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Infrastructure Issues of Decoupled Hydrogen/ Electricity Production with Carbon Capture and Storage

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1 Introduction

On the way to establish a large scale “hydrogen economy”, the undertaking of consequent upfront infrastructure costs is generally anticipated as the main obstacle. Indeed, a high risk of stranded investment exists while no demand market has been proved on the end-user side. In order to reformulate this “chicken-or-egg” dilemma, the present work explores a possible transition path based on existing mid-term energy options for electricity generation.

For a conceivable fossil-fuelled electricity production strategy with CO₂ capture, the location of available storage options could play a key role for plant siting, as expensive CO₂ transport infrastructure might be required in some configurations. The possible spatial separation of electricity generation and centralised fossil hydrogen production with CO₂ capture and storage allows an additional degree of freedom in the system in enabling the transport of hydrogen instead of electricity.

In this study, we analyse energy conversion and transport tasks associated with the plant locations offered by this enhanced scheme. By considering various scenarios for Germany, we describe different gasification/ reforming options with CO₂ capture and estimate their cost, including where new infrastructures are required.

2 Methodological Approach and Limits of Analysis

2.1 General system definition

Different options for the installation of new fossil-fuelled electricity generation facilities within Germany are discussed. We consider imported hard coal and natural gas as primary energy carriers, the former being delivered at existing harbours in the Benelux or in the north of Germany whereas the latter is directly sold at the power plant gates to electric utility consumers. For reasons of simplification, we assume that no secondary energy carrier enters our system. Secondary energy carriers considered here are high voltage electricity delivered to the big energy consumption areas identified below and optionally gaseous hydrogen as an intermediate. We do not formulate any assumption on the final use/ conversion of the electricity.

The modelled fossil-fuelled power or gasification/ reforming plants are equipped with carbon capture systems. The captured CO₂ will have to be transported to underground storage options.

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Costs associated with all processes modelled in our system are evaluated to make different pathways comparable. Upstream CO₂ emissions like contributions of primary energy carrier exploration and transport are not assessed here.

Accordingly, this study should neither be regarded as a Well-to-Wheel study nor as a Life-Cycle-Assessment but aims at analysing conversion and transport options.

2.2 Conversion tasks

In a conceivable fossil-fuelled electricity production strategy with CO₂ capture, we selected the hard coal Integrated Gasification Combined Cycle (IGCC) and the natural gas Combined Cycle (NGCC) technologies. The pre-combustion capture process envisaged for the IGCC produces a hydrogen rich gas as an intermediate product. Instead of burning it in a syngas combined cycle, it can be further cleaned to make hydrogen available as a product of a gasification power plant. We also retained the natural gas reforming option with carbon capture as an alternative for hydrogen production. The hydrogen can fuel a combined cycle for central decoupled electricity generation.

2.3 Plant locations

The choice of power plant location is classically driven by the main operational constraints², namely the proximity of water courses (or sea) able to meet the process cooling needs, the possibility to deliver the fuels and to export the relevant secondary energy carrier. In addition to these criteria, the present study explores the relevance of siting carbon capture power plants nearby a CO₂ storage option (for Germany, as a rule, carbon dioxide storage options are not located near existing power plants or import/ exploration sites). The decoupled hydrogen/ electricity production is also envisaged to add a further degree of freedom to the system. As an example, we detail in Table 1, the allowable plant locations for the hard coal alternative in the base case of one seaport, one consumption centre and one storage option. Figure 1 depicts illustrative examples.

Table 1: Power plant locations and associated processes – hard coal alternative.

Power Plant	Power Plant Location	Electricity	Note
IGCC	Seaport	Coupled	Consumption Centre and/ or Storage Option in some scenarios
Gasification to H ₂	Seaport	Decoupled	Storage Option in some scenarios
IGCC	Consumption Centre	Coupled	Seaport and/ or Storage Option in some scenarios
H ₂ Combined Cycle	Consumption Centre	Decoupled	
IGCC	Storage Option	Coupled	Consumption Centre and/ or Storage Option in some scenarios
Gasification to H ₂	Storage Option	Decoupled	Seaport in some scenarios

² In addition to usual building requirements: site accessibility and constructability under sustainable economical and environmental conditions together with the successful completion of the permitting process.

2.4 Transport tasks and infrastructures

Transport tasks required by the conversion processes and plant locations retained in this study are listed in Table 2, together with the associated infrastructure. This provides the basis of the scenario comparison proposed in this article.

Table 2: Transport tasks and associated infrastructures.

