OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS

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Background to the Study

Most assessments undertaken by IEAGHG and others have assumed that power plants with CCS will operate at base load. It is now becoming clear that in many cases CCS plants will need to be able to operate flexibly because of the variability of electricity demand, increased use of variable renewable energy sources such as wind and solar and poor flexibility of some other low-CO_2 generation technologies such as nuclear. However, relatively little work has so far been published on this subject.

IEAGHG has commissioned Foster Wheeler Italiana to carry out a study to review the operating flexibility of the current leading power generation technologies with CCS and to assess performance and costs of some techniques for improving flexibility. This overview of the report was written by IEAGHG.

Scope of Work

The study assesses the flexibility, performance and costs of several examples of power plants with CCS but it is recognised that there are many other potential design options with different degrees of flexibility. The study covers the following leading technologies for power generation with CCS:

- Ultra-supercritical pulverised coal (USC-PC) with post combustion capture using solvent scrubbing
- Natural gas combined cycle (NGCC) with post combustion capture using solvent scrubbing
- Integrated coal gasification combined cycle (IGCC) with pre-combustion solvent scrubbing
- Pulverised coal oxy-combustion

The study makes use of baseline plant performance and cost data from earlier IEAGHG studies, taking into account cost inflation that has occurred since those studies were undertaken.

The following techniques for improving flexibility and increasing peak power output were assessed:

- Turning off CO_2 capture
- Storage of CO_2 capture solvent
- Storage of liquid oxygen
- Storage of hydrogen
- Storage of CO_2 or solvent to provide a constant flow of CO_2 to transport and storage

The report also includes a brief overview of energy storage techniques for large scale electricity generation.

Results and Discussion

Operating flexibility of power plants without CCS

Typical flexibilities of power plants without CCS are summarised in Table 1. It should be noted that actual flexibilities of power plants depend on the plant design and the preferences of vendors and operators.

Table 1 Typical operating flexibilities of power plants without CCS

	NGCC	USC-PC	IGCC
Minimum load, %	40-50	30	50
Hot start-up time, hours	0.75-1	1.5-2.5	6-8
Cold start-up time, hours	3	6-7	80-100
Ramp rate, % per minute	4-6 (40-85% load) 2-3 (85-100% load)	2-3 (30-50% load) 4-8 (50-90% load) 3-5 (90-100% load)	3-4

The flexibility of NGCC plants has improved in recent years as suppliers continue to respond to customers' requirements for greater flexibility and modern NGCCs are typically capable of fast start-up, shut–down and load cycling. The minimum operating load is usually determined by the increasing environmental emissions at low loads.

USC-PC plants are also characterised by low minimum operating loads and good cycling capabilities and start-up times. In contrast, IGCC plants have relatively low cycling capabilities, high minimum load and long start-up times although faster start-up may be possible if an auxiliary fuel is used in the gas turbines.

Operating flexibility of power plants with CCS

There is currently relatively little information in the public domain on operating flexibility of CO_2 capture processes and more practical research and dynamic modelling is needed. This report provides illustrative information on CCS plant flexibilities but it should be recognised that flexibilities depend to some extent on the needs of the operators and there is a trade-off between flexibility, costs and efficiency, which is explored to some extent in this report. The characteristics of electricity systems in future may be significantly different to those at present, so it is important that there is a dialogue between CCS process developers and electricity system planners, modellers and operators to ensure that CCS processes are designed to have the appropriate degree of flexibility.

One of the general constraints on part load operation of CCS plants would be the CO_2 compressors which would typically be limited to around 70% turndown. Higher turndown could be achieved by recycling compressed CO_2 but this would impose a significant energy penalty, as the compressor would still be operating at 70% load even when the power plant was turned down further. It would therefore be advantageous to have multiple CO_2 compressors, which may be required anyway due to size limitations, particularly in multiple train power plants. This report is based on power plants that include one or two power generation units. Larger plants with multiple units and common air separation and CO_2 compression may provide improved part load performance.

NGCC and USC-PC with post combustion capture

The introduction of post combustion CO_2 capture may impose additional constraints on the start-up and fast load changing of a power plant but techniques are available to overcome these constraints. In an NGCC plant the gas turbine starts up more rapidly than the heat recovery steam generator (HRSG) and the steam turbine. The regenerator in the CO_2 capture plant requires steam from the HRSG or steam turbine and the regenerator needs to be heated to its operating temperature. To avoid constraints on start-up time and to avoid CO_2 emissions during start up, the CO_2 absorber could be operated using lean solvent from a storage tank and the CO_2 rich solvent from the absorber would be stored and fed to the regenerator later. This would enable an NGCC or USC-PC plant with CO_2 capture to start up and change load as quickly as a plant without capture. This technique is evaluated in the report.

Oxy-combustion
The main constraint on flexibility of a pulverised coal oxy-combustion plant is the air separation unit. The minimum operating load of the cold box is around 50% while the minimum efficient load of the main air compressor is around 70%. At lower loads, part of the compressed air would generally be recycled to the compressor feed, which imposes a substantial efficiency penalty. This could be avoided in a multi-train plant in which one or more of the compressors could be shut down.

The maximum ramp rate of the ASU is typically 3% per minute but the boiler can typically ramp at 4-5%. The difference between the ASU oxygen supply rate and the boiler demand for a 50%-100% ramp is less than 10 tonnes for a $500MW_e$ plant and this can be satisfied by using stored liquid oxygen (LOX). The LOX storage tank can be refilled during times of reduced power plant load. Around 200 tonnes of LOX storage would typically be included in the plant for the safe change-over from oxygen to air firing and in case of a ASU trip, so no additional LOX storage would be needed to satisfy the ramp rate.

