Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Capture and Separation of Carbon Dioxide from Combustion Sources

Edited by

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Chapter 31

TECHNO-ECONOMIC EVALUATION OF AN OXYFUEL POWER PLANT USING MIXED CONDUCTING MEMBRANES

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ABSTRACT

The techno-economic performance of gas turbine power plants with zero or low CO_2 emission has been evaluated. The plant concepts make use of "Mixed Conducting Membranes" (MCMs) to extract oxygen from the inlet air and thus enable combustion of gaseous hydrocarbon fuels in a nitrogen-free environment. This technology is being developed in the ongoing EU FP5 Integrated Research Project "AZEP" (see www.azep.org). Unlike the combined cycle processes investigated in the AZEP project, the concepts considered here are simple cycle configurations. The scenario is based on the CCP Scenario D, a BP gas gathering and processing installation in Prudhoe Bay, Alaska.

Three different base configurations were identified, each run in two different modes (with and without supplementary firing). These six cases were compared to a conventional non-capture, gas turbine plant. The thermodynamic process simulations showed penalties in terms of the net electrical efficiency between 2.4 and 6.8%-points for the different configurations. These penalties include the capture, purification and compression of the carbon dioxide. The economic evaluation revealed very promising figures, estimating costs of CO_2 avoided from 17.3 US$/ton to as low as 7.3 US$/ton, if a value of 20 US$/ton produced CO_2 (as suggested by CCP) is considered.

INTRODUCTION

Development of gas turbine-based power plants with CO_2 capture is hindered by several limitations in the present state-of-the-art. The main hurdles to be overcome using current technology are a substantial reduction in power plant efficiency, a significant decrease in power plant output, and the large investments and operating costs of such plants. Thus, the challenges facing the proposed power plant with CO_2 capture are to enable the use of conventional power plant equipment (with minimum modifications), to minimize the reduction in plant efficiency and power output, and to develop such technology for retrofitting existing power plants.

The mixed conducting membrane (MCM) power concept offers such a possibility. Norsk Hydro, Norway, the original inventor of the concept, and the gas turbine manufacturer ABB ALSTOM Power Sweden AB, first performed a joint feasibility study on the MCM power concept. As this study showed a high potential of the technology—not only in terms of performance figures like gas turbine efficiency and CO_2 capture but also with respect to CO_2 avoidance cost—it was decided to develop this technology in a consortium by inviting other partners with complementary skills. It was decided to develop a so-called "advanced zero emission power plant", AZEP, reflecting the fact that there should be no combustion of carbon containing fuel in the air stream. The following goals of the AZEP Process have been identified:

- achieve 100% reduction of CO_2;
- reduce NO_x emissions below 1 ppm;
- reduce the cost of CO_2 separation (compared to tail-end capture) by 25–35% within 6 years;
- separate CO_2 with a reduction in power plant efficiency of less than 5%-points

Although in the AZEP project there is a limitation to investigate a "zero emission" concept, preliminary estimates showed that an MCM-based power plant with 80–90% CO_2-recovery could further reduce the CO_2 capture cost. Other technologies like amine scrubbing and pre-combustion decarbonization of hydrocarbons generating hydrogen as fuel will operate with a CO_2-capture of around 85–90%, which in most cases is accepted as a sufficient degree of CO_2 capture.

The main goal of the work described in this report was to optimize and quantify the performance and cost of a power plant for a specified CO_2 Capture Project (CCP) scenario making use of MCMs. Thermodynamic modeling and cost correlation of the individual components and the entire systems have been established. Opposed to the original AZEP concept, a simple cycle power generating process (without steam system) has been pursued. This layout could be especially attractive for distributed power generation in remote areas, where it is very important to reduce weight and number of auxiliary units (like an Alaska scenario).

It must be emphasized that this study is *not* an official AZEP study, even though many similarities to this project exist. The AZEP project is investigating a combined cycle with 100% CO_2 reduction, and this report investigates different MCM-powered plants in simple cycle configuration, and in some cases with some emission of CO_2.

STUDY METHODOLOGY

Description of the MCM Power Plant Concept

The MCM power plant in combined cycle mode (like in the AZEP concept) has been explained in some detail by Eklund et al. [1] and Griffin et al. [2]. A short overview of the features characteristic to all MCM based power plant concepts will be given in the following section. All current investigations are based on the Siemens (formerly ALSTOM) GTX100 gas turbine, which was also chosen as the reference for this study.

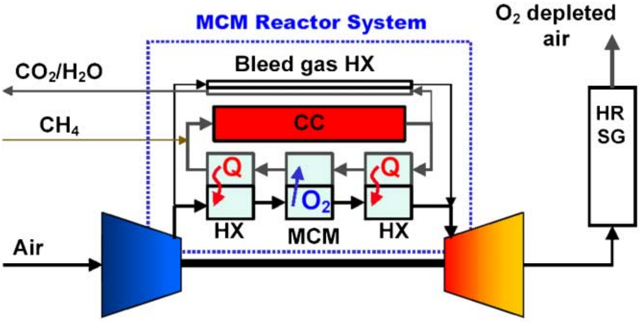

Figure 1: Schematic of an MCM power plant in combined cycle configuration.

The MCM reactor, which consists of a combustor, a low-temperature heat exchanger (air preheater), a membrane section, and a high-temperature heat exchanger, replaces the combustor in an ordinary gas turbine. Figure 1 shows a strongly simplified schematic of an MCM-based combined cycle gas turbine plant. In the depicted concept, air is compressed and led into the MCM reactor. In a first low-temperature heat exchanger (denoted "HX" on the left in Figure 1), the air is heated up by a "sweep gas" to reach the working temperature of the MCM, typically above 800 °C (in this study, the gas circulating on the permeate side of the membrane reactor is generally referred to as sweep gas). The hot air then enters the MCM, which consists of materials with both ionic and electronic conductivity. An oxygen partial pressure difference causes oxygen ions to be transported through the membrane by a diffusive process. Simultaneously, the electrons flow from the permeate side back to the retentate side of the membrane (Figure 2). The transport of oxygen through the membrane increases with increasing temperature. However, in order to avoid significant degradation of the membrane, there is also an upper temperature limit, which is material dependent. In the present study, 1075 °C was chosen as the maximum allowable temperature of the membrane. The operating pressure on both sides of the membrane is approximately 20 bar. After leaving the MCM, the oxygen-depleted air is heated up further in a high-temperature heat exchanger (on the right-hand-side of the MCM module) to about 1250 °C by the permeate stream, before it enters the turbine section where it is expanded to generate power.

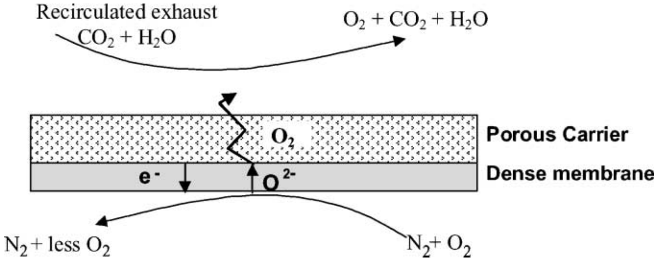

Figure 2: Schematic drawing of the MCM membrane.

The sweep gas is a combustion gas produced in the integrated combustion chamber (CC) by combustion of hydrocarbon fuel in a nitrogen-free environment. The sweep gas leaving the CC consists basically of carbon dioxide and water. It is cooled down in the heat exchangers and the MCM, where it also picks up the oxygen diffusing through the membrane. After the low-temperature heat exchanger, fuel is injected into the sweep gas to sustain the combustion.

A part of the sweep gas must be bled of to maintain the mass balance. In the process shown in Figure 1, the bleed gas is led to a bleed gas heat exchanger, where it is used to heat up an additional air mass flow. This additional flow is mixed with the oxygen-depleted air from the high-temperature heat exchanger and thus increases the total mass flow through the turbine. The water in the bleed gas might then be condensed out and the remaining bleed (mostly carbon dioxide) can be compressed and liquefied (this is not shown in the picture).

