Near-Zero Emissions from Electricity and Hydrogen Production with CO_2 Capture and Storage (CCS)

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SIXTH FRAMEWORK PROGRAMME

Dynamis Consortium

32 partners from 12 countries

Co-ordinator: SINTEF Energy Research

Partners:

- ALSTOM (Schweiz) AG
- ALSTOM Power Centrales
- ALSTOM Power Environment ECS France
- BP International Ltd
- Bundesanstalt für Geowissenschaften und Rohstoffe
- E.ON UK plc
- Ecofys b.v.
- ENDESA Generación S.A.
- ENEL Produzione S.p.a.
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- European Commission - DG JRC – Institute for Energy
- Fraunhofer Institute for Systems and Innovation Research
- Geological Survey of Denmark and Greenland
- IEA Greenhouse Gas R&D Programme
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- Technical University of Sofia
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Contents

Glossary

AGR	Acid Gas Removal
ASU	Air Separation Unit
CHP	Combined Heat and Power
CCS	Carbon/CO_2 Capture and Storage
EGR	Enhanced Gas Recovery
EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
EU	European Union
EUA	Emission Unit Allowance
EU ETS	European Union Emission Trading Scheme
FEED	Front End Engineering Design
GTCC	Gas Turbine Combined Cycle
HHV	Higher Heating Value
IGCC	Integrated Gasification Combined Cycle
IRCC	Integrated Reforming Combined Cycle
IRR	Internal Rate of Return
LHV	Lower Heating Value
NGCC	Natural Gas Combined Cycle
NOx	Nitrogen oxides
PSA	Pressure Swing Adsorption
R&D	Research and Development
SO_2	Sulphur dioxide
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants

1. What is DYNAMIS?

Launched in March 2006 under the European Union's Sixth Framework Programme for Research (FP6), DYNAMIS is an Integrated Project (IP)[1] consisting of 32 partners covering 10 Member States, one Associated Country (Norway) and Switzerland.

Budget: €7.4 million, including €4 million funded by the European Commission (EC); Timeframe: 36 months. Goal: to undertake research and pre-engineering studies to enable the construction of commercial-sized power plants which use fossil fuels to produce electricity and hydrogen – but with only 10% CO_2 emissions, thanks to CO_2 Capture and Storage technology (CCS).

CCS involves capturing the CO_2 at source, transporting it to a storage site, and then storing it permanently in geological formations at least one kilometre underground (Figure 1). The plants studied also involve the production of large volumes of hydrogen, which can then be used for either industry (e.g. refineries) or society (e.g. transport). It means that hydrogen fuel cell vehicles (FCVs) or internal combustion engines (ICEs) can be supplied with bulk hydrogen from coal, lignite or natural gas – but with a minimum of CO_2 emissions.

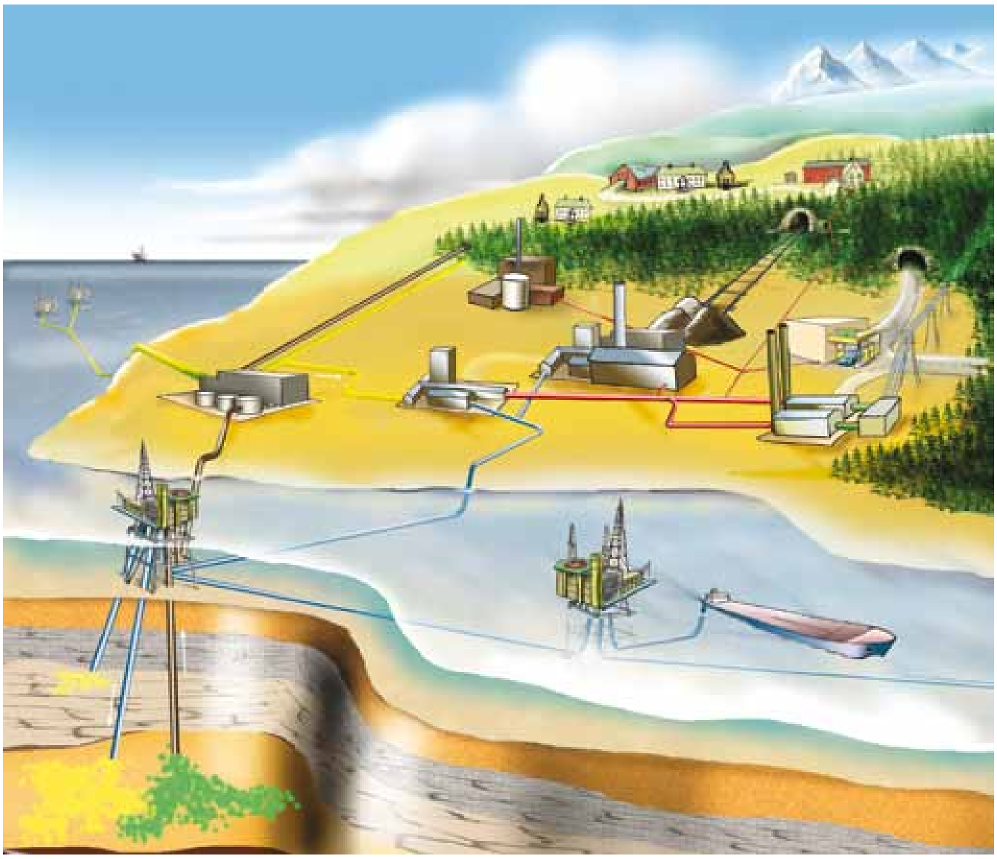


Figure 1: The DYNAMIS vision - towards hydrogen and electricity production with CO_2 capture, transport and storage.

1
Integrated Projects are ambitious, objective-driven multi-partner projects, addressing different research issues via a "programme approach" and usually include several components

Part of HYPOGEN...and aligned with ZEP

To understand the work of DYNAMIS, it must be viewed within a wider context:

- It was designed as part of the HYPOGEN initiative – itself part of the EC's Quick-Start Programme for the Initiative for Growth – whose goal is to provide Europe with a viable route to a hydrogen economy. This includes the construction of large-scale CCS demonstration plants producing both electricity and hydrogen (HYPOGEN projects) as an interim step.
- The European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP)[2] has stated that 10-12 large-scale CCS demonstration plants must be operational by 2015 in order to ensure that CCS is commercially viable by 2020. This was also endorsed by the European Council in March 2007.

DYNAMIS is the first European project to unite the hydrogen community and society with the CCS community. Since both sectors have different stakeholders – hydrogen being dominated by end-users and CCS by the power utilities and primary energy providers – the establishment of some common ground has facilitated for the cross-fertilisation of ideas.

CCS: a critical solution for combating climate change

The concept of CCS was first put forward in the 1980s, while studies on the effects of anthropogenic[3] greenhouse gases (GHG) on the climate were first undertaken on a global scale by the Intergovernmental Panel on Climate Change (IPCC) in 1990. Concern has grown over the last decade and the 4th Assessment Report published by the IPCC in 2008 concluded that it is highly probable that massive emissions of GHGs resulting from human activities are a major cause of climate change.

While estimates differ as to by how much CO_2 emissions need to be reduced, the consensus is that they must remain at least at 2007 levels by 2050 (i.e. some 28 billion tonnes a year) in order to limit the resulting temperature rise to within 2 degrees above pre-industrial levels. This is no small challenge given that business-as-usual scenarios predict a 300% increase in CO_2 emissions by this date if no low carbon policies are employed. Other studies point towards 50% and 80% reductions in relation to 2007 levels, requiring quite costly measures – although here cost is a relative issue.

However, while renewable energy systems are the ultimate goal, their cost and availability at scale means that they are still expected to make up only ~30% of the energy mix by 2030[4] ; while CCS has the potential to reduce global CO_2 emissions by 9-16 billion tonnes a year by 2050[4]. As a safe and efficient method of capturing and storing billions of tonnes of CO_2 underground for thousands of years, CCS therefore represents the bridge to a renewable energy system.

The work of DYNAMIS has therefore focused on five key areas:

- The de-carbonisation of fossil fuels
- Hydrogen separation
- New efficient power cycles
- The reliable geological storage of CO_2
- Societal embeddedness of CCS projects with hydrogen production.

Four case studies covering a range of CCS options

In order to arrive at practical and commercially feasible plant concepts with the best possible performance for coal, lignite and natural gas as fuel, DYNAMIS has undertaken extensive work on technology selections and optimisations. The technical and economic aspects of handling hydrogen and CO_2 have also been assessed.

