IEA - HIA Task 16
Hydrogen from Carbon Containing Materials

Subtask A

Large-scale integrated Hydrogen Production/Decarbonisation

Preface

Task 16 to the IEA Hydrogen Implementing Agreement concerns Hydrogen Production from Carbon-Containing Materials. This Task started in 2002 and is finalised in 2006. The overall objective is to promote the development of efficient and economic processes for hydrogen production from fossil and biomass resources, while keeping CO_2 emissions at a minimum.

The activities are organised in three Subtasks:

A: Large-scale integrated hydrogen production/decarbonisation
B: Hydrogen from biomass
C: Small stationary reformers for distributed hydrogen production

Subtask A has been organised by the IEA Greenhouse Gas R&D Programme (GHG). The activity has been an industry-led project and the work has been carried out partly as a task-shared activity and partly as a cost-shared activity.

The first part of the project, a comparative assessment of the studies done to date of this concept, was completed as an in-kind contribution and with support from the CO_2 Capture Project (CCP[1]). The results from this assessment were used to select a process scheme for a detailed engineering study. The second stage, funded by the CCP and Klimatek (N), has been a cost reduction study which has identified the prospects for lowering costs through repeat construction, standardisation and modularisation of one chosen design.

We would like to thank the IEA Greenhouse Gas R&D Programme for their organisation and collaboration in this work, and to acknowledge the important contribution of the CCP partners for their support in developing the results for this final report.

May 2006

[1] The CCP1 (CO_2 Capture Project) is an international effort of eight of the world's leading energy companies namely BP, Chevron Texaco, ENI, Hydro, EnCana, Shell, Statoil, and Suncor Energy to develop new low-cost technology options for the CO_2 capture and storage.

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[1] Complete main report from Jacobs Consultancy, dated 17 December 2003

Subtask A: Large scale integrated Hydrogen Production/Decarbonisation

Introduction: The work program and activities in Subtask A

The Subtask A activity has been an industry-led project focused on the concept of Precombustion Decarbonisation (PCDC) for power generation. Such a plant would be based on pre-combustion removal of CO_2 and would thus essentially consist of a hydrogen plant integrated with a CCGT (Combined Cycle Gas Turbine) (figure 1). A key objective of the early work would be to reduce the costs of such a unit to the point at which a commercially viable demonstration could be implemented at a suitable future date.

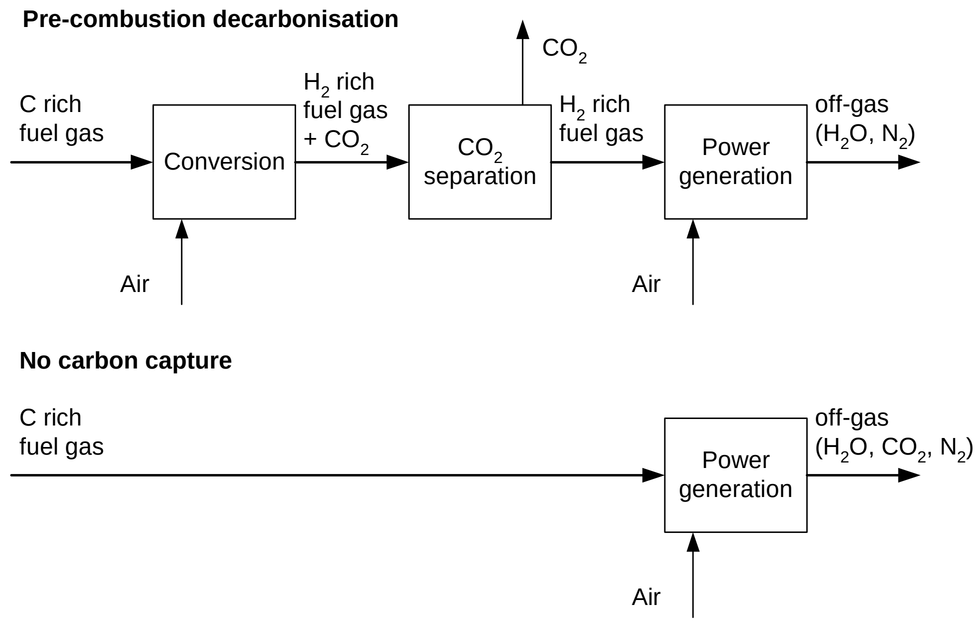

Figure 1: Comparison of pre-combustion decarbonisation scheme with baseline case without carbon capture

Scope of Work

The IEA Greenhouse Gas R&D Programme (IEA GHG) and the IEA Hydrogen Implementing Agreement Programme (IEA HIA) invited in 2002 potential stakeholders in the application of PCDC technology to participate in a project to design a demonstration plant. This project was foreseen to comprise the project phases presented in figure 2. After discussion about the merits of proceeding directly to a full FEED, (Front End Engineering Design - which would typically cost around $ 2 Million for a plant of the proposed size), it was agreed that a more focussed cost-reduction study would be more appropriate at this stage and as basis for Subtask A activities. Steps 1-3 of phase 1 thus comprise the scope of work for Subtask A.

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[1] The CCP companies referred to in this report are the CCP1 companies, as a new group of CCP2 companies represent different companies

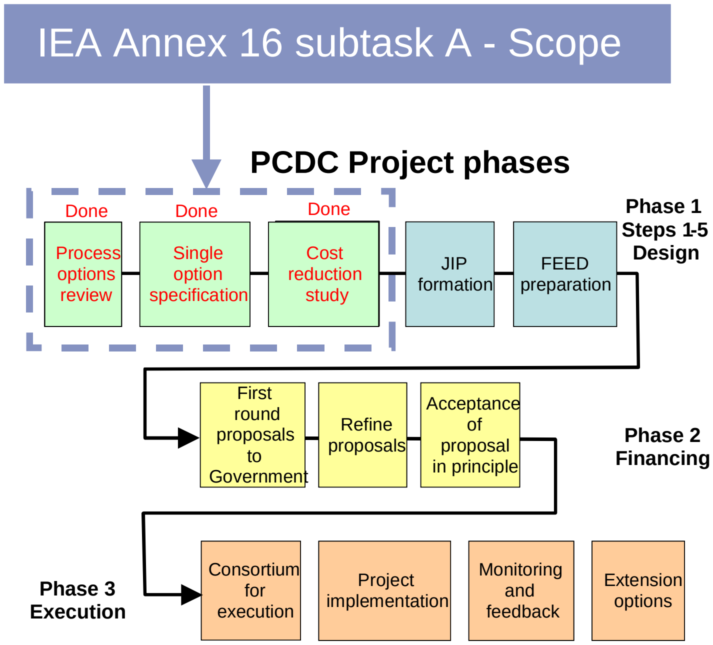

Figure 2: PCDC project phases

The aim of the work described in this report has been to investigate the potential cost reduction of power generation from natural gas with pre-combustion decarbonisation through modularisation and standardisation of proven plant components. The task was divided into two main stages:

I. **Techno-economic comparison** of different process schemes for natural gas fired power stations using pre-combustion with CO_2 separation technology. The results from this comparison were used to select a process scheme for a detailed engineering study in stage 2.

II. **Detailed engineering study** of process scheme selected in stage 1. The study basis is a standard combined cycle unit (400 MWe) that can be accommodate in a later phase or in a revamp situation the carbon free fuel gas. The study compares performance and costs of the natural gas based unit and the standardised PCDC power plants. In order to estimate potential cost savings due to modularisation and standardisation assumptions about the expected number of identical units had to be made. This was done by analysing a number of market scenarios based on a database of fossil-fuelled power plants in different regions of the world.

Highlights – Stage 1. Pre-combustion Decarbonisation for CO_2 capture – Process option review and single option specification

The aim of stage 1 was to assess all previous relevant studies covering PCDC technology for 400 MW combined cycle plants in order to identify the starting points for efficiency, cost and concept and have a common technical and economic basis for stage II. The study was carried out by Hydro as an in-kind contribution[1]. The screening was based on five studies: CCP Advanced Syngas Study (Foster Wheeler), Hydrokraft project (Hydro), Naturkraft Retrofit)(Hydro), different IEA studies (Foster Wheeler and Flour Daniels). The results of the assessment were used to select a process scheme for a detailed engineering cost reduction study in stage 2.

Results

The assessment showed great deviations in investment cost for the PCDC technology part between the different studies, with cost for the PCDC technology ranging from 250 $/kW to 500 $/kW. Even after aligning the scope the difference in cost amounted to almost 100% between lowest cost and highest cost study. For efficiency there was a consensus at around 43-44% (LHV).

Based on the analysis of the study reports available, the recommended PCDC process scheme should contain the following main process steps:

- Desulphurisation unit
- Preheating of feed streams in fired heater
- Air blown ATR
- High pressure steam production downstream of ATR
- HT and LT shift configuration
- Two-step aMDEA system with HP/LP-flash and stripper
- Either steam addition or saturation
- Fuel composition – approx. 50/50 H_2/N_2 (dry basis) with 15-20% water
- Nitrogen content to be determined by maximum air extraction
- Minimum heat integration with gas turbine HRSG

Recommendations for further work

The following areas for further work have been identified:

- Optimum CO_2 capture efficiency
- Revamp option potential, say new CO2 capture technology *e.g.* Sorption Enhanced WGS
- Optimum process parameters, *e.g*. steam/carbon ratio

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[1] Pre-combustion Decarbonisation for CO_2 capture – a review of process schemes for IEA HIA Annex 16 Subtask A and the CCP. Henrik Solgaard Andresen & Jan Schelling, Hydro Research Centre

Highlights – Stage 2. Investigation into the potential cost reduction of power generation with pre-combustion CO_2 capture (PCDC) through modularisation and standardisation.

The scope of work for the detailed engineering cost reduction study in stage 2 comprised:

- Design of Basic Plant based on recommendations from the review and selection study.

- Study of market potential for PCDC based on historic data and predictions from the power industry.
- Optimisation study based on results from brainstorming meeting between CCP, IEA GHG and Jacobs Consultancy. Design and costing of optimised PCDC plant.
- Study of cost reduction from repeat design, modularisation, standardisation. Design and costing of standard PCDC plant.

The engineering cost reduction study was contracted to Jacobs Consultancy and contained the following focus areas:

- Fit for purpose selection and application of codes and standards
- Standardisation of major equipment items
- Prefabrication of modules
- Modularisation of components
- Integration and reduction of general facilities and utility systems
- Value engineering
- Capacity specifications
- Repeat manufacturing and construction

Results

The benefits from standardisation showed the following potential:

- Repeat design (10 per year): 15-20% saving on capital cost
- Modularisation: Only minor savings < $ 2 MM

The optimisation study indicated that the following items would improve the concept by 10 $/t CO2 avoided

- Air extraction from gas turbine
- Fuel gas heating and saturation
- Single shaft air compressor/steam turbine drive rather than electrical motor and steam driven generator.

A base plant was developed based on a retrofit design. Based on brainstorming session several options were investigated.

An optimised concept was established and compared with result from the base case option. CO_2 avoided cost for the different options was estimated using the IEA GHG model.

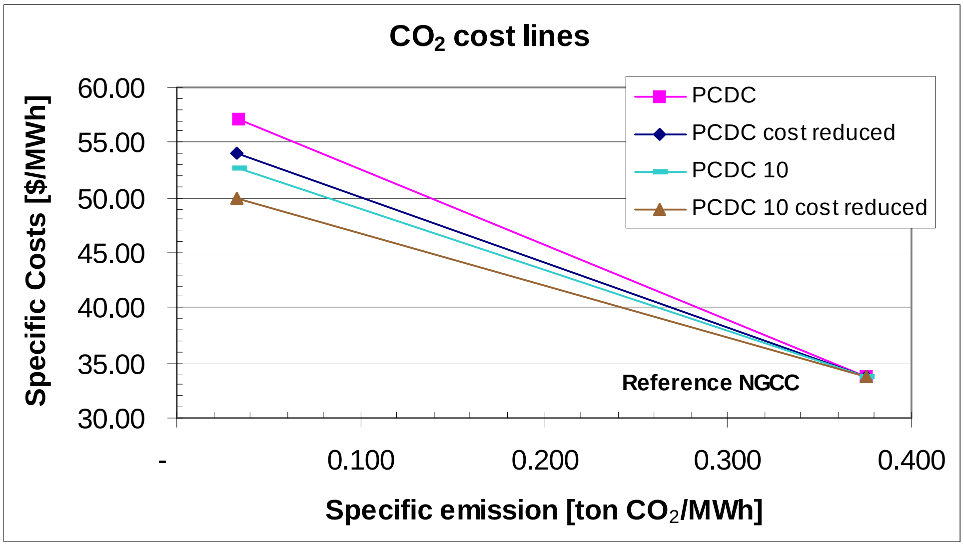


Figure 3: Cost lines reference and reduced cost PCDC plants

From the cost reduction part the following cost reduction curve was developed:

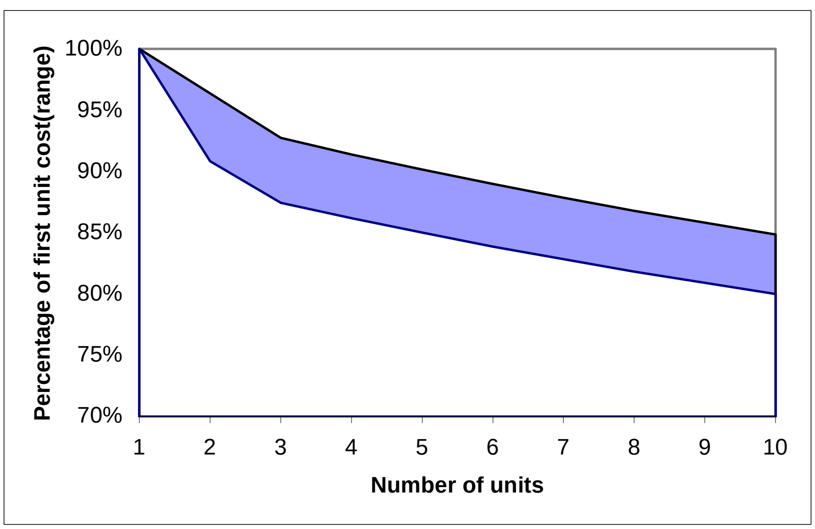


Figure 4: Cost reductions for multiple units

Overall benefits showed that approximately 20% reduction in CO_2 avoided cost could be achieved by cost reduction measures and 15% reduction could be obtained from value engineering and optimisation, thus leading to an overall reduction of 30% from base case to optimised case based on standard design

Recommendations for further work

For future work emphasis should be put on bringing cost down for rotating equipment. According to the Jacobs study 50-60% of the capital cost for the PCDC originates from compressors and steam turbines.

STAGE 1 REPORT: PRE-COMBUSTION DECARBONISATION FOR CO_2 CAPTURE

– PROCESS OPTION REVIEW AND SINGLE OPTION SPECIFICATION

1. BACKGROUND

Concepts to reduce CO_2 emissions from fossil fuel fired power stations can be classified into three distinct categories:

- **Post-combustion decarbonisation**, where CO_2 is separated from the exhaust gas coming from a standard gas turbine combined cycle.
- **Oxy-fuel** combined cycle, which involves close to stoichiometric combustion with oxygen, producing an exhaust gas consisting of CO_2 and water vapour, which can be readily separated by condensation.
- **Pre-combustion decarbonisation**, in which carbon is removed from the fuel before combustion, thus producing a hydrogen-rich fuel for combined cycle power plant (see simplified process scheme in Figure 1-1.)

Pre-combustion decarbonisation (PCDC) has the potential to achieve deep CO_2 reductions using proven hydrogen production technology. The IEA has initiated a project to design a demonstration plant, the next critical step in technical and commercial risk reduction. The first stage of that project is to bring together results of all relevant studies and review process options on a common technical and economic basis. The aim is to examine each option with respect to cost and technical risk and select a preferred or small subset of preferred options.

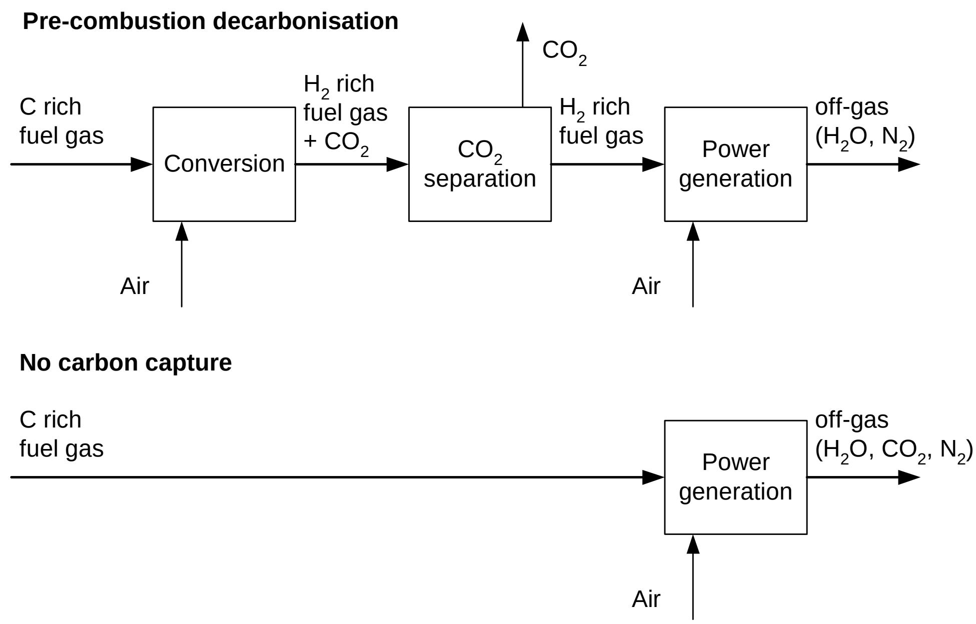


Figure 1-1: Comparison of pre-combustion decarbonisation scheme with baseline case without carbon capture

2. PROCESS OPTIONS

This section lists different technology choices for the process steps required to produce a hydrogen rich fuel for combustion in a gas turbine.

2.1 Reforming technology

The main reactions for converting a methane rich fuel into a hydrogen rich fuel are:

- Steam reforming: $CH_4 + H_2O \Leftrightarrow CO + 3H_2$ +206.2 MJ/kmol CH_4

- Partial oxidation: $CH_4 + 1/2 O_2 \Leftrightarrow CO + 2H_2$ - 35.7 MJ/kmol CH_4
- Water gas shift: $CO + H_2O \Leftrightarrow CO_2 + H_2$ -41 MJ/kmol CO

A number of different natural gas reforming technologies exist:

- **Conventional steam methane reforming (SMR)**
  Main reaction: steam reforming
  The reaction takes place in long catalyst filled reformer tubes. Heat for the highly endothermic reaction is provided directly by burning a fraction of the fuel gas.
- **Heat exchange reformer (HER) / gas heated reformer (GHR)**
  Main reaction: steam reforming
  Heat for the endothermic reforming reaction is provided indirectly from a hot gas stream passing through the reformer.
- **Pressurised combustion reforming**
  is a special case of a heat exchanger reformer where the hot gas is produced by burning a fraction of the H_2 rich fuel gas at high pressure
- **(Non-catalytic) Partial oxidation (POX):**
  Main reaction: partial oxidation.
  Natural gas is mixed with oxygen (or air) in a burner and partially oxidised at high temperature and high pressure to obtain reasonable reaction rates. The heat is mainly generated by the exothermic partial oxidation reaction.
- **Catalytic partial oxidation**
  Main reactions: partial oxidation
  A mixture of natural gas and an oxidants can be ignited on the surface of a noble metal catalyst (*e.g.* rhodium or palladium). The extremely high reaction rates allow very short residence times. This technology is not commercially available for large-scale installations today.
  NB: The term catalytic partial oxidation (CPO) is often used to describe an auto-thermal reformer (ATR), which employs a catalyst for steam reforming. As long as the partial oxidation reaction is not catalysed the term CPO is misleading and is not used in this report.
- **Autothermal reforming (ATR)**
  Main reactions: partial oxidation, steam reforming
  Natural gas is mixed with oxygen (air) and steam in a mixer/burner. In the combustion chamber partial combustion reactions are taking place, followed by methane steam reforming reaction and shift conversion to equilibrium over the catalyst bed. The overall reaction is exothermic, resulting in high outlet temperatures, typically 850-1100°C.
  NB: This process is often referred to as catalytic partial oxidation (CPO) although the partial oxidation reaction itself is not catalysed.

Table 1-1 summarises the features of the reforming technologies available today.

Table 1-1: Features of commercially available reforming technology

	Steam reforming	Partial oxidation	Auto-thermal reforming
Abbreviation	SMR	POX	ATR, CPO
Catalyst	Ni	-	partial oxidation: - steam reforming: Ni
Pressure	15…40 bar	up to 150 bar	20…40 bar

Temperature	750…900ºC	1200…1600ºC	850…1100ºC
Reaction	$CH_4 + H_2O \Leftrightarrow CO + 3H_2$	$CH_4 + 1/2\,O_2 \Leftrightarrow CO + 2H_2$	$CH_4 + 1/2\,O_2 \Leftrightarrow CO + 2H_2$ $CH_4 + H_2O \Leftrightarrow CO + 3H_2$
Enthalpy	+206.2 MJ/kmol CH_4	-35.7 MJ/kmol CH_4	exothermic
H2/CO ratio	3…6	1.8	1.8…3.7

In addition to the reformer technology choices described above, the installation of a catalytic pre-reformer can be considered to increase the overall fuel conversion efficiency. A pre-reformer converts the heavier hydrocarbons while the main reformer unit preferably converts methane to CO and H_2.

2.2 Choice of oxidant

The choices of oxidants are: air, oxygen, and oxygen-enriched air. The advantage of using oxygen or oxygen-enriched air is the reduced amount of inert gas (mainly N_2), which may potentially reduce equipment size. However, in most cases additional steam is required to avoid excessive temperatures in the reformer and CO converter. In addition, the high electricity consumption of an air separation unit (ASU) reduces the thermal efficiency and thus increases the operating costs due to increased natural gas consumption.

2.3 CO conversion

The choice of technologies available to perform the CO conversion is limited. The major differences between different schemes is the number of units and the temperature levels they are operated at:

- High temperature (HT) shift (typically operated at 350ºC)
- Medium temperature (MT) shift: (typical range 250-300ºC)
- Low temperature (LT) shift (typical range: 190-210ºC)

The main choice is between two adiabatically operated CO converters (HT and LT) or a single approximately isothermal MT shift reactor.

2.4 NG bypass

The overall CO_2 capture rate is determined by the fuel conversion efficiency of the reformer and shift reactor will not be as well as the capture efficiency of the CO_2 removal unit. Unconverted hydrocarbons and CO will form CO_2 in the gas turbine. Rejected CO_2 from the CO_2 removal unit will pass through the gas turbine. In case the product of the fuel conversion and CO_2 removal efficiency are higher than the given target, natural gas can be chosen to bypass the frontend and enter the combustion section of the gas turbine directly. This way the thermal efficiency can be increased while the specified overall carbon capture target is met. However, exceeding the carbon capture target is in these cases feasible and does in most cases not increase the effective specific CO_2 capture cost.

2.5 CO_2 removal technology

Several technologies to remove CO_2 from a gas stream exist:

- **pressure swing adsorption** (PSA) is suitable for pure hydrogen applications but with the syngas compositions obtained here, the hydrogen losses would be unacceptable.
- **cryogenic separation.** CO_2 can be physically separated from synthesis gas by condensing it at cryogenic temperatures to produce liquid CO_2 ready for transport to the disposal site. Cooling the entire syngas stream would consume large amounts of electricity and is therefore unattractive.

- **chemical absorption.** The most widely used solution for chemical absorption is activated MDEA (=monodiethanolamine). This process is often referred to as amine scrubbing and the most commonly applied CO_2 removal technology today. Other processes (involving activated hot potassium carbonate processing) are commercially available under the names Benfield and Catacarb.
- **physical absorption** using Selexol may become advantageous at very high pressure but is inefficient in the pressure range of the reforming equipment.
- **membrane separation** is commercially applied for hydrogen separation, but more development is required before membranes can be used on a sufficiently large scale.

All studies considered here conclude that chemical absorption using an MDEA solvent is the most efficient and economical CO_2 removal technology today.

2.6 Steam supply to combustion

To avoid excessive NO_x formation, steam must be present during combustion of the hydrogen rich (N_2-containing) fuel. The steam can either be supplied to using a gas saturator located downstream of the CO_2 removal unit or by injecting MP steam into the H_2-rich fuel stream. A saturator is a relatively costly piece of equipment, while the use of MP steam reduces the power output of the steam turbine.

2.7 Integration of frontend with power plant

Integration between frontend and power station is a critical success factor when pre-combustion schemes are compared to post-combustion schemes.

2.7.1 Process air

In most cases, air for the reforming process will be extracted from the air compressor driven by the gas turbine. Depending on the pressure in the reforming reactor an additional air compressor may be required. In some cases the amount of air that can be extracted from the GT-air compressor is not sufficient. Additional ambient air will then be compressed to the reforming pressure using a separate air compressor.

2.7.2 Heat integration

Process steam for the reformer unit is generally produced in the heat recovery stem generation (HRSG) unit. In addition, the HRSG unit can also be used to pre-heat a number of frontend process streams such as natural gas, process air, etc. In case extensive heat integration with the frontend is applied, supplementary firing in the exhaust gas may be required.

3. PREVIOUS STUDIES

A number of studies were performed recently to investigate the costs related to CO_2 capture and determine the most suitable technology for pre-combustion decarbonisation [1-5]. Table 3-2 lists the key parameters and specifications of the studies analysed in this report.

Table 3-2: Pre-combustion decarbonisation study specifications

Study	A	B	C	D	E
Year	1998	1998	2000	2001	2002
Natural gas inlet pressure	28.6 bar	120 bar	52 bar	90 bar	63.2 bar
CO2 outlet specifications	liquid, 90 bar	gas, 75.5 bar	liquid, 90 bar	liquid, 105 bar	70 bar

CO2 capture target	85 %	90 %	85 %	90 %	90 %
NOx limit		20 ppm	10 ppm		
Net power output	500 MW	1200 MW	800 MW	350 - 400 MW	420 MW
No. of trains	1	3	2	1	1
Location	Netherlands coast	Norway	Netherlands coast	US Gulf Coast	Norway
Ambient air temperature	15 ºC	7.8 ºC	15 ºC	32 ºC wet bulb	7.8 ºC
Cooling water temp.	20 ºC	7.8 ºC	20 ºC	35 ºC	7.8 ºC
Currency factor	-	0.592 USD/DEM	-	1.50 USD/GBP	1.157 USD/EUR
Natural gas LHV, MJ/Nm^3	40.68	41.58	40.68	39.41	37.09
CH4	83.9 %	79.54 %	83.9 %	90 %	85.34 %
C2H6	9.2 %	9.43 %	9.2 %	5 %	10.01 %
C3H8	3.3 %	4.39 %	3.3 %	3 %	0.04 %
C4H10	1.4 %	1.66 %	1.4 %	1 %	0 %
C5H12	0 %	0.69 %	0 %	0 %	0 %
CO2	1.8 %	3.71 %	1.8 %	0.5 %	3.98 %
N2	0.4 %	0.58 %	0.4 %	0.5 %	0.62 %
S	30 ppm	12 ppm	30 ppm	30 ppm	12 ppm

3.1 Study A

A number of pre-combustion schemes are studied such as conventional steam reforming using gas turbine exhaust gas, catalytic partial oxidation, and a process involving a pressurised reformer indirectly heated by the exhaust gas of an external H_2 fuel combustor. Based on technical maturity and effective CO_2 capture cost the ATR process was identified as the most promising option. In addition, a techno-economical data of a base case without CO_2 capture is provided.

3.2 Study B

This study includes technical analyses of a large number of ATR process options. Parameters investigated are steam to carbon ratio, different heat integration alternatives, and the amount of steam added to combustion. Based on the results obtained, an optimised case is developed for a techno-economic analysis. In addition, technical information on a process scheme with a heat exchange reformer is provided. However, as heat exchanger reforming is not considered mature for large-scale application, no economic analysis is performed. The PCDC plant was specifically designed to match the requirements of a GE frame.

3.3 Study C

This study investigates the most promising process scheme (ATR) of the previous study (A) in more detail. Five process variations are developed, two of which are examined in more detail. In this study several CO_2 removal techniques are investigated. These include pressure swing adsorption (PSA), cryogenic separation, MDEA absorption, and physical absorption by Selexol. Chemical absorption using an MDEA solvent was identified as most efficient and economical for the syngas composition and pressure relevant for the reforming processes investigated.

