THE ASSESSMENT OF A WATER-CYCLE FOR CAPTURE OF CO2

Report Number PH3/4
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Title: **The Assessment of a water-cycle for capture of CO_2**
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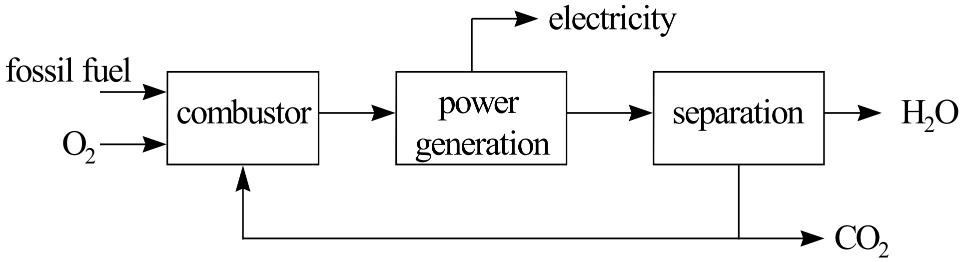
Other remarks:

Background to the study

Various authors have suggested that oxygen-fired combustion schemes could be an attractive way to reduce emissions of CO_2 to atmosphere. In such schemes the presence of air-derived nitrogen is avoided and the products of combustion, i.e. water and CO_2, are readily separated by condensation. Most suggestions are based on the concept of using recycled CO_2 to control the combustion temperature[1]. Figure S1 illustrates the principles. Several versions have been reported in the literature. Practical research on combustion schemes of this nature is known to have been done in Japan, UK, Germany, USA, and Canada. Early work was aimed at producing a CO_2-rich flue gas which could be used in enhanced oil recovery (EOR); more recently schemes of this nature have been a response to the threat of climate change.

figure S1: oxygen-fired combustion (with CO_2 recycle)



The gas leaving the combustor is typically >85%CO_2 by volume and the balance is steam (apart from excess oxygen and any impurities introduced by the fossil fuel). Oxygen is normally assumed to be obtained by cryogenic air separation (ASU) [2] but there are other options such as pressure swing absorption (PSA).

Practical research is in progress on the combustion aspects of CO_2 recycle schemes. Notably, the 'Experimental project on coal combustion in recycled CO_2/O_2 mixtures' an international research project operating under the auspices of the IEA GHG Agreement. The results from this research are potentially applicable to fired-boiler processes which use the heat of combustion in a steam (Rankine) cycle[3]. In the longer-term they are also applicable to the possibility of an O_2-fired gas turbine.

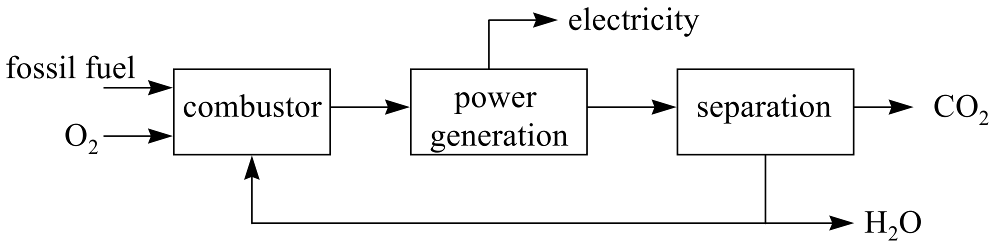
In conventional gas turbine combined cycles (GTCC) the working fluid is predominantly air. A GTCC using oxygen firing with recycled CO_2 would require the development of a novel gas turbine because the working fluid (in both the compressor and the expansion turbine) would be predominantly CO_2. The development of a novel turbine is expensive and there are major questions on the incentives

[1] Processing schemes have been suggested based on recycling part of the flue gas. Such schemes are retrofit or near-term options aimed at increasing the concentration of CO_2 in a flue gas which remains predominantly nitrogen. Combustion is in air (or oxygen-enriched air). Partial recycle of CO_2 is not considered further here.
[2] The production of oxygen in an ASU is energy intensive requiring about 0.25kWh/kg O_2.
[3] A preliminary evaluation of a scheme of this type was done in phase 1 of the Programme (reported in the 'green book' IEA GHG / SR1).

required[4]. Although several researchers have proposed schemes incorporating gas turbines working with recycled CO_2 we are not aware of any practical research. Typically, the efficiency of such schemes is reported in the literature as being in the region of 40 - 45% (LHV) and cost figures are not given[5].