These technical issues were then further illustrated by four commercial case studies of potential HYPOGEN projects, covering the full CCS value chain – from CO_2 capture, through transport

2
Initiated by the European Commission, ZEP is a broad coalition of stakeholders including European utilities, petroleum companies, equipment suppliers, national geological surveys, academic institutions and environmental NGOs

3
Man-made

4
"EU Demonstration Programme for CO_2 Capture and Storage (CCS) – ZEP's Proposal", published November 2008 – see www.zero-emissionplatform.eu/website/library

infrastructure and to storage. Sponsored by industrial partners, these case studies provided considerable knowledge on a range of fuel types, the transportation of CO_2; and the injection and storage of significant volumes. They were based on best practice for a variety of storage sites, including on- and offshore deep saline aquifers and oil fields, together with options for hydrogen use:

- Case study A: East England, UK, sponsored by E.ON UK; bituminous coal-based plant with offshore CO_2 storage
- Case study B: North East UK, sponsored by PEL; bituminous coal-based plant with offshore CO_2 storage, including Enhanced Oil Recovery (EOR)
- Case study C: Mongstad, Norway, sponsored by StatoilHydro; natural gas-based plant with offshore CO_2 storage
- Case study D: Hamburg region, Germany, sponsored by Vattenfall; bituminous coal-based plant with onshore or offshore CO_2 storage.

Non-technical aspects crucial to the realisation of HYPOGEN projects were also assessed. These included, in particular, market perspectives and social, legal and regulatory issues.

Key conclusions

As a result of the work undertaken, some key conclusions have been drawn.

1. Framework project parameters are:
- Electrical power output in the 400 MW class, including a hydrogen-fuelled gas turbine (in the case of coal)
- Hydrogen production corresponding to up to 50 MW higher heating value and meeting European hydrogen infrastructure specifications.
- 90% CO_2 capture rate, requiring considerable storage reservoir modelling, since the implied annual injection rate of 3 million tonnes represents a significant advance on current knowledge.

2. For transport and storage purposes, CO_2 must be kept in a dense phase and recommendations for the composition of the CO_2 stream are provided. The challenges associated with constructing environmentally acceptable North Sea CO_2 pipelines would appear to be no greater than those associated with hydrocarbon pipelines in similar areas, while the impact of constructing a CO_2 pipeline on land is similar to that of a gas pipeline of similar size.

3. Outline modelling of reservoirs chosen for the case studies demonstrates that they are suitable for CO_2 storage (and Enhanced Oil Recovery or EOR in the oil field case). Simulations undertaken also show that pressure build-up in the deep saline aquifers could be mitigated by injection strategies.

4. If suitably bankable income streams can be secured, financial models indicate that there is a potential for whole project capture and storage costs to be reduced below the typical pre-DYNAMIS capture level of €50-€60 per tonne of CO_2.

5. Urgent EC action is required to support project commitment decisions which must be made imminently if CCS demonstration projects are to be operational by 2015.

These conclusions are explained in greater depth in the following sections.

By 2009, DYNAMIS had achieved its targets, leading to the production of a technical prospectus describing of the practical commissioning of such a project by 2013. This would play a significant role in enabling Europe not only to comply with the Kyoto Protocol, but also to fulfil the goal set by the G8 Hokkaido summit for the construction of 20 CCS demonstration plants worldwide, leading to the commercialisation of CCS by 2020.

2. Overview of achievements

Integrating CO_2 capture technology

The CO_2 produced from fossil fuels can be captured using a absorption process which makes use of specially designed absorption chemicals. In simple terms, the mixture of gases containing the CO_2 is passed up an absorption column down which the absorber is passed. The column is filled with packers to maximise the surface area.

The CO_2 (and H_2S) is absorbed into the solvent at a rate which is dependent on the partial pressure of that gas. If the state of the solvent is changed (e.g. by reducing the pressure or increasing the temperature), then the absorbed gases can be released again and the solvent recycled.

For pre-combustion capture (as in the coal-fired case studies), physical absorbtion solvents such as Rectisol or Selexol are used. Because the CO_2 is produced at high pressure and concentration, the process is relatively easy and the reduction of the pressure in stages enables recovery of the CO_2 (for conditioning, re-pressurisation and storage) and the H_2S (for recovery of the sulphur in a Claus unit).

For post-combustion capture (as in the natural gas case), the CO_2 is much more dilute and at low (atmospheric) pressure. Because of the low pressure, the ducts and vessels are very large. Chemical absorption solvents - generally amines - are used. These have to be cooled/ heated in order to release the CO_2, which requires a considerable energy load.

The case studies' specifications require capture of 90% of the CO_2 produced. This represents a realistic level of capture, while avoiding very costly equipment and energy penalties which would be incurred in achieving a higher percentage.

a) Hard-coal and lignite fired plants

Pre-combustion systems convert synthesis gas (from the gasification of coal or lignite or the reforming of natural gas) in a shift reaction, producing streams of CO_2 and hydrogen, which can be separated. The hydrogen can then be used as fuel in a gas turbine combined cycle to generate electricity and/or be supplied to external users (e.g. for transport).

Thus, the choice of technology for hard coal and lignite-fired plants is, IGCC (Integrated Gasification Combined Cycle) with pre-combustion CO_2 capture. The technology choices for the main process steps in the co-production of electricity and hydrogen from hard coal and lignite and their evaluation can be summarised as follows (process units in italics are indicated in the subsequent flow scheme):

- Oxygen production in an *air separation unit* (ASU). Cryogenic air separation is the only commercially viable technology for large-scale production within the timeframes anticipated for HYPOGEN plants

- Synthesis gas production via coal or lignite gasification. Oxygen-blown *gasifiers* are the most appropriate for HYPOGEN plants:
  - The entrained flow type appears to be the optimal option for bituminous coal, providing a high hydrogen production efficiency with minimal production of methane and other gaseous compounds such as, nitrogen and argon. In order to achieve high efficiencies, gasifiers with dry fuel feeding and gas cooling using waste heat boiler (Shell) or water quench (Siemens) were both recommended in the generic concept evaluations and also anticipated in the case studies. Of these, the Shell gasifier is the best proven for hard coal.
  - The gasification of lignite is less straightforward due to its high gasification reactivity, together with high trapped water content, high ash content and low heating value. Lignite is also believed to present problems in water-based slurries because it floats. Of the evaluated options, the moving bed gasifier (BGL, British Gas Lurgi) appears to have significant advantages in terms of its ability to gasify feedstocks with high inherent water contents, while still achieving high efficiencies.
  - Tars need to be separated and recycled, and high methane contents limit CO_2 capture levels to around 80%. Fluidised bed gasifiers (HTW High Temperature Winkler) also achieve high efficiencies, but require pre-drying of lignite and low carbon conversion (~95%). In addition, low carbon conversion (~95%) toghether with high methane contents in the syngas limit CO_2 capture levels to be less than 85%. An entrained flow gasifier with dry fuel feeding and gas cooling using water quench (Siemens) results in higher CO_2 capture levels, while retaining reasonably high efficiencies. Lignite gasifiers will need to be further verified/demonstrated for a full-scale plant.

- Conversion of CO (carbon monoxide) and water vapour to CO_2 and hydrogen by water-gas-shift-reaction. The *shift reaction* is accomplished using a "sour shift" of CO from the raw gas (cobalt-molybdenum sulphur tolerant catalyst) using two catalytic beds.

- Acid Gas Removal (AGR), i.e. desulphurisation (*sulphur removal*) of the synthesis gas and CO_2 separation (*CO_2 absorption* from synthesis gas and *CO_2 desorption* from the solvent). A thorough evaluation of available AGR systems revealed that a physical solvent is most appropriate. Thus the choice was between a DMEPEG process (e.g. Selexol[5]) and Rectisol (methanol). Both have been used in gasification in hydrogen plants. It appears that Rectisol is more complex and energy intensive, but gives a higher purity CO_2 product stream than Selexol. However, the purity requirements of DYNAMIS can also be met by Selexol.

- Compression of separated CO_2 to the required pressure for transport to the storage site.

- Hydrogen purification: with stipulated purity level of at least 99.95 mol%, it was considered that *PSA* (Pressure Swing Adsorption) would be the most suitable for a HYPOGEN plant.