The described power plant emits no CO_2 to the atmosphere and is a very efficient way of producing power while capturing the carbon dioxide. The efficiency losses as compared to a conventional gas turbine are mainly due to the following constraints:

- The temperature of the hot air leaving the MCM reactor is limited to approximately 1250 °C due to material constraints. This limits the power output of the turbine and hence the efficiency of the power plant. To work around this constraint, a supplementary firing or “afterburner” could be added downstream of the MCM reactor to further raise the turbine inlet temperature. Although this alternative will lead to some CO_2 emissions, it might still be the more economic concept and was included as an option in this study.
- The energy of the bleed gas, which is under high pressure, is used only partially in the bleed gas heat exchanger. The bleed stream leaves the system at the high-pressure level of the gas turbine. An efficient way of tapping this potential would be to use a bleed turbine (BT) instead of the heat exchanger and expand the gas, thus producing additional electricity (or shaft power). The working fluid of this turbine, however, would be a mixture of 1/3 of carbon dioxide and 2/3 of water, at a temperature of more than 1200 °C. Such a turbine would require a very high development effort and is presently far from being commercially available. This option, however, was also pursued in this study to show the full potential of the MCM power concept.
- Finally, some energy is needed to compress and liquefy the captured carbon dioxide. The energy consumption of this process depends mainly on the amount and the pressure of the captured CO_2 and the conditions at which it is to be delivered.

Thermodynamic Analysis of the Investigated Plant Concepts

The Alaska scenario

This study was aimed at the investigation of MCM-based power plants in simple cycle configuration. The CCP scenario "D", a BP gas gathering and processing facility in Prudhoe Bay, Alaska, has been chosen. In this scenario, 11 small gas turbines are currently installed performing mechanical drive duties like sea water injection, refrigeration etc. The installed gas turbines are listed in Table 1. The anticipated sink for the captured CO_2 is onshore enhanced oil recovery (EOR). For simplicity, only the summer scenario was considered for the ambient air conditions. Table 2 gives the relevant data.

TABLE 1
INSTALLED GAS TURBINES ACCORDING TO THE CCP ALASKA SCENARIO

# installed units	Type	Model	Horsepower
4	Rolls Royce RB-211	Coberra 6456	30,000
3	GE Frame 5	GE MS-5382-C	40,000
4	GE Frame 6	GE MS-6001-B	60,000

TABLE 2
AMBIENT CONDITIONS, ALASKA SUMMER SCENARIO

Design temperature (°C)	15
Design pressure (bar)	1.01325
Relative humidity	50%

The *raw* gas composition was provided by the CCP scenario definition and is given in Table 3. The lower heating value (LHV) of the gas was calculated from the power plant modeling tool (GateCycle™). The fuel gas is a residue gas collected from a low-temperature separation system. The residue gas is available at approximately 700 psi (ca. 48 bar) and is delivered to the gas turbines at approx. 350 psi (ca. 24 bar). The fuel gas is typically at a temperature of 15–21 °C, with a dew point of −37 to −40 °C. To avoid condensation of hydrocarbons, sulfur containing compounds or water, the fuel gas temperature must be at least 40 °C. Since the gas contains some sulfur in the form of hydrogen sulfide (H_2S) and the MCMs are

TABLE 3
RAW NATURAL GAS FUEL COMPOSITION

Component	Vol%
Methane	79.80
Ethane	5.35
Propane	1.76
i-Butane	0.13
n-Butane	0.25
i-Pentane	0.03
n-Pentane	0.03
n-Hexane	0.07
Carbon dioxide	11.92
Nitrogen	0.65
Hydrogen sulfide	20.0 ppmv

sensitive to sulfur, it was decided to include a desulfurization unit in the plant. Non-regenerative fixed bed desulfurization units based on zinc oxide were chosen.

Some data regarding the heating value of the gas and delivery conditions prior to the fuel gas control valve after the raw gas has been treated to meet the required demands are given below:

- LHV of the gas: 36,647 kJ/kg (calculated by GateCycle™)
- Delivery temperature 400 °C (after FGD unit, delivery temperature 200 °C for Model 3)
- Delivery pressure 24 bar

The gas composition *after* the flue gas treating steps is given in Table 4.

TABLE 4
TREATED NATURAL GAS FUEL COMPOSITION

Component	**Vol%**
Methane	79.80
Ethane	5.35
Propane	1.76
i-Butane	0.13
n-Butane	0.25
i-Pentane	0.03
n-Pentane	0.03
n-Hexane	0.07
Carbon dioxide	11.92
Nitrogen	0.65
Hydrogen sulfide	0.0 ppmv

The captured CO_2 stream is intended for an EOR application, following transmission from the capture plant site via a high-pressure pipeline. The product stream must therefore meet the requirements stated in Table 5 according to CCP. An active dehydration unit with tri ethylene glycol (TEG) and removal of non-condensable gases in the liquefaction process was used to bring the water content of the CO_2 down to 50 ppm. In a three-stage process, the CO_2 is compressed to 221 bar and cooled down to 20 °C. The chosen process for the CO_2 compression/liquefaction and drying is based on a study of Birkestad [3].

TABLE 5
CO_2 PRODUCT STREAM REQUIREMENTS

Carbon dioxide quality	**Deposit grade**	**Unit of measure**
Purity (dry basis)	97	(Mol%) min.
Pressure	220	(bar)
Temperature	50	(°C) max.
Moisture content	50	(ppmv) max.
O_2	To be minimized	–
Total sulfur	To be minimized	–

Although the MCM concept is applicable for retrofits, it was decided to "replace" the installed gas turbines with the GTX100 machine, since this facilitates the transfer of results from the AZEP project to this investigation. Another reason was the accessibility of detailed thermodynamic and economic data for the gas turbine, which is very limited for competitor's machines. Since the performance characteristics of an MCM-powered gas turbine will differ from the installed machines, it was decided not to run the GTX100 gas turbines in mechanical drive application, but to generate electricity for electric motor conversion. This will add slightly to the investment costs, but it will allow for reliable scaling of the power for the different applications and increase overall availability. Table 6 gives some characteristics of a conventionally powered GTX100 in simple cycle configuration.

TABLE 6
DATA FOR A CONVENTIONAL GTX100 IN SIMPLE CYCLE CONFIGURATION (ISO-CONDITIONS)

Electrical output	43.7 MW
Electrical efficiency	36.0%
Heat rate	9998 kJ/kWh
Compressor pressure ratio	19.7:1

The total power needed in the reference scenario amounts to 480,000 hp (ca. 358 MW). The GTX100 has an electrical power output of 43.7 MW, and this is equal to about 58,000 hp Nine GTX100 gas turbines are thus needed to cover the power demand for the selected scenario. When implementing the new power plant concepts (MCM based), more engines are needed since the power output per unit will be lower than for the GTX100. The exact amount of engines needed depends on the power output per unit and therefore on the investigated configuration (see "Results and Discussion").

In a first study, different ways of handling the exhaust gas enthalpy were considered. An economically efficient way of using of the atmospheric hot air exhaust turned out to be difficult in a simple cycle configuration. However, different promising concepts of making use of the pressurized MCM bleed stream were identified. Three different plant concepts were investigated in detail.

Model 1: bleed heat exchanger

The first model, hereafter named "Model 1", includes a heat exchanger to heat up a part of the air from the compressor with the bleed stream. This will reduce the amount of fuel needed in the combustor and thus increase the thermodynamic performance of the plant. Figure 3 shows a simplified schematic of the concept.

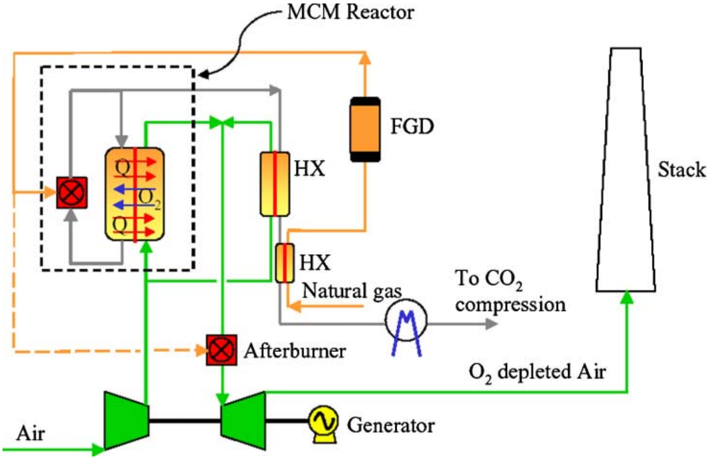

Figure 3: Model 1, utilizing a bleed gas heat exchanger.

