2 sources are located in the Southern and Western part of the country. The identified aquifer traps are distributed more homogeneously. Given the potential locations of electricity and hydrogen plants and reservoirs, transport distances vary between nearly 0 and 200 km. For the short term, we assume CO_2 is transported in dedicated pipelines and stored in onshore gas fields located at 100 km from the plant. In the long term, a network supplying CO_2 to various onshore and offshore gas fields and aquifers is considered. A rough screening of the Netherlands shows that there are not enough large reservoirs nearby the sources to store 20 Mt/yr in total. As the majority of reservoirs in the Netherlands are clustered in the Northern provinces and offshore, a backbone seems advantageous, to which CO_2 sources are connected. For the costs of transporting CO_2 through the trunk line, a fixed tariff of 1.3 €/t CO_2 is used. This tariff is based on transport costs of 20 Mt CO_2/yr over 200 km, including costs of the booster stations [3] and generalised costs of branches to the individual storage reservoirs. In addition, we consider a fixed storage tariff of 2 €/t CO_2 based on CO_2 injection into onshore gas fields (representing the largest storage potential).

the storage reservoir is located offshore, as it avoids large investments of pipeline construction and it offers flexibility in CO_2 purchasing and delivering. The disadvantage is the high cost for liquefaction and buffer storage, which makes ships less interesting for short transport distances. The turning point of

Fig. 3. Location of geological reservoirs and large CO_2 sources in the Netherlands (courtesy of TNO-NITG) and possible configuration of a trunk line as part of a CO_2 network.

transporting 6.2 Mt CO_2/yr is circa 700 km[7]; beyond that point ship transport becomes economically more attractive than transport by pipeline [60]. Transport costs for 20,000 t/day (equivalent of capture rate of 1000 MW_e PC using MEA) over a transport distance of 1000 km are circa 13 \$/t CO_2 [60].

Pipeline diameters are calculated using steady-state equations applied for incompressible flow under isothermal conditions, for which the pressure drop is derived from the Fanning, or Darcy, equation [61]:

$$\Delta p = 2f\rho v^2 \frac{L}{D} = \frac{32 f \rho L Q^2}{\pi^2 D^5}. \tag{3}$$

The friction factor (f) is a function of the Reynolds number (R_e) and the roughness of the pipeline inside surface, according to the Moody chart. The Reynolds number is a dimensionless quantity that indicates the type of flow:

$$R_e = \frac{\rho v D}{\mu}. \tag{4}$$

[7]The transport distance from Rotterdam to the Gullfaks oil field, one of the reservoirs studied for EOR, is circa 1000 km.

For laminar flows ($R_e < 2000$), the friction factor is correlated to the Reynolds number according to

$$f = \frac{16}{R_e}. \tag{5}$$

A turbulent flow ($R_e > 3000$) can be either fully or partially turbulent. Various equations exist to calculate the friction factor for turbulent flows, each of them being specific for a certain pipeline and flow regime. The following generic approximation of the friction factor is used, which results in relatively conservative pipeline design [61]:

$$f = \frac{0.04}{R_e^{0.16}}, \tag{6}$$

where Δp is the pressure drop (Pa); f the friction factor; v the average fluid velocity (m/s); Q the volumetric flow rate (Nm^3/s); L the pipe length (m); D the (internal) pipeline diameter (m); ρ the fluid density; and μ the fluid viscosity.

Fluid properties were derived as a function of temperature and pressure [62]. Onshore pipeline temperature is set at 10 °C, equal to the soil temperature. Offshore pipeline temperature is circa 6 °C [16]. The pipeline diameter is calculated iteratively until the chosen diameter meets the specified maximum pressure drop, which is set at 30 bar, assuming an inlet pressure of 110 bar and no recompression occurs along the main pipeline trajectory. CO_2 pipelines are operated at high pressure to guarantee high densities for optimal pipeline utilisation. In order to avoid phase transition, pressures should be kept well above the supercritical pressure (74 bar). According to Farris [63], the minimum pressure is between 83 and 89 bar. The inlet pressure is generally set to overcome the pressure drop that occurs as a result of friction. Booster stations are required when a large pressure drop occurs, e.g. at long pipelines or hilly terrain. In order to optimise pipeline pressure and diameter, the sum of pipeline and booster station capital and O&M costs plus electricity costs for pumping should be minimised. This 'theoretical' optimum may differ substantially as there is a large variation in capital costs of pipelines and booster stations. The minimum distance between booster stations specified in literature varies substantially, from circa 100–250 km [3,16,64]. Recently, a 330 km pipeline (diameter 0.3–0.36 m) has been constructed transporting circa 5000 tonnes CO_2/day overland without any booster station along the pipeline. The pressure falls from 170 to 148 bar [65]. Offshore, where booster stations are very expensive, pipeline pressure and diameters are generally higher to overcome the pressure drop.

3.4.3. H_2 transmission and distribution

Large quantities of hydrogen are generally transported in gaseous form through pipelines. Liquid and gaseous hydrogen transport by means of trucks may be an alternative for remote locations or for small-scale applications [22,40]. As transition option, hydrogen could be added to the natural gas grid up to 3% without any modifications. The hydrogen content might be increased to 25 vol% (peak concentration), which requires network upgrading and replacement of some end-use equipment [66]. The magnitude of CO_2 abatement (versus 100% natural gas) that can be achieved by blending 25 vol% hydrogen produced by means of SMR with CCS is small (circa 4%) [66]. A current EU project studying the possibilities of hydrogen addition to the natural gas grid shows that the margin of H_2 addition might be much lower [67], especially in the high pressure transmission network, which is designed for peak capacity. Reconsidering these infrastructure options and the fact that this analysis studies large quantities of hydrogen to be transported over relatively small distances, transport by dedicated pipelines seems most appropriate and is projected to give the lowest cost [12,40,68]. In the longer term, part of the natural gas grid may become obsolete when the use of hydrogen takes over as gaseous energy carrier. This may open possibilities for the conversion of parts of the existing infrastructure to transmit and distribute hydrogen.

In order to design a H_2 infrastructure, a hydrogen demand map should be set up, for which we use estimations of potential demand and possible locations of H_2 production plants and end-use markets. The end-use markets vary in size and required hydrogen purity and pressure. We can distinguish high-purity (>99.99%) hydrogen for application in PEMFCs from less pure, 'fuel grade' (<95%) hydrogen suitable for combustion purposes. In this study, we simplify matters by considering a hydrogen grid transporting high-purity hydrogen, connecting a central hydrogen plant with refuelling stations, residential areas and industrial CHP units (see Textbox 3). Hydrogen is transported from the production unit by means of a high-pressure transmission line, after which it enters a regional medium-pressure transmission ringline, similar to the natural gas transmission system. At the city gate stations (to which CHP units are connected), hydrogen is transferred to the main distribution grid, from where it continues its route to refuelling stations and dwellings. The transport inlet pressure of the main transmission line is set at 60 bar, allowing a pressure drop of 20 bar.[8] In the regional transmission lines, pressure is between 40 and 20 bar, after which it is further decreased to 10 bar in the main distribution pipelines. At the refuelling stations, hydrogen is compressed to 480 bar for buffer storage to enable cascade-filling, assuming hydrogen is stored onboard at 350 bar in conventional pressurised tanks [43]. In the

[8]Typical transport pressures of hydrogen transmission are between 10 and 30 bar [12], although pipelines have been operated up to 100 bar [17,68]. We consider a value of 60 bar, which is similar to that considered in recent studies on hydrogen transmission [40,41,69]. The high-pressure natural gas transmission system in the Netherlands is operated at 50–70 bar, after which regional medium-pressure transmission pipelines supply the gas to local gas distribution station at 20–40 bar. The local distribution grid is operated at maximally 8 bar, with the gas finally reaching the consumer at a small overpressure of 250 mbar.

Textbox 3
H_2 infrastructure

Fig. 4 illustrates a conceptual infrastructure to deliver hydrogen from a central hydrogen production unit to various markets. For the Dutch context, the main transmission line is varied between 20 and 200 km, depending on the location of the H_2 production facility. The length of the regional transmission line is estimated using an idealised representation of the Randstad (R1 = 40 km, R2 = 20 km R3 = 5 km). The length of the main distribution system is estimated using an algorithm developed by researchers of UC Davis [40], assuming 250 refuelling stations are distributed over 10 conglomerations. The length of the low-pressure distribution grid to individual dwellings is estimated using statistics on the natural gas grid. The low-pressure gas distribution network has a total length of nearly 85,000 km [66], corresponding to 12 m per household, on average.