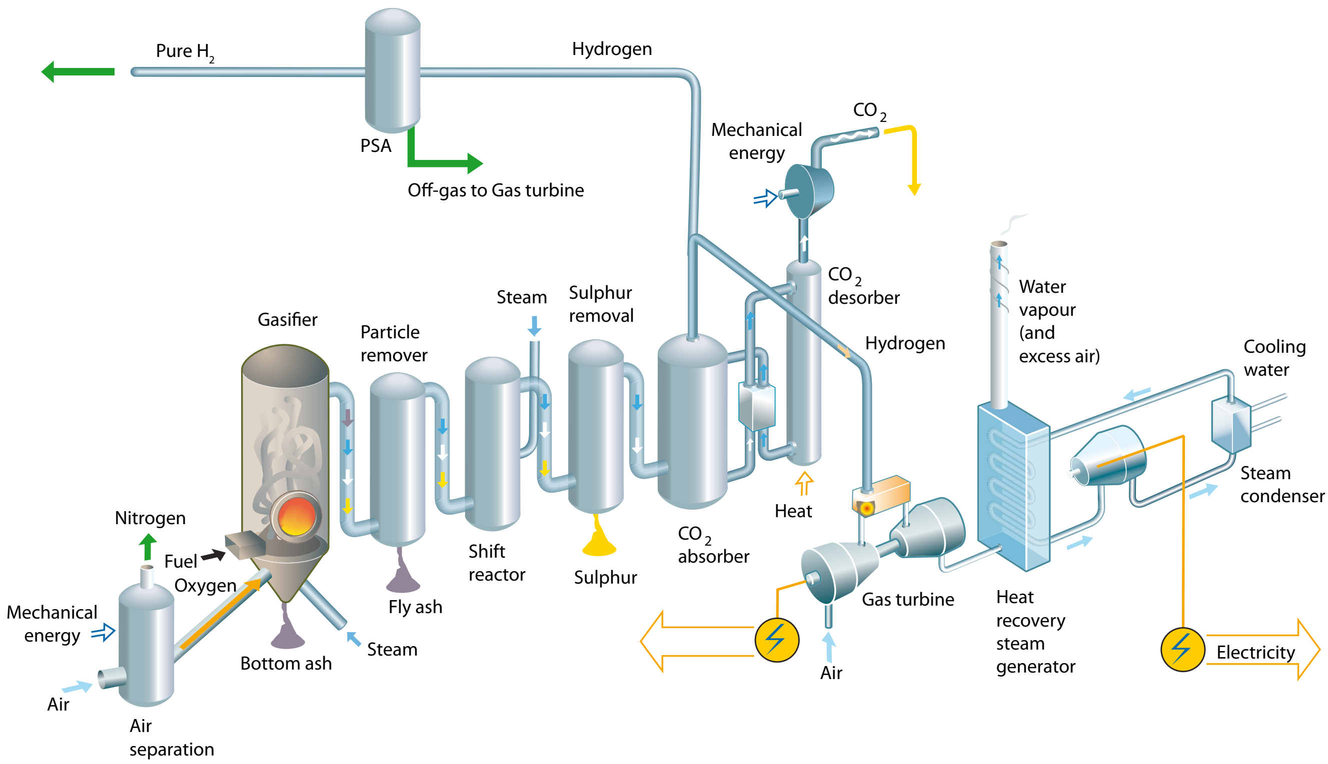
- Power generation in a *Gas Turbine* Combined Cycle (GTCC). The initial generic concepts developed were based on E-class gas turbines, since such gas turbines when modified for syngas are moderately wellproven. DYNAMIS subsequently concluded that the use of F-class gas turbines does not entail excessive risk to the overall reliability, availability and maintainability of the HYPOGEN plant. GE and MHI are both actively promoting the use of their F-class gas turbines with a high-hydrogen fuel (albeit by means of diffusion combustion).

  Both vendors have operating experience in using high-hydrogen fuels. This promotes confidence in their abilityto deliver such technology, although the total number of fleet hours (on high-hydrogen fuels) are low. Furthermore, it was concluded that the performance penalty associated with using E-class gas turbine technology would be a barrier to the successful deployment of pre-combustion capture technology.

These processing steps are shown in the outline flow diagram (Figure 2):

5
The DMEPEG process, Selexol®, is a mixture of dimethyl ethers of polyethylene glycol and has the formulation of $CH_3(CH_2CH_2O)nCH_3$ where n is between 3 and 9

Figure 2: IGCC with pre-combustion CO_2 capture for the co-production of electricity and hydrogen from coal and lignite



The DYNAMIS case studies are designed for one F-class gas turbine combined cycle – thus producing around 400 MW electricity net. Future plants, following the initial demonstrations, could be designed for two or more parallel F-class gas turbines, which will enable larger gas production trains and economies of scale.

The production of hydrogen for external supply offers the possibility of meeting certain power load variation requirements by varying the ratio between hydrogen and electricity production, while at the same time maintaining operation of the gasification process and levels of gas production at full load. Intermediate storage of hydrogen could then also be used in response to hydrogen demand. The technical limitations resulting from such flexibility will be determined mainly by the lowest load at which the gas turbine is still able to operate at acceptable performance levels (i.e. it still provides sufficiently high exhaust gas temperatures).

b) Natural gas-fired plants

For a plant using natural gas, the evaluation of a number of possible concepts – including several IRCCs (Integrated Reforming Combined Cycle) with pre-combustion CO_2 capture – resulted in the choice of a state-of-the-art NGCC (Natural Gas Combined Cycle) with post-combustion[6] CO_2 capture, in parallel with a state-of-the-art natural gas-fired steam reforming plant which, in turn, produces hydrogen.

The steam reformer furnace exhaust gas is also fed to the CO_2 capture unit. In addition, heat from the steam reforming section is used to raise IP steam to HP steam for the combined cycle. All this is mature state-of-the-art technology, except for the post-combustion CO_2 capture unit. The post-combustion CO_2 capture unit consumes significant amounts of energy, mainly in the form of LP steam extraction from the HRSG/steam turbine. An additional consumer of internal energy is, of course, the CO_2 compression process.

This concept is illustrated in the outline flow scheme (Figure 3):

[6] CO_2 is separated from the exhaust gas after combustion

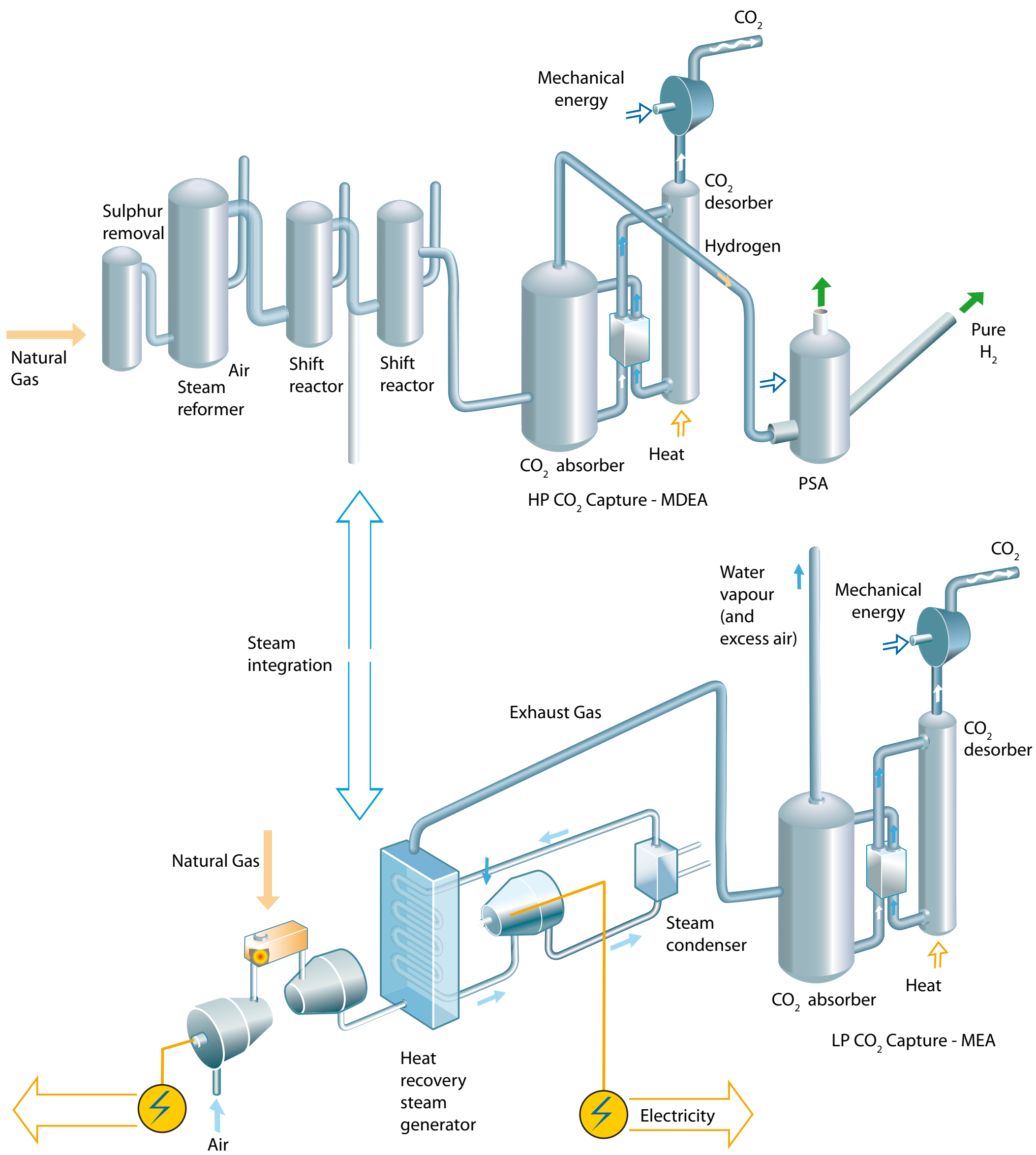


Figure 3: Parallel power and hydrogen generation with steam reforming and post-combustion CO_2 capture technology