Transport	From\To	through	Network Status
Hard Coal	Seaport\Power Plant	Rail/Ship	Existing
Natural Gas	- \Power Plant	Pipeline	Existing
Hydrogen	Power Plant\Consumption Centre	Pipeline	To be built
CO ₂	Power Plant\Storage Option	Pipeline	To be built
Electricity	Power Plant\Consumption Centre	HV Network	Existing

Keeping short every transport route is crucial to avoid losses and/ or additional costs. For that purpose, we used an internally developed Geographical Information System (GIS) to optimise transport distances. This tool finds optimal paths through the given set of the existing German infrastructures (waterways, railways, highways, high pressure natural gas grid and high-voltage transmission network). Transport distances along the existing networks referred to in Table 2 can be measured directly whereas we assume that CO₂ or H₂ pipelines will align the combined existing routes, thus reflecting allowable right of way and local geographic conditions (relief, protected area...) constraining any new infrastructure construction.

3 Model Description and Assumptions

When new infrastructures or power plants have to be built, capital costs are calculated according to the annuity method. Operation and maintenance costs are added to this annual charge.

Costs and performances assumed for the study reflect a plausible status for the year 2030. This is in line with expectable timeframe for designing, gaining necessary consents, building and commissioning the technologies selected here.

To ensure continuity with previous works, all reported costs refer to the year 2000. Likewise, primary energy import prices suit the scenario ranges selected in Hake et al. (2009) [1]: 3,5 respectively 5,9 €₂₀₀₀/GJ_{LHV} for hard coal and 7,0 respectively 11,9 €₂₀₀₀/GJ_{LHV} for natural gas (low respectively high prices). An emission price is also set to 31 €₂₀₀₀/t_{CO2} in line with Umweltbundesamt (2009) [2] scenarios.

A literature review of future expectable hydrogen and electricity generation costs was performed for the proposed power plants equipped with CO₂ capture. Our model proved to fit those expectations after usual fuel price/ inflation/ currency corrections.

Hard coal transport costs per barge and/or rail are modelled following the framework described in Prognos (2006) [3] for Germany. Actual natural gas transport fees against delivery location and volume are difficult to access, moreover taking into account the various

locations of existing gas import options in Germany. Therefore, this study estimates the cost of natural gas sold at the power plant gate³.

Hydrogen transport costs are based on the model from Yang & Ogden (2007) [5] [Yang & Ogden, 2007], crosschecked with other sources. CO₂ transport and storage costs for Germany are set within the range reviewed in Wietschel et al. (2010) [6].

In the absence of accurate information on electricity transport fees through the high voltage network, costs are estimated on a simplified energy loss basis (Neither existing network reinforcement nor construction are accounted for). It should be noted that such electricity transport refers to the high voltage transport network and do not allow for distribution to the final energy consumer (The same would apply for hydrogen, should it be derived at the exit of a transport pipeline⁴).

4 Scenarios and Results

We present a selection of significant scenarios investigated for this study.