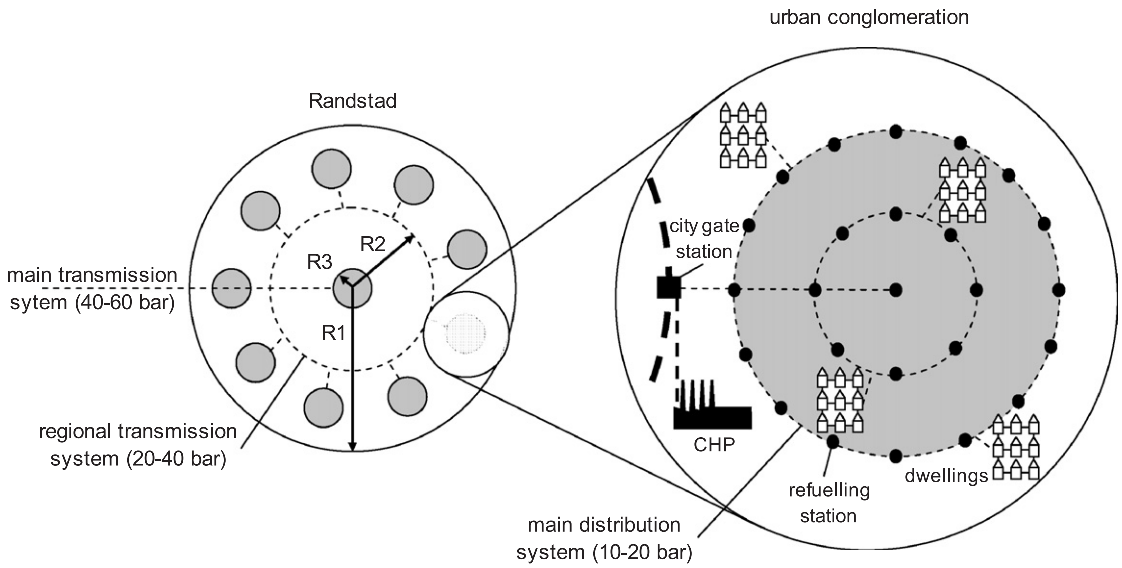


Fig. 4. Conceptual hydrogen transmission and distribution infrastructure.

residential sector, hydrogen is delivered near atmospheric pressure.

For pipeline design, we apply steady-state equations for an isothermal compressible flow [17]:

$$Q_b = 6.65\left(\frac{T_b}{p_b}\right)\left(\frac{1}{f}\right)^{0.5}\left(\frac{p_1^2 - p_2^2}{ZTGL}\right)^{0.5} D^{2.5}, \tag{7}$$

in which Q_b is the flow rate at base (normal) conditions (Nm^3/s); T_b the temperature at base (normal) conditions (293.15 K); p_b the pressure at base (normal) conditions (101,325 Pa); f the friction factor; p_1 the inlet pressure; p_2 the outlet pressure; Z the compressibility factor (1); T the average gas temperature; G the gas gravity (= 0.0696 for H_2); L the pipe length (m); and D the (internal) pipeline diameter (m).

In high-pressure gas transmission lines with moderate to high flows, the flow regime is either partially or fully turbulent. Various specific flow equations are applied in the gas industry to calculate the friction factor [17]. The Panhandle A equation is applied for partially turbulent flow conditions, medium to relatively large diameter pipelines with moderate gas flow, operating under medium to high pressure. Panhandle B and AGA fully turbulent equations are appropriate for high-flow-rate, medium to large-diameter pipelines and high-pressure systems. The pipeline variation is generally below 20% using the different equations. We applied the generic Eq. (6) to calculate the friction factor,

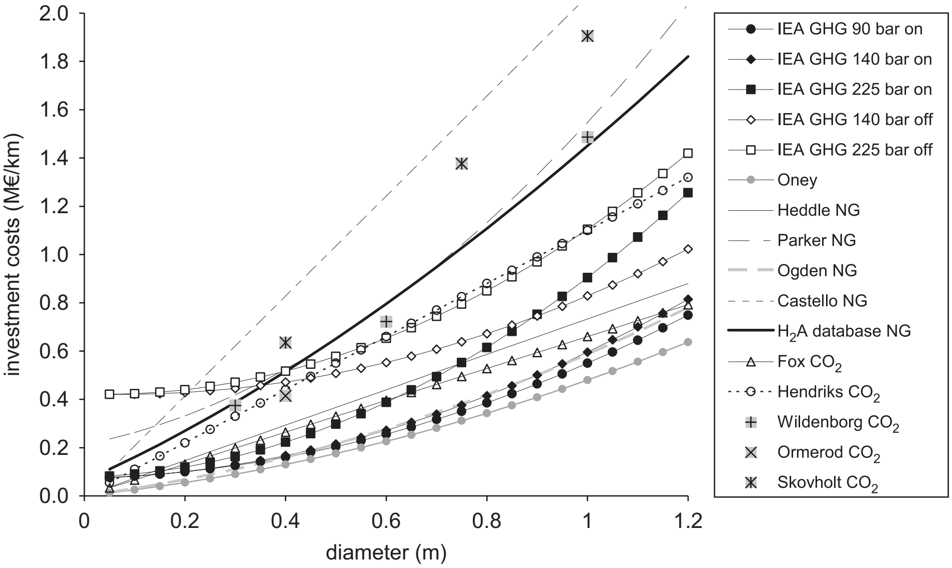


Fig. 5. Pipeline investment cost as a function of diameter [3,6,15,16,22,40,41,71,73,74,77].

resulting in average diameters in comparison to those generated using AGA fully turbulent equation (large diameter) and Panhandle A/B (smaller diameter). This generates sufficiently reliable results given the generic nature of this study, the uncertainty in pipeline costs and the difference between internal and nominal pipe size. Average velocities calculated for the specified pressure drop, assuming no booster stations are installed along the pipeline, are generally between 5 and 20 m/s, which is reasonable for gas pipelines [17]. Given the specified pressure drop, transporting large quantities over small distances results in high average velocities that might exceed the erosional velocity [17]. Therefore, larger pipelines might be required, resulting in higher costs. Note that if the pipeline diameter is doubled, the pipeline capacity is increased by a factor $(2)^{2.5} = 5.66$. This illustrates the importance of considering possible future expansions (when setting up a large scale infrastructure) in the pipeline diameter selection [17].

3.4.4. Costs of CO_2 and H_2 infrastructure

Pipeline costs consist of material, labour, right of way (ROW) and miscellaneous costs. In densely populated urban areas, pipeline construction costs are significantly higher than for rural landscapes, due to safety requirements, higher ROW and the large number of infrastructural crossings. Construction costs in urban terrain can be 20% higher [70] up to 10 times the costs for a pipeline installed in rural area [71]. The difference in landscape, population density, geographical location and steel prices explain the large variety in construction costs quoted in literature (see Fig. 5). Many studies use data on natural gas pipelines. CO_2 pipelines are generally more expensive than natural gas pipelines because the former are operated at higher pressure, requiring a greater wall thickness. For H_2 transmission, embrittlement resistant steel pipelines are required, which are more expensive than natural gas pipelines, generally by a factor 1.3–1.5 [68,69,72]. We use the values of the IEA GHG study assuming a terrain factor of 1.2 [3], as it provides a consistent set of equations suitable for both CO_2 and H_2 pipelines for on- and offshore conditions. Note that these costs are fairy low in comparison to other studies, which may result in an underestimation of transport costs. The costs of H_2 distribution pipelines (and minor CO_2 lines connecting refuelling stations with larger trunk lines) are practically independent on pipeline diameter, as they depend primarily on the labour costs associated with pipeline installation. We use values of 500 €/m for the main distribution grid within the city and 200 €/m for the low-pressure distribution grid in new residential areas based on construction costs for small diameter pipelines [22,40,73]. We assume pipeline O&M costs to be 2% of the investment costs, representing an average value using data from [3,74–76], and an economic lifetime of 25 years.