Similar schemes to the above can be envisioned using recycled H_2O (rather than CO_2) to control the combustion temperature. Such schemes are mentioned in the literature but have not been extensively reported. The reason for this is not obvious, especially as the use of steam to control the reaction temperature is established practice. For example, steam coolant is injected into the gasifier in oxygen-blown integrated gasification combined cycles (IGCC), steam-injected gas turbines (STIG) are commercially available[6], and turbine manufacturers are working on steam injection to cool turbine components. Figure S2 illustrates the concept of using H_2O to control the temperature of oxygen-fired combustion systems - comparing figures S1 & S2 it can be seen that the concepts are the same but the working fluid is different.

figure S2: oxygen-fired combustion (with H_2O recycle)



If H_2O is used as the working fluid of a turbine it can be recycled in the liquid phase thus avoiding the energy penalty associated with compressing a gas (in a conventional gas turbine about 1/3rd of the power produced is used to drive the associated air compressor)[7]. This is the basis of the 'water-cycle' concept that is examined in this report. It is, in essence, a Rankine cycle[8] with a novel expansion turbine having the high temperature characteristics of a conventional gas turbine and the high pressure characteristics of a steam turbine; the cycle avoids the need for a feed gas compressor.

Approach adopted

The objective of the study was to make a preliminary assessment of the water-cycle, to find out whether the efficiency and performance could be attractive enough to compete with 'conventional' processes aimed at CO_2 capture (for example, see report PH2/19 which includes a comparison of pre- and post-combustion decarbonisation options).

A brief scoping-study by SINTEF Energy Research (Norway) has produced a preliminary assessment of the attractiveness of the process; by pre-arranged agreement, work was stopped after the initial evaluation reported here because the process did not look attractive enough to proceed to a detailed techno-economic evaluation.

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[4] At the time of writing the IEA GHG Programme has initiated work to establish the technical, financial, institutional, and any other barriers to the development of novel turbines. It is expected that this work will be reported in mid-1999.

[5] Cost figures based on a novel turbine working with stoichiometric oxygen feed are presented in the 'green book' IEA GHG/SR2; as the technology is novel they are, inevitably, rather speculative.

[6] A STIG cycle is, in essence, a combination in one machine of a conventional gas (and steam turbine) combined cycle.

[7] This is the reason some researchers have suggested processes with a recycle of liquefied CO_2

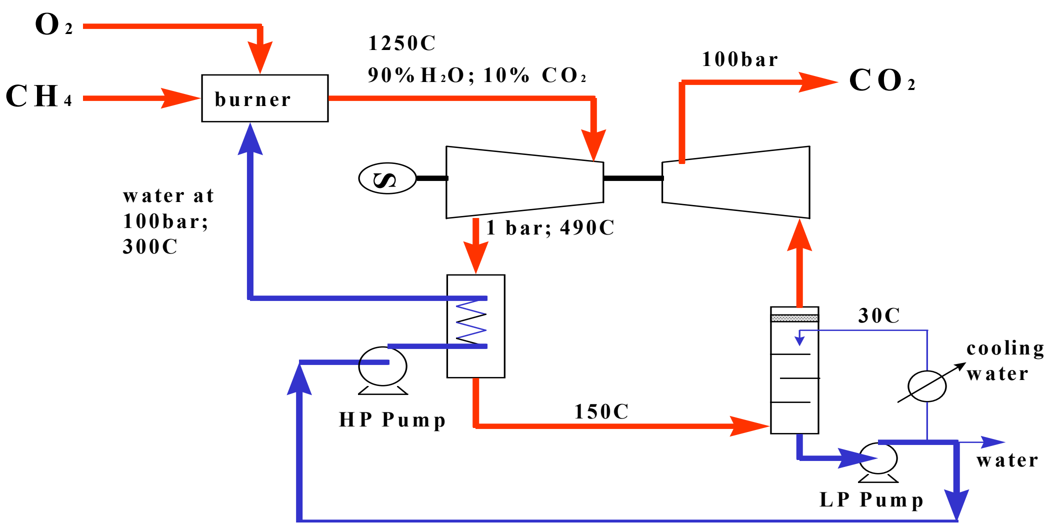
[8] It is worth noting that extensive work on hydrogen combustion in stoichiometric O_2-fired turbines by Westinghouse for the Japanese 'World Energy Network' (WE-NET) programme identified a Rankine-type cycle as the most efficient of the options considered.

The study contractor completed the work to time and budget and made a positive contribution to the activity.