The model is basically a simple cycle variation of the process shown earlier in Figure 1. A part of the compressor air is extracted from the compressor outlet and is heated up by the bleed stream. The hot air is then mixed with the oxygen-depleted air from the high-temperature heat exchanger prior to expansion in the air turbine. In addition to the energetic benefit from the heat transfer, the size of the sweep condenser is reduced. The oxygen-depleted expanded air is emitted via a stack. Since no combustion has taken place on the airside, no NO_x, SO_x or UHC emissions will be emitted, leading to a so-called zero emission process.

A fuel gas desulfurization (FGD) unit was included in all models to remove the hydrogen sulfide (H_2S) from the gas. The FGD unit was designed to operate at 400 °C, which entails a pre-heating of the fuel. This can be done by an additional heat exchanger (HX) that made further use of the bleed stream. After the bleed gas is cooled down in the two heat exchangers, it is led into a condenser for further cooling and removal of the largest part of the water. Since the bleed gas is still under high pressure (ca. 20 bar), this will save compression work in the CO_2 liquefaction train. The relatively pure CO_2 stream is then dried, compressed, and liquefied for pipeline transportation.

As shown in Figure 3, two combustors are installed. The upper one is part of the MCM reactor and is used to heat up the sweep gas to 1250 °C. The second CC (afterburner) is optional and can be included to further raise the temperature of the oxygen-depleted air. This will increase the efficiency and power output of the plant at the cost of emitting some CO_2. Since only a small fraction of the total fuel stream is used in the afterburner, the total CO_2 emissions produced by this supplementary firing will be much lower than the emissions of a conventional power plant. Depending on the financial penalties for CO_2 emissions and on the increase in efficiency attained by the supplementary firing, the afterburner might bring substantial economical benefits, and it was decided to investigate this alternative as an option for all investigated models. The name convention used in the following is "*Case A*" *for the cycles without supplementary firing* (0% CO_2 emissions) and "*Case B*" *when supplementary firing is included*. The afterburner was designed to further increase the gas temperature approximately 1380 °C.

It should be mentioned, however, that with today's burner technology there would be a high risk of self-ignition in the afterburner. The high inlet temperature to the combustor (ca. 1242 °C) makes the auto-ignition time in the combustor very short, obstructing the mixing of air and fuel. Good mixing is important to avoid "hot spots" in the combustion zone that will lead to high emissions (NO_x). To use commercially available burners, a lower inlet temperature (approximately 1100 °C) would be required, increasing the fuel consumption in the afterburner.

Model 2: bleed turbine

The second configuration that was investigated in detail is referred to as "Model 2", see Figure 4. This process makes use of a BT. The hot and pressurized bleed flow extracted from the MCM reactor is expanded through a turbine to produce additional electricity, improving the efficiency of the plant. As the bleed gas consists of about 33 vol% CO_2 and 67 vol% H_2O at high temperature (1250 °C), a new kind of turbine would have to be developed. This of course adds another risk to this configuration. Since the MCM-based power concept is a technology under development, this uncooled bleed turbine was considered a possible option in the long-term future. Model 2 was included in the scope of this study to show the full potential of a simple cycle MCM-based gas turbine power plant.

After the expansion in the bleed turbine, the gas is led into a heat exchanger to preheat the fuel gas. This reduces the temperature of the bleed stream to approximately 600 °C. Prior to compression and drying the gas has to be cooled down further in a flue gas condenser, analogous to Model 1 (see above). The bleed gas is expanded to ca. 1 bar in the bleed turbine, leading to a higher CO_2 compression work than in Model 1. Since only the CO_2 fraction of the bleed stream needs to be compressed, the increased compression work is more than compensated for by the power output of bleed turbine.

Model 3: water injected bleed turbine

Figure 5 depicts the plant layout for Model 3. This process is similar to Model 2. The main difference is that hot water is injected upstream of the bleed turbine to quench the temperature down to a level close to conventional steam turbines. This enables the use of a steam turbine derivative as the bleed turbine instead of the development of an entirely new device. The water needed for the injection can be obtained from the condenser if water resources are scarce. The water must be cleaned and demineralized prior to the injection,

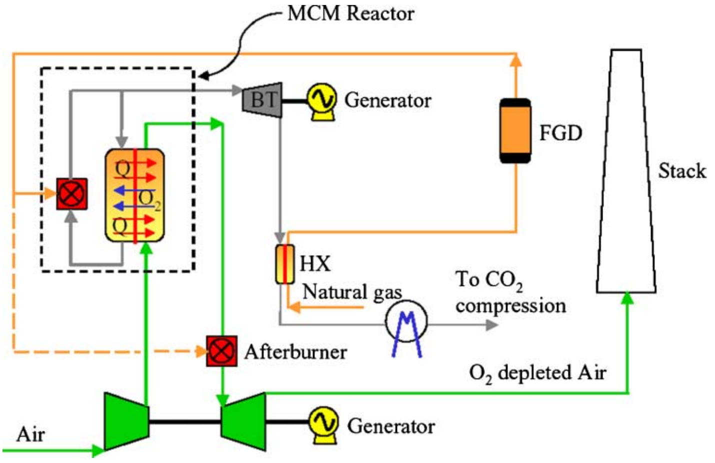

Figure 4: Model 2, utilizing a bleed gas turbine ("BT").

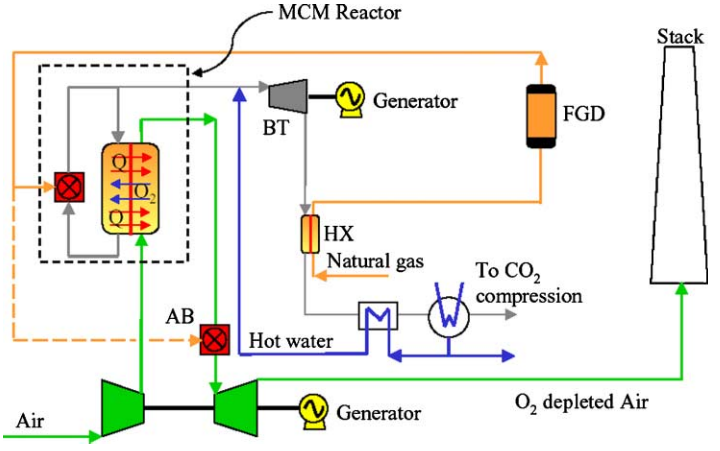

Figure 5: Model 3, utilizing a water injected bleed gas turbine ("WIBT").

leading to slightly higher investment and operating costs. In the modeled configuration, the water from the condenser is heated in an economizer.

In this configuration, the fuel gas can only be heated up to 200 °C before entering the FGD. This leads to a slightly higher consumption of zinc oxide in the FGD and a slightly lower efficiency of the process. Further preheating the fuel gas by heat exchange with the oxygen depleted exhaust air would cause an explosion risk due to the remaining oxygen in the air (approximately 14–15 vol%), and would markedly increase the investment costs due to the large volume flow of the exhaust gas.

In addition to lowering the bleed turbine inlet temperature, the injected water also increases the mass flow through the bleed turbine and thus improves the power output. Although the thermodynamic performance of the water injected bleed turbine is inferior to the uncooled turbine in Model 2, this configuration might be a good compromise between efficiency and feasibility.

Economic Analysis

The economic results were calculated with an ALSTOM in-house tool. In the present study, the cost of electricity (CoE) in the first year of operation will be used as the core economic indicator to evaluate the proposed power plants.

Power plant assumptions

The modeled power plant is based on a GTX100 machine in simple cycle configuration. The costs for the GT components were obtained internally within ALSTOM, whereas the costs for the MCM reactor and FGD unit were obtained from Norsk Hydro. Cost and financial assumptions were used as provided by the "CCP scenario definition" and "CCP common price and unit cost assumptions". When parameters were missing and where the supplied values were not applicable (e.g. maintenance concept for MCM reactor), values were assumed based on in-house experience or input from the corresponding technology providers.