Figs. 6 and 7 show the dependence of CO_2 and H_2 transmission costs on scale and distance. As CO_2 transmission costs decrease considerably with increasing flow rate, especially at larger distance, it may be more advantageous to construct a network instead of dedicated pipelines. A network consists of a large trunk line, which is connected to various CO_2 sources and sinks by smaller branches, similar to the existing natural gas grid. The advantage of a large backbone structure has been investigated for European conditions in [75]. The results indicate that a backbone offers reduced transport cost in

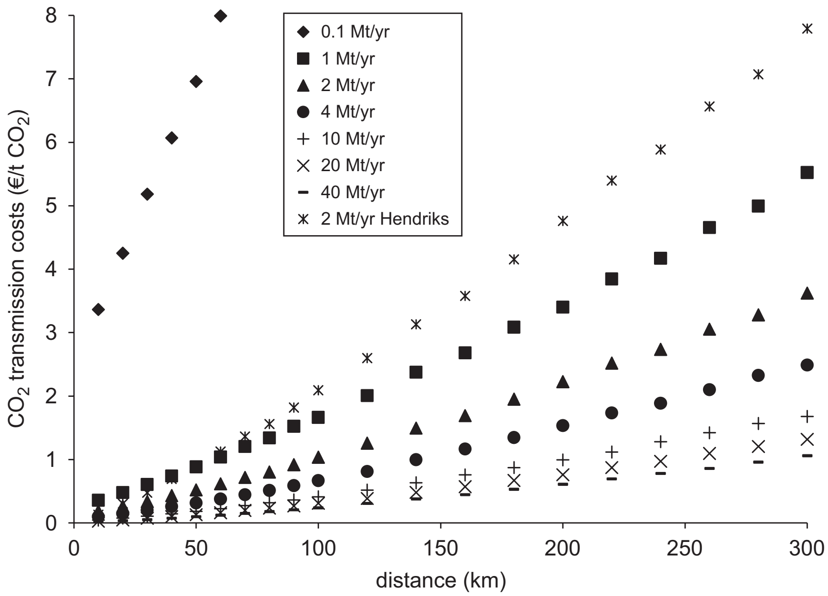


Fig. 6. Onshore CO_2 transmission cost as a function of distance and mass flow rates based on IEA GHG values for cultivated land [3], excluding compression. We also included the transmission costs using the regression fit from Hendriks et al. [77], which are generally in good agreement with various industrial estimates given in [6,16,78].

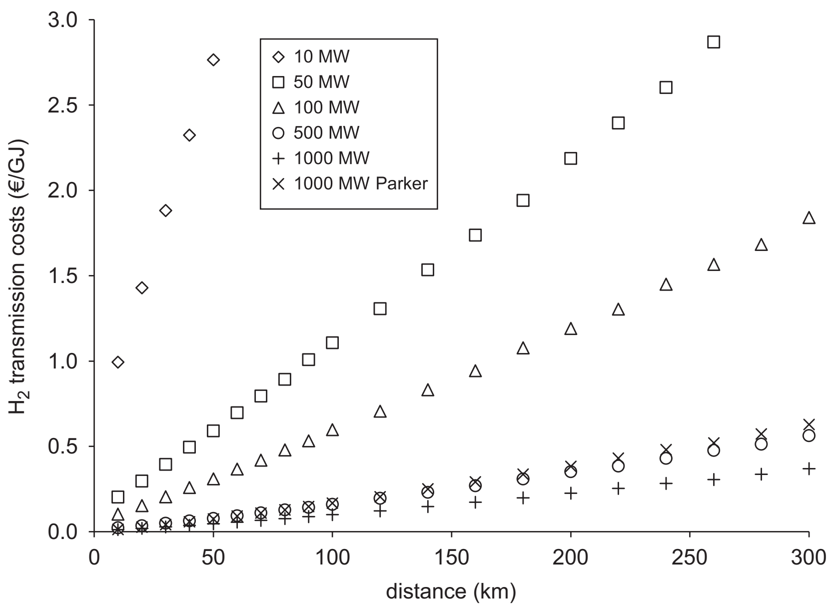


Fig. 7. H_2 transmission cost as a function of distance and energy flow rates based on IEA GHG values for cultivated land [3], excluding compression. We also included the transmission costs for a 1000 MW_{H_2} unit using pipeline costs derived by Parker [73].

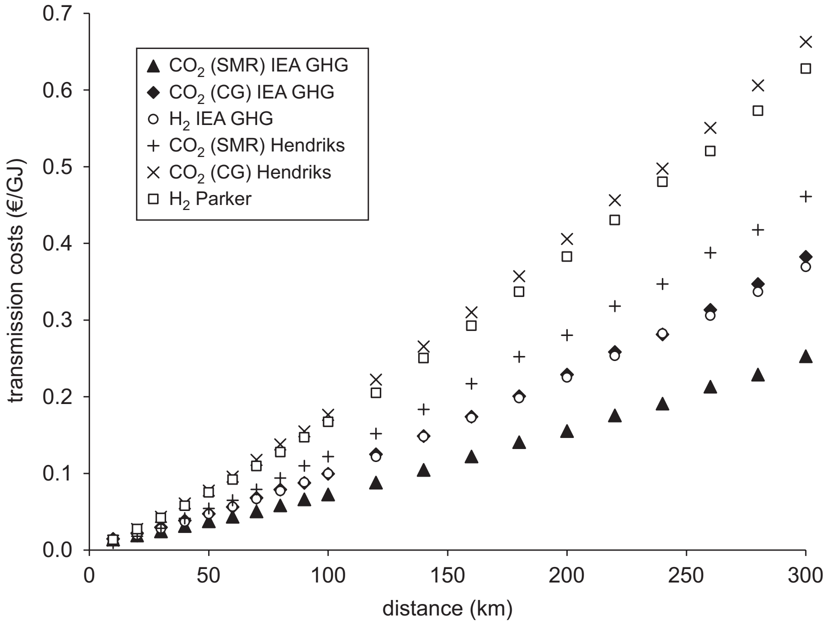


Fig. 8. CO_2 and H_2 transmission cost of a 1000 MW_{H_2} unit using coal (CG) and natural gas (SMR), (excluding compression) using IEA GHG values [3] and regression fits derived from [73,77].

comparison to dedicated pipelines when the availability of reservoirs is restricted to offshore hydrocarbon reservoirs, probably as these fields are clustered and remote from CO_2 sources. Dedicated pipelines would be more attractive when there are sufficient large structures nearby each source. Fig. 6 also makes clear that decentralised CCS plants (20 MW_e SOFC-GT and 2 MW_{H_2} MR, capturing 40 and 2 kt/yr, respectively) to be connected to a CO_2 network need to be constructed close to a trunk line in order to keep transport costs reasonable.

Now insights can be created into the trade-off between the costs of CO_2 and H_2 transmission, which is essential for the optimisation of a hydrogen production plant location. Fig. 8 shows the transmission costs of CO_2 and H_2 for a 1000 MW_{H_2} plant fired with coal (CG) or natural gas (SMR). It illustrates that the costs to transport the CO_2 captured at a SMR unit are lower than H_2 transmission over the same distance. For a coal-fired unit, H_2 transport costs are only slightly lower in comparison to CO_2 transport costs. This observation is in fairly good agreement with the results from Ogden [5]. However, the additional costs to connect to the natural gas grid and the presence of coal terminals should be considered as well in choosing the plant location. Given the substantial transmission costs of natural gas [3], it may be more attractive to produce hydrogen close to the natural gas source as proposed by Mintz et al. [79], provided that CO_2 is captured and can be stored in nearby depleted natural gas reservoirs.

3.4.5. Other H_2 infrastructure requirements

Apart from pipelines, the H_2 infrastructure requirements consist of buffer storage, compressors and dispensers, for which the main features are summarised in Table 9.

The work (head) required for compression can be approximated as an isentropic process according to the following formula:

$$W = \frac{ZRT_1 k}{M(k-1)}\left[\left(\frac{p_2}{p_1}\right)^{\frac{k-1}{k}} - 1\right]. \tag{8}$$

The compressor power, also referred to as brake horsepower or shaft power, can be derived from the isentropic head:

$$P = \frac{W\dot{m}}{\eta_{is}\eta_{m}}, \tag{9}$$

in which W is the work or isentropic head (kJ/kg); Z the compressibility factor (set at 1 for H_2); R the universal gas constant (8.3145 J/mol K); T_1 the suction temperature (K); k the specific heat ratio ($C_p/C_v = 1.41$ for H_2); M the molar mass (kg/kmol);

Table 9
Costs hydrogen supply components

Component[a]	Investment costs	Base scale	Scale factor	O&M (%)[b]
Storage at production unit[c]	10–100 M€	$1.63.10^4$–$1.63.10^5$ kg H_2	1	1
Compressor at refuelling station[d]	20 k€	14 kW	0.75	4
Storage at refuelling station[e]	375 k€	634 kg H_2	0.95	1
Gaseous dispenser[f]	18.3 k€	1740 kg H_2/day	1	—

[a]We consider 15 years lifetime for all components.
[b]Annual costs as share of investment costs derived from [40,80].
[c]In order to safeguard hydrogen supply in case of plant outages, a storage facility is needed for large plants considered in this study. Estimations for required capacity range from 0.5 to 2 days of production [40,41]. We assume a buffer capacity equivalent to 0.5 days. Although geological storage seems the least expensive option for a large unit [12], we consider aboveground storage in pressurised tanks, for which detailed industry figures are available [40].
[d]Representing costs to install a 9-stage reciprocating compressor for compression of maximally 4.8 kg H_2/h from 1 up to 480 bar, including drive motor and intercooling [43].
[e]Storage capacity at refuelling stations is required to store hydrogen produced at night time and as back-up for demand variations. The storage capacity required is estimated at 70% of the daily production capacity based on typical refueling station demand patterns and 58% hydrogen recovery with cascade storage/dispensing [43]. Costs are representative for large steel tanks suitable to store hydrogen at 480 bar [43]. Note that storage requirements may be somewhat lower when hydrogen is delivered by pipeline (as hydrogen could be stored in the pipeline).
[f]Derived from costs of compressed natural gas and prototype hydrogen dispenser adjusted for hydrogen specs and mass production [43]. We assume the refueling station is unattended. Another 20% is added to the capital costs of compressor, storage and dispensers to account for miscellaneous costs and contingencies [43].

p_1 the suction pressure (Pa); p_2 the discharge pressure (Pa); P the compressor power (kW); $\dot{m}$ the mass flow rate (kg/s); η_{is} the isentropic efficiency (0.7–0.75) and η_m the mechanical efficiency (0.99).