Results and discussion

The process scheme assessed in this report is based on the use of recycled water to control the temperature of an oxygen-fired combustion reaction. This approach enables CO_2 to be recovered in a simple manner by condensing water out of a process stream which consists mainly of CO_2 and steam. The optimum operating conditions for such a process were not known and hence a range of conditions was evaluated. Figure S3 illustrates the process and the 'base-case' conditions.

figure S3: Water-cycle base case.



In the process, natural gas (or any other fossil fuel) is burnt in a combustor. High-purity oxygen produced in an ASU is used as an oxidant. The reaction temperature is controlled by the injection of (liquid) water which is recycled after being recovered from the process flue gas. An expansion turbine is used to generate electricity.

The expansion turbine has a novel working fluid which is mainly steam but contains the CO_2 product of combustion. For the purposes of the base-case reported here it was assumed that the turbine would operate with a 1250C inlet temperature i.e. near the upper limit for conventional gas turbines.

In conventional steam cycles the working fluid is pure steam which is isolated from combustion gases by heat-transfer surfaces; the need for a heat-transfer surface (usually metal) limits the practical upper temperature in steam cycles to about 600C. In the water-cycle, the turbine blades determine the maximum temperature of the cycle; it should be possible to cool the blades by injection of recycled water[9]. Hence, the working fluid could be at a much higher temperature than conventional steam cycles i.e. equivalent to the operating temperatures of conventional gas turbines.

Conventional gas turbines are limited to a maximum pressure ratio of, say, 30 because of the energy penalty associated with compression of (atmospheric) air for combustion. Steam turbines can be used at significantly higher pressure ratios (e. g. expansion from 300 bar down to sub-atmospheric pressure) because the feed (to the boiler) is a liquid which can be pumped at high pressure without incurring a major energy penalty. The novel expansion turbine used in the water cycle would take

[9] In preliminary calculations about 3% of the recycled water was used for blade cooling.

advantage of the high temperatures used in conventional gas turbines and the high pressures used in conventional steam turbines.
As with conventional practice, heat in the turbine exhaust can be recovered by interchange with other process streams, or possibly a bottoming cycle (not considered here, in order to keep the analysis simple). Water is condensed out of the exhaust gas leaving a stream of CO_2 for compression and export to sequestration. Excess water is purged out of the loop and the remainder recycled via a high ressure pump to the combustor.

Note that the expansion turbine in the water-cycle (unlike a conventional GTCC) is not integrated with a feed compressor. Also, the CO_2 compressor is illustrated in figure S3 as being on the same shaft as the expansion turbine but does not need to be.

For the purposes of the study, a base-case with operating conditions thought likely to be appropriate was selected for evaluation; cases were also evaluated in which the operating conditions were systematically varied to test the sensitivities.

Table S1 summarises the energy balance data for the base-case and also for the most efficient case examined, which was achieved with a condenser pressure of 0.1 bar (the main report contains the results of efficiency calculations for the base case and several other permutations of pressure and temperature). The results appear quite sensitive to condenser pressure, probably because most of the energy losses are due to the heat rejected by the condenser; this is a consequence of the large volumes of water circulated.

Table S1: Summary of efficiency calculations

	Base-case (%)	**Pressure of condenser =0.1 bar**
Energy in:	100	100
Less heat rejection & mechanical losses of:	-48.55	-43.03
Work produced in turbine	51.45	56.97
Less: methane compression	- 0.08	-0.08
oxygen production	- 6.91	-6.91
oxygen compression	- 3.22	-3.22
feed-water pump	- 0.35	- 0.31
CO_2 compression	- 1.96	- 3.87
Net efficiency	38.9 %	42.6 %

Higher efficiency (in the region of 45%) could be achieved by use of a high combustion pressure (200bar) and low condenser pressure; this specific case was not examined in this limited study but such a result can be inferred from figure 2 of the main report.

The process efficiency of this novel cycle (maximum of about 45%) is lower than can be achieved with the more ‘conventional’ CO_2 capture options (discussed in report PH2/19), which show efficiencies approaching 50% for both amine scrubbing and pre-combustion decarbonisation.

The investment cost required to install a water-cycle is difficult to estimate at present. The overall process is simple and costs will be dominated by the cost of the novel turbine, which would be different from anything built to-date and has a number of major materials challenges. For this reason, only an order-of-magnitude estimate of its cost could be developed.

Expert Group and other comments

Comments were received from a number of our experts.