Turnkey project cost

The turnkey project cost of a plant is a key component of the CoE. For a new plant concept, this cost can be calculated starting from the component costs of the technology. Basically, the known costs of existing systems for a certain size are scaled to the new plant using appropriate scale factors (e.g. six-tenth rule) and the results from the thermodynamic process simulation. The base equipment costs include labor but exclude civil and indirect costs. Their sum is referred to as *Direct Plant Costs for Plant Technology*, or *Plant Technology Cost*. To obtain the *Turnkey Project Cost*, we used the following procedure for the conventional equipment of the plants, if no other information was available:

- The *Direct Plant Costs for the Civil Part*, or direct *Civil Cost* are generally assumed to be 10% of the *Plant Technology Cost*, if no other data are available. *Plant Technology Cost* and *Civil Cost* together make up the *Direct Plant Cost*.
- *Indirect Costs* (including transport, erection on site, engineering, management, commissioning, etc.) are generally assumed to be 35% of the *Plant Technology Cost*.
- When *Overheads* (insurances, bonds and risks; administration and acquisition; R&D; commissions; profit margin) are added to the sum of the direct and indirect costs, the *Engineering, Procurement and Construction Cost* (*EPC Cost*) is obtained. A total overhead of 20% for the plant technology and 10% for the civil part were assumed.
- Finally, the *Project Costs* for the plant owner are added, which include project development services, land purchase, outer development and infrastructure, spare parts and operating supplies, contingencies, and interest during construction. These together with the *EPC Cost* make up the *Turnkey Project Cost*, which is the total initial investment to be made.

The plant technology can be divided into two categories: conventional plant technology and additional plant technology. The conventional plant technology is classified as components conventionally used in a present-day gas turbine power plant. Additional plant technology represents any new components added to the plant. For example, cooling water systems are present in power plants (combined cycles) but not flue gas condensers. Detailed conventional plant technology cost data for the GTX100 were obtained internally within ALSTOM.

For the MCM-based power plant concepts, the gas turbine costs will differ slightly from the reference case. The CC is withdrawn from the gas turbine set, and built into the MCM reactor instead. This will lower the "gas turbine set costs", and add to the "additional plant technology costs". Additionally, the generator costs and the costs for the electrical equipment are scaled on the basis of the power output of the plant.

Project cost and cost of electricity assumptions

Table 7 lists the assumptions used to calculate the economic figures for the different power plant concepts. Some financial factors (e.g. debt share, tax rate, interest rates) were provided by CCP. In addition to the data in Table 7, the following should be noted:

- The variable maintenance cost is assumed to be proportional to the EPC cost, divided into maintenance of the plant technology part and maintenance of the civil part. For the MCM reactor, however, a different maintenance concept has been chosen. The ceramics of the MCM reactor have to be exchanged every five years. To do so, the plant has to be shut down, the reactor has to be opened, and all the piping and connections have to be removed. Based on the experience with conventional "hot path" gas turbine equipment—and to keep the model simple—we assumed that it would be more realistic to exchange the entire reactor every five years.

- The total land area needed will vary depending on the number of units needed to cover the total power demand of 358 MW_e. At the assumed land price, the impact of the required land area is almost negligible.
- The number of personnel varies from plant to plant. The GTX100 plants (44 MW/unit) are assumed to have 27 people employed (for all units), while the MCM power plant cases are assumed to have 32 people employed.

TABLE 7
ASSUMPTIONS FOR THE ECONOMIC EVALUATION

Project investment cost assumptions		
Project development services	10% of EPC	
Site purchase	8 US$/m^2	
Outer development + infrastructure	5% of EPC	
Initial spare parts + operating supplies	1% of EPC	
Contingencies	3% of EPC	
Debt share of capital	100%	
Equity share of capital	0%	
Income tax rate	0%	
Cost of dept (interest rate)	10%	
After-tax cost of debt	10%	
Discount rate	10%	
	Reference case	*MCM based*
Required land area per GT unit	2150 m^2	2688 m^2
Construction period	18 months	24 months
Further project and financial assumptions		
Inflation rate (O&M escalation)	2%/a	
Fuel price escalation rate	2%/a	
Electricity/heat price esc. rate	2%/a	
Operation period	25a	
Debt repayment period	25a	
	Reference case	*MCM based*
Operating hours	7,800 h/a	7,800 h/a
Reliability factor	98%	96%
Availability factor	93%	91%
Variable O&M assumptions		
Fuel energy price (e.g. natural gas, fuel oil)	10.24 US$/MWh (3.0 US$/MMBTU)	
Demineralized water	0.2 US$/ton	
Maintenance of plant technology part	4% of EPC tech./a	
Maintenance of civil part	1% of EPC civil/a	
MCM reactor completely replaced every	5 years	
Fixed O&M assumptions		
Personnel salary	98,400 US$/per./a	
Administration	250,000 US$/a	
Laboratory/analysis	62,000 US$/a	
Taxes (w/o income tax), insurances, licenses	1.5% of EPC/a	

RESULTS AND DISCUSSION

Thermodynamic Results

This section presents the thermodynamic results of the study, obtained by simulation of the processes with GateCycle™ software and Excel™-based modules that were used to model the MCM reactor. Figure 6 gives a quick comparison of the most important results, i.e. net electric efficiency, net electric power output, and CO_2 avoidance rate. The increased fuel consumption of the different MCM-based plants (compared to the non-capture reference plant) is listed in Table 8.

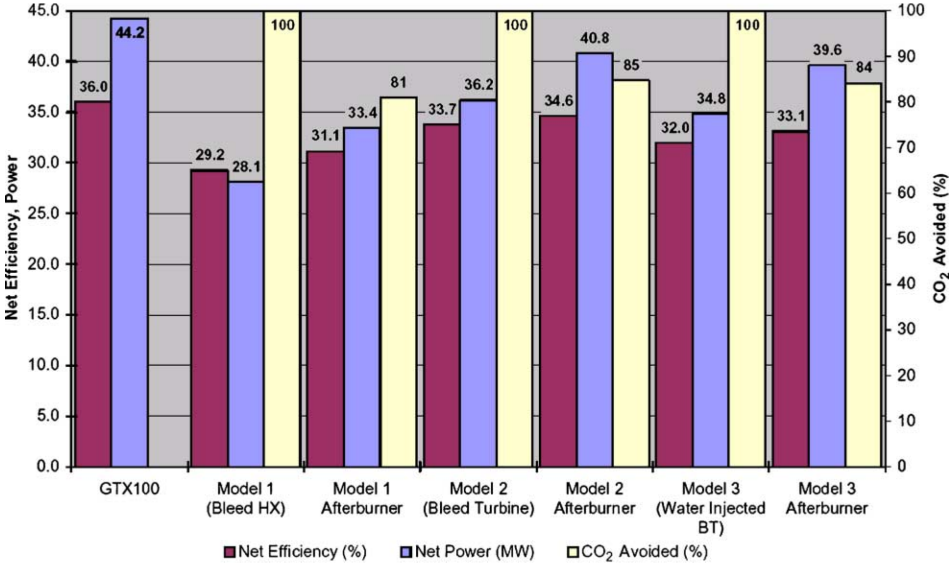

Figure 6: Thermodynamic results for the investigated concepts.

TABLE 8
FUEL CONSUMPTION (MMBTU/KWH$_E$)

Model	GTX100	1A	1B	2A	2B	3A	3B
Fuel consumption	9471	11,672	10,961	10,113	9850	10,679	10,324
Diff. to GTX100		2201	1490	642	379	1209	853

1, 2, 3 = Model; A = no suppl. firing; B = suppl. firing.

Reference case, GTX100

The GTX100 machine is a modern gas turbine with both good performance and low emissions. Due to its robust simplicity, the life-cycle costs are very low. The performance for the GTX100 at ISO-conditions has already been shown. When applying the ambient conditions from the scenario description and the fuel composition thereof, the performance data given in Table 9 are obtained.

Model 1: case A, bleed heat exchanger without supplementary firing

Like all cases denoted with "A" (i.e. no supplementary firing), this configuration represents a zero emission concept. The process calculations simulations yield the performance characteristics given in Table 10.