The choice of a compressor depends mainly on the flow rate and the differential pressure required. For compression of large, continuous quantities of H_2 up to 60 bar, we consider multi-stage centrifugal compressors with an isentropic efficiency of 75% [3,17,81]. Compressing relatively small quantities of H_2 up to 480 bar requires a multi-stage reciprocating compressor. The overall efficiency of a reciprocating compressor is circa 70% [43]. For multi-stage compressors, the power requirements may be overestimated when using Eq. (9) (for a single-stage compressor), as the gas is cooled between the different stages, which reduces the work required for compression. Power requirements for multi-stage compression with N stages can be calculated from Eq. (10) (derived from [82]). For H_2 compression, typically a compression ratio of 2 is applied [43].

$$W = \frac{ZRT_1}{M}\frac{Nk}{k-1}\left[\left(\frac{p_2}{p_1}\right)^{\frac{k-1}{Nk}} - 1\right]. \qquad (10)$$

3.5. CCS chains overview

Tables 10 and 11 give an overview of the chains considered in this study.

4. Results chain analysis

4.1. Electricity

Fig. 9 shows that the contribution of CO_2 transport and storage to the overall electricity costs is relatively small and does not affect the ranking among technologies. This is especially true for the large natural gas-fired technologies, due to the relatively small quantities of CO_2 transported and stored. Storage costs are low as we considered relatively large onshore gas fields. Offshore reservoirs might deserve preference, although this goes at the expense of higher transport and storage costs. Offshore transport costs for a 600 MW_e PC unit over 100 km are estimated at 0.15 €ct/kWh, circa twice the costs for onshore transport. Storage costs for this unit increase to 0.5 €ct/kWh for a typical offshore gas field in comparison to circa 0.2 €ct/kWh for an onshore gas field. In the longer term, transport costs per km are expected to decrease slightly due to economy of scale of the CO_2 network.

The calculations show that COE of decentralised SOFC units with CCS are higher than COE of central units, as the advantage of omitting electricity transmission does seem to be outweighed by the additional costs of CO_2 transport. However, SOFC efficiency forecasts are higher than for advanced

Table 10
Electricity and hydrogen chain definitions

Chain code	Conversion + capture technology
Short-term electricity	
ST-E1	PC + chem. absorption (600 MW_e)
ST-E2	IGCC + phys. absorption (600 MW_e)
ST-E3	NGCC + chem. absorption (600 MW_e)
Long-term electricity	
LT-E1	Advanced PC + chem. Absorption (600 MW_e)
LT-E2	Advanced IGCC + phys. absorption (600 MW_e)
LT-E3	IG-Water (600 MW_e)
LT-E4	IG-SOFC-GT + HSD (600 MW_e)
LT-E5	Advanced NGCC + chem. absorption (600 MW_e)
LT-E6	MR-CC (600 MW_e)
LT-E7	CLC (600 MW_e)
LT-E8	AZEP (600 MW_e)
LT-E9	SOFC-GT + afterburner (20 MW_e)
Long-term hydrogen[a]	
LT-H1-MOB/RES/CHP	Advanced ATR + chem. absorption (1000 MW_{H_2})
LT-H2-MOB/RES/CHP	Advanced CG + phys. absorption (1000 MW_{H_2})
LT-H3-STL	SMR/CG + absorption + direct reduction
LT-H4-MOB	MR (2 MW_{H_2})

[a]MOB = transport sector, RES = residential sector, CHP = industrial CHP, STL = steel production.

Brayton-cycles with CO_2 capture, which makes it a more safe technology with respect to energy price volatility.

Fig. 10 illustrates why CO_2 mitigation costs should be used and interpreted with care, as the outcome is strongly depending on the context, i.e. the choice of the reference system. When the fuel choice is fixed for a specific plant (e.g. due to present/absent infrastructure or strategic choices), one should compare a coal-fired power plant without CCS with a coal-fired unit equipped with CCS. In this setting, CO_2 mitigation costs of coal-fired power plants with CCS are lower than for gas-fired power plants with CCS. When replacing a mothballed PC unit for a NGCC with CCS instead of building a new PC unit, CO_2 mitigation costs are lower than when installing a PC unit with CCS, up to gas prices around 6.5 €/GJ. Mitigation costs will be relatively high for coal-fired units with CCS when the reference is a NGCC. This is mainly explained by the significant CO_2 emissions of a PC unit with CCS in comparison to an NGCC without CCS. CO_2 emissions of power production with CCS are between practically 0 kg CO_2-eq/kWh for advanced gas-fired units up to 0.2 kg CO_2-eq/kWh for a PC, of which circa 60% are direct CO_2 emissions and the remaining 40% are caused by GHG emissions of coal mining and transport.

4.2. Hydrogen

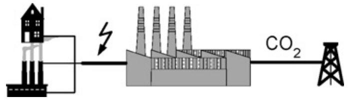
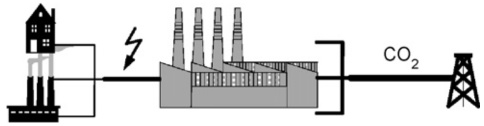
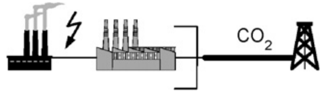
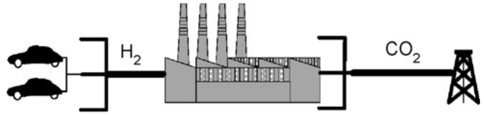
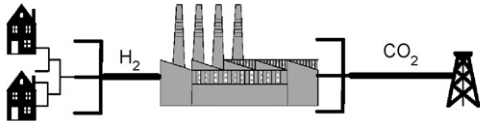
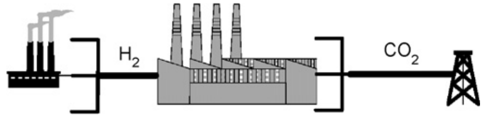
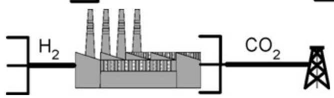
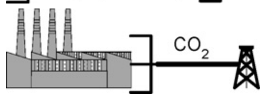
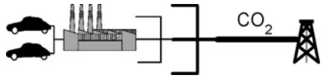
As illustrated by Fig. 11, the additional costs of CO_2 transport and storage are negligible for large-scale H_2 production. As the additional costs of capture are modest as well [1], the carbon price required to induce CCS at advanced large-scale hydrogen plants is relatively low: 10–20 €/t (see black bars in Fig. 12).

Hydrogen costs are to a large extent determined by the infrastructure requirements. For central plants supplying the transport and residential sector, costs of hydrogen infrastructure are equal or higher than the costs to produce hydrogen. It appears that the higher costs of H_2 production and CO_2 transport inherent in decentralised production units do not compensate for the omitted costs of hydrogen infrastructure in centralised chains. In addition, H_2 compression costs for (decentralised) MR units are significantly higher in comparison to centralised chains as H_2 at MR is produced at 1 bar. From that perspective, MR units are more suitable for markets where hydrogen is required at near-atmospheric pressure (e.g. in households). Another disadvantageous factor is that natural gas and electricity costs are significantly higher for decentralised production. Assuming the refuelling stations owner enforces identical price agreements for natural gas and electricity as large industrial users, COH might be decreased to circa 18 €/GJ.