One comment was that the temperature 'pinch-point' used in the cases considered was large and may represent a significant source of efficiency loss for the cycle. The IEA GHG programme team agree with this comment but to search for more optimum arrangements, perhaps including a steam bottoming cycle, is an extensive exercise not believed to be justified at present (the probable outcome is an efficiency peak in the region of 50%, but the turbine development and cost questions still need to be resolved).

Other comments received pointed out that potential cycle improvements, such as use of reheat, or reduction in the condenser exit pressure, had not been extensively covered. But the expert agreed that such optimisation was unlikely to change the overall conclusion. It was also pointed out that the specific power of the machine was large i.e. the machine would be physically much smaller than a conventional turbine of equivalent output.

It was suggested that a steam 'topping cycle' and a gas 'bottoming cycle' (in effect a reversed conventional combined cycle) would be effective and avoid many of the turbine development problems. Most reviewers stressed the difficulties and cost of developing a completely novel turbine and the benefits of cycles that could be used in existing turbines with only minor modifications.

Major conclusions

There are two major technical developments required to establish a water-cycle power plant. The first is a high pressure combustion chamber with stoichiometric firing of oxygen and water cooling; a significant R&D effort is required but there appears to be no major technical obstacles. The second is the development of a high pressure and temperature expansion turbine; whilst there are significant technical obstacles, they are not markedly worse than the obstacles to development of any novel turbine working at high temperature and pressure.

Compared to processes in which CO_2 is recycled to a novel gas turbine, the water cycle has two significant advantages. First, there is no need for a novel gas compressor to be developed. Secondly, the availability of water as the working fluid enables its extensive use as a cooling medium (e.g. for turbine blades).

The water-cycle has a similar efficiency to oxygen-fired GTCC options based on CO_2 recycle and both options require an expensive turbine development programme. Manufacturers would need to charge a significant amount to recover the development costs of such novel turbines; this cost is likely to be more than the cost of alternative CO_2 recovery schemes needing less development. More information on the costs and incentives required for development of novel turbines will be available from a study scheduled to be completed in mid-1999.

It is suggested in the main body of the report that the cost of the turbine for the water-cycle would be about $1800/kWe. The cost is inevitably speculative but it would need to be to be about half this figure to look attractive compared to the pre-combustion decarbonisation options recently assessed. (Costs in the region of 1 000 $/kWe, see PH2/19). Alternatively, a significantly higher efficiency than the predicted region of 45% would be needed to justify the likely high cost of development.

The overall conclusion is that the water-cycle appears to be at least as promising as other gas turbine schemes based on the use of oxygen-firing and recycle of combustion products. However, it seems unlikely that such schemes will be significantly more efficient than, or compete on costs with, CO_2 capture options based on amine scrubbing of flue gases or precombustion decarbonisation.

Recommendations

1. It is recommended that no further work be done at present on the concept of a water-recycle process.

2. The possibilities for further work in this area should be reviewed when the results of the study on barriers to the development of novel turbines are available.

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TITLE

WATER-CYCLE - a stoichiometric fired Rankine type cycle for removal of CO_2.

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RESULT (summary)

The potential for fuel-to-electricity efficiency for the Water-Cycle is established with some preliminary calculations with PRO/II. Further optimisation can be carried out, but this will not significantly change the calculated efficiencies of this concept.

There is a need for R&D effort in order to build such a power plant. Two major challenges should be mentioned: a) high-pressure combustion chamber with stoichiometric firing with oxygen, b) a high pressure turbine with blade cooling.

There is no major technical obstacle for developing such a power plant concept.
There is no need to develop a new large axial compressor (working fluid deviating significantly from air), which must be taken as a big advantage. The use of water as an inert in the cycle, enables extensive use of water as cooling medium for both the combustion chamber walls and the turbine. This is also advantageous.

The Water-Cycle has no advantage compared to other cycle options with respect to fuel-to electricity conversion efficiency.

The cost of the Water-Cycle was estimated to 1700-1800 US$/kW. This is about the same or slightly above that of IGCC projects.
It is relevant to question the commercial attractiveness of the concept. When comparing to other options with stoichiometric combustion, the Water-Cycle seems like a promising candidate. When comparing with options where standard combined cycle technology is used together with CO_2 removal from the exhaust gas or pre-combustion decarbonisation, the Water-Cycle is not promising from a commercial point of view. In general, cycles with use of oxygen from air separtion units have somewhat lower efficiency compared to those using air as the oxidising agent.

KEYWORDS	ENGLISH	NORWEGIAN
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The purpose of Task 1 was to obtain a basis to determine whether the Water-Cycle is on the level with respect to performance/efficiency where it can compete with other known power plant processes “producing” CO_2 for storage purposes.