TABLE 9
THERMODYNAMIC RESULTS FOR THE REFERENCE CASE, GTX100

Electrical efficiency	36.0%
Electrical output	44.2 MW_e
Fuel consumption per unit	3.35 kg/s
Compressor pressure ratio	19.7:1
Heat rate	9,992 kJ/kWh_e
Total CO_2 produced	0.64 kg/kWh_e
Total CO_2 captured	0.00 kg/kWh_e
Specific CO_2 emissions	0.64 kg/kWh_e
CO_2 avoidance rate	0%
Number of units needed	9
Total power output	398 MW_e
Total fuel consumption	30.14 kg/s

TABLE 10
THERMODYNAMIC RESULTS FOR MODEL 1, CASE A

Net electrical efficiency	29.2%
Net electrical output per unit	28.1 MW_e
Fuel consumption per unit	2.63 kg/s
Power for CO_2 compression per unit	0.53 MW
Compressor pressure ratio	19.7:1
Heat rate	12,314 kJ/kWh_e
Total CO_2 produced	0.78 kg/kWh_e
Total CO_2 captured	0.78 kg/kWh_e
Specific CO_2 emissions	0.00 kg/kWh_e
CO_2 avoidance rate	100%
Number of units needed	13
Total net power output	366 MW_e
Total fuel consumption	34.15 kg/s
Total power for CO_2 compression	6.85 MW

Bleed HX, no Suppl. Firing.

The relatively high losses in electrical efficiency and power output compared to the reference case (GTX100) are mainly due to two reasons. The temperature into the turbine is lower compared to the conventional GTX100, because the high-temperature heat exchanger sets a limit to the combustion temperature. In the process calculations, we used a maximum temperature of 1250 °C, which is substantially lower than the GTX100 design temperature. The second reason for the performance penalty is the loss of mass flow in the MCM due to the oxygen separation. This part of the stream is not available for in the turbine, leading to a diminished power output. On the other hand, this loss of mass flow leads to a lower fuel consumption per unit, because less working medium has to be heated up in the combustor.

Additionally, some power is consumed in the CO_2 compressors and the CO_2 pump. These losses are relatively small for Model 1, because the CO_2 enters the compression train at a high pressure level of almost 20 bar.

Model 1: case B, bleed heat exchanger with supplementary firing
Integrating the supplementary firing raises the thermodynamic performance of the plant considerably. First, the temperature of the gas leaving the MCM reactor is raised to approximately 1380 °C. This increases

the net electrical efficiency of the plant by 6% (or 1.9%-points). Additionally, the fuel consumption increases by 11% and both factors together account for an increase in total net power output of 18% compared to Case A. Table 11 shows the results for Model 1 with afterburner.

TABLE 11
THERMODYNAMIC RESULTS FOR MODEL 1, CASE B

Net electrical efficiency	31.1%
Net electrical output per unit	32.4 MW_e
Fuel consumption per unit	2.93 kg/s
Power for CO_2 compression per unit	0.49 MW
Compressor pressure ratio	19.7:1
Heat rate	11,564 kJ/kWh_e
Total CO_2 produced	0.74 kg/kWh_e
Total CO_2 captured	0.61 kg/kWh_e
Specific CO_2 emissions	0.12 kg/kWh_e
CO_2 avoidance rate	81%
Number of units needed	11
Total net power output	368 MW_e
Total fuel consumption	32.23 kg/s
Total power for CO_2 compression	5.39 MW

Bleed HX, no Suppl. Firing.

Due to the markedly increased power output, only 11 units are needed to provide the power demand given in the scenario definition. The power consumed in the CO_2 compression train per unit is close to the value obtained for Case A, but due to the smaller number of units needed, the total power for CO_2 compression decreases.

One thermodynamic drawback of the increased turbine inlet temperature is the increased cooling demand for the turbine. However, the increased performance of the turbine more than compensates for this penalty. It is obvious that the turbine inlet temperature has a major influence on the cycle performance. The costs of the increased performance are the CO_2 emissions that lower the avoidance rate to 81%. How this affects the economic performance of the plant has been investigated in the economic evaluation.

Model 2: case A, bleed turbine without supplementary firing

The results for Model 2, Case A, are shown in Table 12. It is obvious that the performance of this configuration is substantially better than for Model 1. The reason is the use of a bleed turbine, which makes use of a much larger part of the bleed stream enthalpy than a simple heat exchanger.

The power output of the plant is raised by almost 29% compared to Model 1, Case A. A part of this is associated with the higher fuel consumption (+11%), while an even bigger part is due to the higher net efficiency (+4.5%-points or +15.4%). The reason for the higher fuel consumption is that the energy recovered from the bleed stream is not led back into the main turbine to substitute a part of the energy conversion in the CC. Instead, the bleed stream is used entirely to drive the bleed turbine, producing electricity and leaving the system at low enthalpy. This markedly raises the total efficiency, while the mass flow through the CC increases as well.

The power consumption for the CO_2 compression train increases excessively, because the bleed stream is expanded down to 1 bar in the bleed turbine, and hence more compression work is needed. The produced power from the bleed turbine more than compensates for this, since the bleed stream consists of approximately 2/3 of water and only 1/3 of carbon dioxide.

TABLE 12
THERMODYNAMIC RESULTS FOR MODEL 2, CASE A

Net electrical efficiency	33.7%
Net electrical output per unit	36.2 MW_e
Fuel consumption per unit	2.93 kg/s
Power for CO_2 compression per unit	2.36 MW
Power produced by bleed turbine per unit	10.9 MW
Compressor pressure ratio	19.7:1
Heat rate	10,670 kJ/kWh_e
Total CO_2 produced	0.68 kg/kWh_e
Total CO_2 captured	0.68 kg/kWh_e
Specific CO_2 emissions	0.00 kg/kWh_e
CO_2 avoidance rate	100%
Number of units needed	10
Total net power output	362 MW_e
Total fuel consumption	29.25 kg/s
Total power for CO_2 compression	23.63 MW

Bleed HX, no Suppl. Firing.

Model 2: case B, bleed turbine with supplementary firing

When supplementary firing is used for Model 2, the efficiency improves slightly, going up another 0.9%-points or 2.6%, see Table 13. The fuel consumption increases by almost 10%, and accumulated effect is an increase in total net power output of almost 13%, compared to Case A. Like in Model 1, the costs of this improvement are the carbon dioxide emissions associated with the supplementary combustor. With the power output approaching the value for the reference case, this plant shows the best performance amongst the MCM-powered cycles.

TABLE 13
THERMODYNAMIC RESULTS FOR MODEL 2, CASE B

Net electrical efficiency	34.6%
Net electrical output per unit	40.8 MW_e
Fuel consumption per unit	3.22 kg/s
Power for CO_2 compression per unit	2.22 MW
Power produced by bleed turbine per unit	10.2 MW
Compressor pressure ratio	19.7:1
Heat rate	10,329 kJ/kWh_e
Total CO_2 produced	0.66 kg/kWh_e
Total CO_2 captured	0.56 kg/kWh_e
Specific CO_2 emissions	0.10 kg/kWh_e
CO_2 avoidance rate	85%
Number of units needed	9
Total net power output	367 MW_e
Total fuel consumption	28.94 kg/s
Total power for CO_2 compression	19.96 MW

Bleed HX, no Suppl. Firing.

It should be noted, however, that the bleed turbine in Model 2 is uncooled. With a bleed turbine inlet temperature of more than 1200 °C and a working fluid consisting mainly of water and carbon dioxide, such a turbine is far from commercial availability. However, the results for Model 2 show the full potential of the MCM concept when applied to a simple cycle.

Model 3: case A, water injected bleed turbine without supplementary firing
The main difference between Models 2 and 3 is that the latter uses water injection upstream of the bleed turbine to quench the temperature down to 600 °C. With such a turbine inlet temperature, the use of a derivative from a conventional steam turbine seems possible. Some modifications to the steam turbine will be necessary to account for the different working medium (H_2O and CO_2). The thermodynamic results for this concept are given in Table 14.

TABLE 14
THERMODYNAMIC RESULTS FOR MODEL 3, CASE A

Net electrical efficiency	32.0%
Net electrical output per unit	34.8 MW_e
Fuel consumption per unit	2.97 kg/s
Power for CO_2 compression per unit	2.39 MW
Power produced by bleed turbine per unit	9.7 MW
Compressor pressure ratio	19.7:1
Heat rate	11,263 kJ/kWh_e
Total CO_2 produced	0.72 kg/kWh_e
Total CO_2 captured	0.72 kg/kWh_e
Specific CO_2 emissions	0.00 kg/kWh_e
CO_2 avoidance rate	100%
Number of units needed	11
Total net power output	383 MW_e
Total fuel consumption	32.71 kg/s
Total power for CO_2 compression	26.34 MW

Water Inj. Bleed Turbine, no Suppl.