Taking a closer look at H_2 infrastructure makes clear that the costs of distribution are a major contributor to overall production costs for the transport and residential sector. A breakdown of H_2 infrastructure costs shows that especially the costs of the low-pressure distribution grid are the main cause for the high costs to deliver hydrogen to the front door of individual dwellings (80% of transmission and distribution costs). For the transport sector, also the costs of the refuelling stations are relatively high.

Although CO_2 emissions are greatly reduced with CCS, the remaining emissions are substantial: 10–40 kg CO_2-eq/GJ in comparison to 50–120 kg CO_2 captured/GJ. This is part of the explanation

Table 11
Infrastructure assumptions

Chain code	Electricity/H_2	CO_2	
ST-E1-E3	Transmission line + distribution grid	100 km transmission line to onshore gas field	
LT-E1-E8	Transmission line + distribution grid	10 km transmission line to CO_2 trunk line	
LT-E9	Directly connected to distribution grid	50 km transmission line to CO_2 trunk line	
LT-H1-MOB	200 km transmission line + 125 km regional transmission line + 70 km high-P distribution line	10 km transmission line to CO_2 trunk line	
LT-H1-RES	200 km transmission line + 125 km regional transmission line + 70 km high-P distribution line + 2500 km low-P distribution line	10 km transmission line to CO_2 trunk line	
LT-H1-CHP	200 km transmission line + 125 km regional transmission line + 10 km high-P distribution line	10 km transmission line to CO_2 trunk line	
LT-H2-MOB/RES/CHP	20 km transmission pipeline, further infrastructure is identical to LT-H1	10 km transmission line to CO_2 trunk line	
LT-H3-STL	—	10 km transmission line to CO_2 trunk line	
LT-H4-MOB	—	70 km satellite line + 125 km transmission line to CO_2 trunk line[a]	

[a]For all refuelling stations.

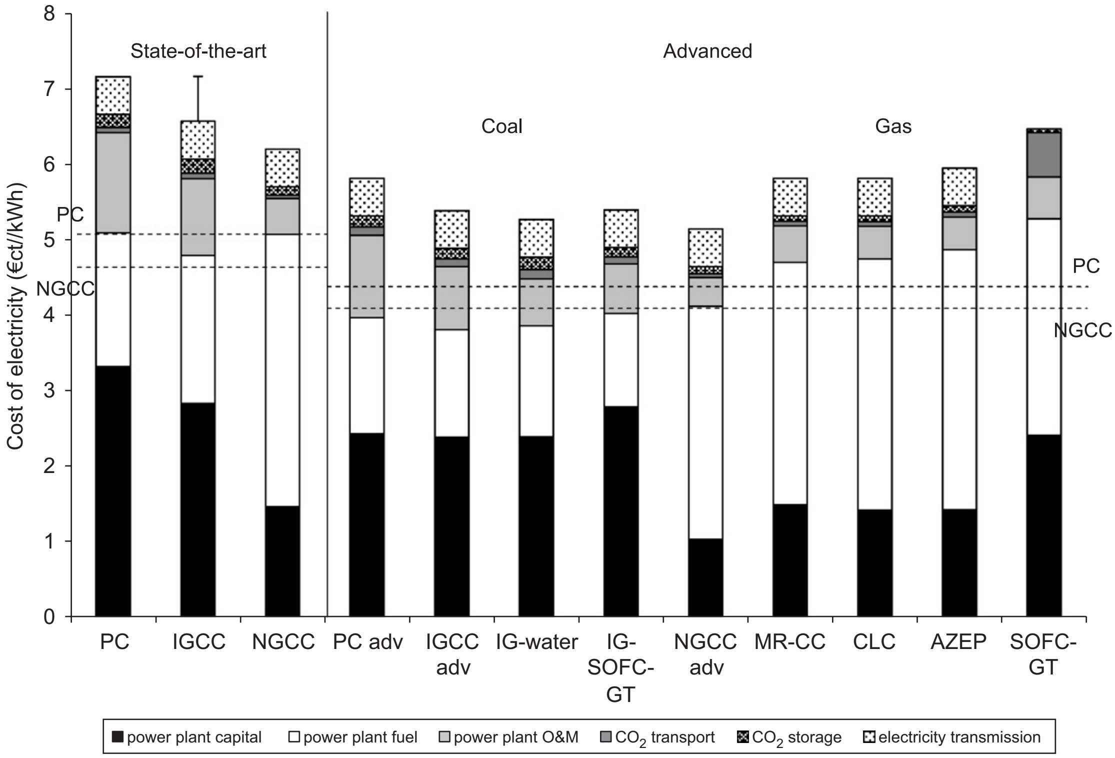


Fig. 9. Electricity production costs including CCS and electricity transmission. The dashed horizontal lines represent COE of PC and NGCC without CO_2 capture.

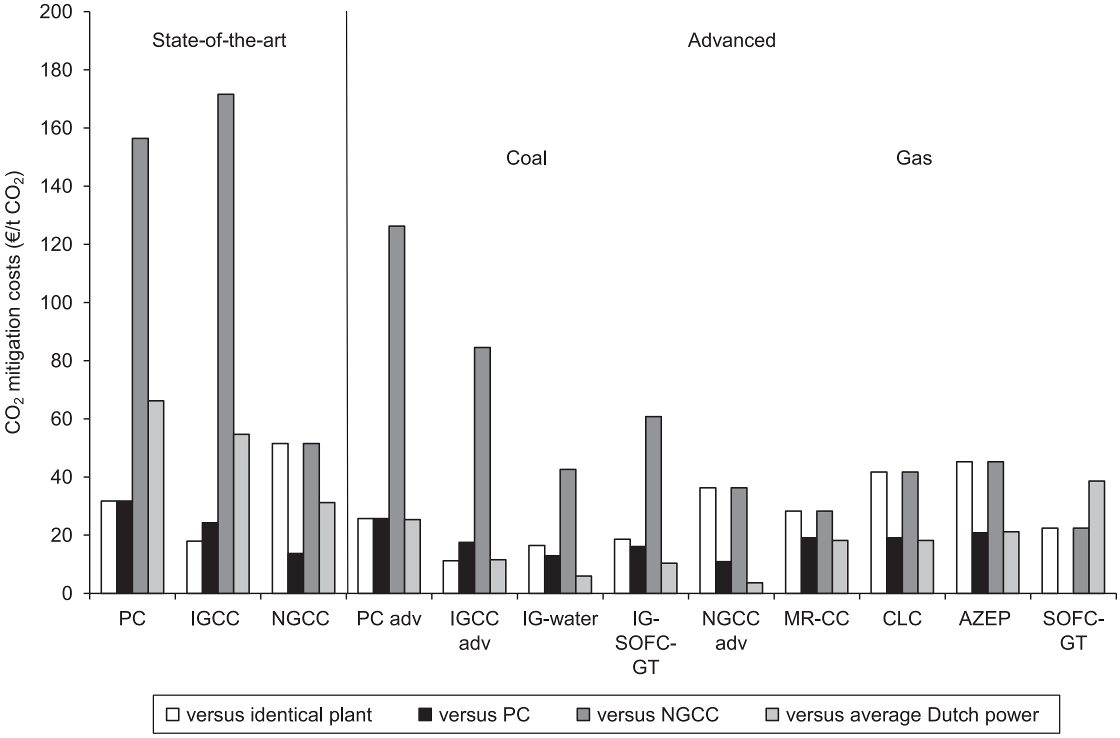


Fig. 10. CO_2 mitigation costs of electricity production with CCS vis-à-vis different reference systems, including indirect emissions of fuel extraction and transport.

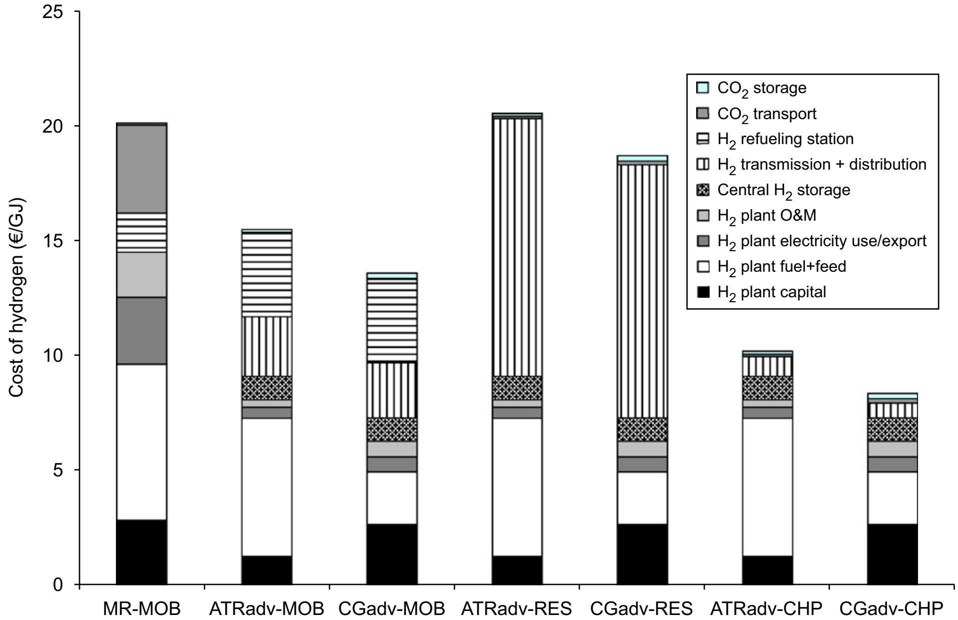


Fig. 11. Hydrogen production costs including CCS and H_2 infrastructure for delivery to various end-users (MOB = transport sector, RES = residential sector, CHP = industrial CHP). Costs of H_2 compression in centralised production have been accounted in the H_2 plant (up to 60 bar) and refuelling station (up to 480 bar). In membrane reformers, H_2 compression is accounted for in the production.