Modelling of the Water-Cycle, as suggested by IEA GHG, has been carried out as well as a number of simulations with PRO/II version 4.15 (Simulation Sciences, Inc.).

The modelling comprise (*see Figure 1*)

- oxygen compression gaseous phase (stream S2)
- fuel (methane) compression and heating (stream Sl)
- reactor (or combustor) with reaction between oxygen, methane and liquid water
- expansion of the combustion products
- thermal recuperation of the expanded combustion products
- cooling of combustion products (condensation of water)
- intercooled compression train for CO_2

The Water-Cycle can be categorised as a Rankine type power cycle. The working fluid (mainly water) is compressed in the liquid phase (oxygen though in the vapour phase in the present study).

The fuel-bound energy is converted to heat in a combustion chamber. This chamber would probably be designed as a water-cooled furnace, much the same as a coal-fired or oil-fired boiler. The steam produced in the walls can be partly be injected close to the fuel nozzles in order to reduce flame temperatures, and partly downstream the flame in order to keep the turbine inlet temperature to a permissible level.

The combustion products (approximately 90% of water vapour and 10% of CO_2) is expanded through a turbine. Temperatures up to 1250 °C were used as combustion chamber exit temperature. Such high temperatures require a cooled turbine. In the present work no calculations were made including the cooling penalty directly. A rather low efficiency was used, 85%, which is well below that of modem steam turbines. This low efficiency should include the cooling penalty on expansion efficiency.

Downstream the turbine the working fluid is superheated, and heat is transferred to the water going to the combustion chamber.

Then the working fluid is further cooled with sea-water in a condenser, where steam is condensed and CO_2 is purged off. The condensate is mainly returned for use in the cycle, while a small fraction, equivalent to the production of water in the combustion, is bled from the power cycle.

The CO_2 is compressed and dried in a multi-stage compression/intercooler train.

Five different cases were simulated. Main stream data are given in *Table 1-Table 5*. The parameters varied compared to the base case are shown in the tables with bold text.

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Table 1 Base case

	Unit	**S1**	**S2**	**S3**	**S4**	**S5**	**S18**
Temp.	°C	150	218.6	300	1250	491	132
Press.	Bar	100	100	100	100	1.0	100
Flow rate	kmol/hr	100	200	939.0	1239	1239	99.4
CH_4	kmol/hr	100					
O_2	kmol/hr		200				
CO_2	kmol/hr				100	100	99.3
H_2O	kmol/hr			939.0	1139	1139	0.1

Table 2 Combustion pressure increased from 100 bar to 150 bar

	Unit	**S1**	**S2**	**S3**	**S4**	**S5**	**S18**
Temp.	°C	150	240.5	282	1244	443	134
Press.	Bar	**150**	**150**	**150**	**150**	1.0	100
Flow rate	kmol/hr	100	200	917	1217	1217	99.4
CH_4	kmol/hr	100					
O_2	kmol/hr		200				
CO_2	kmol/hr				100	100	99.3
H_2O	kmol/hr			939	1117	1117	0.1

Table 3 Combustion pressure increased from 100 bar to 200 bar

	Unit	**S1**	**S2**	**S3**	**S4**	**S5**	**S18**
Temp.	°C	150	256	273	1250	416	132
Press.	Bar	**200**	**200**	**200**	**200**	1.0	100
Flow rate	kmol/hr	100	200	901	1201	1201	99.4
CH_4	kmol/hr	100					
O_2	kmol/hr		200				
CO_2	kmol/hr				100	100	99.3
H_2O	kmol/hr			901	1101	1101	0.1

Table 4 Condenser pressure decreased from 1 bar to 0.1 bar

	Unit	**S1**	**S2**	**S3**	**S4**	**S5**	**S18**
Temp.	°C	150	219	190	1243	286	132
Press.	Bar	100	100	100	100	**0.1**	100
Flow rate	kmol/hr	100	200	818	1118	1118	100
CH_4	kmol/hr	100					
O_2	kmol/hr		200				
CO_2	kmol/hr				100	100	99.9
H_2O	kmol/hr			818	1018	1018	0.1

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Table 5 *Combustion temperature decreased from 1250 °C to 900 °C*

	Unit	**S1**	**S2**	**S3**	**S4**	**S5**	**S18**
Temp.	°C	35	219	195	**900**	279	134
Press.	Bar	100	100	100	100	1.0	100
Flow rate	kmol/hr	100	200	1103	1403	1402	99.3
CH_4	kmol/hr	100					
O_2	kmol/hr		200				
CO_2	kmol/hr				100	100	99.2
H_2O	kmol/hr			1103	1302	1302	0.1