Other process alternatives include non-catalytic partial oxidation (POX) with different oxygen sources (air, pure oxygen, oxygen-enriched air) and the combination of an ATR unit with a gas-heated reformer. Another parameter investigated is the operating pressure in the fuel conversion section. However, neither non-catalytic partial oxidation nor ATR with increased pressure show any significant improvement. Two improved cases that were investigated closer (ATR: case C1 and ATR + GHR: case C2) use increased fuel temperature to the gas turbine and a natural gas bypass to adjust the overall carbon capture efficiency to the specified value and increase the thermal efficiency.

3.4 Study D

This study examines and compares a number of novel process schemes such as a gas-heated reformer (GHR), high pressure auto-thermal reforming and the use of a gas/gas heat exchanger between the ATR and the HT reformer. These process schemes all of which involve some novel technology are compared to the ATR base case. In addition, the effect of relaxed CO_2 specification and capture efficiency is investigated. The technically and economically most attractive case is an ATR process scheme with slightly relaxed CO_2 specifications (>97% CO2).

3.5 Study E

As a follow-up on a previous study (A) a retrofit case is investigated and compared to the optimised base case of the previous study. The aim of the study is to provide a simpler process scheme with significantly reduced investment costs at only slightly reduced thermal efficiency, which is suitable for retrofitting an existing NGCC plant. Two ATR process alternatives are investigated with different amounts of air extracted form the GT air compressor. A techno-economic analysis is provided for a case with 28% air from a separate ambient air compressor and the remaining 72% from the GT air compressor. The PCDC plant was specifically designed to match the requirements of a GE frame.

4. PROCESS SCHEMES

Figures 4-2 to 4-7 contain the simplified flow sheets of the process schemes selected form the studies available.

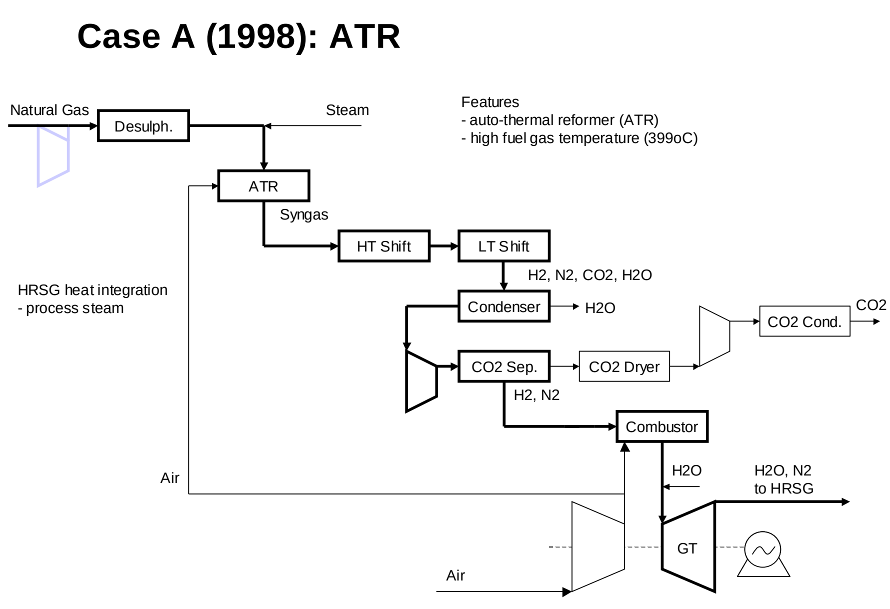


Figure 4- 2: Study A (1998): ATR

Case B (1998): ATR + NG Bypass

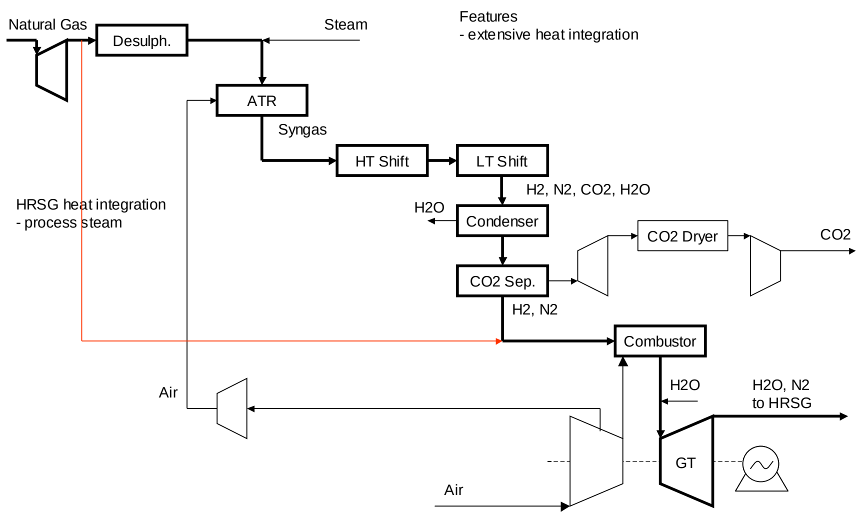


Figure 4- 3: Study B (1998): ATR, optimised base case

Case C1 (2000): Improved ATR + NG Bypass

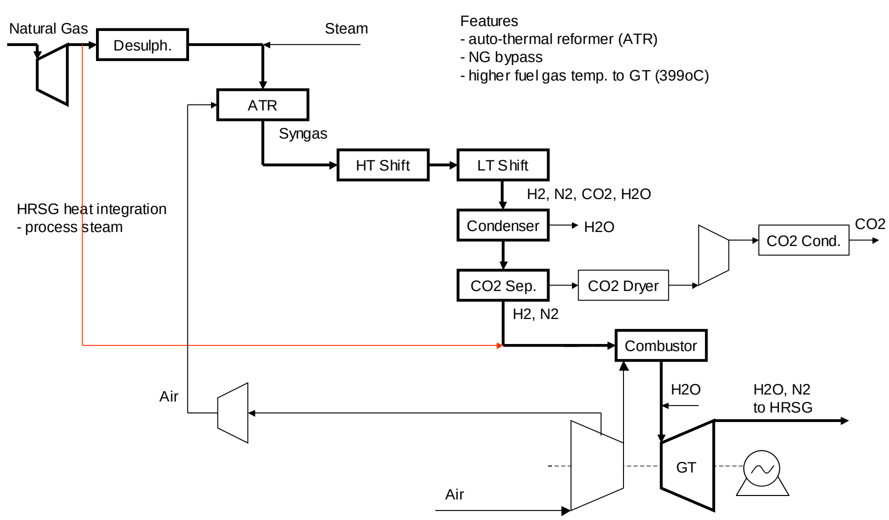


Figure 4- 4: Case C1 (2000): Improved ATR

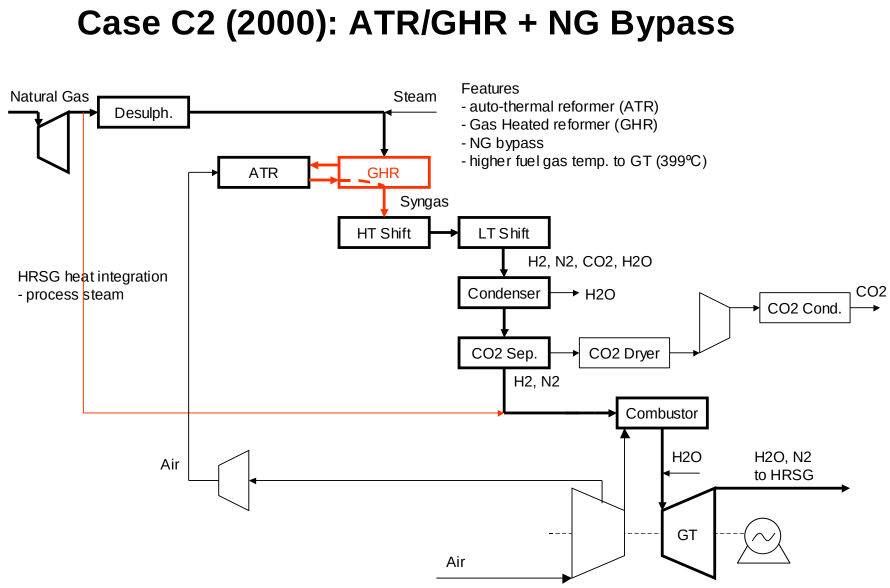


Figure 4- 5: Case C2 (2000): Improved ATR + GHR

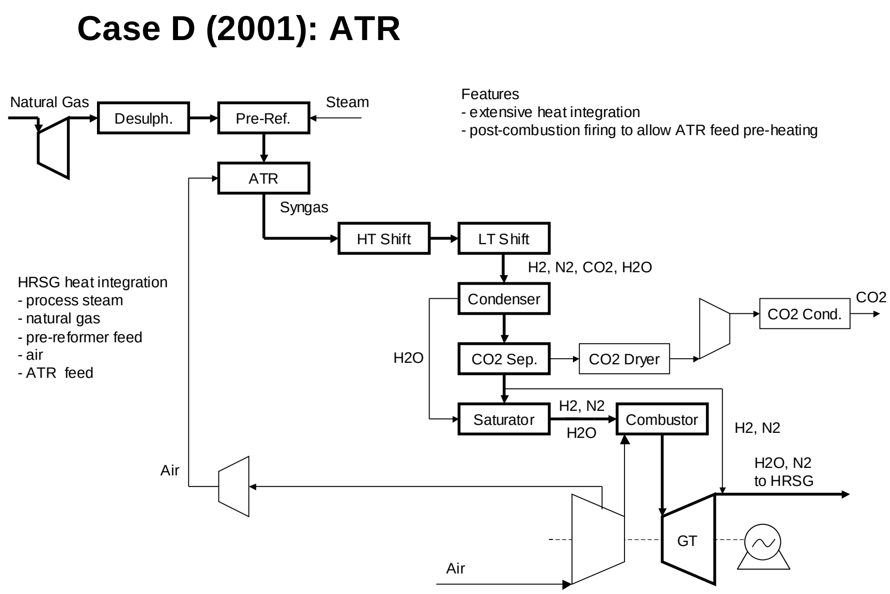


Figure 4- 6: Case D (2001): ATR

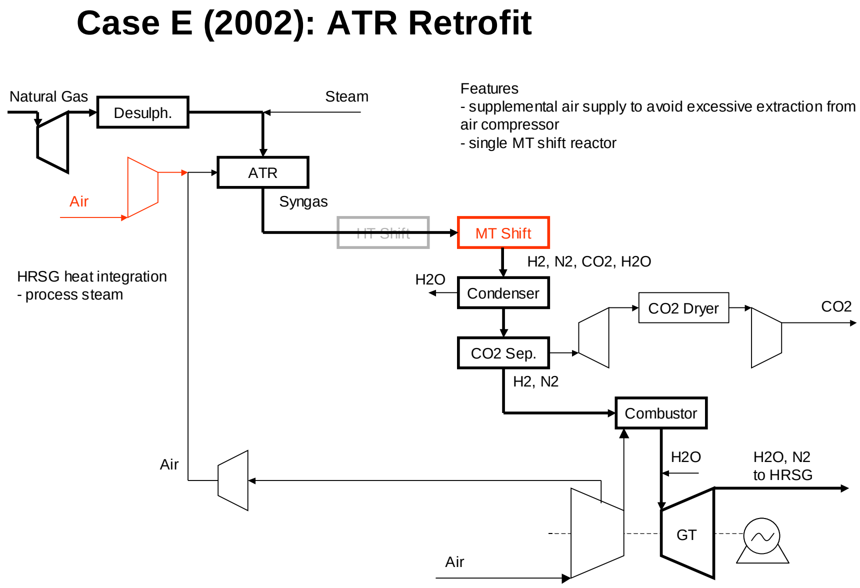


Figure 4- 7: Case E (2002): ATR retrofit

5. PROCESS SELECTION

Adding PCDC to a natural gas power station of a given capacity results in the following additional costs:

- Investment costs for the PCDC hydrogen plant (front-end)
- Increased natural gas consumption due to thermal losses in front-end
- Lost income from electricity sale due to power consumption of front-end and CO_2 compression (reduced net power output)

Alternatively, one can choose to design the PCDC power plant such that the power output and thus the income from electricity sales remains the same as for a power plant without CO_2 capture. In this case the following additional costs occur:

- Front-end investment cost
- Increased natural gas consumption due to reduced overall efficiency
- Investment cost for larger CC unit to compensate for internal power consumption of front-end including CO_2 compression

In this report the second method has been chosen to determine the additional costs for CO_2 capture, as it is independent of the electricity sales price. In addition to technical information, this method requires the following pieces of information:

- Frontend investment cost
- CC investment cost
- Natural gas price

From this information the additional investment costs can readily be calculated using the following equation:

$$\text{additional investment cost} = \underbrace{\text{frontend investment cost} + \text{CC investment cost}}_{\text{investment cost with PCDC}} - \underbrace{\frac{\text{net power output}}{\text{net power output} + \text{frontend power consumption}} \cdot \text{CC investment cost}}_{\text{investment cost without } CO_2 \text{ capture}}$$

The most suitable single parameter to compare different schemes is the effective CO_2 capture cost[1], which is calculated as the specific difference between the total annual cost of a power plant with CO_2 capture and a power plant without CO_2 capture and the same net power output:

$$\text{cost per avoided } CO_2 = \frac{\text{total annual cost of power plant with } CO_2 \text{ capture} - \text{total annual cost of standard power plant with identical net power output}}{\text{total annual } CO_2 \text{ emission of standard power plant} - \text{total annual } CO_2 \text{ emission of power plant with } CO_2 \text{ capture}}$$

The annual costs are assumed to be composed of the following items:

- Capital costs: 10% of the total project costs
- Operating and maintenance: 5% of total project costs
- Natural gas price: 3 USD/MBtu

The NGCC case without CO_2 capture is chosen according to the base cases from the IEA 1998 study:

- Thermal efficiency: 58.7%

Figure 5-8 compares both capture costs and total electric efficiencies of all process schemes for which sufficient data was available. The overall efficiency is in most cases between 42 and 44%. Only study B predicts a significantly higher efficiency up to 49%. This is due to relatively high fuel conversion efficiency in the front-end and a very high electric efficiency of the CC block of 64%.

[1] The term “effective CO_2 capture cost” is often referred to as “CO_2 avoidance cost”

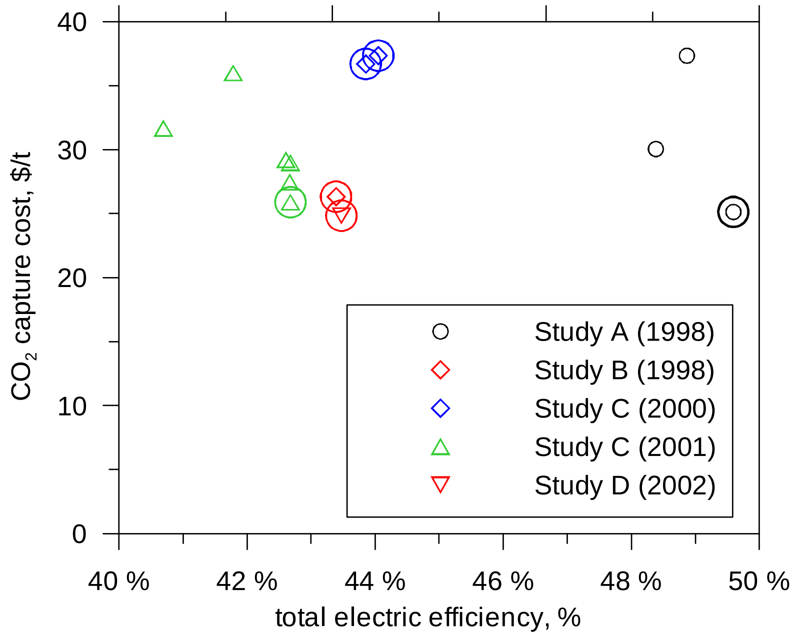


Figure 5- 8: CO_2 capture cost vs. overall electric efficiency for all cases for which sufficient information was available (common cost assigned to CC). Base cases selected for detailed analysis are marked with circles.

By applying the methodology to determine effective CO_2 capture costs as described above, the capture costs and the electric efficiency can be aggregated into a single parameter for any given NG price. Figure 5-9 shows the interrelation between three key parameters that can be used for process scheme selection:

- Effective CO_2 capture cost, USD/t
- CO_2 emissions avoided compared to a NGCC with the same net power output, %
- Additional specific investment costs for CO_2 capture plant, USD/kW

The large spread of the additional investment and effective CO_2 capture costs allows a relatively straightforward selection within the cases of the individual studies. The differences between the cases of one study are expected to reflect actual cost and performance variations relatively well as all cases are evaluated using the same specifications and cost models.

Comparison between cases of different studies is significantly more difficult as the studies are based on different specifications. The most important variations are the gas inlet pressure and the pressure of the CO_2 at battery limit as well as the carbon capture target. The total capacity of the plant is also of major importance as the overhead costs per train are significantly reduced when several identical trains are being planned. Table 3-2 lists the major differences between the specifications for the individual studies. In addition, the selection of cost items included in the cost estimate differs significantly between the studies, as the comparison in Appendix 1 shows.

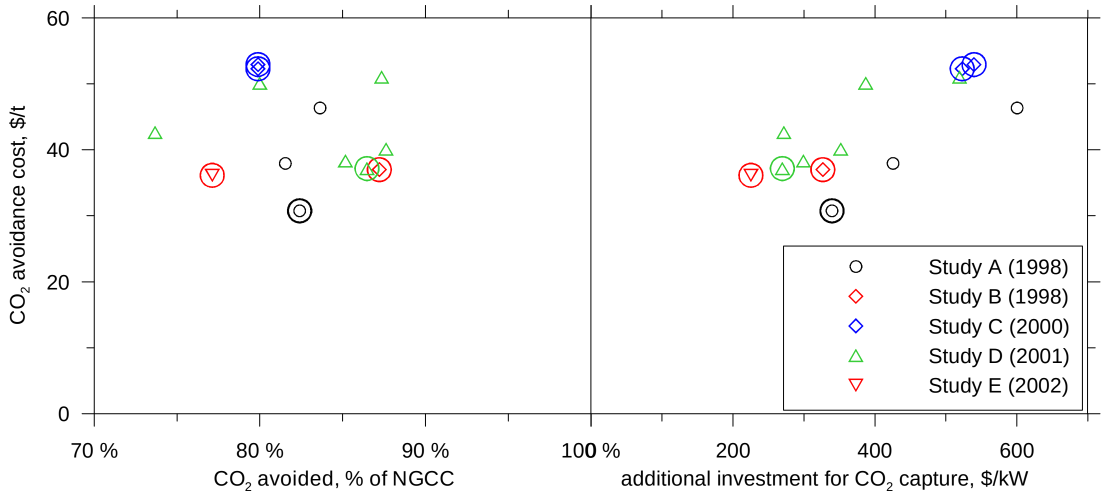


Figure 5-9: Effective CO_2 capture costs for all cases for which sufficient information was available (common cost assigned to CC). Base cases selected for detailed analysis are marked with circles.

In Figure 5-9 the cases selected for further analysis are marked with circles. The cases have been selected based on effective CO_2 capture cost. From the left diagram of Figure 5-9 the Hydro 1998 and the CCP (FW) 2001 process schemes appear to perform best of all cases as they provide relatively low effective CO_2 capture costs at a high avoidance percentage. The costs for the IEA(FW) 1998 process scheme are even lower due to high electric efficiency but causes higher CO_2 emissions. It should be mentioned that the Hydro 1998 study investigates a large unit with 3 identical trains which may reduce the specific costs per installed kW significantly. The costs for the combined cycle unit provided in the Hydro 1998 study are also relatively low compared to the other studies suggesting a generally lower cost level in this study.

Another source of uncertainty when comparing different studies is due to the fact that the common costs need to be assigned to either the CC or the frontend. Figure 5-10 shows the effect of the common costs on both CO_2 capture and effective CO_2 capture costs. This effect is especially pronounced in the IEA (FD) 2000 study where a large sum is accounted to common costs. For all other process schemes the CO_2 capture costs are between 25 and 30 $/t and the effective CO_2 capture cost between 31 and 40 $/t.

The high capture costs from the IEA (FD) 2000 study are due to high front-end investment costs relative to the other studies. The reason for these high costs is unknown as no detailed cost estimate is provided.

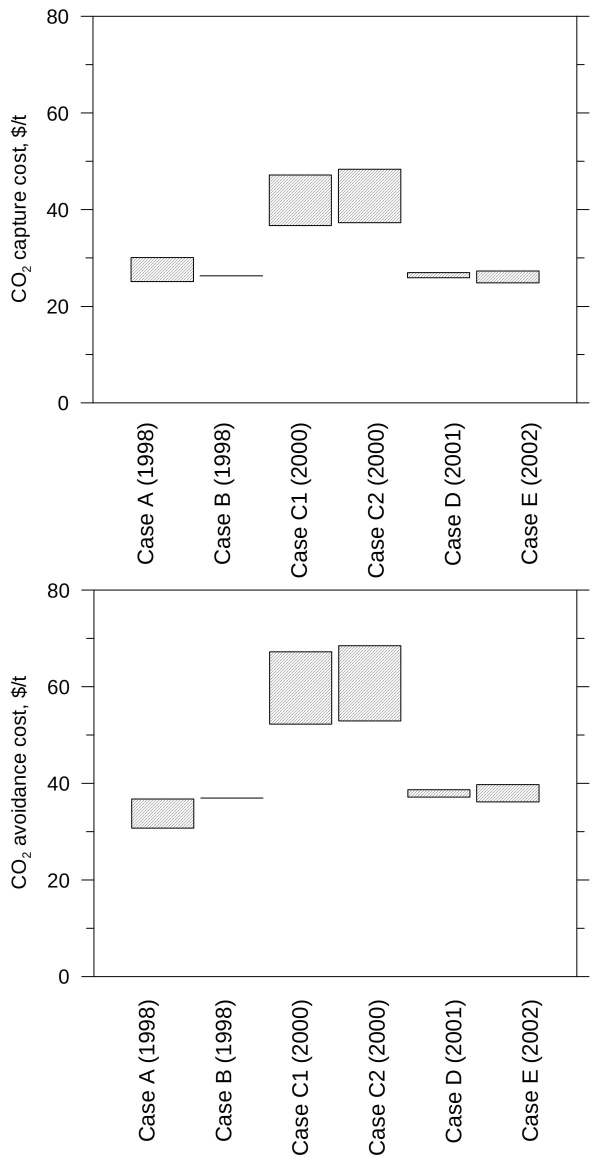


Figure 5-10: CO2 capture (left) and avoidance cost (right) for selected process schemes

The following table presents the key parameters of the process schemes that have been selected for detailed investigation.

Table 5- 3: Key performance parameters of selected process schemes

Case	A	B	C1	C2	D	E
Year	1998	1998	2000	2000	2001	2002
Technology	ATR	ATR NG bypass	ATR NG bypass	ATR+GHR NG bypass	ATR	ATR Retrofit
S/C	2.0	1.65	2.0	2.0	2.0	2.0
Natural gas, Nm3/h	87496	228531	151543	136567	78712	93486
Air from atm., Nm3/h	0	0	0	0	0	72916
Air from GT, Nm3/h	285805	831696	464755	321578	196109	184134
Pre-reformer	no	no	no	no	yes	no
Shift reactor	HT+LT	HT+LT	HT+LT	HT+LT	HT+HT+L	MT

Case	A	B	C1	C2	D	E
Water to GT	MP steam	MP steam	MP steam	MP steam	T Saturator	MP steam
Natural gas in, MW	986	2640	1708	1539	862	963
Natural gas bypass, MW	0	202	134	119	0	0
Natural gas to reactor, MW	986	2438	1574	1420	862	963
H2 fuel to GT, MW	830	1839	1315	1321	669	737
Fuel to GT, MW	830	2042	1443	1430	669	737
Gross power output, MW	534	1259	839	748	400	433
Net power output, MW	**489**	**1145**	**749**	**678**	**368**	**419**
CO2 captured, Mt/y	1.537	4.478	2.658	2.393	1.389	1.472
CO2 avoided, Mt/y	1.257	3.187	1.866	1.689	0.968	1.012
CO2 capture efficiency	85 %	91 %	85 %	85 %	90 %	83 %
CO2 avoided, % NGCC	82 %	87 %	80 %	80 %	86 %	77 %
fuel LHV conversion efficiency	84 %	75 %	83 %	92 %	78 %	77 %
total electricity eff.	**49.6 %**	**43.4 %**	**43.9 %**	**44.0 %**	**42.7 %**	**43.5 %**

Table 5-3 contains parameters describing the technical performance of the process schemes. Table 5-4 lists the key cost parameters. Low and high values of the main results such as capture and effective capture costs are given – depending on whether common costs are assigned to the CC or the frontend. Finally, Table 5-5 lists the cost parameters as specific figures per MWh electricity produced to facilitate direct comparisons.

Table 5-4: Key cost parameters of selected process schemes (absolute figures)

Case	A	B	C1	C2	D	E
Year	1998	1998	2000	2000	2001	2002
Technology	ATR	ATR NG bypass	ATR NG bypass	ATR+GHR NG bypass	ATR	ATR Retrofit
Frontend capital cost, M$	139	338	344	326	85	89
Common capital cost, M$	55	0	208	194	11	25
CC capital cost, M$	265	403	242	228	169	134
Total capital cost, M$	**459**	**741**	**793**	**749**	**264**	**248**
Frontend capital cost, $/kWe	284	295	459	481	230	213
Common capital cost, $/kWe	113	0	278	286	30	60
CC capital cost, $/kWe	542	352	323	337	459	321
Total capital cost, $/kWe	**939**	**647**	**1059**	**1104**	**718**	**593**
Annual NG cost, M$/y	88	237	153	138	77	86
Add. NG cost, M$/y	14	62	39	34	21	22
Add. cap.+ op. cost*, M$/y	25	56	59	55	15	14
Add. cap.+ op. cost**, M$/y	32	56	87	81	16	18
Add. total cost*, M$/y	**39**	**118**	**98**	**89**	**36**	**37**
Add. total cost, M$/y**	**46**	**118**	**125**	**116**	**37**	**40**
CO2 capture cost*, $/t	**25**	**26**	**37**	**37**	**26**	**25**
CO2 capture cost, $/t**	**30**	**26**	**47**	**48**	**27**	**27**

Case	A	B	C1	C2	D	E
Eff. CO2 capture cost*, $/t	**31**	**37**	**52**	**53**	**37**	**36**
Eff. CO2 capture cost, $/t**	**37**	**37**	**67**	**69**	**39**	**40**

* Common cost assigned to CC
** Common cost assigned to frontend

Table 5-5: Key cost parameters of selected process schemes (specific costs)

Case	A	B	C1	C2	D	E
Year	1998	1998	2000	2000	2001	2002
Technology	ATR	ATR NG bypass	ATR NG bypass	ATR+GHR NG bypass	ATR	ATR Retrofit
add. NG cost, $/MWh	3	6	6	6	7	6
add. cap.+ op. cost*, $/MWhel	6	6	9	9	5	4
add. cap.+ op. cost**, $/MWhel	8	6	13	14	5	5
add. total cost*, $/MWhel	**9**	**12**	**15**	**15**	**11**	**10**
add. total cost, $/MWhel**	**11**	**12**	**19**	**19**	**12**	**11**

* Common cost assigned to CC
** Common cost assigned to frontend

6. RECOMMENDATIONS

The minimum requirement to standard design of PCDC scheme should be:

- Avoid provider unique design features
- Avoid technology protected by IPR
- Fit a significant number of gas turbines
- Maximum use of standard equipment
- Minimum use of special equipment *e.g.* GHR, gas/gas exchangers exit ATR
- Use of well-known/proven operating conditions

It is recommended that the PCDC should contain the following main steps:

- Desulphurisation unit
- Preheating of feed streams in fired heater
- Air blown ATR
- High pressure steam production downstream ATR
- HT and LT shift configuration
- Two-step aMDEA system with HP/LP-flash and stripper
- Either steam addition or saturation
- Fuel composition – approx. 50/50 H_2/N_2 (dry basis) with 15-20% water
- Nitrogen content to be determined by maximum air extraction
- Minimum heat integration with gas turbine HRSG

7. POTENTIAL TECHNOLOGY PROVIDERS

Typical partners for the development of the scheme are:

Gas Turbines:

- General Electric
- Alstom
- Siemens
- Mitsubishi

PCDC suppliers

- Haldor Topsoe
- Foster-Wheeler
- Lurgi
- Krupp-Uhde
- Kellogg Brown and Root (KBR)

Main contractors

- Jacobs
- Foster-Wheeler
- Krupp-Uhde
- Snamprogetti
- KBR

8. PROCESS AND DESIGN UNCERTAINTIES

Some of the main uncertainties for the development of standard design are:

- Time: Should we expect development of gas turbine technologies, *e.g.* Low NOx burners for H_2-fuels, higher air extraction pressure and flow, higher combustion pressure etc?
- Gas turbine fit: Can we expect to provide a standard fuel composition in the future that is suitable for all turbines?
- What process parameters are the cost drivers for a standard design?
- Compressors costs are known to be driven by standard design – should we select process parameters that fulfils the compressor need first?