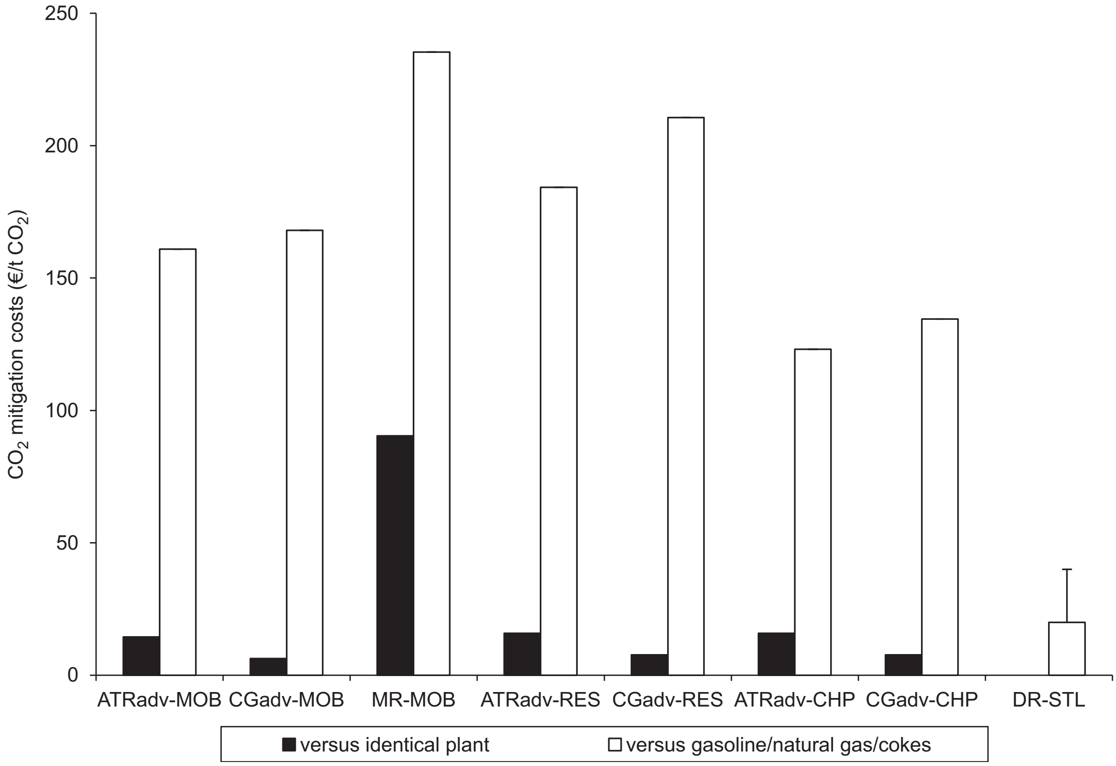


Fig. 12. CO_2 mitigation costs of hydrogen application vis-à-vis different reference systems, including indirect emissions of fuel extraction and transport. MOB = transport sector, RES = residential sector, CHP = industrial CHP, DR-STL = steel production by means of direct reduction.

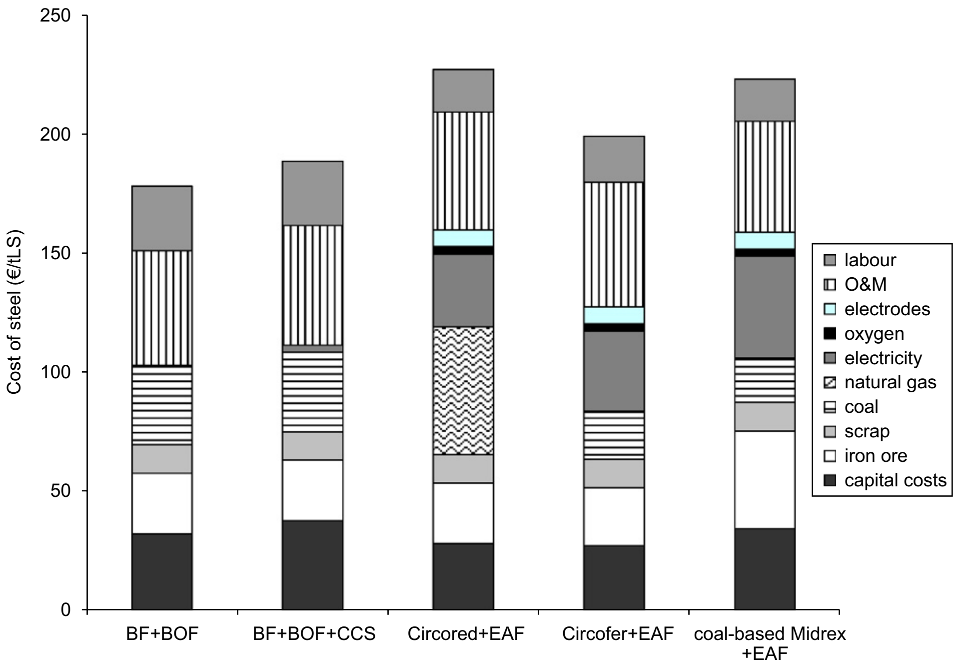


Fig. 13. Steel production costs for a tonne of liquid steel, based on the blast furnace route (with and without CCS) and direct reduction routes (all with CCS).

why CO_2 mitigation costs, depicted in Fig. 12, are relatively high for sectors where natural gas (emission factor of 57 kg CO_2-eq/GJ) is the reference fuel. For the residential area, the other part of the story is obviously formed by the high costs of H_2 supply and PEMFC, which is not outweighed by the higher efficiency of the PEMFC. Mitigation costs in the transport sector are mainly determined by the relatively high costs of the fuel cell. This is illustrated by the costs per driven kilometre: from the 0.06 €/km for an FCV (versus 0.04 €/km for ICEV), circa 20% can be attributed to H_2 costs, the rest being costs of the drive train and storage tank.

In the steel industry, replacing cokes in the traditional BF route for hydrogen or syngas in DR routes results in CO_2 mitigation costs of 20–40 €/t CO_2. Costs of CO_2 capture from BF gas in the traditional BF route are estimated at 15 €/t CO_2, comparable to the value calculated in [83]. Fig. 13 shows the production costs of various steel production technologies. Circored technology results in relatively high production costs due to the high fuel costs. For coal-based Midrex, the explanation lies mainly in higher expenses in iron ore. The costs of Circofer and the traditional BF route with CO_2 capture from BF gas are relatively close. Although the additional costs due to CCS is very small for Circofer (as CO_2 is already separated), the additional indirect emissions due to electricity requirements of EAF make that mitigation costs (versus BF without capture) appear slightly higher in comparison to capture of CO_2 from BF gas in the classical route. So the primary reason to switch to DR would not be CO_2 emission reduction, but the omission of the polluting coke oven plant.