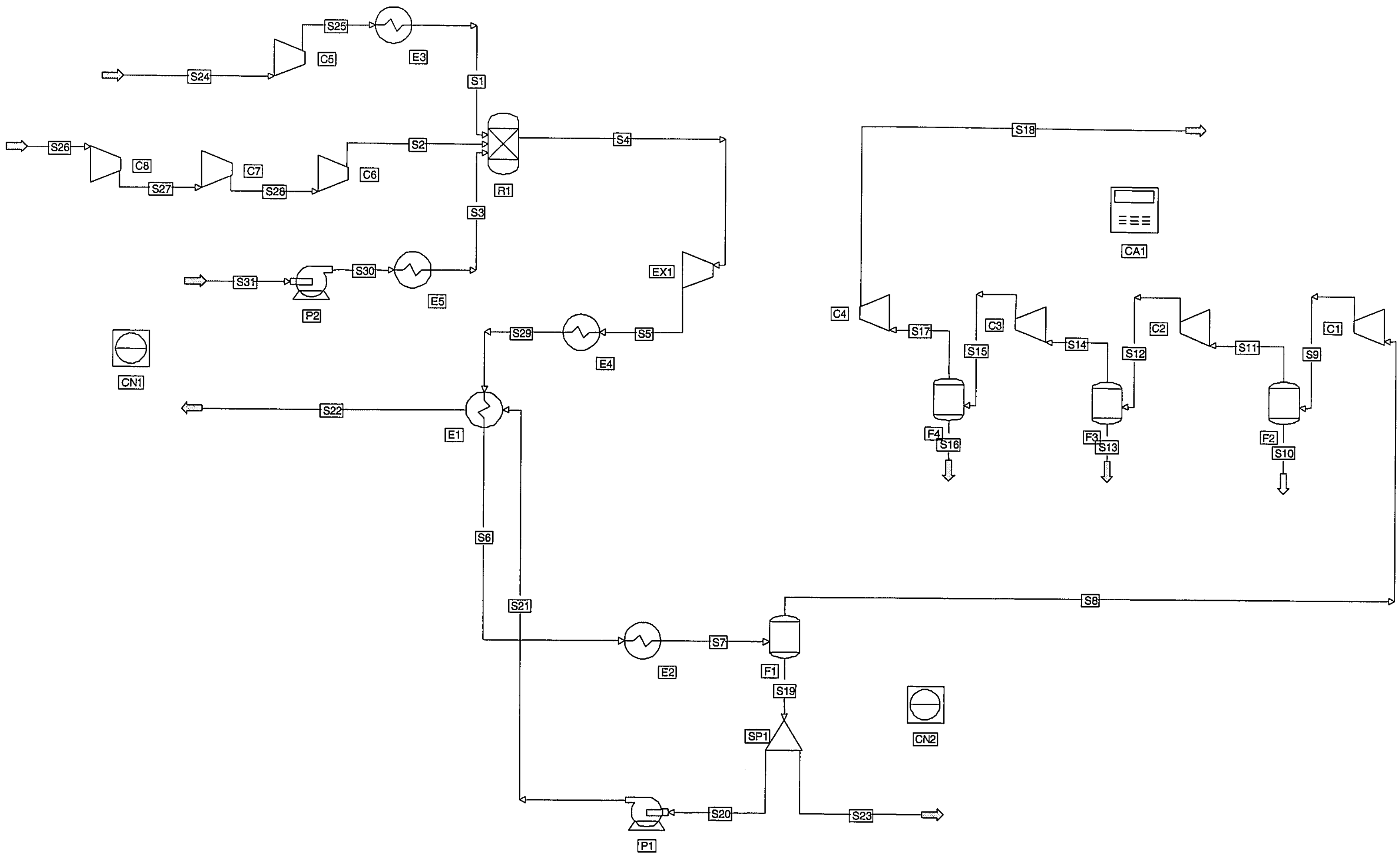

Figure 1 *Water-Cycle flowsheet (as from PRO/II)*

Fuel-to-electricity conversion efficiencies for the different cases are shown in *Figure 2*. The efficiency includes oxygen production/compression, CO_2 compression (100 bar) and internal pump work. The efficiency is related to the lower heating value of methane.