9. FURTHER PROCESS OPTIMISATION

Some focus areas for further development are:

- Optimum CO_2 capture efficiency
- Revamp option potential, say new CO_2 capture technology *e.g*. Sorption Enhanced WGS
- Optimum process parameters, *e.g.* steam/carbon ratio

Appendix 1: Cost items included in cost estimates

Cost area	Cost item	Study A Level 1	Study A Level 2	Study B Level 1	Study B Level 2	Study C	Study D	Study E
Direct Field Material Costs	Equipment	x	x	x	x	x	x	x
	Piping	x	x	x	x	x	x	x
	Instruments	x	x	x	x	x	x	x
	Electrical	x	x	x	x	x	x	x
	Initial catalyst & Chemicals	x	x	-	x	x	x	x
	Spare parts	x	x	x	x		x	x
	Paint			x	x	x		x
	Insulation			x	x	x		x
	Buildings			x	x	x		x
	Structural Steel			x	x	x		x
	Shipping / Freight / Insurance	x	x	x	x	x	x	x
	Import duties	x	x	-	-	-	-	
Direct Field Labour Costs (Subcontract basis)	Civil / Steelworks	x	x	x	x	x	x	x
	Excavation			x	x	x		
	Removal of underground obstructions	-	-	x	x		-	
	Third party inspection	x	x				x	
Subcontract Supply and Erect Costs	Temporary facilities	x	x	x	x	x	x	x
	Protective cover	x	x				x	
	Scaffolding	x	x				x	
	Heavy haul/heavy lift equipment					x		
Indirect Field Costs	Construction management	x	x	-	-	x	x	
Vendor Representative Costs	Vendors engineers	x	x			x	x	
	I.C. Services	x	x				x	
	Miscellaneous	x	x				x	
	Commissioning services	x	x	x	x		x	
Home Office Costs	Engineering			-	x	x		
	Office expenses				x	x		
	Overhead costs, fees			-	x	x		
Contingency	Contingency	-	x	-	x	x	-	
Financing	Financing	-	-	-	-	-	-	
	Escalation	-	x	-	-	-	-	
	Capital / insurance spares	-	-	-	-		-	
Start up	Pre commissioning assistance							
	Performance tests							
	Start-up assistance	-	-	-	x		-	
	Start-up costs			-	-			
	Operating costs	-	-	-	-	-	-	
Fees and Permits	Royalties, licence fees	-	-	-	x	-	-	
	Process guarantees	-	-	-	-	-	-	
	Cost of land							
	Statutory authority & utility company cost							
	Environmental permits			-	-	-		
Decommissioning	Decommissioning	-	-	-	-	-	-	

Appendix 2: Glossary

ATR	auto-thermal reformer
Btu	British thermal unit
CC	combined cycle
CCP	Carbon Capture Project
CPO	catalytic partial oxidation
EUR	Euro (€)
GBP	British pound
GHR	gas heated reformer
GT	gas turbine
HC	Hydrocarbons
HER	heat exchange reformer
HRSG	heat recovery steam generation
HT	high temperature
IEA	International Energy Agency
LHV	low heating value
LT	low temperature
MDEA	monodiethanolamine
MP	medium pressure
MT	medium temperature
NG	natural gas
NGCC	natural gas combined cycle
PCDC	pre-combustion decarbonisation
POX	non-catalytic partial oxidation
SMR	steam methane reforming
USD	US dollar

STAGE 2 REPORT – ATTACHMENT JACOBS STUDY[1] – INVESTIGATION INTO THE POTENTIAL COST REDUCTION OF POWER GENERATION WITH PRE-COMBUSTION CO_2 CAPTURE (PCDC) THROUGH MODULARISATION AND STANDARDISATION

1. MANAGEMENT SUMMARY

This study describes an investigation into the potential cost reduction of power generation with pre-combustion CO_2 capture (PCDC) through modularization and standardization.

The basis is firing a fuel mix of hydrogen and nitrogen in a standard combined cycle power plant. This fuel mix is generated in a natural gas based fuel conversion plant. This plant comprises auto thermal reforming, carbon monoxide shift to carbon dioxide, carbon dioxide removal and CO_2 compression delivering CO_2 at pressure at the battery limit of the fuel plant.

Part of the study is an estimate of the market potential of such type of "Zero Emission" Power Plants.

The study basis is a standard combined cycle unit (400 MW_e) that can accommodate in a later phase or in a revamp situation the carbon free fuel gas. This power plant in itself is highly standardized so benefits of repetitive design are only applicable to the fuel conversion part of the plant.

The investigation compares performance and costs of the natural gas based unit and the standardized PCDC power plants.

During the study a brainstorm session based on functional values was held with the CCP team members and the Jacobs Consultancy study team. This session triggered further improvements in the first concept selected.

The main results of the study are presented in following table and figure.

		Natural Gas Combined Cycle	Standardized PCDC plant	
			Unit 1	Unit 10
Capital expenditure	M USD	180.9	392.4	351.5
Specific electricity cost	USD/MWh	33.69	57.08	54.05
Avoided CO_2 cost	USD/ton	-	68.40	55.45
Overall efficiency	%	55.85	41.3	
Natural gas consumption	MW_{th}	702	882	
Net power production	MW_e	392	365	
CO_2 emitted	MT/y	1.061	0.095	
CO_2 captured	MT/y		1.329	
CO_2 avoided	MT/y	-	0.966	
CO_2 capture efficiency	%	-	93.3	
CO_2 avoided	% NGCC	-	91.0	

Table 1-1 Overall performance comparison

[1] Complete main report from Jacobs Consultancy, dated 17 December 2003

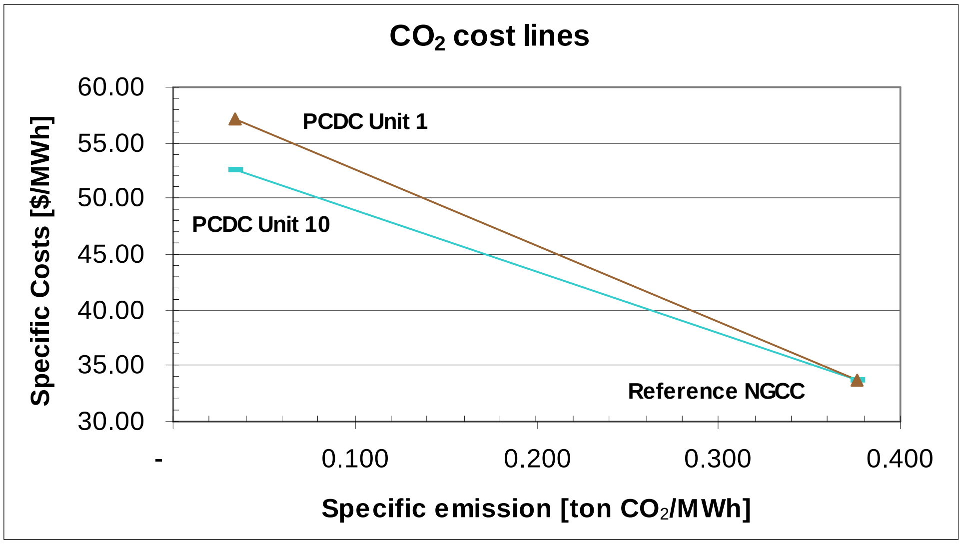


Figure 1-1 CO_2 cost lines

The highlights are:

- CO_2 capture costs for a first of a kind plant are 68.4 $/ton
- CO_2 capture costs decrease by 14% to 55.5 $/ton by standardization/repetitive business.

Using the improvements derived from the brainstorm session, these cost go down to 59.4 $/ton for the first unit and 47.2 $/ton for repetitive design.

The overall effect of standardization/repetitive design is an estimated investment reduction of 40 mln USD, equivalent to about 10% of the total plant investment.

The market study is based on a global annual yearly capacity installed of some 42 GW_e of which 50% is natural gas based. We assumed a 10% market share in the gas-fired units to use the PCDC concept. This results in a market growing from 2000 MW_e or 5 units per year in the early part of this century growing to 4000 MW_e or 10 units per year around 2020. The resulting number of units to be built indeed allows for the predicted advantages of a standardized repetitive design.

2. INTRODUCTION

With this study the CO_2 Capture Project (CCP) team aims at evaluating the cost reduction of power generation with pre-combustion CO_2 capture through standardization. Jacobs Consultancy, part of the international Jacobs Engineering Group, has been selected to execute this study. Jacobs Consultancy is active as a power plant and process consultant.

The CO_2 Capture project is an international effort by eight of the world's leading energy companies, namely BP, Chevron Texaco, ENI, Norsk Hydro, EnCana, Shell, Statoil and Suncor Energy, with a mandate to develop new low-cost technology to capture and store CO_2, currently emitted by fixed sources such as turbines, heaters and boilers. This technology will provide a new set of options for reducing CO_2 emissions that can complement improved energy efficiency and increased use of non-fossil energy sources.

One of the most promising technologies for reduction of green house gas emissions from power generation is through pre-combustion decarbonisation (PCDC) of gas fired combined cycle gas turbine power plant (CCGT). The gas fired CCGT process has highly competitive generation costs compared to alternatives. Addition of CO_2 capture to a power generation process increases the cost of generation and reduces efficiency. The marginal cost of CO_2 capture from coal fired plants is slightly lower than from CCGT but because of low base cost of CCGT, this is likely to be the technology of choice for new generation capacity where capture is planned.

Previous studies [2002-11-08; Norsk Hydro O&E Research Centre; Pre-combustion Decarbonisation for CO_2 capture] of this process have indicated an abatement cost of around 30-70 USD per ton CO_2. These have been based on one off designs, but the exact basis for the cost calculations is not known. The cost could be reduced considerably if a cost efficient, fit for purpose design could be developed and full advantage taken of standardization and modularization. The CCP in conjunction with the IEAGHG R&D program wishes to evaluate this potential for cost reduction with the ultimate objective at a later stage of setting up a consortium to design, build and demonstrate the first of a series of such plants.

Main design issue is the use of standard equipment up to a maximum extent, in order to obtain a proven and reliable concept. Reliability and use of proven design is strongly preferred above high level of integration (with optimum efficiency) between power plant and fuel plant. The first plant will most probably be a retrofit to an existing power plant. This also leads to a minimum integration concept.

For executing the study the following project approach has been applicable:

- Definition of a state of the art 400 MW_e natural gas fired power plant.
- Definition of a reference PCDC plant (fuel plant) based on an air blown auto-thermal reforming process supplying syngas to the power plant

The thermal and economic performance of the reference PCDC plant, combined with the power plant, will be compared with the standard power plant performance.

Furthermore the study will focus on identifying cost reduction elements regarding the PCDC plant. Already identified possible cost reduction items are:

- Modular Construction
- Fit for purpose selection and application of codes and standards
- Capacity specification

Additional possible cost reduction elements have been identified during a structured brainstorm session, after which the most promising options have been evaluated.

The development of a set of three market scenarios (low/medium/high market penetration) is part of this study. This set of scenarios covers a 20-year period, indicating the number of units, capacities and geographic distribution.

3. STANDARD POWER PLANT

3.1 GENERAL

This chapter describes the process design and performance of the standard power plant, including the most significant design parameters for the major equipment and systems.

The study is based on a standard 400 MW_e single train natural gas fired combined cycle power plant. The standard combined cycle power plant comprises:

- A gas turbine
- A triple pressure non fired natural circulation Heat Recovery Steam Generator (HRSG) with reheat
- A steam turbine with a HP, IP and LP condensing section

The gas turbine and steam turbine are connected to a common hydrogen cooled generator. (i.e. single shaft configuration)

The overall plant design, including the selected components, has been based on state of the art proven technology.

3.2 GAS TURBINE

A GE Frame 9FA gas turbine(260 MW_e), with a dry low NO_x combustion system has been selected as a typical representative proven design gas turbine in the power range considered.

Type	GE PG9351(FA)
ISO Base Rating	255.6 MWe
Heat rate	9759 kJ/kWh
Pressure ratio	15.4
Mass flow	623.7 kg/s
Exhaust Temperature	609 °C

Table 3-1: ISO Base rating for the General Electric Frame 9FA (natural gas firing)

This gas turbine can be considered as the current proven state of the art within its power range. Alternative gas turbines within this power range are:

- ABB GT26
- Siemens V94.3A
- Mitsubishi M701F

The performance of the gas turbine will vary with:
- Ambient conditions
- Inlet/exhaust losses
- Type of fuel
- Fouling
- Degradation

The presented performance figures are based on a new and clean plant.

For evaluation purposes the following starting points are used:
- Fuel: Norwegian natural gas

Component	
Methane	83.9%
Ethane	9.2%
Propane	3.3%
Butane +	1.4%
Carbon-dioxide	1.8%
Nitrogen	0.4%
Sulphur (as H_2S)	4 mg/Nm^3
Lower Heating Value	46.899 MJ/kg

Table 3-2 Natural gas composition

- Gas turbine base load operation
- No degradation
- No fouling
- Other starting points:

T ambient	9 °C
P ambient	1013 mbar
Relative humidity	60%
Elevation above sea level	0 m
Inlet pressure drop	10 mbar
Exhaust pressure drop	25 mbar

Table 3-3: Starting points Power Plant Performance evaluation

3.3 HRSG

The HRSG of the standard power plant is a non-fired triple pressure natural circulation boiler with single reheat. As the installation is considered to be a base load operating power plant the design is optimized with respect to the overall efficiency of the system. The higher overall efficiency will consequently result in a reduction of the fuel gas consumption and CO_2 emission.

In the simplified process diagram of the standard design only major components are presented. Additional facilities, which are required for operation of the plant over the complete operating range such as de-superheating equipment, closed cooling water system and instrument air, etcetera are not presented.

The HRSG supplies steam at the following pressures and temperatures:

	Pressure	Temperature
HP: High pressure	120 bar	560 °C
IP: Intermediate pressure	27 bar	560 °C
LP: Low pressure	4.6 bar	300 °C

Table 3-4: HRSG steam conditions

In order to achieve the given steam conditions the HRSG sections are set up according to Table 3-5:

High pressure superheater	Steam temperature	560 °C
Medium pressure superheater/ reheater	Steam temperature	560 °C
Medium pressure superheater	Steam temperature	300 °C
Low pressure superheater	Steam temperature	300 °C
High pressure economizer	Degrees of subcooling	3 °C
Medium pressure economizer	Degrees of subcooling	3 °C
Low pressure economizer	Degrees of subcooling	3 °C
Water preheater	Exit temperature	90 °C
Evaporator (low, medium and high pressure)	Pinch delta temperature	8 °C

Table 3-5: Set-up HRSG sections

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the seawater temperature of 12°C, a maximum allowed temperature rise of 7°C and an approach temperature of 10°C.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency. Therefore the deaerator system will operate at a pressure of 1.2 bar; 105°C with a condensate feed water temperature of 90°C (The feed water temperature shall be approximately 15 °C below the deaerator temperature to ensure a high deaerator efficiency). LP steam will be used for deaeration and heating of the condensate.

The condensate out of the condenser will be heated from 29°C to 90°C by means of a closed water loop, which is using the flue gas heat from the stack to preheat the condensate. Direct heating the condensate with flue gas is not possible because the condensate entry temperature is below the dew point of the flue gas. For modeling purposes this is not achieved by a closed water loop but by mixing 90°C water from the preheat section with 29°C water entering the preheat section in order to increase this temperature from 29°C to a safe level of 60°C.

List of remaining starting points:

- For calculation of the auxiliary power consumption all the pumps used have an overall efficiency of 75%.
- The generator efficiency is 98.3%
- Blow down and deaerator vent is set at 0%
- Minor steam losses, such as the ejector steam and gland steam are neglected.

3.4 STEAM TURBINE

The steam turbine is split up in the following sections:

- A HP section which is supplied with steam from the HP superheater
- A MP section which is supplied with a mixture of steam from the MP superheater and steam from the HP turbine which is reheated in the reheat section
- A LP section which is supplied with a mixture of steam from the LP superheater and steam from the MP turbine section

The steam turbine has the following characteristics:

Section	Overall isentropic efficiency	Inlet pressure	Inlet temperature	Outlet pressure	Outlet temperature
High pressure	87.0%	120 bar	560 °C	27.4 bar	346 °C
Intermediate pressure	88.5%	27 bar	560 °C	4.6 bar	320 °C
Low pressure	90.0%	4.6 bar	318 °C	0.04 bar	29 °C

Table 3-6: Power plant steam turbine characteristics

3.5 ENERGY BALANCE POWER PLANT

The resulting energy balance for the standard power plant firing natural gas becomes:

Energy balance natural gas firing		
Fuel Consumption LHV	702.4 MW	
Gas Turbine	263.6 MW	
GT Gross power		277.9 MW
GT losses		-14.3 MW
Net GT output		263.6 MW
Steam Turbine	140.7 MW	
ST Shaft power		142.1 MW
ST losses		-1.4 MW
Net ST output		140.7 MW
Generator losses	-7.0 MW	
Balance of Plant losses	-5.0 MW	
Boiler feed water pumps		-1.40 MW
Cooling water pumps		-3.04 MW
Condensate pumps		-0.13 MW
Remaining losses (0.1%)*		-0.42 MW
BOP losses		-5.0 MW
Total Plant net power	392.3 MW	
Net efficiency	55.85%	

Table 3-7: Energy balance power plant (natural gas firing)

* Remaining losses are assumed to be 0.1% of the plant gross power output. These losses comprise small power consumers like the closed cooling water system pumps, instrument air compressor, HVAC, etc.

4. REFERENCE PCDC PLANT

4.1 GENERAL

This chapter describes the process design and performance of the reference PCDC plant, including the most significant design parameters for the major equipment and systems. Required modifications to the standard power plant, resulting from the change in fuel gas are also addressed.

The PCDC process studied is an air blown auto-thermal reforming process delivering a mixture of approximately 50/50 hydrogen/nitrogen. CO_2 is removed from the process by amine scrubbing following a shift reaction. Steam addition to the gas turbine combustors may be used in case of syngas firing to control NO_x formation, which is controlled to meet typical regulatory limits (25 ppmvd @15%O_2) for new gas fired CCGT plants. CO_2 taken from the hydrogen production process is compressed to 110 bar and liquefied. This process unit is considered to be part of the PCDC plant and is included in this study.

Main design issue is the use of standard equipment up to a maximum extent, in order to obtain a proven and reliable concept. Reliability and use of proven design is strongly preferred above high level of integration (with optimum efficiency) between power plant and fuel plant.

Process flow schemes are developed together with material balance, utility requirements and main equipment list and a general arrangement plan of the basic process. Cost estimates are prepared on the basis of these documents. A breakdown of the costs into main process units is presented in chapter 7 Capital Expenditure. The reference plant serves as a reference for the assessment of possible cost reduction elements.

4.2 FUEL PLANT

4.2.1 Introduction

The hydrogen production unit converts a feed of natural gas to a fuel gas mixture of hydrogen and nitrogen with molar composition of approximately 50/50 percent. The unit consists of a reforming stage, where a mixture of natural gas with steam and air is converted to a mixture of hydrogen, carbon monoxide, carbon dioxide and nitrogen, followed by two stages of shift reaction, where the carbon monoxide and residual steam are converted to hydrogen and carbon dioxide downstream the gas-liquid (water) separation. The reaction stages are followed by the removal of CO_2 from the reactor product, using a chemical solvent, and delivery of the fuel gas to the battery limits of the power plant. The CO_2 is liberated from the solvent and compressed for delivery to battery limits for subsequent disposal.

The hydrogen production unit also generates steam for internal use from externally supplied demineralized water. Excess steam in the form of high-pressure steam is converted to electricity by a steam turbine generator. Electricity production from the steam turbine generator in the fuel plant is not sufficient to cover the power demand of the electrical consumers in the fuel plant. Therefore electrical power is imported from the power plant.

4.2.2 Reformer section

Natural Gas is first pre-heated and passed through a desulphurization reactor to prevent poisoning of the catalysts. The gas is then mixed with process steam, heated further and passed to the reforming reactor. The reactor is an air-blown Auto-thermal Reformer (ATR), in which the reactions of partial oxidation and steam reforming both take place, thus forming synthesis gas (syngas).

Air for the air blown ATR is compressed with two E-driven two-stage air compressors. Isentropic efficiency of the air compressors is 78% and 80% for the two stages respectively. Electrical consumption of the air compressors is 53.5 MW_e. VSDS systems will be provided for control of the compressor units. Discharge temperature of the last compressor stages is 355°C. When air compressors with higher efficiencies (isentropic efficiency of 85% ; compressor design remains based on discharge temperature 2^{nd} stage of 355 °C) are installed electrical consumption will be 3 MW_e lower. Subsequently the net power output of the plant will increase resulting in an increase of the overall electric efficiency of 0.3%-point.

Compressor Isentropic Efficiency (1^{st} stage/2^{nd} stage)	**78% / 80%**	**85% / 85%**
Discharge temperature	355°C	355°C
Electrical consumption [MW_e]	53.5	50.5

Table 4-1 Influence of isentropic efficiency on compressor performance

The high temperature of partial oxidation maximizes reforming of the gas and minimizes its methane content. The Steam/Carbon ratio used for the ATR is 1.8, based on experiences with ICI catalyst, which is considered to be a proven and reliable ratio.

The enthalpy of the high temperature syngas stream is recovered by raising steam for the internal requirements of the hydrogen unit and by directly heating other process streams. Conversely the sum of these duties must be sufficient to reduce the syngas temperature to that required for the shift reactors described below. To maximize overall thermal efficiency, the syngas leaving the ATR at 950°C is used to preheat the natural gas feed to the ATR and to raise HP steam. Ideally the air feed to the ATR would also be heated by the ATR product syngas, but this is prohibited due to the hazard risk of air leakage into the syngas stream. If the remaining enthalpy available from the syngas were used entirely to raise steam, the quantity raised would be rather higher than necessary for internal use, therefore the following configuration is adopted, incorporating two additional heat exchangers: -

1. The outlet stream from the passes to the first part of the HP steam boiler.
2. Part of the syngas passes to the ATR feed / product exchanger.
3. The first additional exchanger, in parallel to the ATR feed / product exchanger, superheats the HP steam from the boiler described below.
4. The second additional exchanger, also in parallel to the ATR feed / product exchanger, superheats MP steam from the first stage of the steam turbine generator as described later.
5. The combined outlet streams from these three exchangers in parallel pass to the remaining part of the HP steam boiler, which generates sufficient steam to reduce the syngas temperature to 360°C.

The exchangers immediately downstream of the ATR will be of a special design to accommodate the high design temperature of the syngas stream.

4.2.3 Design considerations

<u>Metal dusting</u>

Metal dusting (the Boudouard reaction) is possible in the temperature range of 800°C to about 550°C with the syngas in this plant. The reaction is catalyzed by nickel and iron and is poisoned by sulphur, silicon and aluminium.

The resistance of various metals is difficult to judge without some operating experience or experimental work. However, gas heated reformer technology has demonstrated that several alloys in the 600 series are extremely resistant even for gases with a high carbon forming potential. These alloys are very expensive, but are extensively used in various industries. Based on the experiences and actual research results a gas-gas heater heating the ATR feed gas to 580°C with syngas product of 750°C is considered to be sufficiently proven and reliable design for this type of plant and the current project status. Coatings are used in gas-heated reformers to give additional resistance, but are unsuitable for most heat exchanger designs if movement through conventional tube supports could damage them.

Low alloys are much more resistant and at metal temperatures below 560°C are unlikely to suffer metal dusting due to the very low rate of the Boudouard reaction. However, metal dusting is not impossible at these temperatures and the tubes and shell will require good design and fabrication so as not to produce spots more prone to this type of corrosion.

Use of Pre-reformer

The use of a pre-reformer can be considered for the following two situations:

- Natural gas containing a considerable quantity of higher hydrocarbons and the requirement to heat the natural gas above 520°C when the higher hydrocarbons are likely to crack. The pre-reformer will completely eliminate all these higher hydrocarbons. In this case the pre-reformer would operate at 360 to 400°C.
- Transfer some of the reforming duty into the pre-reformer. This requires heating the feed to the pre-reformer to about 570°C. At the exit of the pre-reformer the temperature will drop to 470°C and to obtain a reduction in ATR duty this then requires reheating to around 650°C.

For the reference PCDC plant a pre-reformer has not been included because:

- The natural gas does not contain much in the way of higher hydrocarbons.
- To use the high temperature version would require an additional heater to be installed in parallel along with the others on the exit of the ATR. The catalyst is very expensive and will require replacement every two or three years. The exchanger to reheat the gas to 650°C will have syngas on both sides and will have very high metal temperatures prone to metal dusting. At these temperatures very exotic materials probably involving special coatings or bimetallic tubes will be required. There will be a performance gain, but the additional involvement would be considerable.

Start-up

To start up the ATR requires that the natural gas is desulphurized and there is a source of ignition. The natural gas would initially be heated by steam from the power plant up to 300°C to enable the desulphurization absorbers to work.

The ignition of the natural gas and air can be accommodated in several ways. One is to add a small catalytic burner into the main burner. Part of the air and natural gas flow over this catalyst and ignite so that the main flow of air and gas can be safely started. The other is to treat the burner like a conventional burner and install a spark ignitor.

The LT CO Shift catalyst will require careful handling using a nitrogen circuit and supply of hydrogen.

4.2.4 CO Shift section

The syngas from the ATR has a high proportion of CO (approximately 12 mole% dry), which must be converted to CO_2 in order to facilitate the removal of carbon species. This conversion is carried out in two shift reactors, nominally high-temperature and low-temperature (HT Shift and LT Shift). The shift reaction is exothermic and the heat of reaction is recovered downstream each reactor by heat exchange with other process streams.

Downstream the HT Shift, which operates at 360 to 430°C, the gas temperature is reduced to 220°C by preheating the natural gas to the de-sulphurizer and boiler feed water to the reformer product boiler.

Downstream the LT Shift, which operates at 220 to 250°C, the gas enthalpy provides heat for the regeneration of the CO_2 removal process, heating of the fuel gas product and preheating of demineralized water to the unit steam system. The gas stream is finally cooled to 50°C for the CO_2 removal process. Residual unreacted steam, which condenses during this heat recovery stage, is separated from the gas and recycled to the unit steam system.

	Inlet Temperature	Outlet Temperature	CO conversion
HT Shift reaction	360 °C	430 °C	73 %
LT Shift reaction	220 °C	250 °C	85 %

Table 4-2: Shift reaction Temperatures

4.2.5 CO_2 removal and recovery

The syngas stream from the shift reactors, comprising mainly hydrogen, nitrogen and carbon dioxide, passes to the CO_2 absorber. The absorber is a two-stage counter-current column where the gas is contacted first with a “semi-lean” solution of solvent, then with a “lean” solution to dissolve the carbon dioxide, leaving the Hydrogen/Nitrogen fuel gas. This gas is reheated to about 125°C prior to delivery to battery limits of the power plant.

The CO_2–rich stream leaving the bottom of the absorber is regenerated by depressurization in three stages. In the first stage the liquid stream passes to the HP Flash Column where the pressure is reduced from about 30 bar to about 6.5 bar, allowing CO_2 gas to flash off. The resulting liquid then passes to the LP Flash Column, at about 1.2 bar, where further flashing takes place and some stripping as the liquid passes through a packed bed counter-current with the vapor stream from the final stage. At the bottom of this column the liquid is sufficiently “lean” to be recycled to the absorber as “semi-lean” solvent.

Approximately 85% of the liquid from the LP Flash column is recycled to the absorber, while the remaining 15% passes to the third stage of regeneration. This stage is a reboiled stripper, where the liquid is contacted in a packed bed with reboiled vapor. The resulting liquid from the bottom of the column is sufficiently low in CO_2 to be recycled to the absorber as “lean” solution. The vapor overhead from the stripper passes through the LP Flash Column, as described above, and through an overhead condenser on this column. The off-gas from the condenser passes to the CO_2 compressor.

4.2.6 CO_2 compression

The co-product CO_2 is compressed to 110 bar for eventual disposal. At an intermediate pressure the gas passes through a dryer package to reduce the water content to approximately 50 ppm. Isentropic efficiency of the six-stage CO_2 compressor is approximately 85%. The electricity consumption of the CO_2 compressor is approximately 18 MW_e.

4.2.7 Steam system

Superheated steam, which is generated at 123 bar by heat recovery from the ATR product gas stream, passes to a 3-stage condensing turbine driving a generator. The outlet steam from the first stage, at 38 bar, is also reheated by heat recovery from the ATR product gas stream. Part of this steam is fed to the ATR as process steam, while the remainder passes to the second stage of the turbine. The second stage outlet, at 3.5 bar, also provides some extraction, with the remainder passing to the third stage of the turbine.