4.3. Sensitivity analysis

Figs. 14 and 15 show the results of sensitivity analyses performed on several promising or likely technologies that may be implemented, encompassing the complete spectrum of *technology* (combustion, fuel cells, gasification), *fuel* (natural gas versus coal) and *scale* (central versus decentralised units). Apart from the basic economic variables, for which the variation is specified in Table 1, the impact of uncertainty in plant capital costs (±30% for state-of-the-art technologies and 50% for advanced technologies such as SOFC and gasification, which are not mature yet) is assessed. Note that the fuel price and capacity factor are correlated to each other, which may result in even a wider range as shown in Fig. 14, especially for NGCC. A power

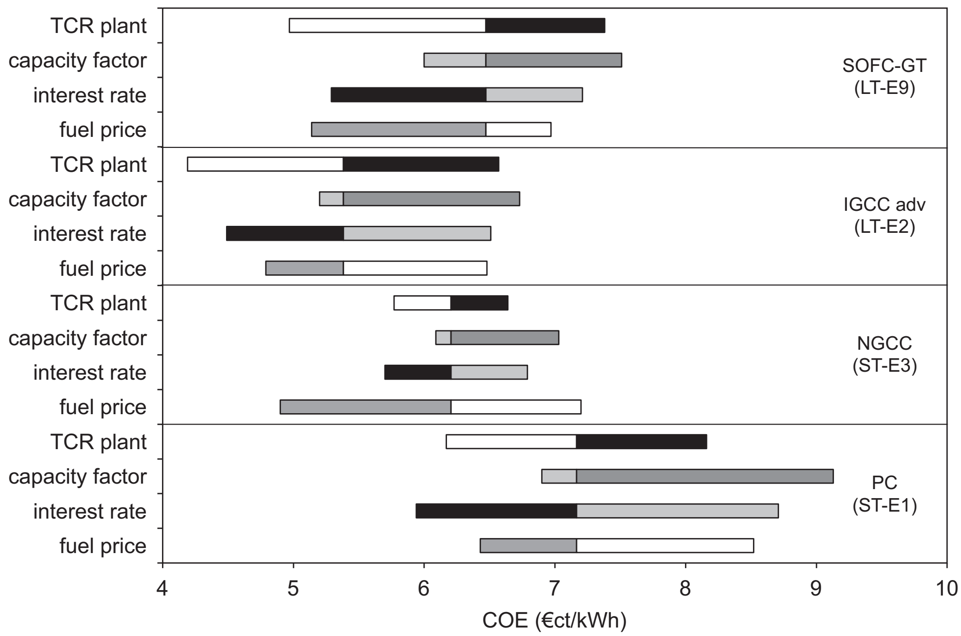


Fig. 14. Sensitivity analyses of various electricity production chains with CCS. The chain codes (see Table 10) are given in parentheses and the variation in parameters is given in Table 1.

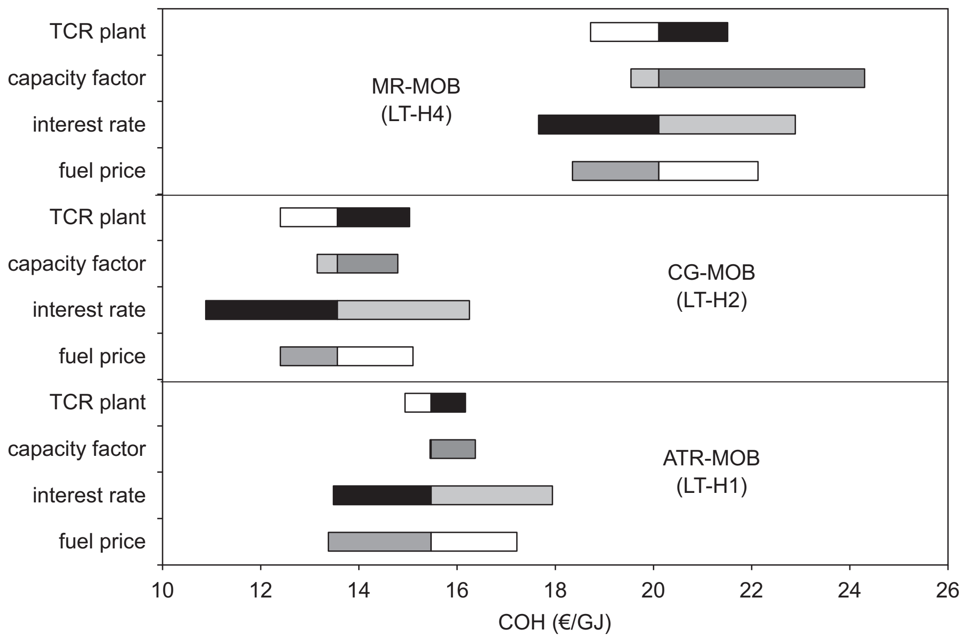


Fig. 15. Sensitivity analyses of various hydrogen production chains with CCS supplying the transport sector (MOB). The chain codes (see Table 10) are given in parentheses and the variation in parameters is given in Table 1. The impact of variation in capacity factor includes the increased CO_2 and H_2 transmission costs when pipelines are underutilised.

plant dispatch model is required to study the joint impact of these parameters in more detail, which is beyond the scope of this study.

The coal-fired power plants and the SOFC-GT are, not surprisingly, more sensitive to variation in capital costs, interest rate and load factor, whereas

COE of NGCC is affected especially by the fuel price. Despite the coal price increase in recent years, prices are likely to moderate the coming decades [84]. Gas prices are subject to various trends such as increased gas-to-gas competition and shift to more global markets. The exact impact in the long term is hard to establish. According to the IEA World Energy Outlook, gas prices in Europe may drop the second half of this decade and then gradually rise to around 4 €/GJ in 2030 (considering oil prices of 25–35 $/bbl) [84]. The natural gas breakeven price at which COE of PC with CCS and NGCC with CCS are equal, assuming a coal price of 1.7 €/GJ and both are operated at equal capacity factor of 85%, lies between 6–6.8 €/GJ for CO_2 prices between 0 and 100 €/t CO_2. Even if the capacity factor for NGCC with CCS is decreased to 60% at the default gas price (4.7 €/GJ), COE would still be slightly lower in comparison to PC with CCS. IGCC with CCS[9] appears more competitive than PC with CCS, resulting in somewhat lower break-even natural gas prices.

The uncertainty in CO_2 transport costs hardly has any effect on the COE. Assuming structurally higher pipeline costs (up to a factor 2 in comparison to the base case) and a maximum transport length of 200 km, COE of a PC unit are increased with a mere 0.3 €ct/kWh. The uncertainty with respect to storage costs is mainly related to reservoir characteristics. In the most pessimistic case, assuming storage costs of 10 €/t CO_2 for deployment of several smaller, deep offshore reservoirs with low permeability, COE for a PC are increased with nearly 1 €ct/kWh.

As illustrated by Fig. 15, centralised chains with large-scale hydrogen production and CCS offer cheaper hydrogen than decentralised production by means of MR with CCS, for the range in parameters studied here. Large-scale ATR units with CCS are competitive with CG units with CCS at gas prices of 3–3.5 €/GJ, which is considerably lower than the breakeven price of their electricity counterparts (NGCC with CCS versus IGCC with CCS). COH are strongly dependent on the interest rate due to the capital-intensive infrastructure required to supply hydrogen to refuelling stations and dwellings. The uncertainty in costs of the distribution network, especially the residential hydrogen grid, has a major impact. The costs of this grid depend on local conditions and might be a factor 2.5 more expensive than our default value, resulting in COH around 33 €/GJ.

CO_2 mitigation costs of hydrogen application as presented in Fig. 12 are to a large extent determined by the assumptions in fuel prices and end-use conversion efficiency and costs, for which large uncertainties exists. Although current oil prices (65–70 $/bbl) are historically high, it is unclear whether such high prices will retain the coming decades. In 2004, the World Energy Outlook forecasted oil prices between 25 and 35 $/bbl up to 2030 [84]. If investments in oil infrastructure in the Middle East are not significantly increased, oil prices might be as high as 50 $/bbl (nearly 9 $/GJ) in the long term [85]. Assuming gasoline costs at the refuelling station of 15 €/GJ instead of the base case value of 9 €/GJ, CO_2 mitigation costs would decrease to circa 80–90 €/t CO_2 for centralised hydrogen chains. Mitigation costs can vary with roughly 100 €/t CO_2 for the range of PEMFC efficiencies quoted in literature [4,43–45]. The uncertainty in fuel cell costs has an even bigger impact on the performance of hydrogen. If we consider vehicle retail prices projected for 2010 as quoted in [34], assuming fuel cell costs of 100 €/kW, mitigation costs would be more than 700 €/t CO_2. Note that a significant improvement still has to be made to achieve a level of 100 €/kW given current fuel cell cost (produced in low quantities) [4,50,86].[10] Although PEMFC costs for stationary purposes are higher than mobile PEMFC costs, as the former requires a longer lifetime and the capacity is lower, it is unclear what cost difference can be expected. A lower range of 500 €/kW for stationary fuel cell systems [87] would decrease CO_2 mitigation costs with 25–30%. Apparently, the impact of PEMFC costs on CO_2 mitigation costs for stationary applications is less severe than for mobile applications; energy costs are a more important factor.