The increase in fuel consumption compared to Model 1 is virtually the same as for Model 2. With a raise in net efficiency of 9.6% (2.8%-points), the electrical power output is 24% higher than for Model 1. The water injected bleed turbine thus substantially improves the power plant performance. The gap with respect to the most advanced model (Model 2) is due to the depletion of energy associated with the mixing of hot bleed gas with cold water.

Model 3: case B, water injected bleed turbine with supplementary firing
The supplementary combustor adds another 4.8% MW or 13.8% to the power output of the plant, bringing the avoidance rate down to 84%. Similar to Model 2, the supplementary combustor has a major effect on the power output while raising the net efficiency only slightly. Table 15 gives the most important thermodynamic results for this concept.

Results of the Economic Analysis
This section shows and explains the results of the economic analysis. The thermodynamic performance and CO_2 emissions were used as given in the preceding sections. Note that different numbers of gas turbine units are required for the individual concepts to cover the total power demand. The absolute numbers hence reflect the costs for the *complete* plant, consisting of several units. Since the different configurations have slightly different total power output, specific costs can be considered more "fair" when comparing the different concepts.

Many of the equipment costs and prices used in this study are based on €. To comply with the standards provided by CCP, we calculated the economic parameters in terms of US$. We used the exchange rate of €1.2 per US$ (based on March 2002) as supplied by CCP. It must be pointed out, however, that due

TABLE 15
THERMODYNAMIC RESULTS FOR MODEL 3, CASE B

Net electrical efficiency	33.1%
Net electrical output per unit	39.6 MW_e
Fuel consumption per unit	3.27 kg/s
Power for CO_2 compression per unit	2.26 MW
Power produced by bleed turbine per unit	9.1 MW
Compressor pressure ratio	19.7:1
Heat rate	10,886 kJ/kWh_e
Total CO_2 produced	0.69 kg/kWh_e
Total CO_2 captured	0.59 kg/kWh_e
Specific CO_2 emissions	0.10 kg/kWh_e
CO_2 avoidance rate	84%
Number of units needed	10
Total net power output	396 MW_e
Total fuel consumption	32.69 kg/s
Total power for CO_2 compression	22.57 MW

Water Inj. Bleed Turbine, no Suppl.

to the recent changes of the exchange rate, this method does not reflect the current economic situation accurately. The cost for the MCM reactor, for instance, were given to us in terms of US$, based on current exchange rates. By mixing these prices with prices based on the exchange rate as of March 2003, the MCM technology appears overly expensive. On the other hand, the conventional gas turbine technology, estimated in € and converted to US$ with the old exchange rate, appears too inexpensive.

Investment costs

The specific investment costs, i.e. turnkey project cost divided by power output, for the investigated cycles are shown in Figure 7. The GTX100 has a specific investment cost of roughly 390 US$/kW under the assumptions and conditions in the considered scenario. This cost is dominated by the gas turbine components with the electrical equipment, instrumentation and control making up the rest. For the MCM powered alternatives the specific costs for the additional plant technology (MCM reactor, sweep gas train, fuel gas treatment, afterburner) amount to approximately 100–115% of the basic gas turbine set cost (including electrical equipment and instrumentation and control). The specific cost for the CO_2 compression unit (including purification and liquefaction) is 10–15% of the GT cost, or ca. 6% of the total investment.

In the more basic concepts, e.g. Model 1, the added investment is not only due to the additional plant technology but also because more units are needed to achieve the required total power output. The more advanced cycles, e.g. Model 2, however, need approximately the same number of units as the reference case. In theses concepts, the added investment is primarily associated with the additional plant technology.

All concepts with afterburner have markedly lower specific investment costs than their counterparts without this device. This shows that the supplementary combustor is a cheap way of considerably raising the power output of the MCM-based power plants. Of course, neither the increased operating costs due to the higher fuel consumption nor the costs associated with the CO_2 emissions produced by the burner are visible in the diagram. Model 2 with afterburner has the lowest specific investment costs among the MCM plants. This is the expected result since only nine units are needed in this configuration, due to the high power output of this very advanced concept.

Figure 7 also shows that the specific investment costs for the MCM-powered concepts are 120–170% higher than for the reference case. For the original AZEP power plant (see for instance Eklund et al. [1]), the fraction of the costs associated with the CO_2 capture is distinctly lower, because the original AZEP concept

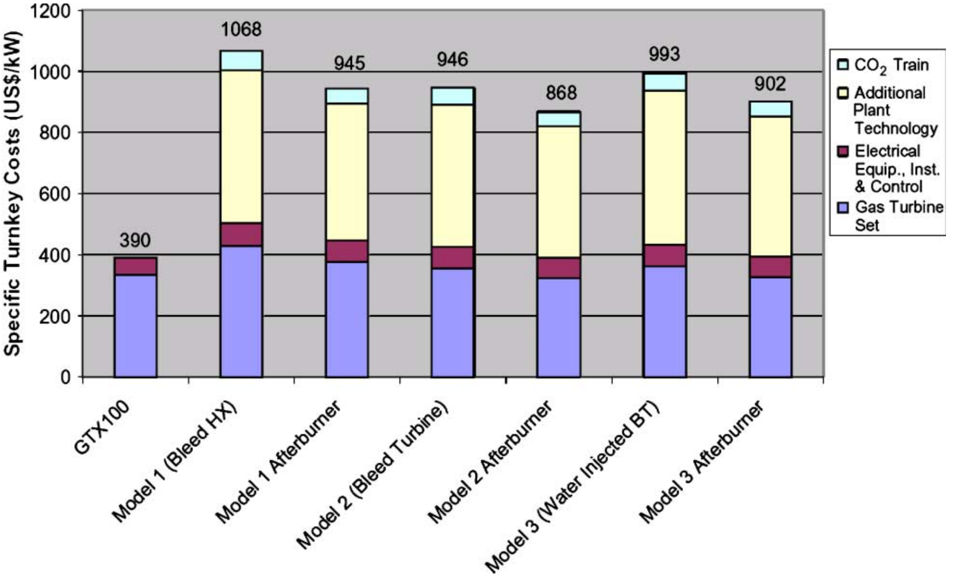

Figure 7: Specific investment costs for all cycles.

is a combined cycle configuration. The added investment for the MCM-based concepts investigated here compares very well with other CO_2 mitigation options, especially when taking into account that the MCM-powered plants without afterburner have 100% CO_2 capture.

Cost of electricity

The CoE is probably the most important economic indicator for power generation plants. Figure 8 and Table 16 show these costs for the investigated concepts, broken down into costs associated with capital debt, fuel costs, variable and fixed operating and maintenance costs. The largest fractional costs are the costs of fuel and these vary mainly with the efficiency of the different power plant concepts. The cost of capital and the fixed O&M costs depend on the investment costs for the power plant and thus reflect the differences in turnkey project costs. The additional plant technology needed for the MCM-based power plants needs a higher level of maintenance and operating personnel than the reference case of the basic GTX100. Especially the MCM reactor causes significantly higher maintenance costs than conventional equipment.

In the Alaska scenario provided by CCP, the captured CO_2 is intended for EOR and thus possesses an economic value. Additionally, a financial penalty (referred to as the "CO_2-tax") is associated with the emission of carbon dioxide to the atmosphere. For reasons of clarity, however, the corresponding sales revenues and costs are not included in Figure 8.

Figure 9 shows the CoE as a function of a hypothetical CO_2-tax. Again, no revenues from CO_2 production are accounted for. At zero CO_2-tax, the GTX100 is—for obvious reasons—the preferred choice, with a CoE of ca. 37 US$/MWh. When a CO_2-tax is taken into consideration, the MCM-powered concepts become economically more attractive. Since the cases without afterburner are real zero emission processes, their CoE is not affected by a CO_2-tax. The plants using an afterburner will emit some CO_2, which will lead to a moderate increase of the corresponding CoE with carbon dioxide tax. The correlation is, of course, much weaker than for the non-capture reference case. The assumed CO_2-tax in the CCP scenario description is 20 US$/ton. Figure 9 indicates that the added CoE for the different MCM-based plants is very low, even when the value of the captured carbon dioxide is not considered.