The choice of the gas turbine, at least for a condensing plant, is made on the basis of power production alone, and a state-of-the-art gas turbine (F-class currently, H-class in the future) would be the choice in most cases. For a Combined Heat and Power (CHP) plant this may not always be the optimal choice; the Mongstad case study is based on a CHP plant using two E-class gas turbines and one steam bottoming cycle, thus producing 190 MWe_{net} and 350 MW heat. The demand for process heat is high and the process is in this case optimised with this in mind rather than for electrical production efficiency.

Defining CO_2 and H_2 purity

For the CO_2 production stream, it is essential to establish quality specifications that meet transport and storage requirements from a technical, geologic and HSE (Health Safety and Environment) point of view. For the hydrogen production stream, such specifications must fulfil the technical requirements for its distribution and use. Such quality requirements must be developed based on solid technical and scientific information. Unnecessarily strict or challenging requirements will result in high additional costs for extensive cleaning.

a) CO_2 purity

Recommendations for the composition of the CO_2 stream from a transport perspective have been made not only to safeguard the safety and durability of the transport system, but also to ensure the effective utilisation of its capacity. Due consideration has thus been given to existing regulations pertaining to safety and toxicity in order to define maximum limits for the concentration of any chemical component that is likely to occur in the CO_2 stream – especially in the event of a pipeline rupture.

Furthermore, owing to the risk of hydrate formation and corrosion, the mechanical integrity of the transport system is very much dependent on the absence of free water. Other impurities should be excluded mainly for technical reasons, e.g. increased compression work and reduced transport capacity. Table 1 below presents the recommended maximum pipeline transport concentration limits for impurities that are prone to occur in a CO_2 stream captured from a HYPOGEN plant.

Component	**Concentration**	**Limitation**
H_2O	500 ppm	Technical: below solubility limit of H_2O in CO_2. No significant cross effect of H_2O and H_2S. Cross effect of H_2O and CH_4 is significant but within limits for water solubility. Note: This recommended upper concentration level is signifidantly higher than in some other CCS projects that specify 50 ppm (*)
H_2S	200 ppm	Health & safety considerations (***)
CO	2000 ppm	Health & safety considerations (***)
O_2	Aquifer < 4 vol%, EOR 100 – 1000 ppm	Technical: Concentration limit for non-condensable gases (**) range for EOR, because lack of practical experience on effects of O_2 underground.
CH_4	Aquifer < 4 vol%, EOR < 2 vol%	Technical: The effect of CH_4 on the solubility of water in CO_2 is significant but not harmful at CH_4 concentrations lower than 5% and water contents below 500ppm. (**)
N_2	< 4 vol % (all non-condensable gases)	Technical: Concentration limit for non-condensable gases (**)
A_r	< 4 vol % (all non-condensable gases)	Technical: Concentration limit for non-condensable gases (**)
H_2	< 4 vol % (all non-condensable gases)	Technical: Concentration limit for non-condensable gases (**) Further reduction of H2 is recommended because of its energy content
SO_x	100 ppm	Health & safety considerations (***)
NO_x	100 ppm	Health & safety considerations (***)
CO_2	>95.5%	Balanced with other compounds in CO_2

Note (*): Under expected transport conditions for a HYPOGEN plant (pressure, temperature and other possible contaminants) this water level is deemed sufficiently low and the risk of free water and hydrate formation is low.
Note (**): The concentration limit for all non-condensable gases taken together, such as O_2, CH_4, N_2, Ar and H_2 should not exceed 4 vol% owing to exergy demand for compression. In particular O_2, N_2, Ar, H_2 and CO are immiscible with oil and they may thus increase the minimum miscibility pressure (MMP). A combined total greater than 5% of these components will impact negatively on EOR operations.
Note (***): Health and safety issues for pipeline transport of CO_2 relate to short term leakages in the event of rupture or blow-out. The maximum concentrations are derived from STEL (Short Term Exposure Limits) for toxic components in relation to STEL for CO_2.

Table 1: Quality recommendations for the captured CO_2 stream at pipeline conditions for a HYPOGEN plant

Geological storage itself is not believed to impose any additional or more severe quality requirements, but this still remains to be verified scientifically. As indicated in the table above, EOR storage options may impose more stringent requirements, due to interactions with the oil.

b) Hydrogen purity

Pre-normative efforts have been made in DYNAMIS to establish a plausible purity level for the hydrogen produced, while at the same time addressing end user requirements, and in particular the PEM fuel cell. These included extensive experimental work carried out at Air Liquide (France), which indicated that special attention must be given to the concentrationsof inert components and carbon monoxide (CO).

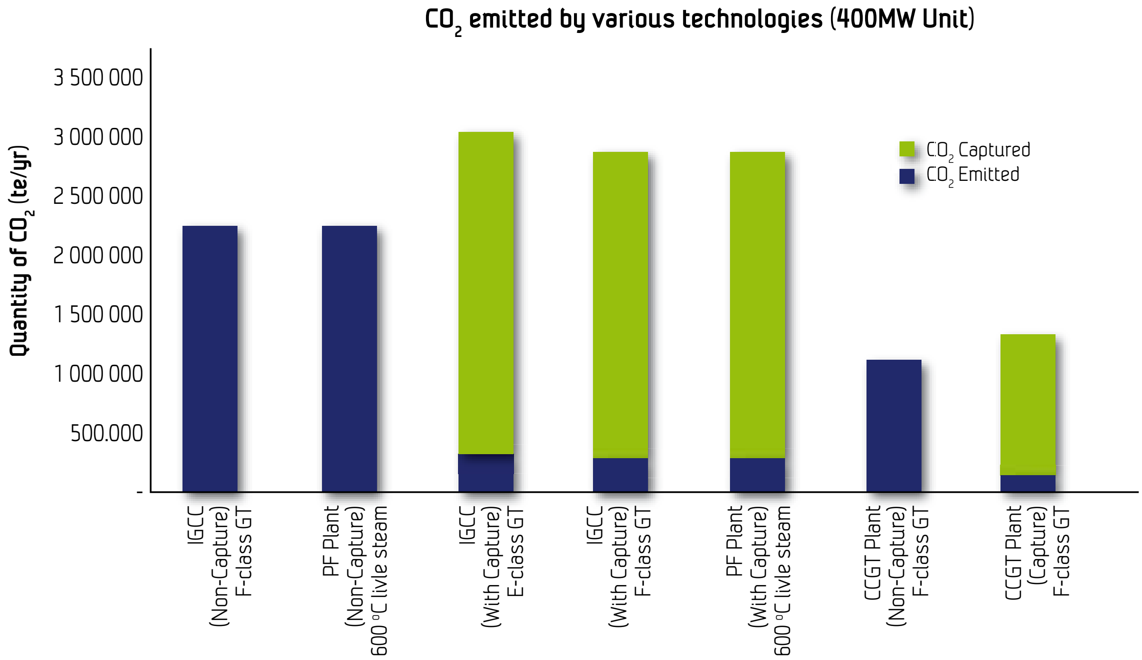
After due comparison of relevant sources, DYNAMIS suggests purity levels for hydrogen as listed in Table 2 below as the new standard for application in a future hydrogen PEM-based transport market. These levels not only comply with the performance and life expectancy of the fuel cells, but minimise investment costs and operational expenses, thereby making hydrogen a more competitive fuel.