Condensate from the final stage of the turbine passes to a de-aerator for eventual recycle to the HP boiler. Process condensate separated from the syngas during cooling is also recycled after passing through a stripping column to remove dissolved process gases. The stripping steam used in the column is part of the process steam fed to the ATR, thus the dissolved gases are returned to the process. A make-up stream of demineralized water is also fed to the de-aerator to replace the process steam consumed in the reformer.

The steam turbine is split up in the following sections:

- A HP section which is supplied with steam from the HP superheater
- A MP section which is supplied with steam from the HP turbine which is reheated in the reheat section
- A LP section which is supplied with steam from the MP turbine section

The steam turbine has the following characteristics:

Section	Overall isentropic efficiency	Inlet pressure	Inlet temperature	Outlet pressure	Outlet temperature
High pressure	86%	123	535	38.3	367
Intermediate pressure	86%	38	490	5.0	246
Low pressure	90%	3.5	213	0.03	24

Table 4-3: Fuel plant steam turbine characteristics

4.2.8 Utility systems fuel plant

Demin water installation

Surface water is treated in a demin water plant in order to obtain HP boiler quality water. The demin water plant typically consists of a pre-treatment module, Reversed Osmosis membrane filters and mixed bed filters. The capacity of the demin water plant is designed at 75 m^3/h. The package also comprises feed pumps, permeate tanks and a neutralization tank.

Cooling water

The condenser uses seawater to condensate the steam from the LP steam turbine. (Capacity: 3600 m^3/h). All other cooling water consumers are supplied with cooling water from a closed cooling water system, which is also cooled by seawater.

Instrument air / Tool air

The instrument air package comprises air compressors, after cooler (cooling by CCW), filters, air separator, air driers and a buffer vessel.

4.3 INTEGRATION ASPECTS

Starting point of this study is that integrating the PCDC plant with the standard power plant has been limited to:

1. Firing of syngas on the gas turbine
2. Possibility of air supply from the gas turbine air compressor to the ATR

4.3.1 Firing of syngas on the gas turbine

The firing of hydrogen rich low BTU syngas instead of natural gas on the gas turbine will result in the following.

- The mass flow of fuel to the gas turbine will increase significantly, which implies a modification of the fuel gas supply/combustion system. The increase of fuel gas mass flow will consequently result in an increased flue gas flow and power output of the gas turbine. To keep the gas turbine within its operating envelope it may be required to reduce the airflow and the fuel gas flow to the gas turbine.
- Because of the high hydrogen content the use of a DLN combustion system is not possible. Therefore a dual fuel - fuel gas system, capable of handling syngas and natural gas is required. Steam injection for NO_x abatement is applied.

According to General Electric (GE) the following modifications are recommended for operation on LHV gas:

- Dismantle of DLN combustion system, headers, acoustic enclosure and fuel valve module
- Install IGCC combustors – liner, flow sleeve, nozzles cross-fire tubes
- Engineering – LHV gas fuel module
- Install LHV gas and NG control valve module
- Install new headers -- NG, LHV gas, steam, N2
- Install nitrogen purge module
- LHV off-base fuel system
- Replace stage 1 nozzle with larger area nozzle
- Steam injection skid for NO_x control
- Complete piping, control cabling, connections
- Install fuel system acoustic enclosure
- Hydrogen sensors and upgraded ventilation system
- Controls modification
- Field setup and validation testing

GE provided a budgetary estimate of USD 6.9 million for the mentioned modifications including engineering and testing.

4.3.2 Possibility of air supply to the ATR

Because it is expected that the compressor/expander combination of the gas turbine (and possibly the HRSG) is not able to cope with increased mass flow due to the syngas firing, it is required to limit the gas turbine exhaust flow by reducing the air inlet flow. This can be achieved by closing the Inlet Guide Vanes (IGV) or by compressor air bleed. Dependent on the selected option this may require modification of the gas turbine compressor.

The choice for either the use of IGV or compressor air bleed is made on the basis of several assumptions. Three options are considered in order to obtain realistic performance.

1. Compressor air bleed and subsequently using the compressed air in the fuel production plant, where it is compressed further
2. Compressor air bleed and subsequently expanding the compressed air in an expander, generating electricity or driving a pump
3. Using IGV to reduce air flow

Starting point for the evaluation is that a standard power plant is already in operation prior to the decision of firing syngas from a fuel plant. Therefore both plants will not be fully integrated.

A standard gas turbine in a power plant will not be equipped with additional bleed valve at the compressor casing. Installing additional bleed valves will be costly. A standard gas turbine is already equipped with IGV for part-load operation.

Option 1 could be interesting if a fully integrated power/fuel plant is built. Air from the gas turbine compressor is compressed to approximately 15 bar. Air in the fuel plant needs to be compressed to 40 bar. For this option the following results are expected:

- Marginal impact on the energy efficiency
- CAPEX reduction
- Critical integration of power plant and fuel plant, which is preferably to be avoided.

Option 2 requires a rather high investment (modification gas turbine compressor, expander, heat recovery integration) and modifications to the power plant, which preferably have to be avoided.

Option 3 seems to be the simplest option because it uses proven, simple technology and will therefore not raise contingency/risk costs for the plant owner. Therefore this option has been selected. It is noted that this option may limit part load operation of the gas turbine when firing syngas, in case the compressor is not modified in order to prevent surge problems.

A set of starting points is defined in order to estimate realistic performance for burning the syngas fuel mixture on a Frame 9FA gas turbine:

- Compressor air flow may not become less than 80% of reference flow
- Exhaust gas flow has to stay more or less the same
- Exhaust temperature must be higher than 550°C to allow for sufficiently high steam temperatures, which are required to avoid steam turbine condensation problems.
- Net gas turbine power produced may not exceed 300 MW because of generator capacity
- Flame temperature must be sufficiently low obtain the 45 g/GJ (25 ppmvd @ 15%O2) NOx emission limit

- Fuel will be heated in the fuel plant to 125°C

It shall be noted that optimization of these starting points may be possible, after detailed discussion with manufacturers.

In order to obtain realistic performance the following resulted:

- IGV have been adjusted to 14% reduction in airflow through the compressor.
- 700 MW_{th} of fuel supplied to the gas turbine
- Firing temperature is reduced with approximately 50°C
- Net power production of the gas turbine is approximately 300 MW_e.

Based on adiabatic flame temperature calculations, previous project experience and vendor information[2] JCN found that a steam injection rate of 3 kg/s is needed to have an adequately low flame temperature. This means that steam injection of 3 kg/s is theoretically necessary in order to obtain 45 g/GJ NOx emission (25 ppmvd @ 15%O2) when burning syngas. The performance calculations have been based on steam injection of 3 kg/s. The calculated performance (clean without degradation) at 100% syngas firing is presented in Table 4-4.

GT Type		**GE PG9351(FA) Syngas Firing**
Fuel Lower Heating Value	kJ/kg	8308
Inlet Press. Loss	mbar	10
Non-HRSG Press. Loss	mbar	25
Fuel Supply Temperature	°C	125
Compr. Inlet Temp.	°C	9
LHV Heat Input to Comb.	MW	700.2
Net Electric Power	MW	292.0
Efficiency	%	41.70
Inlet Air flow	kg/s	531.7
Exhaust Gas Outlet Flow	kg/s	619.0
Exhaust Gas Outlet Temperature	°C	579.7
Steam Injection flow rate	kg/s	3.0

Table 4-4 Gas turbine performance (syngas firing)

4.3.3 Energy Balance power plant

The energy balance for the power plant firing syngas is given in Table 4-5. Net power and efficiency for the syngas fired power plant increase compared to the natural gas fired power plant. This is mainly caused by increased efficiency (defined as power output over fuel LHV input) of the gas turbine, due to high mass flow of high pressure low BTU syngas.

[2] Todd, Batista; GE Power systems; Demonstrated applicability of Hydrogen Fuel for Gas Turbines

Energy balance syngas firing		
Fuel Consumption LHV	700.2 MW	
Gas Turbine	296.6 MW	
GT Gross power		310.9 MW
GT losses		-14.3 MW
Net GT output		296.6 MW
Steam Turbine	129.8 MW	
ST Shaft power		131.1 MW
ST losses		-1.3 MW
Net ST output		129.8 MW
Generator losses	-7.3 MW	
Balance of Plant losses	-4.7 MW	
Boiler feed water pumps		-1.3 MW
Cooling water pumps		-2.8 MW
Condensate pumps		-0.2 MW
Remaining losses (0.1%)		-0.4 MW
BOP losses		-4.7 MW
Total Plant net power	414.5 MW	
Net efficiency	59.2%	

Table 4-5: Energy balance power plant (syngas firing)

4.4 Performance Reference plant

Table 4 -6 presents the key performance parameters of the reference plant:

Key performance parameters		
Natural gas consumption	882.3	MW
Syngas to gas turbine	700.2	MW
Gross power output	414.5	MW
Net power consumption fuel plant 1)	49.7	MW
Net power output	**364.8**	**MW**
CO_2 captured	1.329	Mt/y
CO_2 emitted	0.095	Mt/y
CO_2 capture efficiency	93.3	%
Fuel LHV conversion efficiency	79.4	%
PCDC efficiency	73.7	%
Total electric efficiency	**41.3**	**%**

Table 4 -6 Key performance parameters

1) Gross power consumption is 79.7 MW_e. Power generation of the steam turbine generator in the fuel plant is 30 MW_e, resulting in net power consumption of 49.7 MW_e.

CO_2 calculations are based on Carbon quantities and are calculated, using 8000 yearly operating hours and a load factor of 90%.

5. MARKET SCENARIOS

5.1 INTRODUCTION

This memo describes the results of a limited market study for the potential of low emission power plants using pre-combustion fuel decarbonization (PCDC) technology. The study covers a period from 2005 to 2025 and is based on the foreseen potential for natural gas fired Combined Cycle Gas Turbine (CCGT) plants in the world.

The study comprises a data base inquiry with historical data and figures for capacity planned and under construction. The obtained trends are checked with forecasts for the electricity markets, which are obtained from relevant sources.

5.2 APPROACH

The market study described in this report is based on following items:

1. Data base analysis to establish historical trends and developments
2. Definition of a preliminary medium market scenario based on historical data
3. Testing the preliminary market scenario by data base analysis of plants under construction and planned future plants
4. Analysis of energy and electricity scenario studies by the US Department of Energy and the European Commission
5. Definition of final medium market scenario from 2005 to 2020 based on predicted future developments
6. Definition of high and low market scenario based on sensitivities in future fuel mix and economic drivers like CO_2 emission trade
7. Discussion with major power plant suppliers

5.3 DATA BASE ANALYSIS

The database, which was used for this study, originates from UDI and contains information for over 100.000 power plants worldwide, constructed between 1930 and 2000. Data base analysis of fossil-fired power plants shows the installed new capacity per year for different regions and gives a good understanding of the trends in installed power capacity.

Figure 5-1 shows the new installed capacity per year for different fossil fuel types. The figures represent the sum of capacities of units with a capacity >50 MW_e which are still operational in 2001. A high increase in capacity occurred in the late 1960's, mainly by coal-fired units, followed by a dip in new capacity around 1988. The 1990's show a high increase in newly installed power, together with a high rise in gas-fired capacity.

5.3.1 Coal-fired units

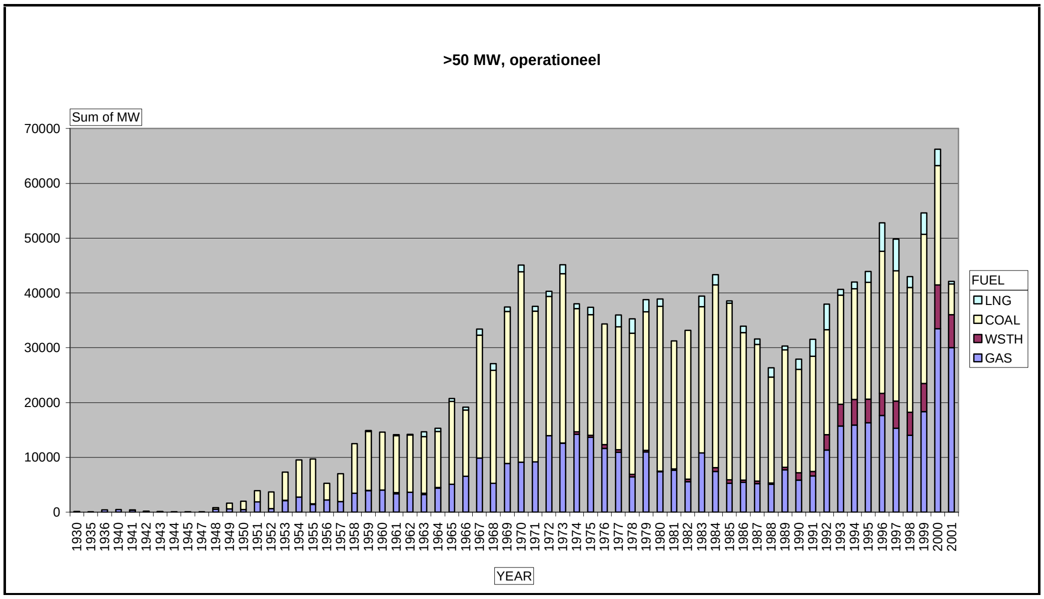


Figure 5-1 Historical overview of yearly constructed capacity still in operation

Figure 5-2 is obtained when coal-fired capacity is filtered from the database and sorted per region.

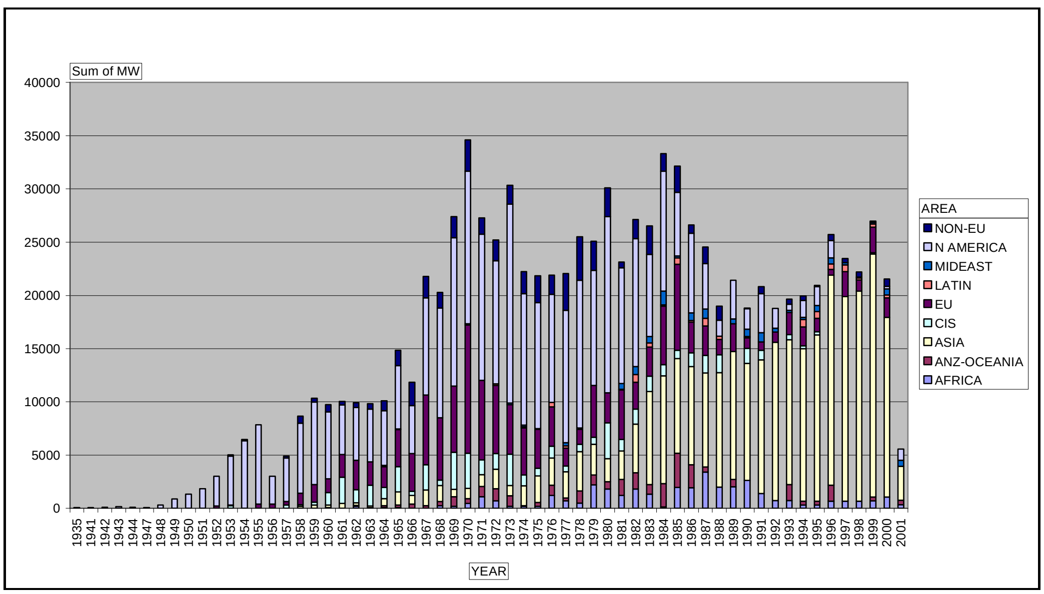


Figure 5-2 Yearly installed coal capacity per region still in operation

The graph shows that a large amount of coal-fired capacity was build from the late 1960's in the Western world until the 1990's. After that a large increase in Asia kept the share of coal in newly installed capacity almost constant, despite of an almost hold to new coal-fired capacity in Europe and North America.

5.3.2 Gas-fired units

Figure 5-3 shows the yearly installed capacity for gas-fired units, sorted to type of installation: Combined-Cycle (CC), Conventional power (ST) or Single Cycle (GT).

In this analysis once again only capacity >50 MW_e, which is still operational in 2000, is taken into account.
The figure shows an increase in conventional capacity after 1965, followed by a dip in the 1980's. This decline could be explained by a trend of diversification in fuel usage in the western world, after the oil crises in the 1970's. Coal became the more popular alternative before gas.
In the 1990's the gas turbine based single- and combined-cycle start to appear on a large scale, resulting in about 45GWe newly installed gas-fired capacity in the year 2000 alone.

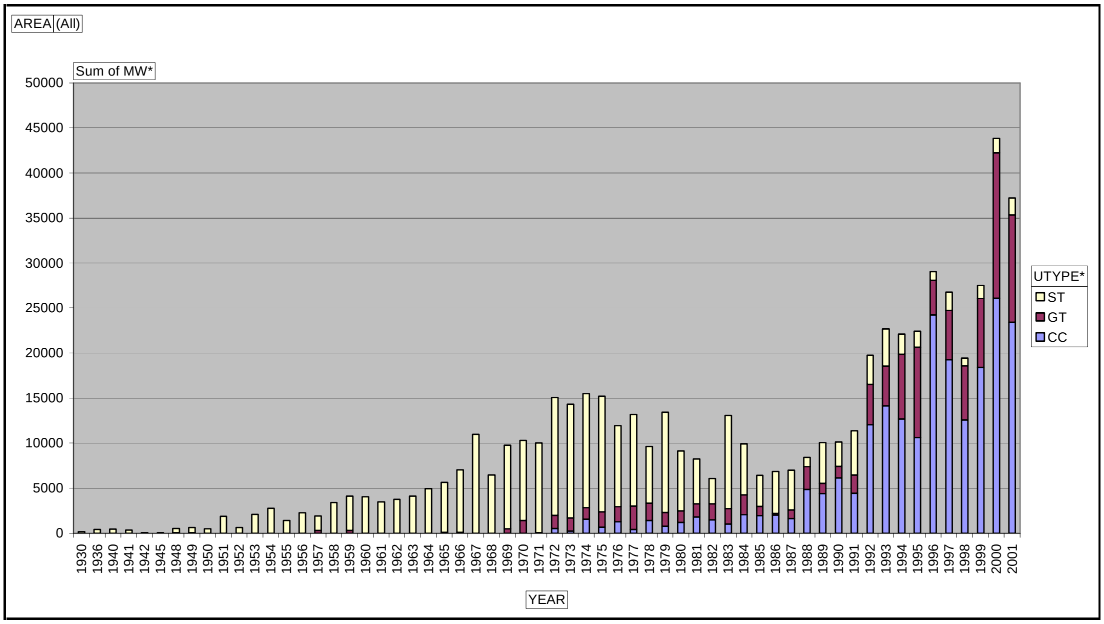


Figure 5-3 Newly installed operational gas-fired capacity

It is noticeable that the largest part of new capacity is combined-cycle technology, but also an increasing amount is coming from single-cycle gas turbine installations. It appears that almost the complete single-cycle capacity is installed in North America (see Figure 5-4).
The boom in single-cycle units can be explained by a high demand for new capacity in North America. Single-cycle units are installed in a relatively short time in comparison to combined-cycle units, and therefore a good way to provide power when there is a short of supply and efficiency is not the most important issue. JCN expects that a fair share of these single-cycle units will be converted in the near future to combined-cycle units for efficiency reasons.

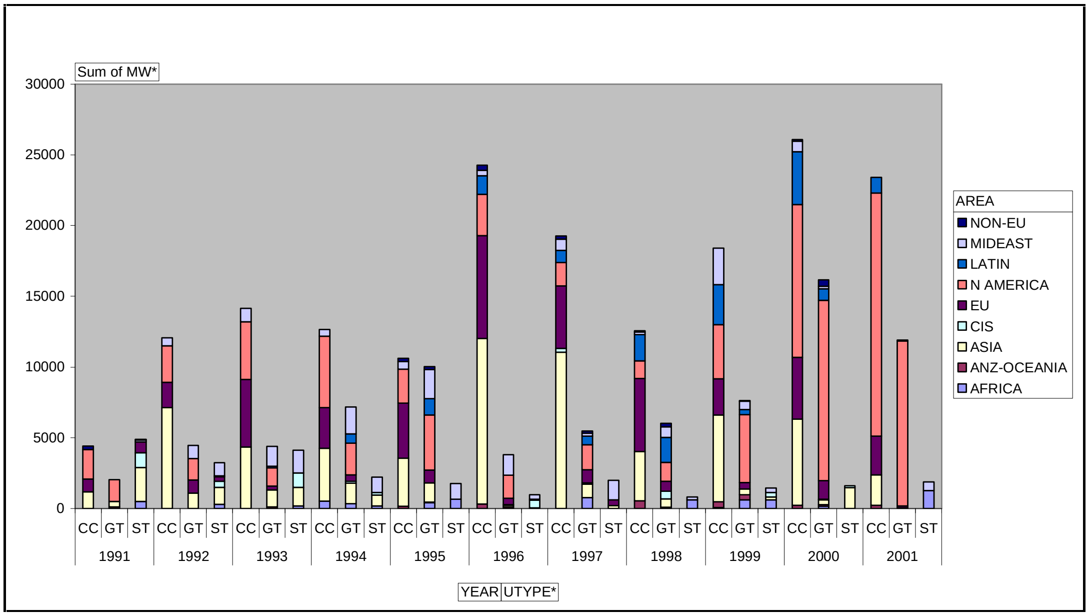


Figure 5-4 Installed capacity per year per technique for different regions, 1991-2001

5.4 MEDIUM SCENARIO ON CURRENT TREND

All figures show a worldwide increase in the installation of new capacity over the recent ten years. In Europe and North America this increase is mainly due to new gas-fired units, while in Asia mainly coal-fired units have been installed.

In the opinion of JCN however this rising trend will not be continued in the forecast for the future developments. The current economical slowdown creates a less interesting climate for large investments compared to the 1990's. The database doesn't show the effects of this dip as the slowdown just started around 2000 and because the decisions on investment for the plants that were installed in 2000, were taken a few years earlier.
This makes it difficult to predict the effect of the current situation on future power capacity installations.

On the other hand there are signals in the market, which indicate the possibility of a shortage in electrical production capacity. A dramatic consequence of this could be seen in California where amongst others underinvestment in new capacity caused a power shortage in 2000, with consequential blackouts. Even in the Netherlands with an assumed overcapacity the discussion on a possible shortage rises from time to time.

5.4.1 Short term

A short term forecast (until 2010) is made based on the trend in installed capacity in recent history, with an economical slowdown taken into account. The figures that present the gas-fired capacity show that over the last five years an average new capacity based on combined-cycle technology is installed of 20 GWe per year (for replacement of old capacity and to meet growing demand). At the same time hardly any conventional capacity is installed, while single-cycle capacity is increasing as well.

The starting point for this study is that PCDC technology will compete with combined-cycle technology, so the forecast focuses at the trend in combined-cycle capacity.

The short-term medium scenario, which is proposed, predicts a stabilization of the yearly installed combined-cycle technology to 20 GWe. The stabilization is caused by the worldwide economic slowdown, which makes large investments less popular. The new capacity that will be installed will mainly be constructed in North America and to a lesser degree in Asia and Europe. Africa and South America are not expected to show a significant amount of new power capacity.

5.4.2 Long term

A long-term estimate can be obtained by looking at the need for replacement of old capacity. Figure 5-1 shows that an average yearly capacity of 33 GWe is installed in the period of 1960-1985. When an average maximum age of 40 years for a production unit is assumed, this 33 GWe has to be replaced with new capacity.

It is assumed that 50% of this replacement capacity will come from gas-fired units, i.e. 17 GWe per year. In addition there will be a need for new capacity to meet the rising electricity demand.

5.4.3 Preliminary conclusion: Market share for PCDC technology

The starting point for the study is that PCDC technology will represent a market share of 10% of new gas fired combined-cycle plants in the world.

The medium scenario for predicting the demand for combined-cycle power plants is derived from the historical data from the UDI database by analyzing the trends for new generation capacity over the last years.

The data base analysis showed a constant amount of newly installed combined-cycle technology of 20 GWe per year. This implies a possible market share for PCDC plants of 2000 MW_e a year until 2010. The slight increase in new capacity, which could be seen in the database, stabilizes because of worsening economic conditions. For the period after 2010 an increase in market potential is considered because of the need for replacement of a large amount of old capacity constructed in the 1970’s and to meet the increasing demand for electricity. An increase of 1000 MW_e/yr per decade is assumed.

Summarizing the statements, the pre preliminary medium scenario derived from history is as follows:

Period	PCDC potential	
2005-2010	2,000	MW_e/year
2010-2020	3,000	MW_e/year
2020-2025	4,000	MW_e/year

This medium scenario will be evaluated by analyzing the units that are planned for the future and capacity that is already under construction.

5.4.4 Base case evaluation with capacity planned and under construction

The UDI database provides information on capacity, which is under construction or planned for installation. With this information the short-term prediction based on historical data can be evaluated, as this database shows the amount of capacity, which will be available in the near future. Figure 5-5 shows the capacity that is to be installed in the near future according to the data from UDI.
JCN has the experience that results for "planned" capacity are not reliable sources to whether this capacity will actually be constructed! During other studies JCN found that plants, of which JCN knew they were not being constructed, were recorded in the database as being "planned".

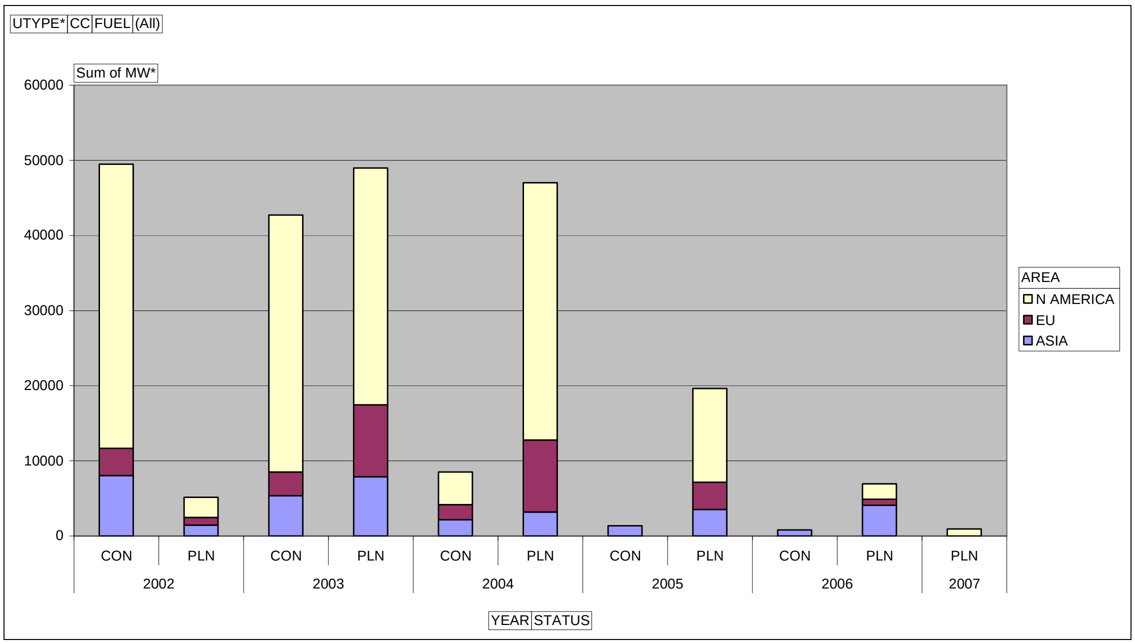


Figure 5-5 Combined-Cycle capacity planned (PLN) and under construction (CON)

The results show that for 2002 and 2003 a combined cycle capacity of 50 GWe and 40 GWe will be installed in North America, Europe and Asia. This is an increase with respect to the capacity installed in 2000, which was expected to stabilize. Especially North America shows a high increase in production capacity.
These results lead to the conclusion that the medium scenario that was defined based on the historical data might be too conservative for the short term. JCN however believes that the large amount of capacity for 2002 and 2003 shown in Figure 5-5 was due to the high demand in the United States to solve the shortage in

supply. This shortage will mostly be covered by 2005 and therefore this will have no effect on the medium scenario.

The coal-fired capacity under construction has also been evaluated, and the results are displayed in Figure 5-6. They show that coal hardly plays a role in North America and Europe, but Asia keeps on constructing new coal capacity. However it is notable that for 2005 and 2007 coal-fired capacity is planned in North America.