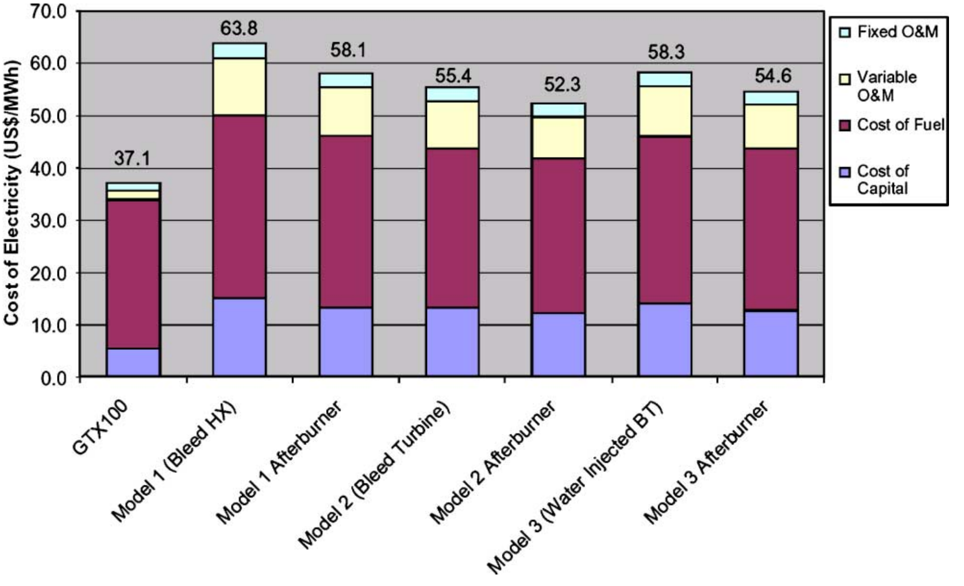

Figure 8: CoE breakdown. Neither the value of captured CO_2 nor a CO_2-tax are considered.

Figure 10 shows the CoE, when the value of the captured carbon dioxide is accounted for. The "common price unit and cost assumptions" provided by CCP suggest a product price of 20 US$/ton carbon dioxide. This value can be subtracted from the CoE and this has been done in Figure 10. The value suggested by CCP for a "CO_2 emission cost" (i.e. CO_2-tax) is also 20 US$/ton. This value is shown as a dashed black line in the diagram. It can be seen that Models 2 and 3 will have a lower CoE than the non-capture reference case when these costs are considered. The basic MCM based concept, Model 1, yields a CoE that is just slightly higher than for the reference case. The diagram clearly shows that an MCM-based plant can be the better alternative—not only from an environmental but also from an economic point of view. Table 17 summarizes the costs of electricity for the investigated cases.

Cost of CO_2 avoided
This section presents the cost per ton avoided CO_2. To prevent confusion of the terms "avoided" and "captured", Figure 11 illustrates the difference between the two concepts. The CO_2 avoided is the difference between the CO_2 emitted by the reference plant and the capture plant, when a given amount of electricity is produced. Due to their lower net efficiencies (and consequently higher fuel consumption), the capture plants obviously produce more CO_2 than the reference plant when generating the same power output. It is clear from the figure that the CO_2 captured is larger than the amount of CO_2 avoided. The cost of CO_2 avoided is defined as the specific difference between the total annual costs for a power plant with CO_2 capture and a conventional non-capture power plant. The cost per ton CO_2 avoided then has to be compared to the penalty (CO_2-tax) per ton CO_2 emitted to see whether the capture concept is economically beneficial.

Figure 12 shows the additional cost per ton CO_2 avoided for the investigated concepts. Considering only the costs and neglecting the value of the captured CO_2 yields avoidance costs that range between 28 US$/ton for the most advanced concepts and 42 US$/ton for the more basic configurations. These figures are shown as dark columns in the diagram. If, however, the value of the captured CO_2 (20 US$/ton as suggested by CCP) is taken into account, this value can be subtracted from the avoidance costs. The results are shown as light columns and range from 17 US$/ton to as little as 7 US$/ton. Similar to the figures for the CoE, the model using the uncooled bleed turbine (Model 2) shows the best performance in terms of the cost of avoided CO_2. But even the basic MCM concept (Model 1)—which is the direct application of the AZEP concept

TABLE 16
COSTS (+) AND VALUES (−) PER MWH ELECTRICITY PRODUCED

Costs (+) and values (−) [US$/MWh$_e$]	**GTX 100**	**1A**	**1B**	**2A**	**2B**	**3A**	**3B**
Fixed O&M cost	1.6	2.9	2.7	2.7	2.6	2.7	2.5
Diff. to GTX100		1.3	1.1	1.1	1.0	1.1	0.9
Variable O&M cost	1.7	10.9	9.2	9.0	8.0	9.6	8.4
Diff. to GTX100		9.2	7.5	7.3	6.3	7.9	6.7
Cost of fuel	28.4	35.0	32.9	30.3	29.5	32.0	31.0
Diff. to GTX100		6.6	4.5	1.9	1.1	3.6	2.6
Cost of capital	5.5	15.1	13.4	13.4	12.3	14.0	12.7
Diff. to GTX100		9.6	7.9	7.9	6.8	8.5	7.2
CO_2 emission penalty[a]	12.7	0	2.4	0	1.9	0	2.0
Diff. to GTX100		− 12.7	− 10.3	− 12.7	− 10.8	− 12.7	− 10.7
Value of captured CO_2[b]		− 15.7	− 12.3	− 13.6	− 11.3	− 14.3	− 11.8

[a] CO_2-tax: 20 US$/ton (suggested by CCP).
[b] CO_2 product value: 20 US$/ton (suggested by CCP).

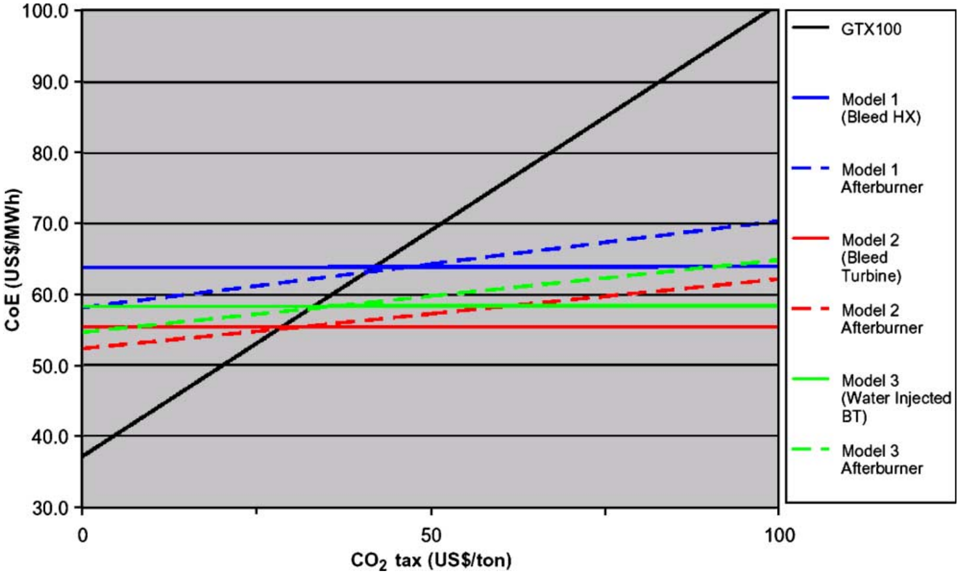

Figure 9: CoE as a function of CO_2-tax. Value of captured CO_2 is not considered.

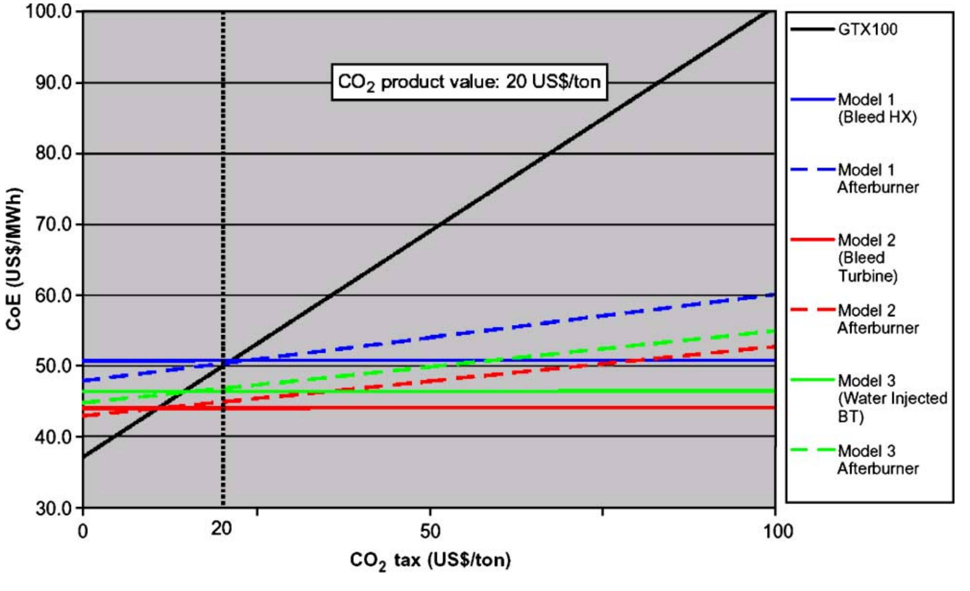

Figure 10: CoE as a function of CO_2-tax. Value of captured CO_2 is accounted for with 20 US$/ton.