The energy consumption for producing oxygen is a very important parameter for the efficiency, and is in *Figure 2* given as a parameter. In the present work the energy consumption for producing 1 kg of O_2 atmospheric (95%+ purity) is assumed to 0.24 kWh. Additionally, the compression work required for the combustion pressure is calculated (100-150-200 bar). The total energy requirement for producing 1 kg O_2 at combustion pressure was calculated to 0.35-0.39 kWh.

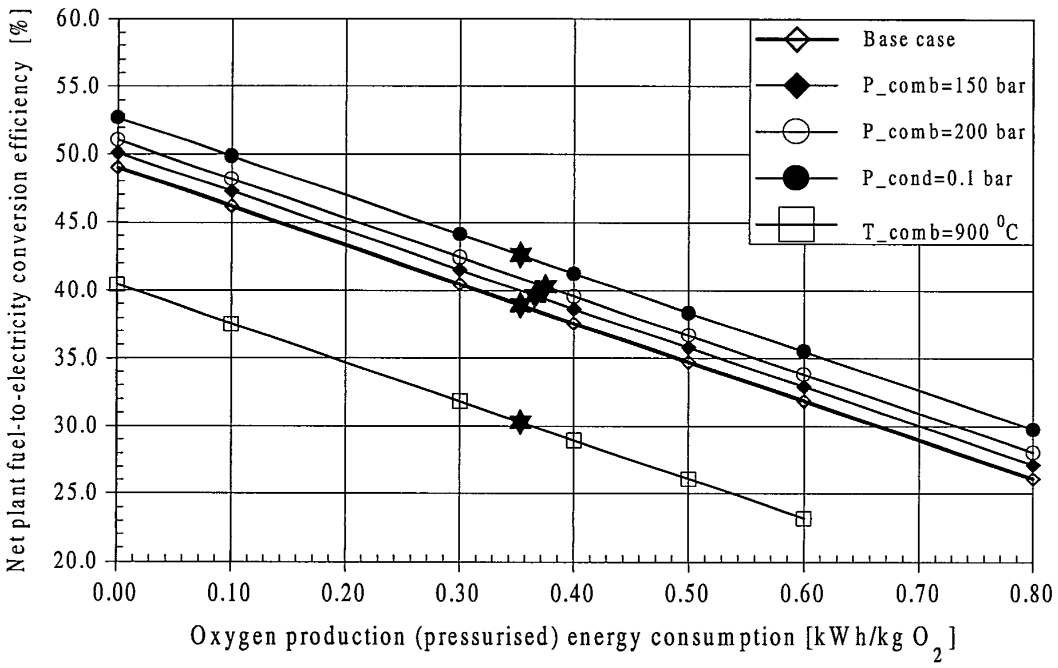

Figure 2 *Fuel-to-electricity conversion efficiency. The stars indicate the calculated points in the present study.*

The turbine exit pressure/condenser pressure is an important parameter for the efficiency. When decreased from 1.0 bar to 0.1 bar, it gave a 3.6% points rise in efficiency. Decreasing the combustion temperature to 900 "C (in order to avoid turbine cooling), gave a significant reduction in efficiency. Increasing the combustion pressure (from 100 bar to 150/200 bar) gave an increase in efficiency.

When combining a condenser pressure of 0.1 bar and a high combustion pressure, the efficiency potential lies around 45% for this type of cycle. There is room for a further optimisation on parameters, but this will not significantly increase the total plant efficiency beyond 45%.

A breakdown of how the losses cycle in the cycle is given in *Table 6*.

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Table 6 A breakdown of how the losses occur in the cycle

	Base case	P_comb= 150 bar	P_comb= 200 bar	P_cond= 0.1 bar	T_comb 900 °C
Fuel Lower Heating Value	100 %	100 %	100 %	100 %	100 %
Turbine work	51.45 %	52.83 %	54.03 %	56.97 %	42.87 %
Methane compression	-0.08 %	-0.24 %	-0.37 %	-0.08 %	-0.08 %
Oxygen production (1 bar)	-6.91 %	-6.91 %	-6.91 %	-6.91 %	-6.91 %
Oxygen compression	-3.22 %	-3.58 %	-3.85 %	-3.22 %	-3.22 %
Feedwater pump	-0.35 %	-0.51 %	-0.67 %	-0.31 %	-0.41 %
CO2 compression	-1.96 %	-1.96 %	-1.96 %	-3.87 %	-1.96 %
Net efficiency	38.9 %	39.6 %	40.3 %	42.6 %	30.3 %

The energy balance for the base case is the following (see *Table 7*):