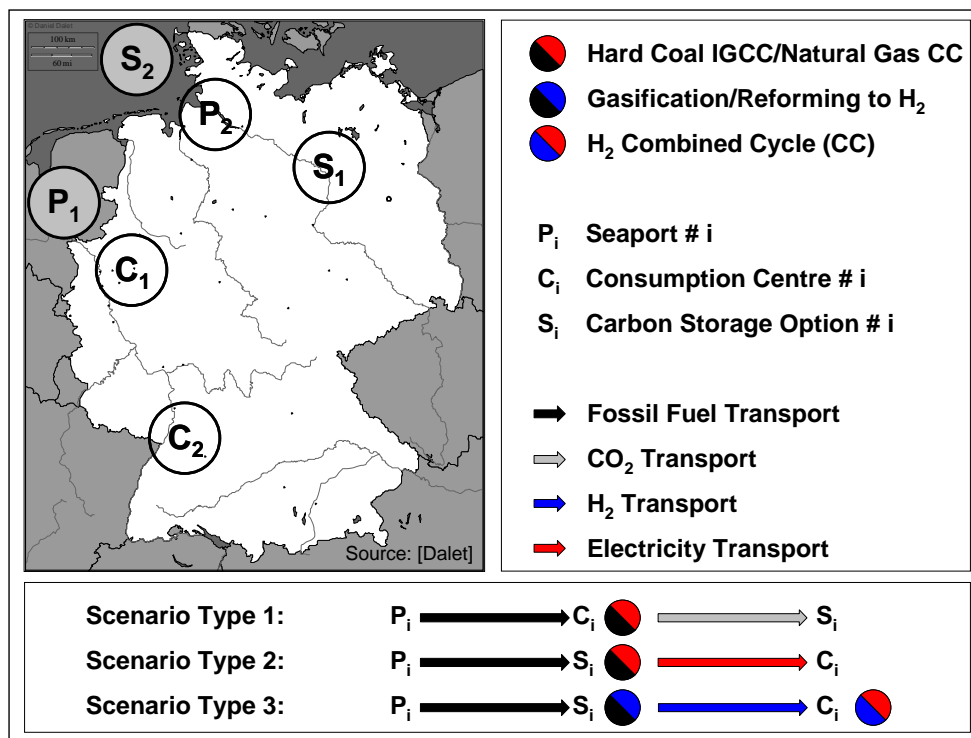


Figure 1: Selected locations and definition of three types of scenarios [7].

Figure 1 summarizes the conversion tasks, plant locations and transport tasks associated with these scenarios (See also the base combinations of locations and tasks listed in Table 1 and Table 2). Scenario Type 1 refers to the fossil fuel conversion at the consumption centres

³ From the difference between border and utility delivery prices, gas transport within Germany can be roughly estimated to increase its sell-price by 9 to 13% (including profit margin), Bundesnetzagentur (2009), [4]

⁴ Central delivery at the pipeline exit, gaseous state – 3 to 4 MPa in our case.

whereas scenario Types 2 and 3 correspond to the fossil fuel conversion nearby carbon storage options, into electricity or hydrogen respectively.

From Figure 1, a scenario naming convention is defined for this article. As an example the abbreviation “Coal/Type 1/P₁/C₁/S₁” is referring to “Primary energy Coal/Scenario Type 1/Seaport #1/Consumption Centre #1/Carbon Storage Option #1”.

4.1 General trend and implications

Representative base scenarios are compared in Figure 2 for the hard coal and gas alternatives. The cost of electricity produced and transported to consumption centres stays within a similar range for all three types of scenarios proposed and mainly differs in the resulting transport tasks. The costs associated with an additional hydrogen generation step (and transport infrastructure) seem to be moderate. Despite good efficiencies and reasonable investment costs, the natural gas case is penalised by high shares of fuel costs in the final electricity costs. This is even more emphasised for scenarios of high energy prices depicted by the thin bars in Figure 2.

We also note that the question of transporting electricity instead of hard coal is more open with carbon capture and storage power plants, as additional CO₂ transport costs arise when fossil fuel is converted near to energy consumers. A more refined model of electricity transport costs would be required to address this point (reflecting high voltage network access costs, possible additional capacity needs...).

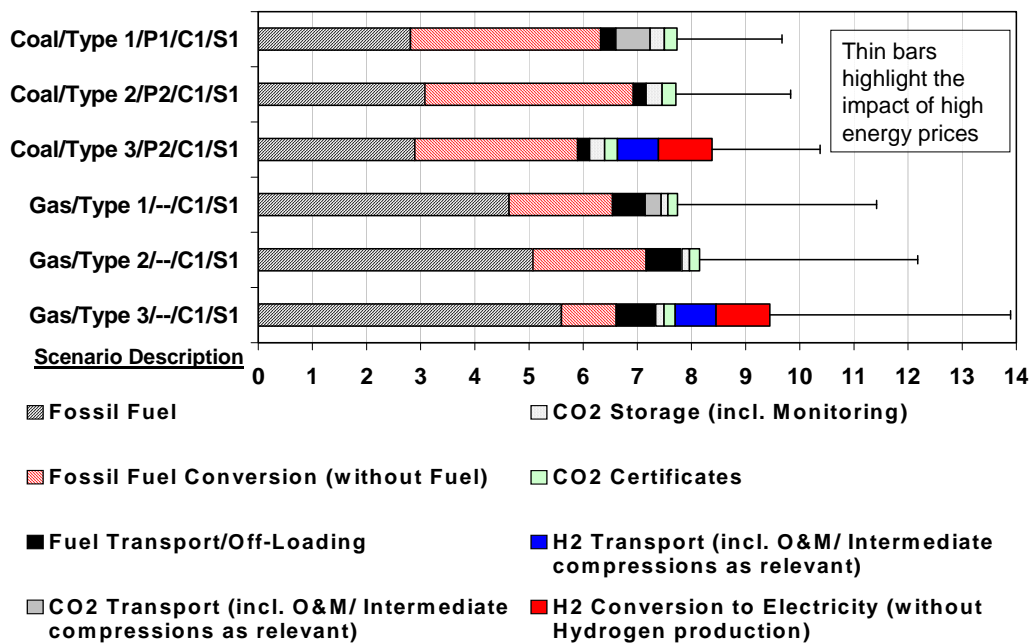


Figure 2: Costs of electricity (Eurocent₂₀₀₀/kWhe) at consumer centres (High voltage – excluding distribution) for selected scenarios.