TABLE 17
COMPARISON OF COST OF ELECTRICITY.

Model	CO_2 emission tax = 0 \$/ton; CO_2 product value = 0 \$/ton		CO_2 emission tax = 0 \$/ton; CO_2 product value = 20 \$/ton		CO_2 emission tax = 20 \$/ton; CO_2 product value = 20 \$/ton	
	CoE	ΔCoE	CoE	ΔCoE	CoE	ΔCoE
GTX100	37.1	–	37.1	–	49.9	–
1A	63.8	26.7	50.8	13.7	50.8	0.9
1B	58.1	21.0	47.9	10.8	50.3	0.4
2A	55.4	18.3	44.0	6.9	44.1	− 5.8
2B	52.3	15.2	42.9	5.8	44.9	− 5.0
3A	58.3	21.2	46.4	9.3	46.4	− 3.5
3B	54.6	17.5	44.8	7.7	46.8	− 3.1

$\Delta CoE = CoE - CoE_{GTX100.}$
All values expressed as US\$/MWh.

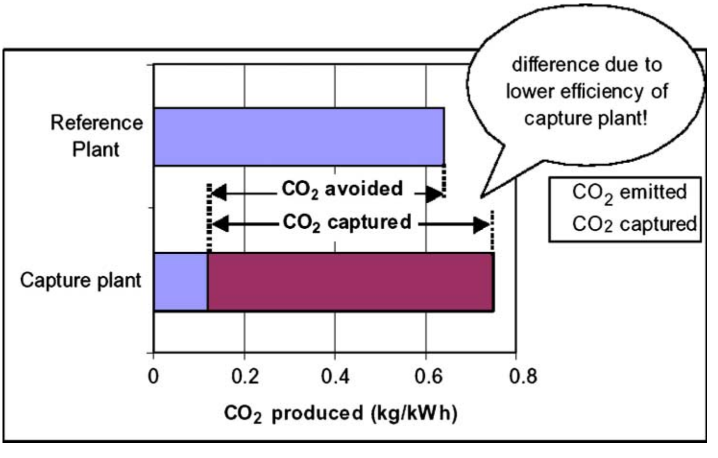

Figure 11: Definition of captured and avoided CO_2.

to a simple cycle gas turbine process—yields very promising results and is economically slightly more efficient than the non-capture reference case, considering that a CO_2-tax of 20 US\$/ton would have to be added for every non-avoided ton CO_2.

CONCLUSIONS

The thermodynamic and economic analyses have shown that the MCM-based power generation process has the potential to be a very economic and efficient way of producing power at low or zero carbon dioxide emissions. Assuming a penalty for carbon dioxide emissions of 20 US\$/ton and a value of the captured and pressurized carbon dioxide of 20 US\$/ton (as suggested by CCP), four of the six investigated models are markedly more economic than the non-capture reference concept, while the two most basic cconcepts

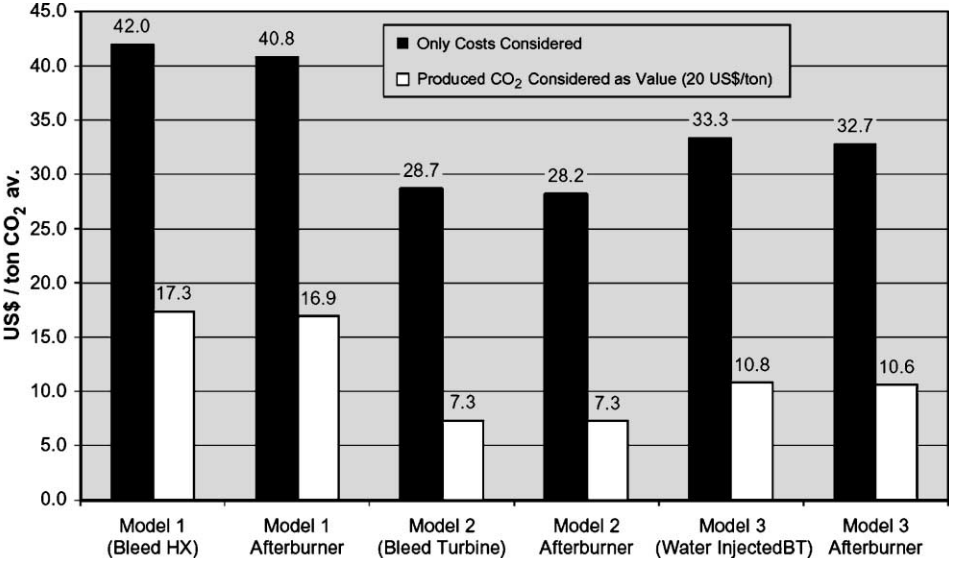

Figure 12: Additional cost per ton avoided CO_2.

(Model 1, Cases A and B) are at close to being economically viable. These figures are very promising for simple cycle gas turbine configurations.

As for the thermodynamic performance, the results indicate that zero emission processes based on simple cycle gas turbine configurations can operate at efficiencies within a few %-points of the non-capture reference plant, if the full potential of the MCM power process is tapped. However, the results also suggest that further research efforts are needed on how to efficiently utilize the high-pressure bleed stream. This applies not only for simple cycle concepts, but also for the combined cycle processes that are being investigated in the AZEP project.

The CCP scenario D: Prudhoe Bay, Alaska, which has been used in this study, is a very particular scenario. While in this case, the simple cycle configuration appears to be a promising solution, it has to be noted that the combined cycle generally will be the preferred choice. The main reasons for this are:

- The total efficiency is markedly higher for combined cycles.
- The added specific investment for the CO_2 capture is much lower due to the higher total output per unit.

RECOMMENDATIONS

Since the MCM-based power technology is a future technology and still in the development stage, there are a number of risks that might hinder the realization of the power plants investigated in this study. These risks include the following new components: the MCM module itself, the fuel ejectors, the integrated CC, the high-temperature heat exchangers, the supplementary combustor, and the bleed turbine. In particular, the application of high-temperature ceramic parts (>1000 °C) with the associated sealing elements within gas turbines presents significant challenges as regards plant reliability and availability. All these items are being addressed in the ongoing EU FP5 Integrated Research Project, and the present study—like other investigations—underlines the promising opportunities of the MCM technology for a future power generation with low or zero carbon dioxide emissions.

NOMENCLATURE

a	annum
A	case where no supplementary firing is used
B	case where supplementary firing ("afterburner") is used
AB	afterburner
AZEP	advanced zero emission power
BT	bleed turbine
CC	combustion chamber
CCP	carbon capture project
CH_4	methane, general hydrocarbon fuel gas
civ	fraction related to civil costs
CoE	cost of electricity
e	electrical (related to the net electrical power output)
EPC	engineering, procurement, and construction
FGC	flue gas condenser
FGD	fuel gas desulfurization
GE	general electric
GT	gas turbine
GTX100	gas turbine by Siemens (formerly ALSTOM) in simple cycle configuration
HRSG	heat recovery steam generator
HX	heat exchanger
LHV	lower heating value
MCM	mixed conducting membrane
pers	person
Q	transferred heat
tech	fraction related to technology costs
TEG	tri ethylene glycol unit, used to dry CO_2
TIT	turbine inlet temperature
TPC	turnkey project cost
UHC	unburned hydrocarbons
WIBT	water injected bleed turbine
ZEP	zero emission power
Δ	difference to the reference case

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