Pressure	70 barg	
H_2 purity	99.95% (mol)	
Impurities (maximums) :		**Comments**
CO	<0.5 ppmv	Limit because of long term voltage losses
CO_2	<1 ppmv	It is recommended that CO_2 content be reduced as much as possible before PSA unit. Further relaxation of this limit to 100 ppmv should be considered by the Fuel Cells community, based on experimental experience with long term operation.
Sulphur Compounds	<0.01 ppmv	Further relaxation of this limit to 0.1 ppmv should be considered by the Fuel Cells community
Total Hydrocarbons - C_2+ - CH_4	 < 2 ppmv < 100 ppmv	
O_2	< 5 ppmv	
Ammonia	< 0.1 ppmv	Further relaxation of this limit to 5 ppmv should be considered by the Fuel Cells community
Inert gas (N2, Ar, He)	Sum < 500 ppmv	Further relaxation of this limit to 0.2-1% should be considered by the Fuel Cells community. This could increase hydrogen recovery by up to 6 % points for the coal-based cases studied in DYNAMIS.
H_2O	< 5 ppmv	

Table 2: Proposed hydrogen quality recommendations for a HYPOGEN plant, based on a consideration of PEM fuel cells currently in use in the market.

Maximising plant efficiency

DYNAMIS has put considerable efforts into the selection and optimisation of technologies in order to obtain practical and commercially feasible plant concepts that manufacturers would be prepared to offer. These exhibit the maximum possible energy efficiencies and minimum possible CO_2 emissions, while retaining good/acceptable operability, reliability and maintainability. The best achievable CO_2 emissions and efficiencies for these concepts compared with relevant alternatives are illustrated in Figure 4 below.



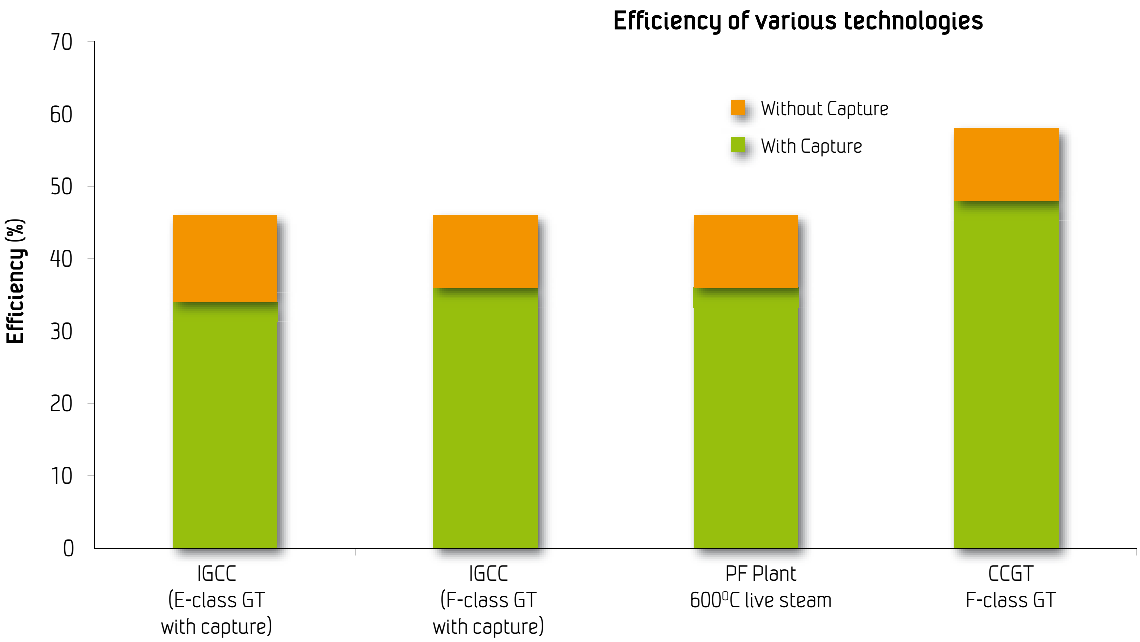


Figure 4: Best achievable CO_2 emissions and electrical power production efficiencies for plant concepts developed in DYNAMIS (when producing electric power only), compared to state-of-the-art power plants without CO_2 capture and PF (pulverised fuel) plant concepts with CO_2 capture[7]

7 CO_2 capture and compression require additional energy, resulting in increased fuel consumption. Volumes of captured CO_2 will therefore be higher than the achieved reductions in CO_2 emissions

a) Coal and lignite-fired plant

An IGGC with pre-combustion capture is a rather complicated process, involving several sequential stages. Like most other CO_2 capture technologies, the plant's on-site energy consumption is significant compared to an IGCC without CO_2 capture, mainly due to the steam used to convert CO and water vapour to hydrogen and CO_2, and the electricity used for CO_2 compression. Much effort in the design phase is thus focused onefficiency improvements, including heat and steam integration, and possibly other measures such as gas turbine air extraction to ASU in order to reduce/avoid separate air compression. Integration levels are carefully balanced against increasing complexity, so that good/acceptable levels of operability, reliability and maintainability are preserved.

Operational experience with several existing IGCCs indicates that some air integration between the gas turbine and the ASU can be beneficial if the gas turbine has a suitable off-take, but that such integration should be limited to around 30%. Heat (steam) integration can also create considerable improvements in overall efficiency, but this should be limited to the main heat flows because the resulting gains in efficiency will not be worthwhile once the additional capital cost and plant complexity are taken into account.

The initial generic concepts developed were based on E-class gas turbines. Their resulting net efficiencies (in electricity-only mode) were 32% - 33% for hard coal[8] and 35% - 38% for lignite[9] (calculated based on fuel LHV, Lower Heating Value).

As mentioned above, DYNAMIS concluded that the use of F-class gas turbines does not entail excessive risk to the overall reliability, availability and maintainability of the HYPOGEN plant, while the performance penalty associated with E-class gas turbines would be a barrier to the successful deployment of pre-combustion capture.

The three case studies for hard coal-fired power plants with CCS were therefore based on F-class gas turbines. These achieved 33% -36 % net electrical power production efficiencies in condensing mode (with no hydrogen production), depending mainly on the detailed properties of the types of gasifiers and gas turbines chosen.

b) Natural gas-fired plant

As mentioned above, a state-of-the-art NGCC with post-combustion CO_2 capture in parallel with a state-of-the-art natural gas-fired steam reforming plant (which, in turn, produces hydrogen) was chosen as the optimal design from among the generic concepts studied.

Such a concept – using a state-of-the-art F-class gas turbine, producing 366 MWel (net) and 50 MW (HHV) hydrogen – can achieve almost 50% total efficiency (calculated based on fuel LHV). Additional energy consumption compared to state-of-the-art NGCC and steam reforming plants without CO_2 capture, is incurred by processes such as steam for desorption of captured CO_2 by re-boiling the amine absorbent, and electric power for the CO_2 compression. This concept exhibited the highest levels of efficiency, while at the same time requiring less integration than the IRCC concepts with pre-combustion CO_2 capture.

The DYNAMIS natural gas-based case study is based on a CHP plant. Much effort in the design phase was thus focused on the optimisation of the post-combustion CO_2 capture process and its integration into the plant.

8
Hard coal: 8% moisture. Efficiency based on LHV (Lower Heating Value)~1% point higher than efficiency based on HHV (Higher Heating Value)

9
Lignite: 55.5 % moisture. Efficiency based on LHV ~6%-points higher than efficiency based on HHV. Pre-drying of lignite used to increase efficiencies. On the same basis, efficiencies based on HHV are lower than those for hard coal.

Optimising use of heat production

Major demands for district and/or process heat from low temperature thermal sources such as in coal/lignite and gas-fired plants may provide additional income. The supply of district heat introduces certain plant design implications and offers numerous additional heat integration opportunities. District heating has additional benefits in that it utilises low grade heat. This form of heat is produced in excessive amounts in the IGCC plants studied here and, in most cases, cannot be utilised economically within the plant.

Such opportunities have been exploited in the Hamburg coal-based case study D (district heat supply to the city of Hamburg) and the natural gas-based Mongstad case study C (steam generation and preheating of crude oil for the refinery).

The Hamburg plant produces varying amounts of district heat, at a maximum of 400 MW and a yearly average of 270 MW. This lowers the net electrical efficiency to a yearly average of 33%, with 56% total efficiency (electricity + heat).

The Mongstad case study C is based on a CHP plant using two E-class gas turbines and one steam bottoming cycle, producing 190 MWe net and 350 MW heat. The demand for process heat is high and in this case the production of such energy is optimised at the expense of electrical power production efficiency. The process achieves only 25% net electrical power production efficiency (with no hydrogen production), but 70% total efficiency (including both electricity and heat).