Types of scenarios are defined in Figure 1; Seaport for hard coal P₁: ARA (Amsterdam, Rotterdam, Antwerpen); P₂: Hamburg; Consumption Centre C₁: Ruhr area; Carbon Storage Option: S₁: Onshore Aquifer

4.2 Alternative locations

The impact of different locations for consumption centres and storage sites has been evaluated for the hard coal example. We propose in Figure 3 the comparison of two consumption centres, namely the Ruhr area (C_1) and Karlsruhe area (C_2). The overall cost of electricity is reasonably affected by the almost doubled transport distances for hydrogen and CO_2 . The pipeline starting/ ending at Karlsruhe were forced to cross the Ruhr area to suit an expectable future pipeline demand in this big consumption centre. This penalising assumption reflects plausible pipeline routes but should be balanced by the possibility to mutualise pipeline costs with other users.

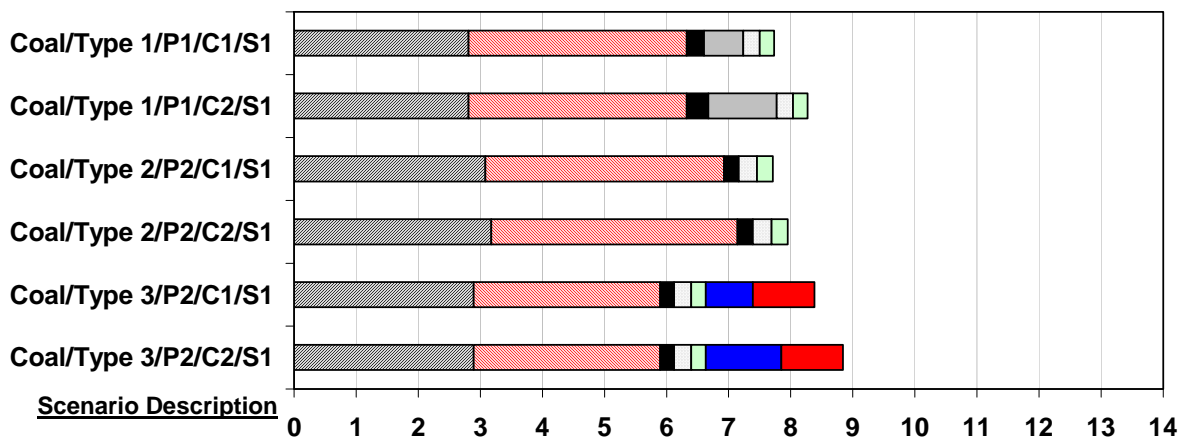


Figure 3: Costs of electricity (Eurocent₂₀₀₀/kWh_e) at consumer centres (High voltage – excluding distribution) for selected scenarios.
Consumption Centre C_2 : Karlsruhe area; Other assumptions and keys as defined in Figure 2

Alternative carbon storage locations were also analysed. Under our assumptions, choosing the offshore aquifer option S_2 would be slightly more expensive than the onshore aquifer option S_1 . All scenarios would be penalised by the expected higher costs for offshore pipelines and sequestration. Moreover, for scenarios Types 2 and 3, the fossil fuel conversion would occur near to a seaport (not at the storage location directly) and require the construction of CO_2 transport pipelines (offshore) which were avoided for scenarios Types 2 and 3 associated with an onshore storage option.

5 Conclusion

Taking climate protection constraints into account, the CO_2 emissions of fossil fuelled power plants have to be captured and safely stored. Such a strategy implies the construction of a sufficient infrastructure. For fossil-fuelled electricity generation with CO_2 capture, siting power plants near to carbon storage options should be considered further. Electricity or hydrogen can be transported to make these emission-free secondary energy carriers available near to consumers. In addition, it seems that moderate additional costs could allow the implementation of a first level hydrogen transport infrastructure instead of building a CO_2

transportation network. This could be a smooth way to finance and facilitate the transition to a future larger "hydrogen economy". On the long term, this infrastructure would be in place for the transport of a non fossil H₂ generation.

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