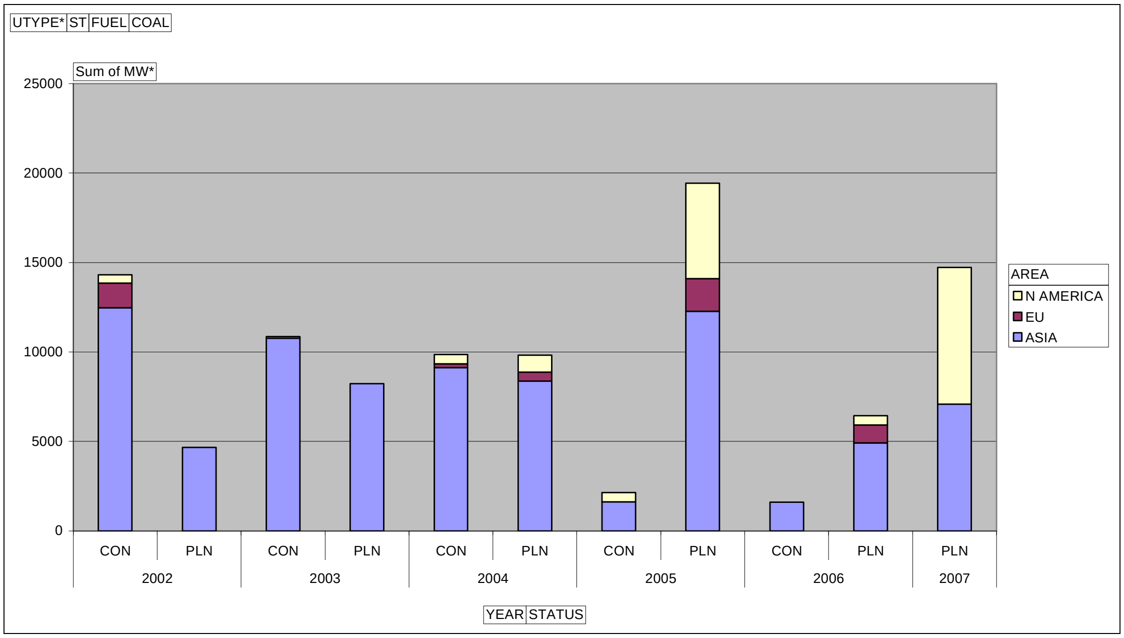


Figure 5-6 Coal-fired capacity planned and under construction

5.4.5 Forecast from external sources

To evaluate the base scenario on long-term, the forecast made by the following reliable sources are analyzed to help understand the future demand for electricity.

The first source is “International Energy Outlook”, published by the US Department of Energy. This report gives a view for the future developments in the energy world for the period until 2025.

The main conclusions for electricity production and demand are:

- The world energy demand will rise with 58% between 2001 and 2025
- The largest increase will occur in Asia with an average of 3% per year
- Natural gas will account for 50% of the increase in electricity production capacity as a fuel for new combined-cycle plants.
- Natural gas will be the fastest growing form of primary energy, with a share of 19% in 2001 and a share of 30% in 2025 in world electricity consumption.
- The share of coal in the world’s energy production will decline from 34% in 2001 to 31% in 2025.
- Coal use for electricity production will decrease strongly in Europe and the former Soviet-Union because of a shift to natural gas, while Asia (especially China and India) sees a strong increase in coal-fired capacity.
- Nuclear power will lose market share.
- The share of renewables will not increase without governmental support
- Worldwide electricity consumption will increase at an average rate of 2.4% per year. Asia will see the largest grow. China’s electricity demand will rise with 4.3% per year, in comparison with a grow of 1.7% in the industrialized world.

The second source of information with respect to market forecasts is the "World energy, technology and climate policy outlook", which is published by the European Commission in 2003. This report presents forecasts for the timeframe till 2030.
The most important conclusions in this report are:

- World electricity demand and production rise with an average annual rate of 3%
- Share of conventional coal in power production decreases from 36% in 2000 to 12% in 2030.
- Share of gas in power production increases from 16% to 25%
- Advanced coal (supercritical, IGCC and direct coal-fired combined-cycle) takes a share of 33% of total world electricity production in 2030.
- Nuclear power falls to a share of 10% of total electricity production in 2030.
- Regional effects: Share of coal decreases in North America and increases sharply in Asia, where advanced coal power plants are expected to represent no less than three quarter of total coal-based electricity production. In the former Soviet Union and Europe the share of gas increases significantly and is expected to represent 47% in 2030.

The main statements are compared in the table below:

Comparison between publications	US Department of Energy	European Commission
World electricity demand	+ 2.4% /year	+ 3% /year
Share of natural gas in E-production	Increases from 19% in 2001 to 30% in 2025	Increases from 16% in 2000 to 25% in 2030
Share of coal in E-production	Decreases from 34% in 2001 to 31% in 2025	Increases from 36% to 45% in 2030

5.4.6 Base case evaluation with forecasts and replacement capacity

The forecasts on energy issues give an increase in worldwide electricity demand and production of 2.4% - 3% a year.

The total operational gas and coal fired capacity in 2000 is equal to about 1500 GWe. When production and demand is considered to grow a 2.5% per year, the yearly average demand for new capacity will increase from 38 GWe in year one to 70 GWe in year 25. This amount is needed to cover the increased demand for electricity.

In addition to this, the older existing power plants are to be replaced. When Figure 5-1 is considered, it can be seen that between 1960 and 1985 an average amount of 33 GWe is installed per year. When the average maximum age for a power plant is assumed to be 40 years, the same amount of capacity has to be replaced completely over the period from 2000-2025.

It can be concluded that on the basis of the electricity market forecasts and analysis of the capacity needed for replacements of old units, a yearly demand for new capacity increases from approximately 70 to 100 GWe.
It is assumed that 50% of this newly installed capacity are gas fired plants (the other 50% are mainly coal fired plants), leading to a market potential for new gas plants of 0.5 * 85 = 42 GWe per year average for the period 2005-2025. When PCDC technology can get a market share of 10% of the gas fired power plant market, a demand of 3500 –5000 MW_e per year is foreseen for this technology.

5.4.7 Final conclusions base case

The market analysis based on the historical data seems to be somewhat conservative, when the capacity which is planned and under construction is studied. However JCN thinks that this is a temporary effect due to shortage of capacity in the US, which created high incentives for new capacity. The long-term forecasts for energy demand and the need for replacement of older units show an increasing demand for gas-fired capacity.
Therefore the following medium scenario is presented for the potential of PCDC technology till 2025:

Period	**PCDC potential**	
2005-2010	2,000	MW_e/year
2010-2015	3,000	MW_e/year
2015-2020	4,000	MW_e/year
2020-2025	5,000	MW_e/year

5.5 SCENARIOES

The market share for PCDC technology is largely dependent on a few drives:

1. Environmental drive: government support for low CO_2 emission technology
2. Economical drive: CO_2 trading
3. Public drive: phase out nuclear power
4. Political drive: choice of fuel mix

<u>1. Environmental drive</u>
In the industrialized countries there is a commitment to decrease CO_2 emissions, among others under the influence of the Kyoto protocol. Government support (lower taxes, subsidies) for low CO_2 emitting techniques could help to overcome (part of) the extra costs for PCDC technology

<u>2. Economical drive</u>
The industrialized world is making preparations for creating markets where CO_2 emissions can be traded amongst parties. If these developments continue and CO_2 has a fair pricing, it can increase the cost-effectiveness of PCDC.

<u>3. Public drive</u>
About 20% of world electricity is produced with nuclear energy. The expected share of nuclear power in the world is decreasing under the influence of public opinion. Old nuclear capacity will be replaced with fossil fuel capacity.

<u>4. Political drive</u>
The fuel mix is of strategic importance for each country, as it does not want to be dependant on one fuel source. This could in some cases slow the installation of gas-fired capacity in favor of for example coal-fired plants.

Three cases are presented for the market penetration of PCDC technology for 2005-2025. The medium scenario is defined above and a high and low scenario with respect to this medium scenario is developed.

In the high scenario there is:

- Government support for low CO_2 emission technology, which results in subsidies
- CO_2 trading is installed and a full-grown market for CO_2 is created.
- No new nuclear capacity is installed
- No limitations because of fuel mix issues

The high scenario shows a higher share of PCDC technology of 15% of combined-cycle demand, compared to the 10% in the medium scenario. Furthermore the total combined-cycle market penetration is 25% higher. This will not be applied to the period between 2005-2010 because this will not influence the market penetration on such a short term.

The low scenario shows:

- Low government interest in CO_2 reductions
- No trading possibilities for CO_2
- Coal is a low cost option, and environmental disadvantages are taken for granted.
- Demand for independency from the Middle East or Russia for natural gas make the fuel mix shift towards coal.

The low scenario comprises a PCDC market share of 5% of combined-cycle demand and combine-cycle demand is decreased to 50% compared with the medium scenario.

The following table shows the market penetration for PCDC technology in the three scenarios.

Period	Low case	Medium scenario	High case	Total New built (NG)	
2005-2010	0	2,000	2,000	35,000	MW_e/year
2010-2015	750	3,000	5,500	40,000	MW_e/year
2015-2020	1,000	4,000	7,500	45,000	MW_e/year
2020-2025	1,500	5,000	9,500	50,000	MW_e/year

6. COST REDUCTION

6.1 INTRODUCTION

Main objective of the study is to identify cost reduction elements for the PCDC plant, which may contribute to reducing the Total Cost of Ownership (TCoO) without affecting the safety, reliability and availability of the plant. The most promising cost reduction elements will be evaluated against the reference case with respect to their technical and economical impact.

At the start of the study already a number of promising cost reduction elements have been identified, which will be addressed further on in this chapter.
The already identified cost reduction elements are:

- Modular construction
- Standardization and repeat manufacturing and construction
- Fit for purpose selection / application of ‘general’ codes and standards
- Capacity specification (i.e. optimum PCDC plant capacity for a 400 MW_e power plant)

During a structured brainstorm session, which is part of the value engineering process, an additional number of promising cost reduction elements have been identified, which will also be addressed in the study.

6.2 MODULARIZATION

6.2.1 Introduction

A study is performed of the Pre-Combustion Decarbonization (PCDC) process to determine what areas can be modularized and to identify the potential project impact. The study was performed using the preliminary plot plan and process data. In this study, the fuel plant is a separate stand-alone facility and is not integrated with any aspect of the CCGT.

Starting point was to initially look at what could be modularized using “typical” truck shipping limitations. This would allow for the greatest flexibility in implementing the modular approach at any future site. As an alternate, the opportunities are investigated if the module shipping envelopes were increased to accommodate the largest pieces of equipment in the PCDC process.

As a baseline for this study it is assumed that the module fabrication is to be performed in the Jacobs Charleston, SC facility and the project site being located in the United States. A wide range of variables must be considered when applying these results to other sites worldwide.
The starting points and results of the study for the United States situation have been evaluated for the PCDC plant to be located in the Netherlands with the required SC facilities in Europe. From that evaluation it appeared that the data provided for the North East Region of the United States provide a good similarity to the situation in the Netherlands.

6.2.2 Modular Technical Investigation

Utilizing a preliminary plot plan, flow diagrams, and equipment list analysis is made where modules could be incorporated into the Standardized PCDC Plant. The initial focus was to look at areas where equipment and piping systems can be arranged to fit into “standard size” truck shippable modules. The size of most process equipment and its associated piping prohibits the use of truck shippable modules. With the minor pipe racks at 4m wide, it is possible to break this rack into suitable lengths for truck shipment. The main rack, however, will have to be a minimum of 6 meters wide with three tiers or 8 meters wide with two tiers. The only way for the main rack to fit within truck shipping limits is to split it lengthwise down the middle. This can be done, but would require a significant amount of additional steel to accommodate the split design.

Due to the fact that only a limited amount of work can be accommodated in truck shippable modules and that significant additional steel is required to do so, it is determined that it is logical to look at where larger modules can be implemented.

Alternate Approach
In order to establish a suitable module size limit for the alternate approach, the list of equipment that would be shipped assembled is evaluated. The following equipment was considered:

Equipment ID#	Diameter	Length
T-401 (CO_2 absorber)	7.0 m	48 m (split)
T-403 (HP flash column)	7.5 m	13.5 m

T-404 (LP flash column)	8.2 m	12 m

Based on this information, a module size limit of 7.5m wide x 7.5m high x 25m long is established for this alternate approach. This size module will likely require a special permit for over-the-road transport, but can be easily managed with standard heavy haul transportation equipment.

This larger module size will eliminate the need for any of the racks to be split lengthwise. Assuming a bent spacing of 6m, would break the modules into 24m long sections. The racks will be assembled complete with the required piping, insulation, and heat tracing or instrumentation as shown in this photo. The rack bents will be shipped loose to the site and installed prior to setting the rack modules. The air coolers located on top of the rack will be field installed after the modules are set in place.

Figure 6-1 Example of a 9m wide x 18m long pipe rack module being transported to site.

The towers and reactors are large diameter and self-supporting (not requiring structural steel). Unless a significant amount of piping and instrumentation can also be assembled with the equipment into a module, the additional steel and shipping costs for this approach will make it uneconomical. Because of the large diameter and limited piping associated with this equipment and because of the long lead nature of these pieces of equipment, it is recommended that this equipment is shipped directly to the site and field set.

Unless the pumps have a significant quantity of piping and instruments located immediately around the pump, or unless they can be included on a common module with other process equipment, there is very little value to be obtained modularizing the pumps. The pumps in this process are typically tied to the towers and vessels and there is, therefore, no benefit from combining them with the heat exchangers on a common module frame.

Many of the exchangers are either manifolded or piped in series and can therefore benefit from being assembled on common modules. When modularizing exchangers, attempt is made to locate the associated valve manifolds and instrumentation on the module frames. These modules will be constructed on a steel frame that is buried and covered with a concrete slab at site. This will yield a final appearance similar to a typical field erected system. The exchanger module sizes are based on the overall exchanger lengths not exceeding 7.5 meters.

Figure 6-2 Example of exchangers being bundled on a module with valve manifolds located at the rear of the module. The lower frame of this module was buried in the concrete slab at site.

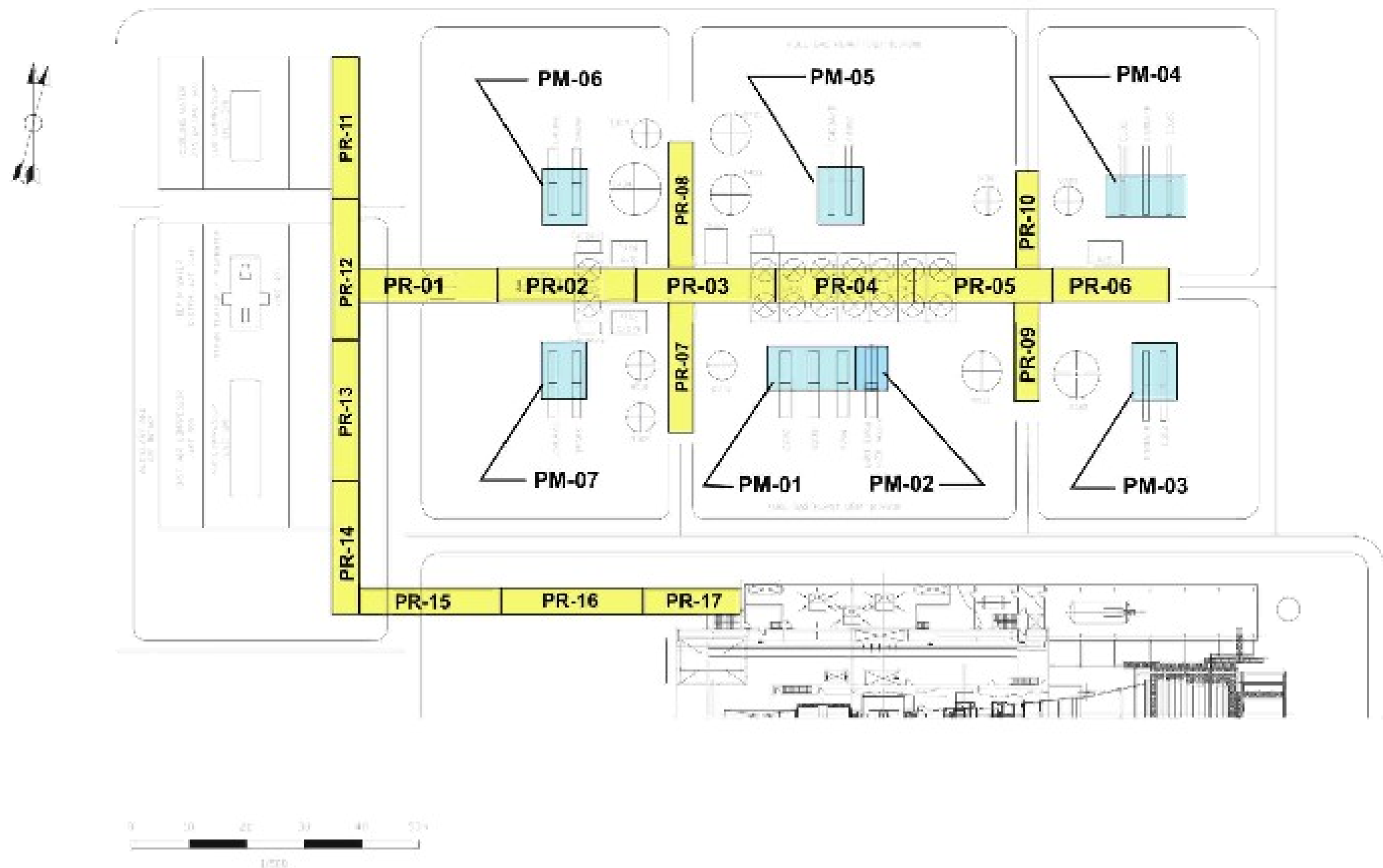
In Table 6-1, as well as on the plot plan on the following page, the modular opportunities for the Alternate case are identified. The yellow highlighted modules on the plot plan indicate pipe rack modules. The blue modules on the plot plan indicate process equipment modules.

Unit 100 represents the desulphurization, reformer and CO shift system
Unit 200 represents the CO_2 removal system
Unit 300 represents the CO_2 compression system

Unit	Module #	Approximate Module Size (LxWxH) (m)	Equipment In Module
100	PM-1	25 x 7.5 x 7.5	E201, E202, E203, E204
	PM-2	7.5 x 6 x 7.5	V201
	PM-3	10 x 7.5 x 7.5	E301A/B, E302
	PM-4	12 x 7.5 x 7.5	E303, E305A/B/C
200	PM-5	10 x 7.5 x 7.5	E402A/B/C
	PM-6	10 x 7.5 x 7.5	E401, E406, Spare
300	PM-7	10 x 7.5 x 7.5	E501A/B, Spare
Main PR	PR-1 thru 5	24 x 6.5 x 6.5	
	PR-6	20 x 6.5 x 6.5	
Minor PR	PR-7, 8	24 x 4 x 4	
	PR-9	15 x 4 x 4	
	PR-10	12 x 4 x 4	
	PR-11 thru 16	24 x 4 x 4	
	PR-17	15 x 4 x 4	

Table 6-1 Module List

In the concept drawing (Figure 6-3), it is demonstrated how the modular concept can be implemented for modules PM-01 and PM-02. The drawing details how the lower part of the frame is buried below the slab at grade. The frame above grade serves to support the large diameter piping as well as the Steam Drum V-201. This configuration, with clear access to the exchanger heads, suits a modular approach without sacrificing any of the necessary maintenance requirements. For some heat exchanger modules, it may be practical to use only the lower frame and eliminate the structural steel above grade.



Standardized PCDC Preliminary Module Layout Plan

10/31/03

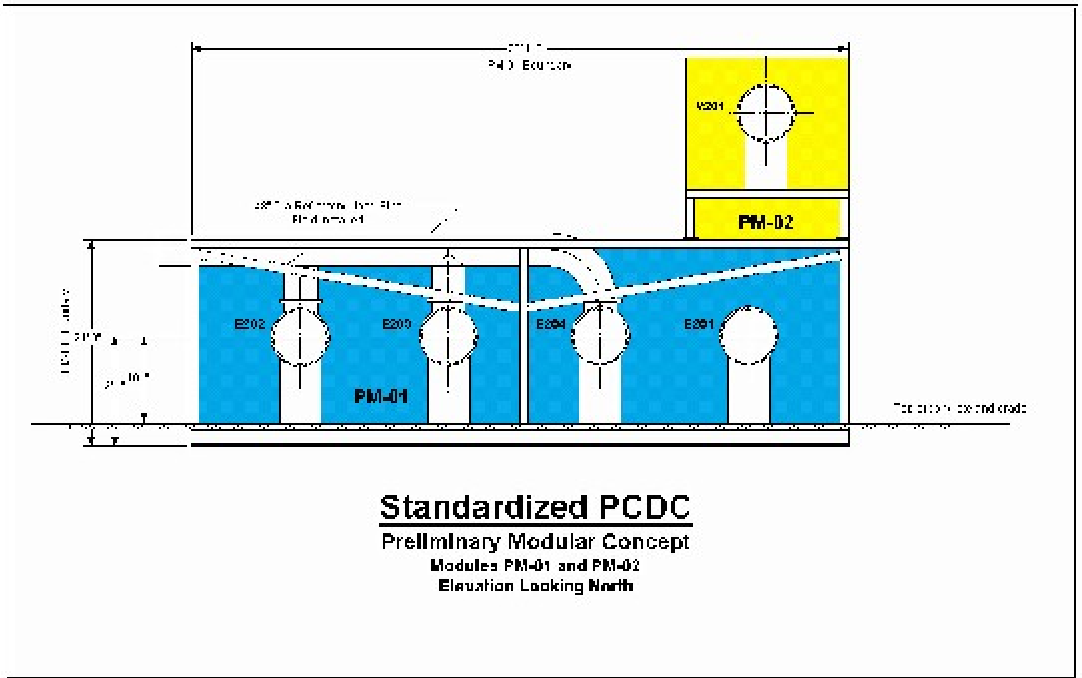


Figure 6-3 Modular concept

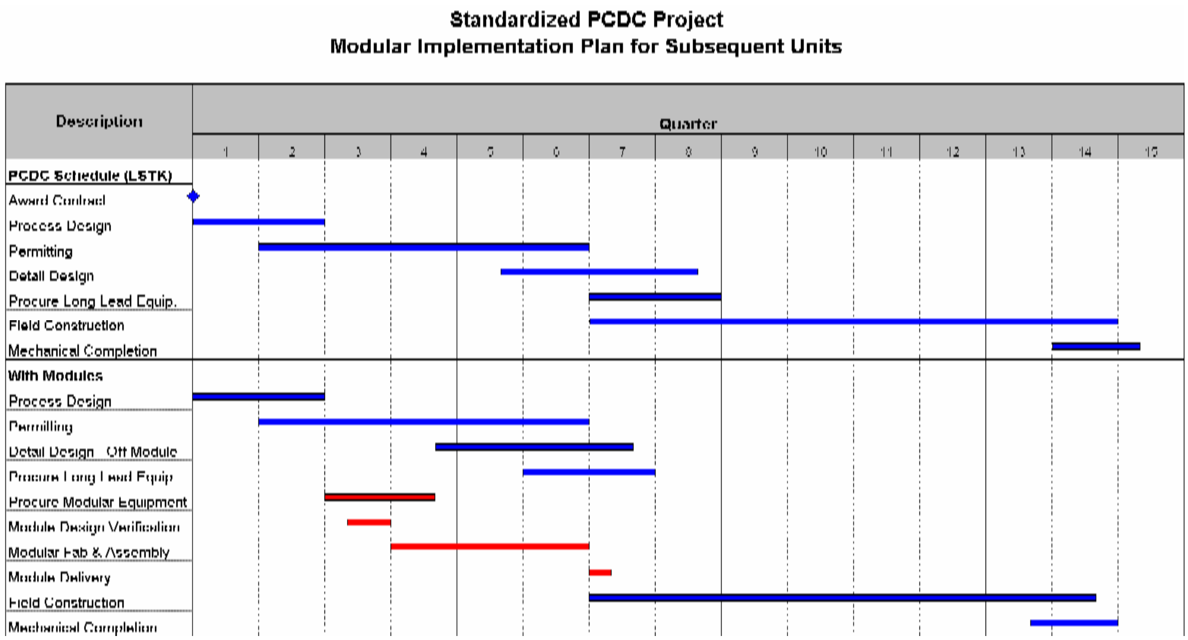
6.2.3 Schedule Analysis

Implementing a standardized modular construction approach can have a positive impact on the project schedule. On subsequent units, the design duration can be significantly reduced for the module scope of work, with the primary engineering effort centered on the site specific civil and foundation requirements and on verifying that the module structure meets the local design criteria.

For the first system, there will be some additional design and coordination efforts that must be closely evaluated. The biggest issue will be in finalizing design of the main pipe rack. Typically, piping design of the central distribution rack will be one of the last piping areas that is completed due to the traditional approach of locating tie-in points after the off-rack piping design is complete. This rack, however, is important to have in place prior to setting equipment in order to facilitate piping installation. For this rack to arrive in time on the first project, it will be necessary to use a design approach that fixes the rack tie points earlier. This may be achievable by using a contracting approach other than Lump Sum Turn Key (LSTK) on the first system, which would allow for detail design to start earlier than indicated on the baseline schedule shown below. In a worse case scenario, it may be necessary to stick build the module frames for the main rack on the first system. On subsequent projects, the rack modules would be fully assembled, shipped, and set prior to the equipment arriving on site. This early completion of the main rack will allow for earlier installation of the long lead equipment.

The time required to get a construction permit can have a significant impact on the project schedule. The permitting duration becomes more important once the design is standardized, because there will be an opportunity to either start construction much earlier or else delay the project funding until later. Modularization will have a significant impact on projects where the permitting process is lengthy because construction can begin prior to permit approval. The modules will be ready for delivery to the site as soon as the foundations are completed.

In the baseline schedule shown below, there is a 15-month permitting cycle with a 24-month construction duration. Based on a total installed cost of USD 230 million, this project will require approximately 1 million craft hours to construct. Over a 24-month construction window, this averages out to 42,000 hours/month (63,000 hours/month at the peak). As is discussed later in the cost analysis, the modular scope of work is estimated to represent approximately 71,000 hours. Based on this information it is expected that moving this work off-site will result in at least a 1-month shorter construction schedule. This shorter schedule is supported and may be further compressed through earlier order & delivery of the field set equipment. If schedule reduction is not the primary concern, moving this work off-site will result in reduced craft staffing levels at site or can be used to offset schedule related risks (weather, late deliveries, labor shortages, etc.).



6.2.4 Cost Analysis

There are a number of factors to consider when evaluating the cost impact of implementing modular construction. The results of the analysis vary significantly depending on variables such as the plant location, module fabricator's site, local labor costs, labor availability, and issues that drive craft labor productivity. For purposes of this analysis, two possible jobsite locations within the United States are compared. The Gulf Coast region represents a lower cost labor market with mild weather, greater availability of skilled craft labor, and relatively high worker productivity. The Northeast region represents a higher cost labor market with greater seasonal weather impacts and lower labor productivity. The lower craft wage rates and greater labor availability in the Gulf Coast region yields the lowest cost benefits for modular construction. However, regardless of the region in which it is constructed, field construction projects have less cost predictability.

Labor Productivity

One of the more significant cost impacts results from labor productivity improvements that are gained by moving the work to a more controlled manufacturing shop environment. Building modules at grade and out of the weather can result in productivity improvements ranging from 5-20% depending on the project type and site location. Given that only a portion of this project requires work to be done in an elevated situation, the productivity improvement is expected to range from 5% in the Gulf Coast to 15% in the Northeast.

An adequate supply of motivated and adequately skilled craft labor in the vicinity of the plant can have a compounding impact on this productivity comparison. These labor conditions are unique for each job site and should be considered separately for each site. Craft worker productivity has been seen to swing widely in some parts of the United States and even more so in some less developed countries.

When a design has been standardized, there is a potential for additional craft labor productivity improvements when fabricating multiple units. Improvement in craft labor productivity is very dependent on the actual timing of each project release as well as on the use of a consistent, dedicated craft force. In a situation where these conditions are met, a 5-15% productivity improvement is expected in subsequent units over the first. In addition to productivity improvements, it is expected that utilizing the same modular workforce from project to project will also result in improved quality (less rework).

Region	**Weather & Elevation**	**Site Location Specific**	**Duplicated Multiple Units**
Gulf Coast	5-10% (use 5%)	Assigned by client	5-15% (use 10%)
Northeast	10-20% (use 15%)	Assigned by client	5-15% (use 10%)

Table 6-2 Labor Productivity Improvement

Craft Labor Cost

The cost of labor in the Charleston Module Shop is roughly equivalent with the Gulf Coast Region where a journeyman pipe fitter earns approximately USD 18/hr as a base wage rate. When considering an “all-in” wage buildup, this Gulf Coast/Charleston labor will be approximately USD 50/hr. In the Northeast, this “all-in” rate can be USD 20-30/hr more than the Gulf Coast or even greater in some areas.

The current trend at field construction sites in the United States is to offer guaranteed overtime and per diem incentives in order to attract the required skilled labor. This can create an even greater wage gap between field construction labor and modular shop labor. It is our experience that these types of incentives are not typically required to attract labor at the modular facility.