Assessing CO_2 storage capacity

In Europe, experience with onshore storage of CO_2 is limited,, with the Ketzin project in Germany and small-scale EOR/EGR projects carried out by MOL in Hungary being the only examples. However, there is a very good record of offshore experience from the Sleipner project, and lately also from the Snøhvit CO_2 storage project, both located in offshore Norway. The DYNAMIS case studies are all quite different to these and other ongoing projects, and demonstrate the additional R&D required and the validation challenges to be met in the future.

DYNAMIS has undertaken a screening of sites suitable for both CO_2 capture power plants and CO_2 storage using methodologies developed as part of separate work packages. In order to meet certain basic requirements, there a need to further develop integrated methods involving the different disciplines for screening full value chain projects.

Almost all deep saline aquifers confined by appropriate permeability barriers could be used for CO_2 storage. Indeed, an earlier European project, GESTCO (2001-2003) confirmed the widespread presence of CO_2 storage capacity in structural traps in porous and permeable reservoir rocks – in both onshore and near-shore sedimentary basins – across the EU. Since then, a follow-up project, GEOCAPACITY (2006-2009) has focused on countries in eastern, central and southern Europe not previously covered in detail.

In some areas, assessments of the capacity of onshore storage sites can suffer from limits on the availability and accessibility of data. In these cases, project developments need to balance the possibility of discovering previously unknown storage sites close to otherwise advantageous power plants sites, against known investment costs for pipeline transportation to regions where knowledge of storage sites is relatively well advanced. This trade-off is illustrated in the DYNAMIS case studies.

- Case study D, Hamburg. Knowledge regarding on regional storage opportunities is low. Better-known areas require relatively long transportation distances. DYNAMIS has shown that regional storage sites do exist – the drawback is simply a lack of data. In the trade-off between transportation distance and the existence of regional opportunities, there are indications that investments in the latter are well worth considering.

- Case studies A and B, Eastern England and North Eastern UK. Here, the regional geological setting is such that it is necessary to search for suitable storage sites at some distance from the plant.. These case studies have shown that publicly available data in the UK adequate for the assessment of promising offshore storage sites. The trade-off between regional and more distant opportunities clearly points to the need to explore for offshore aquifers in the Southern North Sea, while EOR can support long distance pipelines to the Central North Sea and beyond.
- Case study C, Mongstad. Here, the distance from the planned power plant to the storage site has been a key factor in this case study. In order to assess CO_2 storage, a regional offshore deep saline aquifer was chosen for the simulation model. The construction of this gridded simulation model was based mainly on seismic horizons from an interpretation of a seismic survey in the area. To verify the aquifer as a safe storage site, an appraisal well now needs to be drilled and reservoir cores taken in order to carry out petrophysical measurements and the verification of sealing faults.

Considerable efforts have been devoted to CO_2 injection strategies modelling. The targeted 3 million tonnes annual injection rate is a significant step-up from current projects at Sleipner, Snøvhit and In Salah (Algeria), which all handle about 1 million tonnes of CO_2 per year.

Increasing injection rates requires a greater awareness of to reservoir pressure management; and results from DYNAMIS case study reservoir simulations show that injection strategy modelling can mitigate the problem of large pressure build-up in the reservoir. However, further work is needed in this area, taking into account the regional impact of simultaneous injection into neighbouring storage sites when setting relevant boundary conditions for reservoir models. Further work is also needed to further develop CO_2 monitoring techniques.

For transport and storage purposes, CO_2 must be kept in a dense phase and preferably at the lowest practical temperature. As previously described, recommendations for the composition of the CO_2 stream have been provided by DYNAMIS in order to ensure the safety and durability of the transport system and the most efficient use of transport capacity. Continued R&D is needed to address corresponding recommendations for CO_2 storage.

Meeting the needs of an Environmental Impact Assessment

In order to obtain a permit for CCS facilities and gain support for the technology, the operator must be able to show that the environmental benefits of CCS outweigh any negative impacts that may arise.

For this reason, DYNAMIS focused on those aspects of an Environmental Impact Assessment (EIA) that were peculiar, and particularly relevant, to the CCS aspects of a project. These included, inter alia:

- The visual, traffic and noise impacts of the capture plant
- The environmental impact of capture solvents and emissions
- The impact of subsea infrastructure and potential CO_2 leakage on marine ecology
- Onshore pipeline impacts.

From the wide-ranging work undertaken, the conclusion is that there are relatively few areas where the impact of CCS gives rise to major environmental issues. The case studies indicate that there are no substantial environmental issues related to emissions to the air during the operation of the power plant. On the contrary, IGCC plants combined with pre-combustion CO_2 capture can result in substantial reductions in gaseous emissions (including CO_2), compared to existing plants.

Furthermore, no significant changes to cooling water requirements were found that would result in negative environmental consequences due to CCS. In general, there is no indication that the challenges associated with constructing environmentally acceptable North Sea CO_2 pipelines are any different to those encountered in connection with hydrocarbon pipelines in similar areas. The impact of constructing a CO_2 pipeline on land is similar to that of a gas pipeline of similar size.

However, there are a few remaining issues where further work would be useful for the purposes of establishing confidence in the safe environmental boundaries for CCS technology:

- For post-combustion capture, more information is required on the environmental properties of amines and their degradation products. Specific attention should be focused on the properties of waste products and their emission into the atmosphere.

- Power plants are generally located in the vicinity of major cities, where population density is high. The transport of the CO_2 from the power plant to the storage site may take place in complex urban environments, and may come into conflict with other interests such as nature reserves and industrial activities. Risk mitigation and management is therefore one of the main challenges of CO_2 transport. However, to put it into perspective, natural gas is already transported via pipelines through many major cities.

- As part of the risk assessment process, it will be necessary to estimate potential leakage characteristics and environmental impacts. At present, there is a lack of information regarding potential leakage rates and likely timeframes for CO_2 emissions for a range of reservoir conditions, in the unlikely event of leakage through a well or fracture. Most of the current information on environmental impacts relates to specific species rather than whole ecosystems.

- For offshore storage, future environmental impact assessment would benefit from further research on marine ecosystems in the North Sea. Such research on the possible impacts of CO_2 on the marine environment is ongoing.

Creating financial models for HYPOGEN projects

Framework financial models were generated for each of the case studies, covering the entire CCS chain – from power plant to storage site. These models have been used to assess the commercial viability of the case studies and, in particular, the EU ETS (EU Emission Trading Scheme) carbon price necessary to support them under certain scenarios.

Two main energy scenarios were used, derived from the EC PRIMES[10] work. Firstly, a Low case based on a fairly flat oil price, starting at about $55//bbl, and secondly, a High case in which the oil price escalated from $75/bbl. Other energy prices were in line with the main assumptions, while district and process heat prices were derived from the average prevailing gas price.

Inflation and escalation of fuel prices were fixed at 2%, except for the short-term capital cost escalation (to escalate 2008 prices towards the project's financial close), which was set slightly higher at 2.5%. Debt, where applicable, was taken to be available at a rate of 8%, and the term of the projects and debt was assumed to be 20 years. It was decided to set a minimum hurdle rate for the IRR of the complete case study projects at 13% nominal to reflect a reasonably commercial level at which a project could be supported.

Because of the diversity of the projects – including infrastructure and storage costs – and because two different background scenarios were used, a range of results has been derived. The Hamburg and Mongstad case studies also benefit from additional incomes derived from the provision of district heat to the city of Hamburg, and steam generation and the preheating of crude oil to the refinery, respectively. It is believed that the range derived is reasonably representative of the uncertainty inherent in the requirements for such projects which have been designed by commercial sponsors to be as cost-effective and as efficient as possible.

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EC Second Strategic Energy Review, An EU Energy Security And Solidarity Action Plan {COM (2008) 744}

In order to derive reasonable figures, it has been necessary to make certain assumptions. The most important of these are;

- The plant will run baseload, given a reasonable availability profile
- Income streams and cost levels (in particular, the carbon price) are achieved at the level described through fixed price contractual arrangements, rather than having a high market uncertainty.

Possible support for CCS has been factored into the models in what appears, at present, to be the most likely form, which is assumed to consist of a free additional Emission Unit Allowance (EUA) for each tonne of CO_2 stored in Phase III of the EU ETS (2015 – 2020). It has also been assumed that plants will be operational in time to obtain this support.

Given this set of assumptions, the range of the EU ETS carbon price needed to make the case studies financially viable is as follows (in each case excluding case study B against the High scenario, where it is supported by high oil revenues):

- Without any support: 42 – 80 €/tonne of CO_2
- With 6 years support: 28 – 53 €/tonne of CO_2

At these levels it would appear that debt financing with a Debt Service Cover Ratio of around 1.5 might just be achievable, but the percentage level of debt may have to be reduced to achieve a satisfactory margin.