Table 7 Energy balance for the Base case

	Energy in %	Energy out %
Higher heating value of the fuel	97.4	-
Sensible heat of the fuel	1.7	-
Sensible heat of oxygen	0.9	-
Turbine power output		45.3
Condenser heat rejection		52.9
CO_2 to compression		1.5
Excess water removal		0.3

In *Table 8* a comparison is given of plant efficiencies for different CO_2-removal options for large natural gas fired power plants. The numbers given in *Table 8* include CO_2-compression to 100 bar. The option with a combined cycle with exhaust amine absorption of CO_2, gives the highest efficiency (50-52%) of the compared options.The Water-Cycle is close to the other options with respect to efficiency (≈45%).

Table 8 Comparison of plant efficiencies for different CO_2-removal option for large natural gas fired power plants.

	Power[1]	Plant efficiency
"State of the art" combined cycle, no removal of CO_2	100%	58%
"State of the art" combined cycle, exhaust gas amine absorption of CO_2	85%	50-52%
"State of the art" combined cycle, decarbonisation of fuel, combustion of hydrogen-rich fuel	88-90%	43-49%
Combined cycle with stoichiometric combustion of oxygen	-	46-48%
Present work: Water-Cycle with stoichiometric combustion with oxygen	-	43-47%

[1] Related to use of existing heavy duty gas turbines

Costs:
An estimation of the investment costs were made (*Table 9*). It is assumed that the net power output is 500 MW. This gives a fuel flow (methane) of 25 kg/s (efficiency 40%) and an oxygen flow of 100 kg/s. A large air separation unit is required; 8640 tons/day. This will be close to the largest air separation plants that exist. The plant will produce 5940 tons CO_2 per day or 2.2 million tons/year.
Most of the components in this concept are known and proven technology. However, the key components combustor and turbine does not exist, and implies a challenge in design and development.

In terms of costs, a comparison to conventional steam plants may be in place. There are, however, some main differences between the combustor/turbine of this concept compared to a conventional steam plant. The combustor is pressurised (100-200 bar) and the turbine operates at much higher temperatures with cooling requirements. The technology, combustor and turbine, will be more like that of gas turbines. In this concept there will be less heat transfer surfaces and no flue gas treatment like desulphurisation, de-NO_x or dust removal. Because this technology implies development of new equipment, the cost strongly depends on market penetration.

It is likely that the turbine will be the most expensive component, both with respect to development and production. It is assumed that the cost power plant (except air separation and CO_2 compression) will be slightly higher than for conventional steam plants. Such an estimate must regarded as a very rough one, and it should be clearly stated that cost estimation of this concept is difficult because the major components are only to a small extent comparable to existing equipment.

Table 9 Cost for the Water-Cycle

	Specific cost	Unit	Cost [mill US$]
Oxygen plant	20000	US$/day-ton	174
Power plant[1]	1100	US$/kW$_{\text{turbine output}}$	687.5
CO2-compression/drying	4200	US$/day-ton	25
Total	1773	US$/kW$_{500\ \text{MW}}$	886.5

[1] Combustor, turbine, condenser, see-water cooling system

Conclusions
The potential for fuel-to-electricity efficiency for the Water-Cycle is established with some preliminary calculations with PRO/II. Further optimisation can be carried out, but this will not significantly change the calculated efficiencies of this concept.

There is a need for R&D effort in order to build such a power plant. Two major challenges should be mentioned: a) combustion chamber with stoichiometric firing with oxygen, b) a high pressure turbine with blade cooling.

There is no major technical obstacle for developing such a power plant concept. There is no need to develop a new large axial compressor (working fluid deviating significantly from air), which must be taken as a big advantage.

The use of water as an inert in the cycle, enables extensive use of water as cooling medium for both the combustion chamber walls and the turbine. This is also advantageous.

The Water-Cycle has no advantage compared to other cycle options with respect to fuel-to-electricity conversion efficiency.

The cost of the Water-Cycle was estimated to 1700-1800 US$/$kW_{netoutput}$. This is about the same or slightly above that of IGCC projects.

It is relevant to question the commercial attractiveness of the concept. When comparing to other options with stoichiometric combustion, the Water-Cycle seems like a promising candidate. When comparing with options where standard combined cycle technology is used together with CO_2 removal from the exhaust gas or pre-combustion decarbonisation, the Water-Cycle is not promising from a commercial point of view.

In general, power cycles (with removal of CO_2) with use of oxygen from air separation units tend to have somewhat lower efficiency compared to those using air as the oxidising agent.