5. Discussion and conclusion

A chain analysis has been performed for promising CCS options, incorporating a wide variety of technologies, infrastructural settings, hydrogen

[9]Note that the IGCC in Fig. 14 represents an advanced concept, which cannot be compared to state-of-the-art PC and NGCC.

[10]The cost of current fuel cell systems for mobile applications is estimated at 250–300 $/kW at a production volume fof 500,000 units per year [51].

end-use markets and reference systems to study various CCS configurations under specific conditions and assumptions. The results indicate that the overall impact of CCS on CO_2 emissions and electricity production costs is significant. CO_2 emissions per kWh are reduced with 75% up to practically 100% with respect to an equivalent power plant without CCS. Note that the overall chain emission of a PC unit with CCS is still more than half the emission of a NGCC without capture. Electricity costs are increased with 25–50% and 15–35% for state-of-the-art and advanced concepts, respectively. The range of studies presented in the IPCC special report on CCS [88] shows a higher upper boundary. Some studies forecast a COE increase of 90% for PC or NGCC with post-combustion capture, transport and storage, which can mainly be explained by more conservative estimations for capital costs and/or energy use of CO_2 capture.

The cost increase is dominated by CO_2 capture and compression, representing 65–90% of the additional costs due to CCS. Only 2–11% of total production costs for central units can be attributed to CO_2 transport and storage. According to Rubin et al. [89], the share of CO_2 transport over 160 km and storage into an aquifer is 5–10% of the COE. For typical Dutch conditions (i.e. a maximum transport distance of 200 km), transport costs for a large power plant are estimated at 1–7 €/t CO_2 (the upper range representing offshore conditions), corresponding to 0.05–0.3 €ct/kWh. Although CO_2 transport costs are low on a kWh basis, the total investment costs to construct a CO_2 network are large. Considering the length of the high-pressure transmission grid for natural gas, we estimate the investments costs of a CO_2 network at a few billion Euros. The extent of the CO_2 network could be minimised when power plants with CCS are constructed in the Northern provinces, where the bulk of storage capacity is located. Only a limited capacity can be fit into the current network; investments may be required to strengthen the existing electricity grid to carry the electrons from the North down to the major electricity demand centres. More in-depth research is required to study this trade-off for optimal decision making on new plant locations.

The contribution of CO_2 transport is significantly higher for decentralised power generation with CCS. The general consensus is that decentralised technologies are not suited for CCS for this reason and due to concerns over economies of scale in capture technology. However, specific decentralised technologies that enable inherently low-cost CO_2 capture such as SOFC may produce electricity with CCS at reasonable costs, provided that the plant can be connected to a CO_2 trunk line located nearby. Another option would be to install the plant on top of a CO_2 storage reservoir. Note that storage costs will increase when CO_2 from a single 20 MW_e distributed unit is injected into a reservoir that is characterised by a permeability that allows for much higher injection rates.

CO_2 storage in onshore and offshore gas fields or aquifers costs 1–10 €/t CO_2 at injection rates of at least 1 Mt/yr, corresponding to 0.05–0.9 €ct/kWh. In the Netherlands, natural gas fields are the primary target reservoirs for CO_2 storage. Whether enough suitable gas reservoirs (excluding Groningen) will be available to store large quantities in the longer term is open to question, considering future UGS demand and risk profiles of reservoirs. Possibly, aquifers and coal seams also need to be exploited.

The prospects and competition between different CCS technologies are depending on several uncertain parameters such as fuel prices, capacity factor and capital costs, for which a sensitivity analysis was performed. COE for NGCC with CCS are lower than for PC with CCS over the studied range in parameters (gas prices up to 6 €/GJ). Only combinations of high gas prices and low capacity factors favour PC with CCS. The breakeven natural gas price for IGCC with CCS is somewhat lower in comparison to PC with CCS. It should be noted that NGCC *without* CCS is the most competitive technology in a world where natural gas prices prevail below the range from 5.5–7 €/GJ and CO_2 prices of 0–55 €/t CO_2. Kreutz and Williams [90] came to comparable findings, although in their analysis the perspectives for IGCC are somewhat more optimistic and NGCC with CCS enters the playfield at much higher CO_2 prices.

The impact of CCS on costs of centralised hydrogen production and supply is not as substantial as for electricity production; they add another 1–2 €/GJ for transport distances up to 200 km. Of the total costs of centralised H_2 production (between 8 and 21 €/GJ for base case assumptions on fuel price etc.), maximally 0.5 and 0.7 €/GJ are added by CO_2 transport and storage, respectively. Hence the carbon price required to equip hydrogen units with CCS is rather low; typically in the order of 10–20 €/t CO_2. Mitigation costs for replacing natural gas or gasoline with hydrogen produced with CCS are 100–200 €/t CO_2.

These values should be considered with care, as they are strongly dependent on the choice of the reference system and assumptions in fuel prices and fuel cell performance and costs. Nevertheless, these costs are fairly high in comparison to mitigation costs of CCS application in the power sector, which are estimated at 10–170 €/t CO_2, but in most cases below 60 €/t CO_2. So hydrogen production with CCS and application for any other purpose than current (chemical) use does not deserve preference as CO_2 mitigation option. Hydrogen could also be adopted in the steel industry. However, CO_2 mitigation costs of hydrogen replacing cokes are somewhat higher in comparison to CO_2 capture from the blast furnace gas in the traditional BF route using cokes.

Hydrogen production and supply costs are to a large extent determined by the H_2 infrastructure requirements. Even for those chains with minimal infrastructure (e.g. CHP units), supply costs are significant, mainly due to the need of a centralised buffer. The base case costs to produce and deliver hydrogen to decentralised CHP units are estimated at 8-10 €/GJ (versus current natural gas price of circa 5 €/GJ). Base case hydrogen costs for the transport sector are between 14 and 16 €/GJ for large, advanced CG/ATR units, respectively, versus gasoline costs at the refuelling station of 9 €/GJ. Approximately 50% of the costs are attributed to H_2 storage, transmission, distribution, compression and dispensing. Ogden [40] estimated hydrogen production and delivery costs for a similar configuration at 18 €/GJ. The difference lies mainly in the refuelling station; Ogden estimated costs of a manned refuelling station at circa 6 €/GJ (of which circa 50% labour costs) versus 3.7 €/GJ for an unmanned station considered in our study.

In a future envisioning hydrogen supply to households, total production and supply costs may even exceed 20 €/GJ (versus 8 €/GJ for natural gas), mainly due to the extensive low-pressure distribution grid. Hence H_2 supply to a CHP system on a block-level, from where electricity and heat are delivered to individual households, may be more attractive. In such a multi-family configuration, H_2 delivery costs would be around 10–12 €/GJ assuming a heat grid is present (as in many new build locations in the Netherlands). Another argument for multi-family instead of single-family PEMFC units is economies of scale of the fuel cell system, as was demonstrated by Kreutz and Ogden [91].

Apart from the costs of hydrogen supply, the construction of a dedicated hydrogen infrastructure may involve practical problems, as the Netherlands is a densely populated country with a high density of natural gas pipelines and other infrastructure. The risks associated with hydrogen transmission, distribution and end-use is of major concern, and might inhibit the use of hydrogen, especially in households and cars. From a wider perspective, the value-added of hydrogen for stationary purposes is rather poor due to the relatively high share of relatively 'clean' natural gas. For the transport sector, the problems (oil dependency, GHG emissions and problems with local air pollution) are more urgent, which may prove a strong driver for hydrogen use.

If penetration levels of hydrogen in the transport sector appear slower than projected, centralised hydrogen production with CCS may enter the playfield beyond 2030. Alternatively, decentralised MR would be an interesting technology when hydrogen demand (density) is too low to justify centralised production, although COH (20 €/GJ) are still noticeably higher than for centralised production. As the facilities to enable CCS could be added relatively simple, MR might first be operated in the non-capture mode when there is no CO_2 infrastructure to which it can be connected.

This chain analysis has shown the impact of different CCS chains in a non-dynamic way, in which the level of H_2 application and CO_2 reduction was fixed. A more detailed analysis is required to assess the consequences of demand and supply fluctuations on load factor, pipeline utilisation and storage requirements. Part of the fluctuations may be covered by the buffer capacity offered by the extensive pipeline network. For storage of large quantities H_2, alternatives for costly steel tanks (composite tanks, geological reservoirs or liquefied hydrogen, as present in the existing hydrogen network in the Rijnmond area) should be considered.

Finally, the extent of CO_2 emission reduction by CCS has been set at 20 Mt/yr in 2030. Further research should focus on the factors that affect CCS implementation rates in order to define scenarios that allow for a more structural assessment of the potential and costs of CCS in the coming decades.

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