Table 6-3 indicates a rough order of magnitude estimate of the number of craft hours associated with each module. Historical data from similar projects is used to approximate the number of hours. A more precise estimate of craft hours will need to be developed once the scope is more fully defined.

Unit	Module #	Approximate Module Size (LxWxH) (m)	Equipment In Module	Approximate Module Craft Labor Hours
100	PM-1	25 x 7.5 x 7.5	E201, E202, E203, E204	5,000
	PM-2	7.5 x 6 x 7.5	V201	2,000
	PM-3	10 x 7.5 x 7.5	E301A/B, E302	3,000
	PM-4	12 x 7.5 x 7.5	E303, E305A/B/C	3,600
200	PM-5	10 x 7.5 x 7.5	E402A/B/C	3,000
	PM-6	10 x 7.5 x 7.5	E401, E406, Spare	3,000
300	PM-7	10 x 7.5 x 7.5	E501A/B, Spare	3,000
Main PR	PR-1 thru 5	24 x 6.5 x 6.5		25,000
	PR-6	20 x 6.5 x 6.5		4,000
Minor PR	PR-7, 8	24 x 4 x 4		4,000
	PR-9	15 x 4 x 4		1,200
	PR-10	12 x 4 x 4		1,000
	PR-11 thru 16	24 x 4 x 4		12,000
	PR-17	15 x 4 x 4		1,200
			Total	**71,000**

Table 6-3 Craft cost

Design Standardization

Standardizing a modular design can have the benefit of eliminating some of the repeat design costs on subsequent units. The modular units are typically regarded as a pre-engineered package that can be placed at any site. It may be necessary to modify the structural design if the plant site is in a high wind or seismic zone, but a significant portion of the design can usually remain intact. Using worst-case design assumptions in the standardized design can reduce this design effort even further.

A project of this type could be expected to have a cost breakdown as follows:

Account	**% of Total Installed Cost (TIC)**
Equipment	30-35%
Materials	20-30%
Labor	20-30%
Design	12-15%

In a project cost breakdown like this, design represents approximately 50% of the cost of labor. In the following analysis it is assumed that 60% of the design costs associated with each block of work can be eliminated on repeat units.

Multiple Unit Discount

One advantage of using modular construction is that it permits you to establish buying power with a fabricator when offering multiple units. The business plan for this process is expected to be 5 units/year for the first five years and 10 units/year for each year thereafter. The module fabricator's material costs will be relatively fixed for multiple units, but a 5-10% reduction in the labor component of the module costs could be expected for multiple orders. For purposes of this cost analysis a 5% labor cost savings is used.

Scaffolding

An additional savings with modular construction is the elimination of scaffolding. Because modules are built at grade, most of the work is conducted from the floor or off stepladders. The need for scaffolding is significantly reduced and is therefore recognized as a project savings. Scaffolding on a typical field construction project will represent approximately 8-12% of the overall direct labor cost. Some scaffolding will be required with the modules at the site in order to complete the module interconnects. For this analysis a 50% reduction in the required scaffolding for the module scope is used.

Other Owner Costs

Often there are costs that the owner incurs during construction efforts that may not be fully reflected as a part of the project indirect costs. These costs can include items such as the need for additional parking, utility consumption, plant security concerns, plant involvement in construction planning and issuing work permits, operator oversight when working around existing operations, etc. These costs are significantly a function of the amount of work that must be completed on site. As labor is moved off-site, the owner will experience a reduction in many of these un-recovered costs.

Additional Steel

Modularization will require more steel to be used than in a conventional construction design. In the case of pipe racks, there is only a small incremental increase in the steel required (5-10%). This steel is mostly in the form of additional bracing. Where exchangers located at grade are packaged on a modular shipping frame, approximately 80% of the module steel is additional cost to the project, because it would not otherwise be required (the remaining steel would be required for pipe supports). Table 6-4 below indicates the estimated additional steel required for the modules.

Unit	Module #	Approximate Module Size (LxWxH) (m)	Equipment In Module	Approximate Additional Steel (tons)
100	PM-1	25 x 7.5 x 7.5	E201, E202, E203, E204	27
	PM-2	7.5 x 6 x 7.5	V201	11
	PM-3	10 x 7.5 x 7.5	E301A/B, E302	8
	PM-4	12 x 7.5 x 7.5	E303, E305A/B/C	22
200	PM-5	10 x 7.5 x 7.5	E402A/B/C	8
	PM-6	10 x 7.5 x 7.5	E401, E406, Spare	8
300	PM-7	10 x 7.5 x 7.5	E501A/B, Spare	8
Main PR	PR-1 thru 5	24 x 6.5 x 6.5	Field erect air coolers	15
	PR-6	20 x 6.5 x 6.5		3
Minor PR	PR-7, 8	24 x 4 x 4		2
	PR-9	15 x 4 x 4		1
	PR-10	12 x 4 x 4		1
	PR-11 thru 16	24 x 4 x 4		7
	PR-17	15 x 4 x 4		1
			Total	**122**

Table 6-4 Additional steel

Module Shipping and Erection Cost

Module shipping costs can vary significantly depending on the location of the module fabricator, site location, distance from ship/barge offloading area, and obstructions or restrictions in over road transit. For this analysis, the shipping cost based on delivery of three barges from the Jacobs Charleston, SC facility to a site with water access in the Gulf Coast of the United States is estimated. These costs are only intended to be for a high level evaluation and should in no way represent a standard cost or percentage for any project. In addition to the shipping costs, there are some additional costs associated with preparing the modules for shipment. The costs estimated in this analysis accounts for this basic shipping preparation.

Module erection costs are greatly impacted by site-specific issues (labor costs, site restrictions, etc.) and the erection plan (schedule, sequence, etc.). It is expected that on a project of this size, adequately sized cranes would already be mobilized on site. Crane mobilization costs can also impact the module erection costs. In order to fully evaluate this cost, it is necessary to investigate the specifics for each project.

Activity	Quantity	Approximate Cost
Load Out	24 modules	USD 400,000
Barge Transit	3 barges	USD 900,000
Offload/Transport to Site	24 modules	USD 600,000
Erect Modules	24 modules	USD 600,000
	Total Cost:	**USD 2,500,000**

Design & Coordination Costs

For the first system, there are additional design and coordination costs that warrant consideration. These costs are primarily associated with the additional structural design requirements as well as the management and coordination required with a second construction site. These costs are expected to result in a 20% increase in design costs. After the initial effort required for designing and constructing the first unit, additional coordination costs will be minimal on subsequent projects.

6.2.5 Cost Summary

Using the information discussed above, the possible cost impact when implementing modular construction is developed.

Table 6-5 reflects the cost analysis for a first time implementation. In this scenario there is no savings from productivity improvements on repeat units or design standardization and there is a first time design/coordination cost impact.

Table 6-6 considers the additional cost savings from constructing subsequent units from additional labor productivity improvements as well as from reduced design costs. The following is a summary of the assumptions used in this cost analysis:

Category	**Basis**
Modular Scope Craft Hours	71,000 hours
Productivity Improvement	
Gulf Coast	5%
Northeast	15%
Multiple Units	10% additional
Craft Labor Cost (all-in rate)	
Gulf Coast/Charleston	USD 50/hr
Northeast	USD 75/hr
Design Standardization	60% reduction in engineering
Multi-Unit Discount	5% on labor

Scaffolding Reduction	5% of labor cost
Additional Steel	122 tons
Module Shipping/Erection Cost	USD 2,500,000
First Time Design & Coordination	20% increase on design costs

	Gulf Coast Region	**Northeast Region**
Savings		
Shop Conditions Productivity = (site labor rate) x (module craft hrs) x (prod. diff.)	(USD 180,000)	(USD 800,000)
Repeat Project Productivity = (site labor rate) x (module craft hrs) x (prod. diff.)	N/A	N/A
Cost of Labor Differential = (labor differential) x (module craft hrs)	USD 0	(USD 1,780,000)
Design Standardization = (module craft hrs) x (site labor rate) x 0.5 x 0.6	N/A	N/A
Multi-Unit Discount = (module craft hours) x (module labor rate) x (0.05)	N/A	N/A
Scaffolding Reduction = (module craft hrs) x (site labor rate) x 0.05	(USD 180,000)	(USD 270,000)
Value of Delayed Construction Start or Early Completion	Client Assigned	Client Assigned
Other Owner Costs (e.g. site security, utilities, parking, work permitting, site coordination)	Client Assigned	Client Assigned
Added Costs		
Additional Steel Cost = (additional steel tonnage) x USD 3,000/ton	USD 360,000	USD 360,000
Shipping & Erection Costs	USD 2,500,000	USD 2,500,000
First Time Design & Coordination = (module craft hrs) x (site labor rate) x 0.5 x 0.2	USD 350,000	USD 350,000
Total Cost Impact	**USD 2,850,000**	**USD 360,000**

Table 6-5 First time implementation

	Gulf Coast Region	Northeast Region
Savings		
Shop Conditions Productivity = (site labor rate) x (module craft hrs) x (prod. diff.)	(USD 180,000)	(USD 800,000)
Repeat Project Productivity = (site labor rate) x (module craft hrs) x (prod. diff.)	(USD 350,000)	(USD 530,000)
Cost of Labor Differential = (labor differential) x (module craft hrs)	USD 0	(USD 1,780,000)
Design Standardization = (module craft hrs) x (site labor rate) x 0.5 x 0.6	(USD 1,000,000)	(USD 1,000,000)
Multi-Unit Discount = (module craft hours) x (module labor rate) x (0.05)	(USD 180,000)	(USD 180,000)
Scaffolding Reduction = (module craft hrs) x (site labor rate) x 0.05	(USD 180,000)	(USD 270,000)
Value of Delayed Construction Start or Early Completion	Client Assigned	Client Assigned
Other Owner Costs (e.g. site security, utilities, parking, work permitting, site coordination)	Client Assigned	Client Assigned
Added Costs		
Additional Steel Cost = (additional steel tonnage) x USD 3,000/ton	USD 360,000	USD 360,000
Shipping & Erection Costs	USD 2,500,000	USD 2,500,000
First Time Design & Coordination = (module craft hrs) x (site labor rate) x 0.5 x 0.2	N/A	N/A
Total Cost Impact	**USD 970,000**	**(USD 1,700,000)**

Table 6-6 Multi-Unit Implementation

Additional Cost Risk

An IPA study, presented at the Industrial Benchmarking Conference in 2001, stated that modular projects have better cost predictability. This supports our findings, as well as information received from our clients. In fact, some clients have indicated to us that they commonly experience 10-20% cost growth on stick build construction projects. Better cost predictability with modular construction results largely from the fact that modular design must be fixed early, discouraging ongoing design changes, and because work is performed in a controlled environment. Modularization will not eliminate the potential for cost growth but will minimize it. For purposes of this risk analysis a 5% differential in cost growth between modular and stick build construction is used.

Because the same equipment is used in both modular and stick build projects, the difference is concentrated in the labor and materials. On a project like the one analyzed in this study, the labor and materials make up approximately 50% of the total project cost. This tells us that the cost growth risk for labor and materials on stick build construction would be 10% (=5%/0.5) greater than the value of the module labor and materials. Given the scope of work that would be modularized, the following cost growth risk could be avoided.

Approximate Value of Module Labor & Materials	USD 7,000,000
Cost Growth Risk Factor	x 0.10
Cost Growth Risk Avoidance	USD 700,000

6.2.6 Safety Consideration

An important evaluation criterion for modular construction centers on safety. Work at site will involve exposure to weather, elevated work, and often require working around an operating plant. Because the majority of modular manufacturing is performed at grade and in a controlled environment, it is inherently safer. Moving craft hours off the site will also serve to reduce craft density and further improve site safety.

6.2.7 Summary

The PCDC Process does have the potential for modular implementation. Equipment sizes necessitate the use of modules that exceed standard truck shipping limits but that fall within the size of other equipment that must be transported to site. Estimated to remove approximately 71,000 hours from the field, modules will represent less than ten percent of the overall craft labor required on site. This results in limited impact on the schedule but serves to provide some schedule and cost risk avoidance.

The PCDC design is not expected to produce cost benefits on the first implementation unless the wage rate and productivity differences between the module shop and field construction site are significant. The greatest cost benefits will be recognized once the design is standardized and multiple units are constructed using the same module manufacturer. This analysis indicates that under all circumstances it is a cost benefit to modularize only when there is a differential in labor cost and productivity.

The single largest factor that adds cost to the modular approach is in the cost of transporting and erecting the modules on site. These costs can vary significantly depending on the relative location of the module shop to the project site. For this reason a more detailed study of this cost component may be warranted for each project site.

The decision on whether or not to use modules in a standard design should be carefully weighed for future flexibility. Standardizing on a modular approach does not preclude the use of stick build construction on sites that will not benefit from a modular approach. It is possible to simply field construct the modules at site where off-site manufacturing is not warranted. Conversely, it is not possible to easily switch to modular, once a stick build standard has been established, without considerable redesign.

Given this analysis, a reasonable approach would be to standardize on a modular design but only implement modular construction where the cost parameters are favorable. At a production rate of 5-10 units/year it is perceived that a sufficient number of these projects would warrant a modular approach and could reap the cost benefits demonstrated in the multi-unit implementation analysis.

6.3 STANDARDIZATION, REPETITIVE DESIGN AND IMPLEMENTATION

Experiences within Stork GLT, a consortium of five partners Jacobs (Design), Stork Industry Services (Construction), Yokogawa (Instrumentation and Automation), Siemens Demag Delaval Turbumachinery (Compressors), Siemens (Electric drives), renovating 29 gas production clusters, including installation of large compressor units (> 20 MW), with a total investment cost per cluster of approximately USD 45 million, showed the opportunities of reducing the TIC (Total Installed Cost) as a result of standardization, repetitive design and implementation. In order to benefit optimally from the repetitive character of the project the following items have been identified:

- Include 'lessons learned' from the first unit.
- Development of a generic design: large parts of the project are identical. This is called the generic design. Other parts of the design differ from one location to the other (examples are soil structure and impact on the civil design, CO_2 export facilities and location). These items are called the specific design.
- Optimizations: based on the design of the first project identified optimizations have to be worked out. Optimizations have to be evaluated based on Total Cost of Ownership, not only focusing on TIC. Apart from TCoO savings, also additional functionality to improve overall performance of the project shall be part of the evaluation. Examples of TIC reduction are: rerouting of lines to prevent bends, combining the control building and the electric building into one, modularize systems such that these can be transported over the road instead of constructed on-site.
- Fit for purpose: Restrictive specifications limit the design and equipment alternatives and leave little latitude for the contractor and equipment suppliers to challenge the design in respect to quality, cost and functionality. Conversely functional specifications foster contractors and equipment suppliers to consider alternative solutions, which may be more economic from a Total Cost of Ownership (TCoO) perspective.

For the type of power plant concerned for this study the above-mentioned approach is already used. Based on a functional specification the contractor will design and construct the plant within the applicable functionality (i.e. capacity, availability, reliability, flexibility, maintainability, etc.) in line with the local and national regulations and the normal applicable standards. This will result in a plant, which meets all requirements, for the minimum cost. However for this type of plant this approach developed in principle itself (i.e. manufacturer driven) as the plant is based on an already standardized equipment component (i.e. the gas turbine), which determines the overall design. For a combined cycle unit based on a GE Frame 9FA in 1996 of approximately 350 MWe the specific budget price was approximately 480 USD/kWe (Gas Turbine World). In 5 years this specific budget price decreased to 400 USD/kWe for a 390 MWe plant (Gas Turbine World). This price reduction is caused by a combination of repetitive business/standardization and economy of scale. Roughly correcting the specific prices of the combined cycle plant for inflation and economy of scale a price reduction of approximately 20 % has been achieved because of repetitive business/standardization. The specific cost for a standardized gas turbine reduced with approximately 10 % (The specific budget price of a GE PG9171E Simple Cycle gas turbine of approximately 125 MWe was approximately 180 USD/kWe in 1991 (Gas Turbine World). In 10 years the specific budget price for this gas turbine increased to 210 USD (Gas Turbine World ; price increase of 17%). When correcting this budget price for inflation and design modifications (i.e. DLN combustion system) a price reduction of approximately 10 % is obtained.)

For a PCDC plant a similar approach is possible when the PCDC contractor will be free to design and construct the plant on a functional specification. Based on the available technology suppliers for the reformer system there may be a parallel development of a number of concepts. This will be a proper development as this means a competitive environment, which will improve the striving for a lowest overall cost concept.

As the PCDC plant is built next to the (existing) power plant as a separate plant all safety measures can be taken into account to minimize additional measures at the standard plant (e.g. change of area classification resulting in more severe requirements to the area and equipment/systems). Therefore it is expected that this item will not impose additional costs to the power plant. Within the design of the PCDC plant itself it shall be clear that special attention shall be paid to the location of the equipment and the area classification concerned to prevent special requirements resulting in a significant price increase (e.g. IEC system classifications Exd or Exe for air compressor units by location in 'unsafe' area). Within the preliminary design and cost estimate of the reference plant these items already have been taken into account and therefore no further cost reduction is expected.

6.3.1 Impact of standards to the equipment price

The impact of using different standards to the price of equipment has been assessed for rotating and static equipment. The assessment has been focused to compressor units and pressure vessels/heat exchangers as these equipment items are the basis of the PCDC plant.

Rotating equipment

Within the PCDC plant the large rotating equipment (air compressors, CO_2 compressor and steam turbine) are responsible for approximately 50 % of the Total Installed Cost (TIC) of the PCDC plant. To impose additional requirements to the manufacturers standard design will result in an increase of the equipment price. For rotating equipment especially API requirements may have a considerable impact. Price increases up to 30 % are possible.
However it appears that the equipment prices and a possible price increase because of additional requirements is very dependent on the manufacturer concerned in combination with the specific equipment service (i.e. fluid, pressures, turn down requirements, etc.) and capacity.
If the manufacturer has to offer equipment, which does not have an 'optimal' fit within the manufacturers standard available frame sizes this already may result in a significant higher price compared to a competitor with an 'optimal' frame size. Price differences up to 20 % are not unusual.

For rotating equipment in critical service without spare equipment to be suitable for a minimum service lifetime of 20 years and continuous operation with extended service interval the use of API standards in general is recommended.

Results of an evaluation executed for selecting several compressor units for refinery service are presented in Table 6-7. All manufacturers offered their standard design (i.e. fit for purpose) as well as a design in line with the clients API based standard.

	Equipment Price (relative to Man. 1)		
	Manufacturers standard	**Client standard**	**Price Change**
Manufacturer 1	100%	100%	0%
Manufacturer 2	97%	95%	-1%
Manufacturer 3	122%	141%	16%
Manufacturer 4	137%	170%	24%

Table 6-7 Equipment Prices

It becomes clear that the price difference between the manufacturers standard compressor units is already significant (ranging from –3% to +37%). The impact of the client standard also varies significantly per vendor and it can be noted that imposing the additional client requirements does not affect the equipment prices in a similar way. Manufacturer 1, which was the preferred vendor when supplying manufacturers standard, remains the preferred vendor when supplying the equipment according client standard. Manufacturer 4, which was already expensive with his standard design, becomes even significantly more expensive when supplying the equipment in line with the client standard. Manufacturer 2 even shows a price decrease for supplying client standard equipment, which is caused by the fact this manufacturer offers standard an expensive feature, which is not allowed according the client standard.

It shall be clear that additional scope related items (e.g. magnetic bearing systems and VSDS) might even have a larger impact on the equipment price. To evaluate the economic feasibility of these items a detailed case-to-case evaluation based on the total life cycle cost shall be performed.

Static equipment

Pressurized static equipment in the Netherlands shall be supplied according the European Pressure Equipment Directive (PED 97/23/EC). This directive allows the manufacturer (and client) to design, fabricate, inspect and test the equipment according one of the available national standards (e.g. Stoomwezen, AD Merkblätter, CODAP, etc.). The requirements of the codes concerned are similar and will therefore result in a similar equipment price.

In case of additional client requirements, specifically based on the ASME codes, there will be price increase for the temperature range up to approximately 300 °C as ASME considers a minimum temperature for the mechanical design calculations. The result is a more robust and heavier equipment. The final price impact is dependent on the size and pressure rating of the equipment. In general the price increase will be less than 10%.

Specific client requirement could also result in a price increase. These requirements could be to apply integrally reinforced nozzles instead of reinforcement rings in case of H2- or low temperature service or special construction details but also additional process design related requirements such as design allowances for design capacity, pressure and temperature.
The impact of these specific client requirements may vary between 0 up to a maximum of 30% of the fit for purpose equipment price.

The cost estimate for the PCDC plant has been based on fit for purpose equipment without adjustments for special requirements, which do ‘not’ contribute to the overall performance of the plant.

6.3.2 Repetitive design

The resulting design is called the generic design and shall be applicable to all following projects. The first project is also called ‘First of a kind’, reflecting the approach of the project whereas the second project is called ‘first of a series’.

During the project execution, design shall be strongly focused on sticking to the generic design. There shall be a common understanding that reduction in TIC is to be realized in procurement and construction and not through reduction in design expenditure. Based on this the following focus areas for design have been identified to optimally achieve TIC savings:

- No Change Policy: minimizing changes within the design has several important results: Procurement is able to make long term agreements with suppliers, can negotiate better prices and has possibilities to improve quality, thus building a long term relation. Construction is able to re-use work packages but also to optimize the construction process in the field as the design is always the same. An example is the re-use of formworks. Another important aspect is that the inevitable mistakes made during construction can be minimized. Also returning issues that consume time and money can be addressed and thus be prevented during following clusters.
- For specific specialized equipment (e.g. air compressor unit) it is advised to have an agreement with one manufacturer to maximize the advantage of standardization and limit the engineering, purchasing and construction efforts. For standard (static) equipment it will probably be beneficial to use local manufacturers as production cost may be significantly lower and the impact to the generic design will be marginal.

  In case of continuous competition there will be a high unpredictability of design, schedule and the project cost, which will be mainly driven by the actual market situation. In the end it is expected that the proposed approach will result in a consistent design, tight schedule, best safety track record and the lowest overall cost on an average weighed basis.
  - Construction driven design: Improvement proposals leading to design changes to be mainly based on improving constructability. An extensive impact assessment to be carried out before implementing changes within the generic design. A Change Board with all relevant partners to review the impact assessment and to decide whether to implement the change or not. Criteria for implementation to be known throughout all parties concerned. Modular design and construction for several items to be considered.
  - Focus of the design team on quality of the design documents and planning compliance.

6.3.3 Cost reduction through standardization, repetitive design and implementation

Based on the above mentioned project approach the following cost reductions could be achieved:

- Engineering man hour cost	75%
- Procurement man hour cost	40%
- Construction man hour cost	20%
- Equipment + material cost	12%

When taking into account the above-mentioned percentages for the PCDC cost estimate (reference is made to appendix 10) the following cost reductions are expected:

-	Total equipment	*	7.0 mln USD	(12%)
-	Total commodity materials	*	3.4 mln USD	(12%)
-	Total subcontracts		10.9 mln USD	(20%)
-	Total HOSCM services	**	13.0 mln USD	(51%)
-	Total cost reduction of " Bare" cost estimate		34.3 mln USD	(21%)

* A similar reduction is applicable for all equipment/materials concerned.

** The home office engineering can be split up in approximately 85% engineering man hour cost and 15 % procurement man hour cost. The reduction of procurement man hours is less than the reduction for engineering man hours because certain time consuming aspects of the procurement process can not be reduced further (e.g. follow up of vendors and inspections).

An ultimate overall cost reduction of the TIC of approximately 15-20% is expected. It shall be clear that this approach is not driven by a reduction of the Design expenditure and TIC but mainly driven on a reduction of the TCoO. In chapter 8, Economic analysis, this issue will be discussed further.

In the graph below the cost reduction as a function of the number of units is presented.

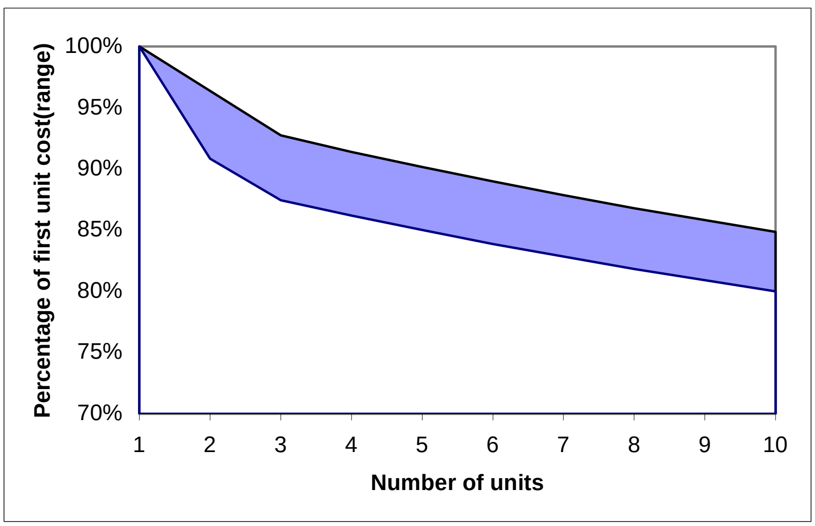


Figure 6-4 Cost reduction of multiple units

6.4 CAPACITY

The capacity of the reference fuel plant has been designed for the base load fuel consumption of the power plant at the yearly average ambient conditions. However changing ambient conditions has an impact on base load performance and fuel consumption of the gas turbine. With a fixed control setting the fuel consumption will increase with a decreasing ambient temperature.

Based on the starting point that the PCDC power plant is a base load installation, the following operating modes are available:

a. Control the fuel gas quantity to the power plant by reducing the capacity in case of ambient temperatures above 9°C and supply additional natural gas into the fuel gas (or dual fuel firing) in case of ambient temperatures below 9°C.

b. Control the fuel gas quantity to the power plant by reducing the capacity in case of ambient temperatures above 9°C and operate at a reduced load (i.e. fuel gas capacity PCDC plant) in case of ambient temperatures below 9°C.

By changing the design capacity of the plant the operating envelope for supplying additional natural gas (or load reduction) will also change.

For the sensitivity analysis a PCDC plant with a capacity varying between 100% and 50% of the reference plant capacity is evaluated. The evaluation is based on the average ambient conditions. The required fuel input to the gas turbine will be matched by supplying natural gas in addition to the fuel gas of the PCDC plant.

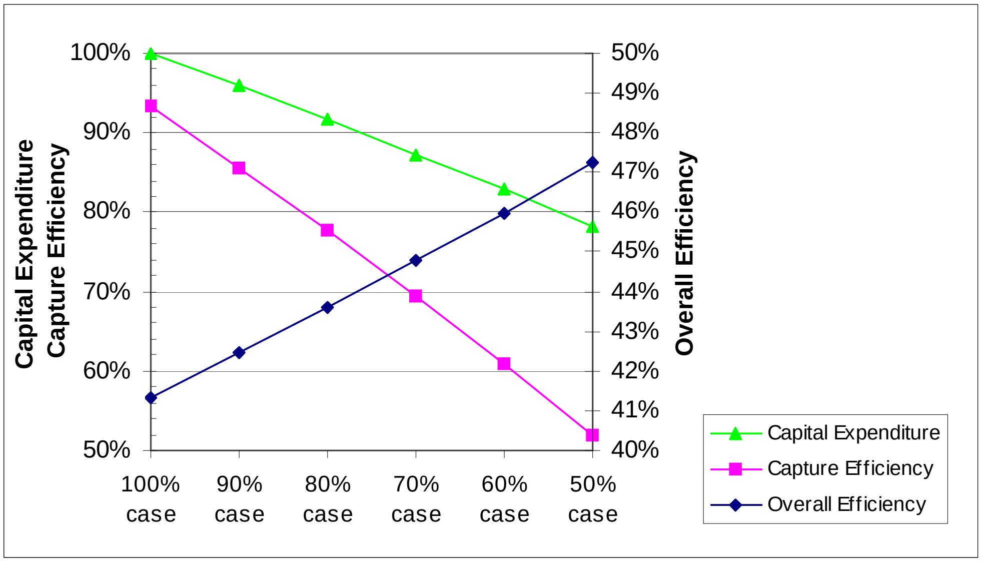


Figure 6-5 Sensitivity to capacity

Figure 6-5 shows the results from sensitivity analysis on fuel plant capacity decrease and natural gas bypass to the gas turbine in the power plant.
Influence of capital expenditure is calculated by using a scale factor.

6.5 APPROACH BRAINSTORMING MEETING

For the brainstorm meeting the following approach has been taken:

Available documents:

- Process Flow Diagrams reference PCDC plant
- Simple lay-out
- Performance data
- Preliminary OPEX and CAPEX data

Starting points:

- Power plant capacity (400 MW_e)
- Minimum integration fuel plant – power plant
- Proven and reliable equipment/design
- Reformer type (ATR)
- Fuel gas specification
- CO_2 specification

- Overall efficiency (± 42% as a minimum)
- CO_2 capture efficiency (± 85% as a minimum)

To enable an efficient brainstorm process the PCDC plant has been split up in the following five (5) functions:
Conversion of natural gas to syngas (air compression, gas treatment, ATR)
Conversion of CO to H_2
CO_2 removal
CO_2 compression
Utilities

For each function a separate brainstorm session has been executed. After identification of the possible cost reduction elements per function a ranking took place to identify the most promising cost reduction elements (See appendix 9).