N.B. These results are intended to provide general indications for the purposes of these evaluations and cannot be assumed to represent either the fixed required carbon price limits, or the prices required by the industrial sponsors of individual case studies. In comparing levels with values derived from different sources, it is also vital to ensure that such comparisons are made on an equivalent basis and with compatible assumptions.

3. Making HYPOGEN projects a commercial reality

The recently published "EU Demonstration Programme for CO_2 Capture and Storage (CCS) – ZEP's Proposal" provides detailed recommendations for the implementation of large-scale CCS demonstration in Europe[4]. Indeed, this is essential in order to accelerate technology development, drive down costs, build public confidence, and guarantee the commercial viability of CCS by 2020.

The proposal concludes that if such a demonstration programme takes place, we could see 80-120 commercial CCS projects in Europe by 2030. This would represent a reduction in annual CO_2 emissions of ~400 million tonnes[11] (the EU's current annual CO_2 emissions are ~3.8 billion tonnes) – with the potential to reduce annual global CO_2 emissions by 9-16 billion tonnes by 2050[4].

This would generate a potential for a significant number of HYPOGEN projects – each 400 MW plant avoiding 3 million tonnes of CO_2 per year, combined with CCS projects using other new capture technologies in the future.

Indentifying remaining R&D gaps

Conclusions from DYNAMIS regarding further R&D and validation needs are as follows. These conform closely to a similar assessment carried out by ZEP[12].

IGCCs with pre-combustion CO_2 capture

- Increase the robustness of adapting F-class gas turbines to the combustion of hydrogen-rich gases, whilst keeping nitrogen oxides (NO_x) emissions low.
- Improve the partial load operation of key power plant components and overall design of power plant integration in order to increase overall efficiency whilst maintaining good/acceptable operability, reliability and maintainability.

Natural gas-fired parallel NGCC with post-combustion CO_2 capture and steam reforming

- Up-scale the amine-based absorption process (which is a well-known technology), from about 200 tonnes of CO_2/day (compared to approximately 6000 tonnes/day in the Mongstad case).
- Develop control philosophy and new controllers if the CHP operates on a varying load.
- Improve choice of proper gas analysers for monitoring emissions of amine, ammonia, sulphur dioxide (SO_2), NO_x and CO_2.
- Enable the assessment of the environmental impact of amine waste at full-scale and the degradation of amines emitted to the air from the absorber.

CO_2 infrastructure and storage

The qualification of a CO_2 storage site involves several important steps, starting with the screening phase. Subsequent work in the investigation phase is outside the scope of DYNAMIS and its R&D needs are therefore not covered (e.g. risk assessment procedures).

- Assess routing of CO_2 pipelines in densely populated areas and the management of safety distances.
- Establish reservoir pressure management in cases where a CO_2 storage project will impact on the pressure build-up in an area that extends beyond that covered by the storage licence.

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"Carbon Capture & Storage: Assessing the Economics", published by McKinsey and Company, September 2008 – see http://www.mckinsey.com/clientservice/ccsi/pdf/CCS_Assessing_the_Economics.pdf

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"CO_2 Capture and Storage (CCS) – Matrix of Technologies", published October 2008 – see http://www.zero-emissionplatform.eu/website/library

- Avoid setting stringent CO_2 quality standards too early, thereby limiting future possibilities for R&D on novel capture technologies. Currently, stringent requirements are imposed on certain components in relation to EOR, although this process is regarded as only a limited resource for future CO_2 storage projects.
- Develop and demonstrate a robust CO_2 measurement and verification system in order to promote confidence among both regulators and the public.

Establishing financial support mechanisms

The case studies examined within DYNAMIS are carefully optimised and are therefore expected to be forefront candidates for demonstration projects.

CCS projects in general

- Early deployment will be facilitated through economies of scale by building large-scale projects in clusters, facilitated by EC Stimulus Funds

All CCS projects will need substantial additional financial support, part of which may become available through the EU CCS demonstration programme. Wide deployment of CCS will also be facilitated through economies of scale, derived not only from building projects of a size at least equal to that of the DYNAMIS case studies, but also in clusters designed to enable the sharing of infrastructure. Here, the provision of EC Stimulus Funds will play a key role in stimulating early deployment and mitigating development risk.

- Confidence in the maintenance of a sufficiently high carbon price during Phase III of the EU ETS is essential for the financeability of CCS projects

Given the high levels of capital investment, the main residual economic risk to be managed is that relating to the uncertainty of the future carbon price, as the financeability of CCS projects will be highly dependent on this income stream. Confidence in the maintenance of sufficiently high carbon prices during Phase III of the EU ETS can, to an extent, be maintained by imposing tight caps on EUAs, a limit to the import of credits and high penalties for projects that produce emissions without an EUA.

Early HYPOGEN and other large-scale CCS demonstration projects

The first HYPOGEN and other large-scale CCS demonstration projects will not be economically viable under envisaged market environments due to:

- High capital costs arising from capture equipment and transport/storage infrastructure
- First-of-a-kind uncertainties in outturn cost levels
- Demonstration projects being built on a smaller than economically optimal scale in order to limit high financial risks (e.g. HYPOGEN projects will only have one gas turbine)
- The likely outcome of initial lower operational availability due to immature technology
- The uncertainty of future carbon prices.

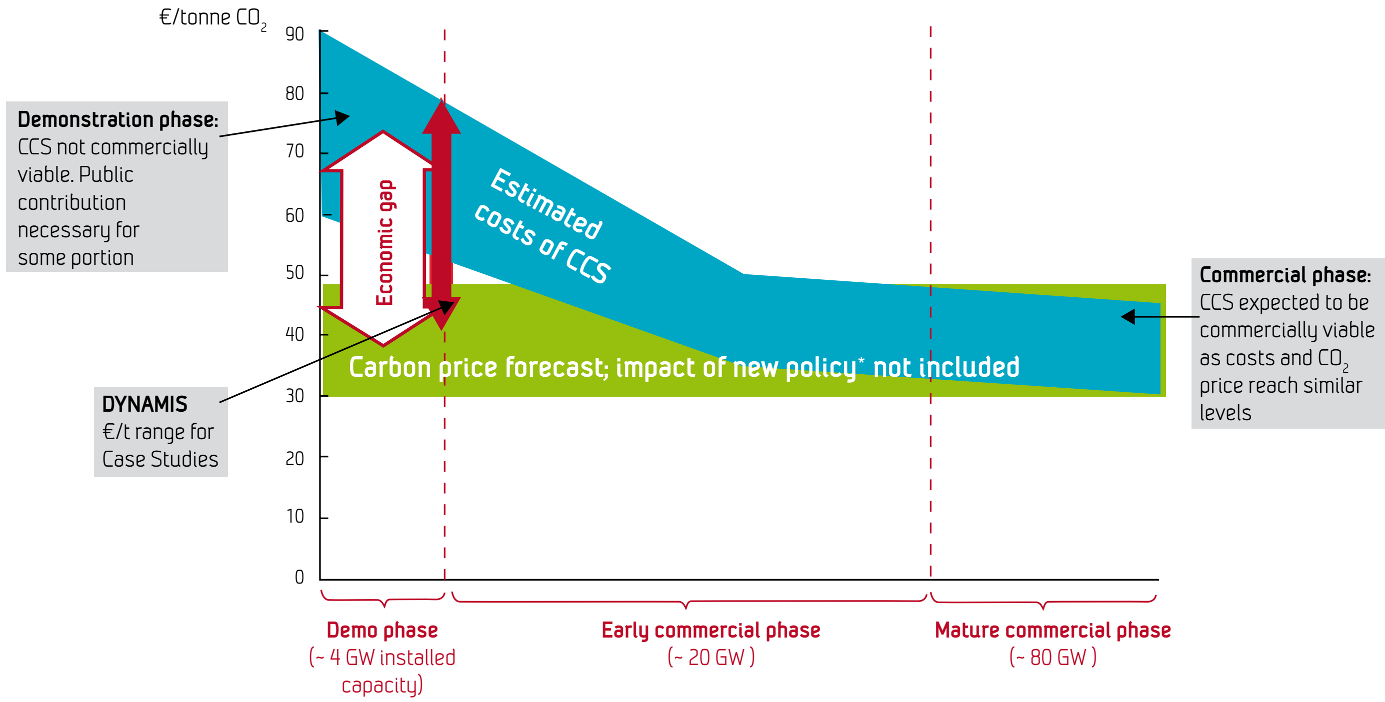
The current financial crisis limits the availability of capital funds and thus further emphasises the need for sound cost and income levels to be secured before investment decisions can be made. Analysis shows that for the base fuel price scenario assumed, acceptable project returns would not be achieved for the case studies. It also suggests that without additional support, projects would need EU ETS outturn prices considerably in excess of current post-2012 forecasts.