Jacobs Consultancy evaluated the items raised during the brainstorm meeting with the highest ranking. As a result of the evaluation it was decided to modify the reference PCDC plant for the following issues:
Different set-up of heat exchangers downstream ATR to obtain lower metal temperatures (i.e. minimize risk of metal dusting)
Delete by-pass CO_2 removal system (use of steam injection for NOx reduction if required)
Decrease steam turbine extraction pressure for deaeration (3.5 bara)
Increase demin water temperature to 95°C (reduction duty air cooler and steam consumption deaerator)

For the revised reference plant the following sensitivity analyses regarding the investment and operating cost will be executed:

1. Pressure drop PCDC plant / supply pressure to power plant (approximately 20 – 30 bar)
2. Steam / Carbon ratio (approximately 1 – 1.8)
3. CO_2 capture efficiency
    a. Natural gas bypass
    b. Only HT shift reactor
    c. Single stage CO_2 removal system
4. More efficient use of high temperature heat
    a. Increase maximum tube wall temperatures
    b. Additional fuel gas heating (up to 300°C)
5. Fuel gas saturation
6. CO_2 quality (e.g. no dryer package; no after cooler)
7. Integration of gas turbine air compressor with reformer air compression system
8. Combining steam turbine and compressor(s)

Note:

1) The items raised during the brainstorm meeting, their individual ranking and the evaluation of the most promising items raised is presented in appendix 9

2) A fully integrated PCDC / power plant (i.e. integration of air compression, water-steam cycle and utilities) will result in the installation with the highest efficiency and the lowest cost of investment. It shall be clear that in this case the design of the power plant shall not be in line with a 'standard' power plant and therefore this optimum configuration will only be possible when this is a starting point for the design of both PCDC and power plant. When installing a PCDC plant next to an (existing) standard power plant, as is the starting point for this study, the 'maximum feasible' integration will be limited to integration of air compression.

3) *For the sensitivity analysis only one parameter will be varied per analysis*.

6.6 PRESSURE DROP PCDCPLANT/BATTERY LIMIT PRESSURE

Both the pressure drop over the PCDC plant and the supply pressure of fuel gas at the battery limit of the power plant have significant impact on the overall performance and cost of investment. This impact is mainly caused by the reduction of air compressor capacity as a pressure (drop) reduction will result in an increased volumetric flow / size (i.e. cost) of the static equipment/piping.

The design of the reference case has been based on the following:

- Fuel gas supply pressure at battery limit power plant 30 bara
- Feed pressure PCDC plant 40 bara

The fuel gas supply pressure to the gas turbine is depending on the gas turbine requirements. A supply pressure of 30 bar is selected as it is assumed this pressure meets the requirements of all the available gas turbine manufacturers. However it may probably be possible to optimize (i.e. reduce) the supply pressure in consultation with the gas turbine manufacturer(s). Based on the Jacobs experience with the Demkolec IGCC unit in Buggenum a minimum supply pressure of approximately 21 bara may be possible.

The sensitivity analysis will be based on the following starting points:

- Fuel gas supply pressure at battery limit power plant 21 bara
- Feed pressure PCDC plant 30 bara

First compressor stage pressure ratio is adjusted in order to lower outlet pressure from 40 to 30 bar. Changing the pressure ratio of the first compressor stage does not influence air temperature to the ATR. Net power output increases by approximately 6.5 MW_e due to a decrease of air compressor power consumption and a reduced MP steam level (i.e. increase of steam turbine output).

The overall CAPEX will increase with approximately 13 mln USD as a result of the cost increase due to the increase of dimensions compensated for the reduced pressure.

Note
It shall be noted that Mitsubishi Heavy Industries (MHI), one of the possible gas turbine manufacturers, claimed a minimum fuel gas supply pressure of 30.4 barg for low BTU applications. The compressor ratio of an Alstom GT26 gas turbine is even approximately 30. Therefore the minimum fuel gas supply pressure for this gas turbine is expected to be even 35 barg or higher. Therefore the option for a reduced fuel gas supply pressure at the battery limit seems only feasible for the General Electric Frame 9 and Siemens V94.3 gas turbines. However also GE stated a fuel gas supply pressure of approximately 32 bar for this application.

6.7 STEAM/CARBON RATIO

The S/C (Steam/Carbon) ratio for the reference case is approximately 1.8, which is based on experiences with catalyst provided by ICI. As there are technology suppliers claiming a high conversion with a significant lower S/C ratio, the impact of operating with a S/C ratio of 1.4 and 1.0 have been studied.

The results of the sensitivity analysis are presented in Figure 6-6.

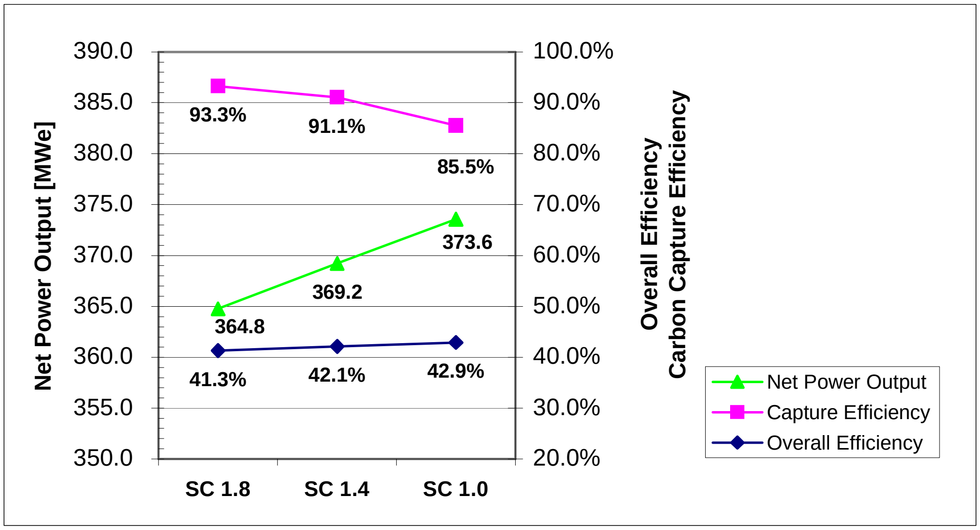


Figure 6-6 Sensitivity to S/C ratio

It becomes clear that reducing the S/C ratio of 1.8 to 1.0 will result in an increase of the net power output of approximately 9 MW_e in combination with a reduction of the natural gas consumption of 1.3%. The overall efficiency will consequently increase with 1.6% point to 42.9%.

The impact on the CAPEX is considered negligible. Because of the lower S/C ratio it is expected that the lifetime of the catalyst will be reduced with 20%. The resulting increased operating costs will be taken into account in the economic calculations.

6.8 CO_2 CAPTURE EFFICIENCY (COMBINED WITH CAPACITY)

The CO_2 capture efficiency in combination with the overall plant efficiency (i.e. avoided CO_2 emission) may have a significant impact on the overall economical performance of the plant. The following three (3) cost reduction elements have been identified related to the CO_2 capture efficiency:

1) Natural gas bypass
2) HT shift reactor only
3) Single stage CO_2 removal

1. Natural gas bypass

Using a natural gas bypass is similar to a PCDC plant with a reduced capacity. Reference is made to section 6.7.

2. HT shift reactor only

Eliminating the LT Shift Reactor from the flow scheme increases the overall efficiency of the plant to 80.2%, however the carbon efficiency of the plant drops below the minimum target 85% to 78.4 %. With similar heat input to the gas turbine the natural gas consumption decreases by approximately 1.0% and the net power output increases with approximately 3 MW_e by a reduced CO_2 compressor power consumption.

This option will have a cost reduction of approximately 9.5 mln USD because of deletion of the LT shift reactor system and the reduced CO_2 removal/compression capacity.
There is also a reduction of the cost for catalyst.

3. Single stage CO_2 removal

The use of a single stage CO_2 removal unit with no flashes increases the specific energy of the removal unit of CO_2 absorbed significantly. For the CO_2 removal a significant amount of additional LP steam will be required. For the analysis it is assumed this LP steam will be supplied by an additional natural gas fired LP steam boiler. The number of pressure vessels required however reduces from 7 (with column ID ranging from 3.7 - 8.3 m and T-T length from 8 - 40 m) to 3 (with column ID ranging from 5.5 - 7.6 m and T-T length from 8 - 30 m), which will result in a significant cost reduction. This option will therefore result in an overall cost reduction of approximately 15 mln USD in combination with a reduced overall efficiency.

Note:
As an option LP steam supply from the steam turbine within the PCDC plant and/or the power plant is possible. This alternative will have a better performance and could be considered if this option appears to be feasible.

6.9 EFFICIENT USE OF HIGH TEMPERATURE HEAT

The (more) efficient use of high temperature heat (i.e. minimum pinch) would increase the overall plant efficiency. However presently there are limitations with respect to proven materials/design available to utilize the high temperature heat at the outlet of the reformer in the most efficient way (e.g. because of metal dusting problems too high tube wall temperatures to be avoided).
Within the design of the reference plant the two (2) following items have been identified which will result in a more efficient use of the heat.

- Increase maximum tube wall temp.
- Additional fuel gas heating

6.9.1 Increase maximum tube wall temperature

The increase of the maximum tube wall temperature is considered to be an option which will be available in due time when there is more experience with high temperature resistant alloys in the environment concerned. Certainly in case a considerable number of similar plants will be realized, this will be a drive for development of materials/equipment resistant to the metal dusting problem. At this moment there are already developments showing the presence of materials with a good resistance to metal dusting.

The reference case is already based on relatively new developed materials (reference is made to appendices 3 and 4) with a high metal dusting resistance, as in the opinion of Jacobs this material will be sufficiently proven prior to realization of the first PCDC plant.

To present the impact of a more conservative approach by limiting the tube wall temperature (< 535°C) the following main modifications to the design are applicable:
- Natural gas temperature outlet desulphurizer is approximately 350°C
- Fired heater (natural gas) to increase the fuel gas temperature inlet reformer to 580°C
- Increase of steam generating capacity and steam turbine capacity

Feeding the reformer with the reduced natural gas temperature could also be considered as an option. This will result in a higher natural gas feed flow to the reformer to compensate for the reduced heat input by the lower gas temperature.

The impact to the overall plant performance is:
- Increase of power output with approximately 12.5 MW_e
- Increase of fuel consumption with approximately 35 MW_{th}
- Decrease of overall efficiency with approximately 0.2 %-point
- Decrease of Carbon capture efficiency to 85.5%

The CAPEX will rise with approximately 8.5 mln USD, mainly because of installation of the additional fired heater and the larger steam turbine generator.

6.9.2 Additional fuel gas heating

Additional heating of the fuel gas is an option, which could be integrated anyhow. The maximum allowed temperature to be discussed with the gas turbine manufacturer concerned.

Heating the fuel gas to the gas turbine with process heat available will have a positive impact on the overall plant efficiency as this added heat can be considered as an increase of the heating value of the fuel. Based on experiences with similar low BTU gas fired gas turbines a maximum fuel gas temperature of 300°C may be acceptable. However MHI states a maximum acceptable fuel gas temperature of 200°C. GE in its turn accepts even a fuel gas supply temperature of 340 °C. To identify the cost reduction potential of fuel gas heating the following approach has been taken:

- An additional fuel gas heater upstream of the HT shift
- The gas temperature at the inlet of the HT shift will be kept constant (i.e. heat input for steam generation will be reduced; in case a concept with a lower HT shift operating temperature is selected an additional increase of the overall efficiency would be achieved)

As a result of the additional fuel gas heating the net power output will increase with approximately 9 MW_e with identical fuel input. This increase in power output is a result of a 21 MW_e increase of power plant output in combination with a reduction of the PCDC steam turbine generator output of 12 MW_e (i.e. the fuel gas heating is at the cost of steam generation). This finally results in a 1.1% point increase of the overall efficiency to 42.4%.

The CAPEX will even reduce with approximately 5 mln USD as the smaller steam generator in combination with a smaller steam turbine generator will be less expensive than the cost for the fuel gas heater and the high temperature fuel gas line/system to the gas turbine.

6.10 FUEL GAS SATURATION

Fuel gas saturation will have a positive impact on the overall efficiency, as it will make the use of steam injection on the gas turbine for NOx reduction superfluous while it is possible to saturate the fuel gas with available waste heat without reduction of the fuel gas temperature. Therefore the saturator will be located at the location of the product fuel gas heater. As the duty of the saturator system is (significantly) higher than the duty of the product fuel gas heater the temperature upstream the demin water heater will decrease but it will still be possible to achieve the maximum demin water duty. The final consequence is that also the fuel gas outlet temperature of the demin water heater will decrease, which will result in a reduced duty of the air cooled absorber feed cooler (heat discharged to atmosphere).

As a result of the fuel gas saturation the net power output will increase with approximately 1.6 MW_e with identical fuel input. This results in 0.2% point increase of the overall efficiency to 41.5%.

The installation of the separator system will balance with the cost for the gas-gas heater and therefore the impact to the CAPEX will be negligible.

6.11 CO_2 QUALITY

The reference CO_2 quality at the battery limit of the PCDC plant is:
110 bar @ 34°C @ 50 ppm water content

It is assumed for this analysis that the pressure will remain constant as this pressure will be required for transport/supply the CO_2 to the storage system. In case a lower pressure is acceptable this will of course have a positive impact on the CAPEX as well as the OPEX because of the reduction of compressor capacity.

In case a higher battery limit temperature is acceptable, a significant cost reduction could be achieved by deleting the aftercoolers (approximately 2 mln USD). However it shall be evaluated when studying the transport/storage system concerned if the higher battery limit temperature will result in a cost increase of the transport/storage system (i.e. larger pipe size, additional safety measures, etc.), which outweighs the above-mentioned cost reduction.

Allowing a higher water content in the CO_2 and deleting the absorber system will also lead to a significant cost saving (approximately 7.5 mln USD). However a proper evaluation of this issue is only possible if the design of the transport/storage system allows for the higher water content.

6.12 INTEGRATION GAS TURBINE AIR COMPRESSOR

Air extraction from the gas turbine compressor and compression of the air to 40 bar in a booster compressor is analyzed in order to estimate the influence on CO_2 cost per ton.

Extracted air has to be cooled before it can enter the booster compressor. The available heat is used to produce superheated LP steam, which is supplied to the LP section of the steam turbine. The possibility of supplying additional steam to the steam turbine has to be incorporated in the steam turbine design.

Air extraction from the gas turbine is limited because of compressor design, operation and control. Following calculations assume that the total amount of compressed air needed for the air blown ATR (100 kg/s) is extracted from the gas turbine.

With 100 kg/s hot air of 400°C a LP steam production of approximately 8.4 kg/s @ 372°C (4.6 bar) is achieved. Supplying this steam to the LP steam turbine will result in approximately 5 MW_e additional power output compared to air extraction without additional steam supply to the steam turbine. Gas turbine output decreases, resulting from additional air compression. Net power plant output, incorporating air extraction and additional steam supply, decreases from 416.5 MW_e with approximately 34.5 MW_e to 382 MW_e.

Air is cooled from 400°C to approximately 173°C before it enters the booster compressor, which compresses the air without intercooling from 15 to 40 bar. Booster compressor exit temperature is 355°C. Booster compressor power consumption is approximately 19 MW_e. Air compressor power consumption decreases from 53.5 MW_e also with approximately 34.5 MW_e to 19 MW_e.

This implies that net efficiency of the PCDC plant does not change because of the proposed changes. (Starting point is that the gas turbine fires 700.4 MW_{th} syngas in both cases.)

By using the gas turbine air compressor for supply of air to the reformer system via a booster system the CAPEX will be reduced with approximately 15.5 mln USD.

6.13 COMBINING STEAM TURBINE/COMPRESSOR (S)

Within the design of the reference plant the ATR air compressors (2 * 50% ; 2 * ±26 MW_e) and the CO_2 compressor (±18 MW_e) are equipped with dedicated electric motors, while the surplus of steam generated is supplied to a steam turbine generator (±35 MW_e), which is partly generating the electric power consumed by the PCDC plant.
Combining the steam turbine generator system with one (1) or more compressor systems may result in a significant cost saving. Besides the cost saving it will also have a positive impact on the overall performance.

It is assumed that the most significant option can be achieved by the following measures:

- Combine both 50% air compressor units to one (1) 100% compressor unit
- Single shaft design of the air compressor, the steam turbine and a ±20 MW_e electric motor for start-up (and control) of the air compressor

It shall be clear that the envisaged combined steam turbine – compressor train is not a standard package unit. However if it becomes clear that a considerable number of similar units will be built this option probably will become a standard package.

By implementing this option the net power output will rise with approximately 2 MW_e, due to reduction of power conversion losses, in combination with a reduction of the CAPEX with approximately 12 mln USD. Fuel consumption and carbon capture efficiency remain the same.

Note
It is assumed that also integrating the CO_2 compressor in the single shaft configuration will increase the complexity of design and operation, while additional cost saving are not expected. Therefore this option is not considered.
This option may-be feasible in case it is decided to use bleed air of the gas turbine compressor for the ATR. The power required for the booster compressor is significantly lower than the stand-alone compressor power consumption, which would allow for integration of the CO_2 compressor in the single shaft configuration as well.

7. CAPITAL EXPENDITURE

7.1 INTRODUCTION

To evaluate the economic feasibility of a PCDC plant in combination with a standard power plant it is required to have an overview of the capital and operational expenditures for all alternatives considered.
The capital cost figures of the 400 MW_e power plant, the reference PCDC plant and the alternatives to the reference PCDC plant have been based on the following general starting points:

- The processes to be assessed will be state-of-the art for construction in the year 2004.
- The plants will be assumed to be on the NE coast of the Netherlands, within 1 km of the sea (i.e. availability of seawater for cooling purposes and ship unloading facilities).
- A green field site with no special civil work implications will be assumed
- The plants will be built on a turnkey basis and are provided with all required (auxiliary) systems. The power plant and the PCDC plant both have dedicated auxiliary systems (i.e. minimum integration). Facilities and infrastructure required outside the plant limits, e.g. HV connection, fuel supply, transport and storage of CO_2, etc. are not included in the cost estimate.
- The power plant and the PCDC plant will not be realized simultaneously. It is assumed the PCDC plant is located next to the existing power plant.
- All cost figures are presented in USD (exchange rate used: USD/EUR = 1.2).

Besides the general starting points also the following specific cost estimating approach will be applicable:

Power Plant
The capital cost for the power plant will be based on actual cost figures from plants recently taken into operation and/or under construction. All costs with respect to the power plant will be presented as one total cost figure.

PCDC Plant
The capital cost for the PCDC plant will be based on actual cost figures for the individual equipment with an installation factor per equipment. The estimating department of Jacobs Nedrland B.V has executed the cost estimate. The individual equipment costs have been obtained by price calculation of the equipment based on the actual design information and price comparison with prices available of similar equipment. The installation factors, used for cost estimating, are based on the experience of Jacobs with similar units/processes. All costs with respect to the fuel plant are presented for the following main process functions:

- Conversion of natural gas to syngas (i.e. air compression, desulphurization, auto thermal reformer)
- Conversion of CO to H_2
- CO_2 removal
- CO_2 compression
- Utilities (cooling water, demin water, instrument air, power generation, control building, etc.)

Per function also the major cost item(s) as a percentage of the total function cost is presented in Table 7-2.

The estimated cost for integration of the PCDC plant with the power plant (e.g. modification of the gas turbine fuel gas system, start-up facilities, etc.) will be presented as a separate item.

The individual cost for all individual systems/activities such as individual equipment, auxiliary systems, civil, electrical, instrumentation, etc. will not be presented. To present an accurate cost overview for all individual systems/activities a great effort is required as this is only possible with a detailed break down per system/activity. As a (detailed) break down will not contribute to the aim of this study the above mentioned estimating approach has been followed.

The overall accuracy of the overall cost estimates is in the range of $\pm$30%.

For determining the overall project cost the following additional charges are applicable:

- A cost of 5% of the installed plant cost (overnight construction) will be assumed to cover land purchase, surveys, general site preparation, etc.
- A cost of 1% of the installed plant cost (overnight construction) will be assumed to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.
- A cost of 2% of the installed plant cost (overnight construction) will be assumed to cover fees in addition to the contractor's fees in addition to the contractor's fees for designing and building the plant.
- A cost of 10% of the installed plant cost (overnight construction) will be assumed to cover project contingency.

7.2 CAPITAL EXPENDITURE

A summary of the capital expenditure (excluding interest during construction) and specific costs in USD per kWe of installed capacity for the standard power plant and the reference PCDC power plant are presented in Table 7-1.

Capital Expenditures			NGCC	PCDC CC Unit 1	PCDC CC Unit 10
Overnight construction costs		M USD	153.3	325.5	292.2
Land purchase; Surveys	5%	M USD	7.7	16.3	14.6
Specific services	1%	M USD	1.5	3.3	2.9
Fees	2%	M USD	3.1	6.5	5.8
Contingencies	10%	M USD	15.3	32.6	29.2
Confidence limits PCDC CC	5%	M USD		8.3	6.7
Total installed cost		M USD	180.9	392.4	351.5
Specific investment		USD/kWe	461	1,076	964

Table 7-1 Capital expenditures

A summary of the investment cost per function is presented in Table 7-2.

Investment per function group (MUSD)		
1 Conversion NG to syngas	63.4	31%
2 Conversion CO (to H2)	16.4	8%
3 CO_2 removal	51.1	25%
4 CO_2 compression	30.7	15%
5 Utilities	43.0	21%
Total Fuel plant incl allow.	**204.6**	
NGCC Power Plant	180.9	
Integration costs	6.9	
Total	**392.4**	

Table 7-2 Investment per function

The main cost components per function are:

Function 1:	Air compressors	66%
Function 2:	LT shift reactor	50%
	HT shift reactor	35%
Function 3:	CO_2 absorber	34%
	HP Flash column	10%
Function 4:	CO_2 compressor	68%
	CO_2 desiccant dryer	24%
Function 5:	Steam turbine generator	52%

A summary of the delta investment cost and specific costs in USD per kWe of installed capacity for the PCDC plant, is presented for the standard power plant, the PCDC plant and the for the studied sensitivity cases of the PCDC plants in Table 7-3.

		Capex Change	Spec. Investment
		M USD	**USD/kWe**
NGCC	**Standard power plant**		**461**
PCDC CC	**Reference fuel plant**		**1076**
Case A	Pressure drop	13.1	1092
Case B1	SC 1.4	0.0	1063
Case B2	SC 1.0	0.0	1050
Case C1	NG Bypass 10%	-20.3	1024
Case C2	NG Bypass 20%	-41.1	973
Case C3	NG Bypass 30%	-62.5	921
Case C4	NG Bypass 40%	-84.4	869
Case C5	NG Bypass 50%	-107.1	816
Case D	HT shift only	-9.7	1041
Case E	Single stage CO_2 removal	-15.4	1034
Case F	Fired heater	8.7	1063
Case G	Fuel gas preheat	-5.1	1036
Case H	Fuel gas saturation	0.0	1071
Case I	CO_2 quality	-9.6	1049
Case J	Integration/air extraction	-15.4	1034
Case K	Combination ST/Air Compr	-12.3	1036

Table 7-3 Capex for sensitivity cases

The specific costs in USD per kWe net generated power are presented in 8.1.

8. ECONOMIC ANALYSIS

8.1 INTRODUCTION

An economic analysis will be executed to evaluate economic performance of the reference PCDC plant against the standard power plant. Similar analysis will be executed for the PCDC plant, including the identified cost reduction elements, to determine the sensitivity to the overall economic performance/ input to the cost of CO_2 capture.

For the reference plant economic calculations will be made based on the starting points as attached (See appendix 2).
Sensitivity analysis is carried out in order to quantify the effects of the cost reduction elements.

Results are expressed in power production costs and costs of avoided CO_2, based on avoided CO_2 compared with equivalent power production in a natural gas fired combined cycle power plant (reference power plant).

The economic evaluation is based on the standard economic criteria for IEA studies, except for some starting points as provided by CCP.

As most of the identified main cost reduction elements will be considered in the project when a Total Cost of Ownership (TCoO) concept is applied, special attention will be paid to this subject.

8.2 TOTAL COST OF OWNERSHIP CONCEPT

8.2.1 Introduction

Traditionally owners and investors in the chemical and process industries tend to focus on the capital cost (CAPEX) involved in building production facilities. However, the financial return from these high value installations depends on the total cost per unit output, comprising the accumulation of costs associated with acquisition and asset development (capital investment), operation, maintenance and other supporting services.

Considering a service life of usually 20 - 30 years, the total lifetime cost of these installations is often many times larger than the initial capital investment. A one sided emphasis on only capital cost (CAPEX) when acquiring and developing high value assets can result in a serious exposure of the projected margins with a high degree of uncertainty on the actual cost during the service life of the installation.

For a low emission power plant the overall cost involved with the capture of CO_2 are very critical. Therefore it requires innovative ways to reduce unit cost and manage risks and uncertainties in order to secure long-term competitiveness and profitability.

In this environment the need for a reassessment of the traditional approaches to asset development, operation and management is required. As part of an Asset Life Cycle Management (ALCM) a wide spectrum of integrated services focused on maximizing the value of new and existing industrial assets is required. These services include life cycle costing, value engineering, reliability and availability analyses, application of functional specifications, maintenance concept development etc. In addition it is advised to create inter and intra organizational cooperation and exchange of critical information by developing in an early stage multi angular relationships with all the parties involved in an asset development project: the client, end users, strategic equipment suppliers, construction contractors and maintenance contractors.

The cornerstone of this approach is the application of the Total Cost of Ownership concept for relating the cost implications of major decisions during the development of an asset to the production profile during the life of an asset.

8.2.2 Total Cost of Ownership Concept

The development of industrial assets is the product of an on-going decision-making process, in which the following aspects are duly considered:

- Projected profitability (GRM)
- Capital investment budget
- Anticipated operating and maintenance cost
- Maximum allowable schedule
- Plant capacity and utilization
- Process and technology selection
- Design alternatives to be considered
- Level of reliability and availability
- Type of equipment to be considered
- Maintenance strategy and concept
- Etcetera

The aim of this process is to ultimately deliver an installation, which is compliant with the owner's requirements within predetermined time and budgetary constraints.

The applied criteria to support these decisions are of critical importance to the operational performance of the installation and the running and maintenance costs. In a traditional approach where the contractor aims to minimize Total Investment Cost (TIC), emphasis is primarily laid on short term expenditures for design, erection and commissioning of the installation, while little attention is given to the subsequent impact of the cost of running and maintaining the installation. This approach leaves a significant potential for cost reductions unused since operating and maintenance cost have not been considered as a criterion for evaluating alternatives in the development stage of an asset. However the decisions made during the front-end design of an installation have a significant impact on the actual operating and maintenance cost during the service life of the installation.

In comparison to a strictly "capital cost restriction" oriented approach our experience indicates that a significant reduction in unit output cost can be accomplished by implementing the Total Cost of Ownership concept in an early stage of a project.

The Total Cost of Ownership concept provides a systematic approach for evaluating capital expenditure alternatives based on life cycle cost considerations, with the aim to maximize the value of an asset over its projected service life.

The Total Cost of Ownership of an item of material, considering the period of its project service life, takes into account the aggregated costs of acquisition, personnel training, operation, maintenance, modification and disposal, and is used in the decision making process for new or changed requirements and as a control mechanism in service, for existing and future items.

The basis for a Total Cost of Ownership evaluation model is derived from the total cost of production divided by the number of unit's output within product specification.

From this it becomes apparent that besides the initial capital investment cost, a number of other factors determine the cost of ownership and thus the owners financial returns. The main cost drivers in addition to the capital investment cost are in general:

- Operating cost (comprising e.g. feed, utility consumptions, consumables etc.)
- Maintenance cost (including planned maintenance, breakdown maintenance, test and inspections, spare parts etc.)
- Cost of production losses due to under scoring of availability targets

If these factors are not considered from the very beginning of an asset development project, owners will be confronted with a great deal of uncertainty and risk with regard to the actual cost of production during the service life of the asset.

An effective tool, providing accurate information on expected life cycle cost and its constituents, would provide owners and investors with the prior benefits of a more realistic assessment of their likely returns.