Current EC proposals to allocate up to 300 EUAs to CCS represent a very useful step towards generating improved economic conditions for early CCS demonstration projects. However, in order to achieve a bankable income stream from the EU ETS carbon price, it will be necessary to achieve high levels of confidence in terms of underlying price volatility.

This could be achieved in a number of ways by using, among others;

- Feed-in tariffs (which are favoured in some Member States)
- Price swap contracts (or support via a collar mechanism) with a third party or parties such as e.g. Member State governments or the European Investment Bank (EIB), with the addition of top-up support from the Member States, as appropriate.

The need for additional support for "Early Movers" was also recently highlighted by ZEP[4].



Carbon price band for 2015 based on estimates for 2008 - 2015 from Deutsche Bank, New Carbon Finance, Société Generale, UBS, Point Carbon. The impact of the (possible) new ETS directive and the Copenhagen conference is not included in the analysis.

Source: McKinsey & Company "CCS - Assessing the Economics" for the cost numbers; policy implications drawn by ZEP.

Figure 5: An illustration showing how it is envisaged that the EU ETS will match additional costs for CCS in the event of commercial application, and the need for additional financial support for the first large-scale demonstration projects[4]. The range of EU ETS carbon prices needed to make the unsupported DYNAMIS case studies financially viable is superimposed.

If the range of carbon prices derived for the unsupported case studies is superimposed on Figure 5 (shown in red in the Demo phase), it can be seen that this analysis is very much in line with that undertaken by the ZEP. However, the detailed assumptions made in the ZEP case were not available to the DYNAMIS project, so it is not possible to guarantee consistency of approach.

With this caveat in mind, DYNAMIS underpins the general levels and uncertainty in the required EU ETS carbon price for CCS. The resulting range would suggest that the DYNAMIS case studies would be strong contenders for projects within the EU CCS demonstration programme. However, since they do not identify specific additional costs related to first-of-a-kind problems, the first HYPOGEN demonstration projects could turn out to be more costly.

Resolving legal/regulatory issues

The legal environment surrounding CCS is changing rapidly. Among the major developments are the inclusion of CCS in the London Protocol, the OSPAR Convention, the Directive to amend the EU ETS, and the adoption of the Directive on Geological Storage of CO_2[13]. Key legal and regulatory issues that must now be resolved include:

- The implementation of the Directive on Geological Storage of CO_2, and Monitoring and Verification Guidelines (MVG) for the revised Directive on the EU ETS in the relevant Member States
- The establishment of procedures for the qualification of pipelines for CO_2 transport (especially in densely populated areas), and for deep saline aquifers for CO_2 storage
- The removal of barriers for the trans-boundary transportation of CO_2 in Europe
- The removal of uncertainties associated with the handling of divergent gas quality specifications in CO_2 value chain projects
- The development of methodologies and recommendations related to storage formation pressure management.

Accelerating the time to market

ZEP's Proposal for an EU CCS Demonstration Programme[4] describes why 10 - 12 projects are necessary in order to de-risk CCS for all players within the value chain and achieve commercialisation by 2020. This includes outlining "generic" timelines for implementing both the first CCS demonstration projects and subsequent "early commercial" projects.

Anticipated timelines for the DYNAMIS case studies (and other large-scale CCS projects in which DYNAMIS partners are involved) have also been summarised in the form of "typical" timelines for CCS demonstration projects. These are reasonably in line with ZEP's timelines, and a composite version is illustrated in Figure 6 below.

The following important conclusions may be drawn from these projections.

- If "early commercial" projects are started as soon as possible during the construction phase of the demonstration projects, they would benefit from obtaining their permits at an earlier stage, and would still be able to integrate some of the knowledge gained during both the design and operational stages of the demonstration projects.
- Shortening permit allocation processes will accelerate investment decisions.
- Decisions to start FEED studies leading to financial investment decisions/EPC contracts will depend on appropriate fiscal mechanisms being in place to encourage power production with CCS. This includes sufficient financial support (public funding) and market incentives (EU ETS), in combination with the appropriate legal frameworks.
- An efficient tendering process to qualify for public funding within an EU CCS demonstration programme is essential.

In short, urgent action is required in order to allow project commitment decisions to be made so that CCS demonstration projects can be operational by 2015, leading to the post-2020 commercialisation of CCS and its wide-scale deployment as a crucial mechanism towards to combating climate change.

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Official title is: Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the geological storage of carbon dioxide and amending Council Directives 85/337/EEC, 96/61/EC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC and Regulation (EC) No 1013/2006

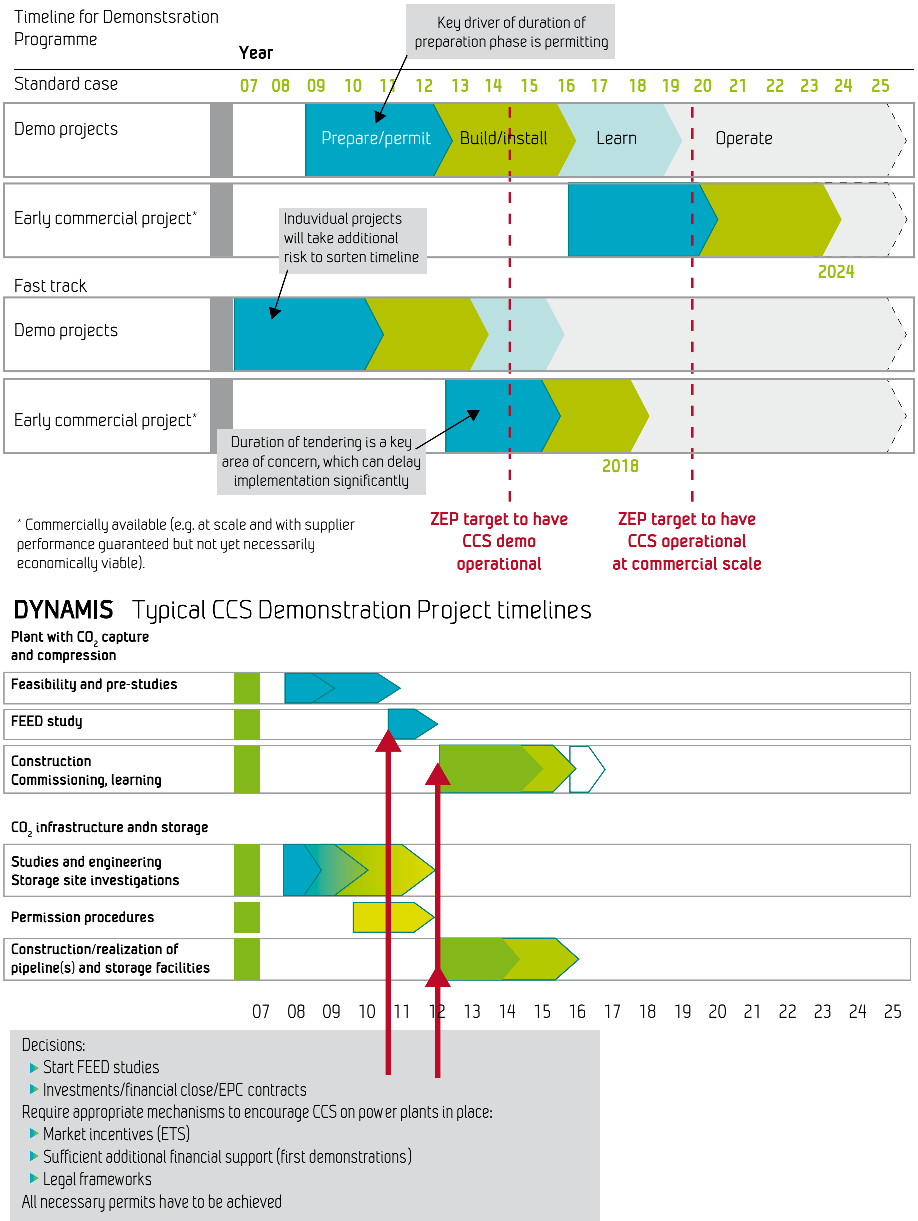

Figure 6: Possible "generic" timelines for implementing CCS demonstration projects and "early commercial" projects from ZEP[4] and DYNAMIS partners

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