The Total Cost of Ownership concept is such a tool, which focuses concurrently on front-end optimization (minimum TCoO). The sum of all costs, associated with production, are to be minimized over the lifetime of an asset with due consideration to the interdependence of its constituents and the various quality, function, and price tradeoffs. Significant emphasis should be placed on the value of lost production revenue when compared to the initial investments appropriately placed to minimize such down time and maximize availability.
For example:

- Equipment selection which consequent of its selected specification would be more expensive but delivers a higher availability, lower power consumption or savings on maintenance expenditures could be justified by a reduction of the total life cycle cost;
- Additional functionality requiring higher initial investment cost could be outweighed by corresponding reduced operator burden and thus lower operating cost;
- Additional cost through application of high quality materials could result in lower production losses due to off spec production or reduced downtime.

Regarding the denominator parameters, optimization is achieved by specification of appropriate levels of performance criteria, which yields a corresponding improvement in the plant performance and utilization, again over the entire life cycle of the installation.

Equipment reliability targets and overall plant availability targets are to be set at the "appropriate level" such that additional investments for higher quality equipment, or enhanced preventive maintenance for reliability and availability improvements, are outweighed by the gains of higher availability or longer intervals between services.

The application of TCoO methodologies in front end design has numerous advantages for owners and investors in high value assets by:

- Providing insight in the life cycle cost structure of an installation
- Early identification of the main cost drivers

- Providing an objective tool for economic and technical decision support
- Stimulating and improving communications and exchange of information between all parties involved in the development of an asset
- Providing cost saving opportunities in the procurement process
- Fostering early development of maintenance strategies
- Forecasting the owners' future budget needs
- Reducing unforeseen risk based operating cost surprises
- Maximizing the value of the asset over the project life
- Minimizing yield losses.

JCN's experience in major projects, wherein TCoO methodologies have been applied, substantiates the significant cost saving potential of the TCoO concept. JCN's direct experiences in TCoO and its application have attained cost savings in the order of 5-10% of the total life cycle cost. Through our experience we firmly believe that if adequate attention and commitment is afforded to the subject in all facets of application then significantly higher gains are consistently achievable.

8.3 CASH FLOW CALCULATIONS

8.3.1 Background

Using cash flow calculations one can determine the real cost of electricity production. This paragraph shows the calculation method and the criteria used. As a result the cost of electricity production for the different power plant configurations is summarized.

The cash flow calculation shows the cash flows of a power plant throughout its lifetime and calculates the net present value of these cash flows. The net present value (NPV) is the value of a project today if all future cash flows (including investments) are discounted to today's value using a discount ratio.

The cash flows include the following items:

- Revenues
- Fossil Fuel costs
- Maintenance costs
- Labor costs
- Chemicals and consumables costs
- Insurance
- Capital expenditures
- Working capital
- Decommissioning costs

The cash flow is calculated for 2 years of construction followed by 25 years of operation. The production costs per kWh of electricity are calculated by setting the NPV of the power plant to zero. This can be achieved by varying the kWh price until the revenues balance the costs over the whole lifetime of the power plant.

8.3.2 Starting points

The yearly cash flow is calculated using the criteria as mentioned in appendix 2.
Criteria that need further explanation are discussed below:

<u>Discount ratio and cost of capital</u>

All cash flows will be discounted using a discount ratio of 10%. These cash flows also include the debts made during the design, construction and commissioning.

Commissioning

A 3-month commissioning period will be allowed for all types of plant. In effect this means that during the first year the load factor of the plant is reduced by 25%. The power plant will operate at a load factor of 90% during the first year; by adding a commissioning period of 3 months, the load factor will be reduced to 65%.

Load factor

The power plant will operate at a load factor of 90% during a normal year. The load factor affects the electricity production, consumption of all consumables, disposal of wastes and maintenance costs. It does not reduce the labor costs and insurance.

Decommissioning

The costs associated with shut down of the plant are taken as a percentage of the capital investment. However since these costs occur only once at the end of the lifetime of the power plant, the discounted cash flow is reduced to a minimum. As a result the decommissioning costs only comprise 0.1 to 0.2% of the kWh price and are insignificant.

Maintenance

The Maintenance expenditures are 4% p.a. of the installed plant costs.

Confidence limits and Contingencies

An allowance is made for estimating error and process unknowns / development. This allowance is set as a percentage of the overnight construction cost. A contingency factor of 10% covers most of the risks.

Labor

The labor cost for one operator is set to 75.000 USD/year. A percentage is added to the labor cost for indirect costs for supervision (20%) and administration + overhead (60%). The number of operators necessary for each plant is assumed to be 9 for a natural gas fired combined cycle and 13 for the PCDC plant.

Consumables and Working capital

The consumables consist of the following components:

- Chemicals for boiler water treatment
- Chemicals for waste water treatment
- Lubricants
- Potable water
- MDEA solution + additives
- Catalyst + internals

Working capital for storage of consumables is assumed to be USD 26,000 for the standard power plant and USD 180,000 for the PCDC plant.

Fuel Price

The fuel price is set at 3.52 USD/GJ (LHV) for natural gas. A sensitivity analysis to a gas price of 3.0 USD/BTU (HHV) is presented in the last section of this chapter.

Calculations of 10th unit

For the economic calculations of the 10th unit the following has been assumed:

- 20% reduction of the TIC of the 1st PCDC plant (i.e. fuel plant only)

- The maintenance expenditures are 2% p.a. of the installed plant costs
- Performance remains identical to 1st unit

8.4 RESULTS

The results from the cash flow calculations are presented in table 8-1. The results are given for the standard natural gas fired power plant, the reference PCDC plant and for the following cases, which represent sensitivities to changing design and/or operational parameters:

Case A	Lower fuel pressure (See section 6.6)
Case B1	Lower Steam/Carbon ratio ATR (S/C 1.4) (See section 6.7)
Case B2	Lower Steam/Carbon ratio ATR (S/C 1.0) (See section 6.7)
Cases C1-C5	Natural gas bypass (10 – 50%) (See section 6.5)
Case D	HT Shift reactor only (See section 6.8)
Case E	Single stage CO_2 removal system (See section 6.8)
Case F	Increased maximum allowable tube wall temperatures (See section 6.9.1)
Case G	Additional fuel gas heating (See section 6.9.2)
Case H	Fuel gas saturation (See section 6.10)
Case I	Lower CO_2 quality (See section 6.11)
Case J	Air extraction from gas turbine (See section 6.12)
Case K	Steam turbine driven air compressor (See section 6.13)

		Electricity production cost	**Spec. Investment**	**Overall Efficiency**
		USD/MWh	**USD/kWe**	**-**
NGCC	**Standard powerplant**	**33.69**	**461**	**55.9%**
PCDC CC	**Reference fuel plant**	**57.08**	**1076**	**41.3%**
Case A	Pressure drop	56.84	1092	42.1%
Case B1	SC 1.4	56.32	1063	42.1%
Case B2	SC 1.0	55.54	1050	42.9%
Case C1	NG Bypass 10%	55.03	1024	42.5%
Case C2	NG Bypass 20%	53.04	973	43.6%
Case C3	NG Bypass 30%	51.05	921	44.8%
Case C4	NG Bypass 40%	49.09	869	46.0%
Case C5	NG Bypass 50%	47.11	816	47.2%
Case D	HT shift only	55.60	1041	42.1%
Case E	Single stage CO2 removal	59.56	1034	37.2%
Case F	Fired heater	56.81	1063	41.1%
Case G	Fuel gas preheat	55.38	1036	42.4%
Case H	Fuel gas saturation	56.82	1071	41.5%
Case I	CO2 quality	56.51	1049	41.3%
Case J	Integration/air extraction	56.17	1034	41.3%
Case K	Combination ST/Air Compr	56.04	1036	41.6%

Table 8-1 Electricity production costs

8.5 CALCULATION OF CO_2 COST

Costs per ton of avoided CO_2 resulting from decarbonization are calculated by comparing electricity production costs and specific CO_2 emission with the costs and emission of the standard power plant.

Electricity production costs are calculated as described in section 8.3. Specific CO_2 emission is calculated by dividing the avoided amount of CO_2 per year by the yearly power production. Both figures assume 8000 yearly hours of operation and a load factor op 90 per cent. The avoided amount of CO_2 is based on the difference between the emitted CO_2 of a natural gas fired combined cycle power plant with a net power output of 392.3 MW_e and the emitted CO_2 of the PCDC plant with equivalent power output.

		Specific avoided CO_2	**Cost of avoided CO_2**
		Ton CO_2/MWh	**USD/Ton CO_2**
PCDC CC	**Reference fuel plant**	**0.342**	**68.40**
Case A	Pressure drop	0.343	67.59
Case B1	SC 1.4	0.332	68.24
Case B2	SC 1.0	0.305	68.40
Case C1	NG Bypass 10%	0.342	69.89
Case C2	NG Bypass 20%	0.305	71.84
Case C3	NG Bypass 30%	0.269	74.25
Case C4	NG Bypass 40%	0.234	77.56
Case C5	NG Bypass 50%	0.198	82.06
Case D	HT shift only	0.163	81.55
Case E	Single stage CO_2 removal	0.269	90.44
Case F	Fired heater	0.286	76.46
Case G	Fuel gas preheat	0.302	63.27
Case H	Fuel gas saturation	0.343	67.61
Case I	CO_2 quality	0.342	66.73
Case J	Integration/air extraction	0.342	65.73
Case K	Combination ST/Air Compr	0.342	65.33

Table 8-2 Cost of avoided CO_2

All cases are compared on the basis of electricity production costs and specific emission figures using Figure 8-1. The results for the reference case (Unit 1 and 10) are presented in Figure 8-1. The slope of a line for a certain design case represents the specific CO_2 cost of that case relative to the NGCC reference case.
Sensitivity analysis is carried out by comparing influence of design/operational changes on specific costs and/or specific emissions.

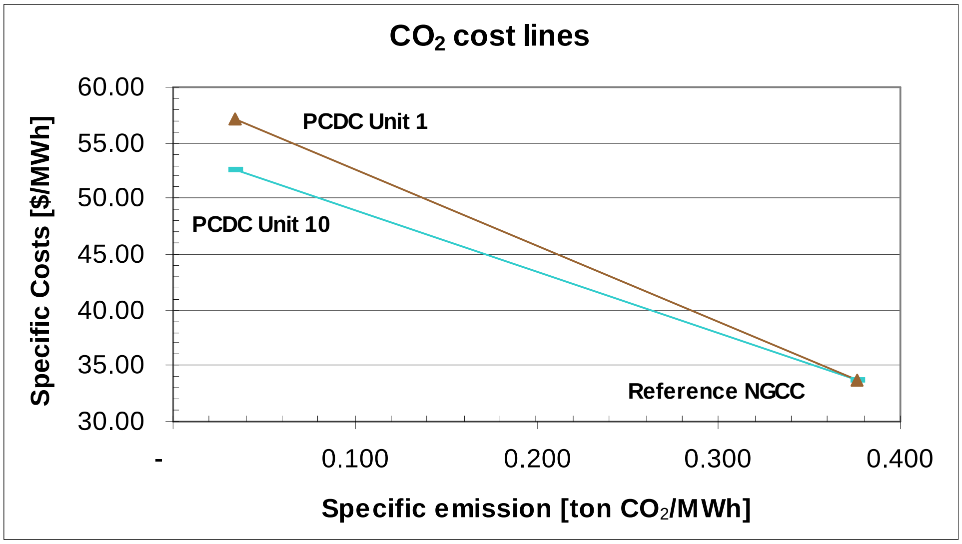


Figure 8-1 CO_2 cost lines

8.6 Sensitivity analysis to gas price ANd availability

The calculations in this report are generally based on:

- Gas price 3.52 USD/GJ
- Load factor 90%
- 8000 yearly operational hours

Additional calculations are made for lower gas price and maximum availability, using the following starting points:

- Gas price 3.16 USD/GJ
- Load factor 100%
- 8760 yearly operational hours

CO2 prices (USD/Ton CO_2)	PCDC CC	Reduced cost	10^{th} PCDC	10^{th} PCDC red
High Gas price / Low availability (load)	68.40	59.38	55.45	47.22
Low Gas price / Low availability (load)	66.03	57.29	53.09	45.13
High Gas price / High availability (load)	61.42	53.41	50.13	42.82
Low Gas price / High availability (load)	55.77	48.54	45.07	38.53

Table 8-3 CO2 price sensitivity to gas price and load pattern

A comparison between costs of avoided CO_2 emission is presented in Table 8-3.

The impact of lower gas price and high load pattern is a decrease of the CO_2 price between 18% and 19%.
The impact of possible cost reductions is described in chapter 9.

9. CONCLUSIONS, RECOMMENDATIONS AND DISCUSSION

9.1 CONCLUSIONS

In line with the expectations it is clear that natural gas fired power generation without CO_2 emission to the atmosphere will result in a significant increase of the cost of investment and the operating cost compared to a conventional NGCC unit. Also the use of fossil fuel will increase significantly because of the reduced overall efficiency. Consequently this will result in an increase of the cost of power produced.
Main data for the standard natural gas fired 400 MW_e power plant (NGCC) and the power plant in combination with the PCDC reference plant are presented in Table 9-1. For the PCDC plant the evaluation has been made for the 'first' plant to be built and in case there is a standard plant with repetitive design and implementation.

		Natural Gas Combined Cycle	Standardized PCDC plant	
			Unit 1	Unit 10
Capital expenditure	M USD	180.9	392.4	351.5
Specific electricity cost *	USD/MWh	33.69	57.08	54.05
Avoided CO_2 cost	USD/ton	-	68.40	55.45
Overall efficiency	%	55.85	41.3	
Natural gas consumption	MW_{th}	702	882	
Net power production	MW_e	392	365	
CO_2 emitted **	MT/y	1.061	0.095	
CO_2 captured **	MT/y		1.329	
CO_2 avoided **	MT/y	-	0.966	
CO_2 capture efficiency **	%	-	93.3	
CO_2 avoided **	% NGCC	-	91.0	

Table 9-1 Overall performance comparison

* The specific electricity cost is calculated for the project with a Net Present Value (NPV) of 0.

** The CO_2 data for the PCDC plant are corrected for the net power output of the standardized PCDC plant in relation to the net power output of the NGCC (i.e. correction factor = Pe NGCC / Pe PCDC). CO_2 quantities are calculated using 8000 yearly production hours and a load factor of 90%.

Only by governmental rules, which impose a value to captured/avoided CO_2 low emission power plants will become competitive to standard power plants, without any provisions to reduce the CO_2 emission.

Conclusions presented hereafter are related to the main objectives of this study, which are:

1. Development of a reference PCDC plant, where reliability and proven design is strongly preferred above a high level of integration between the power plant and the PCDC plant
2. Identifying cost reduction options, which will improve the economic performance of the low emission power plant, without affecting the reliability/availability of the plant. Main identified cost reduction items are standardization, modular construction, fit for purpose design and plant capacity.

One of the main conclusions of the study is that standardization in combination with a Total Cost of Ownership (TcoO) approach and repetitive design and

implementation will have a significant impact on the Total Installed Cost (TIC ; 15 - 20 % reduction) as well as the Total Life Cycle Cost (5 – 10% reduction).
However it shall be clear that these cost reduction items are of a general nature and in principle valid for all type of plants.
A specific issue for the PCDC plant, like modularization, has a (limited) cost reduction potential but it does not show an all time benefit with respect to the TIC. Modularization will only result in a cost benefit when there is a positive differential for labor cost and productivity between the SC facility and the site concerned. For the Dutch situation there is no direct financial benefit expected for the first units to be realized. However modularization will have a (limited) positive impact on the schedule and provided some schedule and cost risk avoidance.

With respect to the results of the market study for low emission gas fired power plants there in principle appears to be sufficient potential available in future to realize the above-mentioned targets. Dependent on the market scenario the number of units/year to be realize will vary from 2 – 4 for the low scenario to 5 – 12 for the middle scenario and even from 5 to 24 for the high scenario.
The market penetration for low emission power plants will be depending on:

- Government interest in CO_2 reduction
- Trading possibilities for CO_2
- Fuel mix

Regarding the optimal capacity of the PCDC plant as a percentage of the average power plant fuel consumption, it becomes clear that within a capacity range of 50 - 100% the lower capacity will present the lowest specific power generation cost but the higher cost per CO_2 avoided because the CO_2 capture will decrease with the larger natural gas bypass capacity. Therefore from the perspective of installing a low emission power plant a PCDC plant with 100 % fuel capacity is preferred.

Regarding specific technical cost reduction items the following has been concluded after executing sensitivity analysis:

<u>Reduction of the pressure drop PCDC plant / supply pressure to power plant</u>
A reduction of the pressure drop PCDC plant / supply pressure to power plant has a positive impact on the overall performance but will result in an increase of the TIC. The potential regarding a reduction to the pressure drop is limited with respect to the equipment design. The supply pressure is dependent on the gas turbine manufacturer. Based on actual received manufacturer information (MHI, GE) a fuel gas supply pressure below 30 bar is required, even while the combustor pressure is approximately 15 bar. However in a next project stage this should be discussed in more detail with the manufacturer. Previous project experiences show that fuel gas supply pressures of approximately 20 bar may be possible. It shall also be noted that the GT 26 gas turbine has a combustor pressure of approximately 30 bar. In this particular case even higher fuel gas supply pressure will be required.

<u>Steam / Carbon ratio</u>
A reduction of the S/C ratio shows a positive impact on the overall efficiency. However there are some uncertainties regarding the conversion efficiency in combination with the lifetime of the catalyst.

<u>CO_2 capture efficiency</u>
It is possible to optimize the economic plant performance with the CO_2 capture efficiency. The following three options have been identified:
a. Natural gas bypass (reference is made to the optimal PCDC plant capacity)

b. HT shift reactor only will result in a reduction of the TIC and a reduced CO_2 capture. The impact on the specific electricity cost is positive, but the cost of avoided CO_2 will rise significantly because of the decreased capture efficiency.
c. Single stage CO_2 removal system will also result in a reduction of the TIC and a reduced CO_2 capture efficiency. The impact on the specific electricity cost is negative because of the significant reduction of the overall plant efficiency (i.e. high specific heat consumption for CO_2 removal)

Efficient use of high temperature heat

For a (more) efficient use of high temperature heat, resulting in a higher overall efficiency, the following two options have been identified

a. Increase of maximum tube wall temperatures will allow for a high temperature feed-effluent heat exchanger, which makes the use of a fired furnace superfluous. This will result in an increased overall efficiency and higher CO_2 capture in combination with a reduced TIC. This will finally result in a reduced specific electricity cost.
b. Additional fuel gas heating will result in an increased overall efficiency in combination with a reduced TIC. This will finally result in a reduced specific electricity cost.

Fuel gas saturation

Fuel gas saturation will allow for the use of ’low temperature’ waste heat in combination with the reduction of the amount of steam injection for NO_x abatement. As the TIC will not change the specific electricity cost will be reduced as a result of the higher overall efficiency.

CO_2 quality

Changing the requirements to the CO_2 quality at the battery limit of the PCDC plant will lead to a cost reduction within the PCDC plant. On the other hand it may lead to additional cost outside the PCDC plant, which undo the advantage.

Integration of gas turbine air compressor with reformer air compression system

Integration of the gas turbine air compressor with the reformer air compression system will result in a cost reduction. It shall be clear that by introducing this option a critical integration between the power plant and the PCDC plant is established.

Combining steam turbine and compressor drive(s)

A single shaft steam turbine – air compressor system will lead to a significant cost reduction. It will also result in a more complex system, which is not yet standardized. However in case of repetitive design and implementation of units this option could be standardized.

9.2 **RECOMMENDATIONS**

Based on the sensitivity analysis for the specific (process) technical cost reduction items, raised during the brainstorm meeting, the following reduced cost option is recommended:

- Desulphurization unit
- Preheating feed gas with gas – gas heater
- Air blown ATR with bleed air supply from the gas turbine and a steam turbine driven booster compressor with maximum air outlet temperature for direct feed to the ATR
- High pressure steam production downstream the ATR

- HT and LT shift configuration
- Two-stage CO_2 removal system (MDEA)
- High temperature fuel gas heating with saturation
- CO_2 compression system

The additional items to the reference PCDC plant, included to improve the overall plant performance, are:

- Integration gas turbine air compressor (case J)
- Single shaft configuration steam turbine/air compressor fuel plant (Case K)
- Additional fuel gas heating (Case G)
- Fuel gas saturation (Case H)

For the reduced cost option the expected performance is presented in Table 9-2.

		Natural Gas Combined Cycle	Standardized PCDC plant Reduced cost option	
			Unit 1	Unit 10
Capital expenditure	M USD	180.9	368.8	327.9
Specific electricity cost *	USD/MWh	33.69	52.65	49.89
Avoided CO_2 cost	USD/ton		59.38	47.22
Overall efficiency	%	55.85	42.6	
Natural gas consumption	MW_{th}	702	882	
Net power production	MW_e	392	376	
CO_2 emitted **	MT/y	1.061	0.093	
CO_2 captured **	MT/y		1.290	
CO_2 avoided **	MT/y	-	0.969	
CO_2 capture efficiency **	%	-	93.3	
CO_2 avoided **	% NGCC	-	91.3	

Table 9-2 Reduced cost option performance

* The specific electricity cost is calculated for the project with a Net Present Value (NPV) of 0.
** The CO_2 data for the PCDC plant are corrected for the net power output of the standardized PCDC plant in relation to the net power output of the NGCC (i.e. correction factor = Pe NGCC / Pe PCDC). CO_2 quantities are calculated using 8000 yearly production hours and a load factor of 90%.

In Figure 9 -1 the specific CO_2 cost for the PCDC reference plant and PCDC reduced cost option are presented, both for the first unit and for repetitive design.

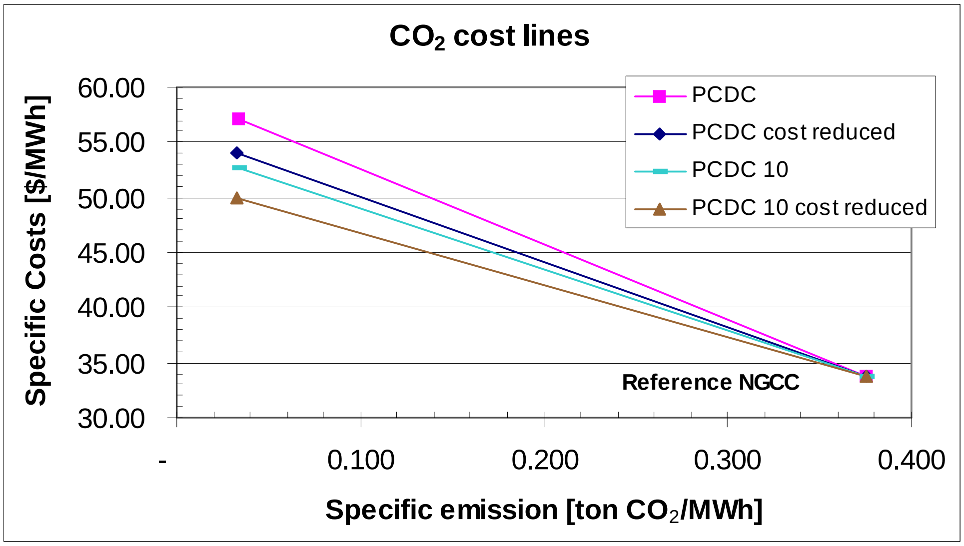


Figure 9-1 Cost lines reference and reduced cost PCDC plants

It shall be noted that also for the reduced cost option integration between the PCDC plant and the power plant has not been considered except for gas turbine bleed air supply to the reformer. A fully integrated PCDC-power plant (i.e. this implies a modified design of the power plant) will have a better thermal and financial performance than the options studied. However this is only valid for new plants to be built and not for revamps.

9.3 DISCUSSION

When presenting the Total Cost of Investment (TIC) for the ATR based PCDC plant it was noted that the Jacobs cost estimate showed a significant difference to the cost estimate of an ATR based PCDC plant studied by Haldor Topsoe (HT) for Norsk Hydro in 2002. It shall be clear that part of the price difference is caused by the fact that both concepts are not completely identical. However even the TIC for the reduced cost option in the Jacobs report, which also used gas turbine compressor bleed air to feed the ATR like the HT concept, is still significantly higher than the TIC of the PCDC plant estimated by HT.
To benchmark the cost of the PCDC plant a global comparison with other 'similar' type of Hydrogen production processes/plants has been executed. The assessment has been based on the following sources:

- Literature
- Experiences Jacobs UK with Steam Reformer Plants
- Report "Pre-combustion Decarbonisation for CO2 capture, A review of process schemes for IEA Annex 16 Subtask A and the CCP" by Norsk Hydro (2002-11-08).

It shall be clear that it only concerns a global comparison to obtain an indication of the TIC for a Hydrogen producing plant with an identical capacity. A detailed scope for all plants concerned is not available.

The results of the comparison are presented in table 9-3.
The plants presented in table 9-3 are:

1. Steam reformer plant (Kirk-Othmer Encyclopedia of Chemical Technology Volume 13, fourth edition)
2. Steam reformer plant (Process Economic Program yearbook 1997)
3. Steam reformer plant(s) with CO2 compression (data Jacobs UK)
4. ATR based PCDC plant base case (Jacobs PCDC study 2003 for CCP)
5. ATR based PCDC plant, reduced cost option (Jacobs PCDC study 2003 for CCP)
6. ATR based PCDC plant (Haldor Topsoe PCDC study 1998 for Norsk Hydro) *
7. ATR based PCDC plant (Haldor Topsoe PCDC study 2002 for Norsk Hydro) *

* The information concerning this plant has been obtained from the study "Pre-combustion Decarbonisation for CO_2 capture, A review of process schemes for IEA Annex 16 Subtask A and the CCP" by Norsk Hydro (2002-11-08).
Both Haldor Topsoe studies are based on using gas turbine bleed air for air feed to the ATR. This is similar to the Jacobs reduced cost option. It is not clear if a utility system, including a condensing steam turbine generator, is included in the design and cost estimate of the Haldor Topsoe studies.

The 2002 study is a follow-up of the 1998 study and the aim of this study is to realize a simpler process scheme, suitable for retrofitting an existing NGCC plant, with significantly reduced cost of investments. Main differences identified between both concepts are:

- Fuel capacity for 1 power train of approximately 400 MWe instead of 3 power trains
- Additional ambient air supply to the ATR instead of 100% gas turbine bleed air supply
- MT shift instead of HT + LT shift
- 83 % CO2 capture efficiency instead of 91%
- 70 bar CO2 outlet pressure instead of 75.5 bar
- 63 bar natural gas pressure instead of 120 bar

	Plant	1	2	3	4*	5 *	6	7
Base data								
H_2 production capacity	Mln Nm3/year	1019	743	2000	1994	1994	5200	2100
Total Installed Cost	Mln USD	83	86	232	240	212	338	89 **
Year of estimate		1987	1997	2003	2003	2003	1998	2002
Corrected data **								
H_2 production capacity	Mln Nm3/year	1994	1994	1994	1994	1994	1994	1994
Total Installed Cost (2003 USD currency)	Mln USD	183	193	232	240	212	191	88
Year of estimate		2003	2003	2003	2003	2003	2003	2003
TIC compared to Jacobs PCDC plant base case		76%	81%	97%	100%	88%	80%	37%

Table 9-3 Total Cost of Investment Hydrogen Production Plants

* TIC excluding IEA allowances

** The study indicates a TIC for the frontend (89 mln USD) and additional common capital cost (25 mln USD).

*** For obtaining the corrected data for the H_2 production capacity and the capital cost the following correction factors have been used:

- exponential scale factor of 0.7 to correct for the H_2 production capacity
- inflation rate of 2% to correct for USD rate

From the above presented comparison of the various H2 production plants the following could be concluded:

- The Jacobs base case TIC of the ATR based PCDC plant is 10 – 25 % higher than the literature based corrected TIC of the steam reformer based H2 production plants. This difference can be explained by the cost for large air compressor units and a CO_2 compression system, which are part of the PCDC plant. In addition the literature-based plants are probably not provided with a complete utility plant with a steam turbine generator because the steam generated is probably consumed internally or supplied to other units.
- The TIC data provided by Jacobs UK for a similar steam reformer plant with CO_2 capture are in line with the Jacobs estimate for the PCDC plant.
- The difference between the estimate of the Jacobs for the reduced cost option and the corrected estimate for the 1998 Haldor Topsoe study is less than 10%. Both estimates are based on a similar concept. Only it is not clear if the cost for a dedicated utility plant, including a steam turbine generator, is included in the Haldor Topsoe estimate. Also the CO_2 outlet conditions are only 75.5 bar for the Haldor Topsoe study instead of 110 bar for the Jacobs study.
- The TIC of the 2002 Haldor Topsoe study is significantly lower than the TIC of the other similar type of plants. When comparing the concept of this study with the concept of the 1998 Haldor Topsoe study the main difference noted is the use of a MT shift in stead of a HT + LT shift. However this cannot be the only reason for the significant cost reduction. As further detailed information is not available Jacobs Consultancy cannot explain the low TIC of the 2002 Haldor Topsoe study at this moment.