IGCC
As mentioned earlier, the flexibility of IGCC plants without capture is relatively poor but the addition of capture is not expected to significantly affect the flexibility because for example the changes to the design of the acid gas removal plant have no impact on the plant flexibility. Plants with capture will however have reduced part load efficiency for example due to the lower efficiency of CO_2 compression at part load which is discussed earlier.

Part load efficiencies
The efficiencies of power plants with CO_2 capture at part load are shown in Figure 1.

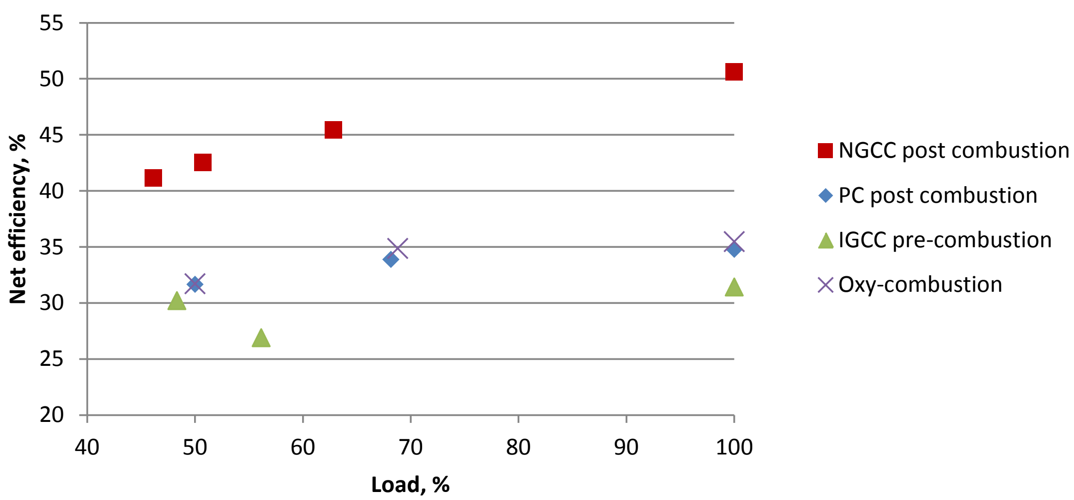

Figure 1 Part load efficiencies of plants with CO_2 capture

The efficiency reduction for operation at 50% load is 3.1 percentage points for the PC plant with post combustion capture. This is higher than for a plant without capture, mainly due to the need to maintain the pressure of the steam extracted from the turbine for the CO_2 capture plant, the lower efficiency of CO_2 compression and miscellaneous changes within the capture unit. The efficiency reduction for PC oxy-combustion is similar at 3.8 percentage points. The main reasons for the higher efficiency reduction in this case are the lower efficiencies of the ASU and CO_2 compressors.

The part load efficiency reduction for NGCC and IGCC depends mainly on the performance of the gas turbine and the data in this report are based on a model of gas turbine that has a relatively high part load efficiency loss. In recognition of the increasing importance of plant flexibility some gas turbine vendors are introducing turbines that have improved part load performance, as illustrated in the main report.

The data points in Figure 1 for NGCC at 50% load and IGCC at 56% load are for operation with both of the gas turbines turned down. The data point for IGCC at 48% load is for operation with one of the gas turbines shut down and the other operating at 100% load, which is significantly more efficient. This operating mode could also be used for NGCCs but it was not analysed in this study.

Assessment of techniques for improving flexibility

Turn off or turn down of CO_2 capture

The net power output of a plant could be increased by turning down or turning off the CO_2 capture and compression units and emitting more CO_2 to the atmosphere. The ability of a plant with capture to ramp up power output could in principle be better than that of a plant without capture if the load of the capture unit was reduced at the same time as the load of the power generation unit was increased. This study assessed the option of turning off capture but various intermediate options involving turning off or turning down parts of the capture plant may also be attractive.

Turning down or turning off capture would increase emissions of CO_2 to the atmosphere so regulations would have to permit CCS plants to emit more CO_2 during times of peak power demand. This would for example require emission performance standards to be assessed over long periods such as a year. To comply with performance regulations it may be necessary to capture a higher percentage of CO_2 during normal operations to compensate for the extra emissions when the capture plant is turned off. The feasibility and costs of doing this have not been assessed in this study.

Turning down or turning off post combustion capture would reduce the plant’s internal consumption of electricity and the low pressure steam that would otherwise be consumed by the capture unit could be used to further increase the net power output, provided the plant was built with the necessary extra low pressure turbine capacity.

Turning off capture in IGCC plants is less straight forward than in plants with post combustion capture because the CO_2 capture unit is an integral part of the acid gas removal (AGR) unit which also removes sulphur compounds from the fuel gas. However, it is possible to tune to a certain extent the CO_2 capture rate by varying the solvent circulation rate flowrate in the AGR unit, in order to absorb sufficient H_2S while only absorbing part of the CO_2. With this strategy the capture rate range at which it is possible to operate is limited by both the AGR design and the flexibility of the gas turbine to accept a variable fuel composition. In the plants considered in this study the captured CO_2 that is available at high pressures from the AGR is fed to the gas turbines. This enables the quantity of nitrogen that has to be compressed for use in the gas turbines to be reduced, which reduces the compressor power consumption and hence increases the net power output of the plant. CO_2 that is available from the AGR at low pressure is vented to the atmosphere but changes to the plant need to be made to reduce emissions of trace components in the vent stream, particularly H_2S and CO, to environmentally acceptable concentrations. In this study two techniques were assessed:

1. Modification of the AGR to improve the purity of the CO_2 vent stream.
2. Include a partial oxidation unit and an activated carbon bed to clean-up the CO_2 vent stream.

The modified AGR case has the higher peak power output and efficiency during peak load operation and a lower capital cost but it has a lower efficiency during the time when CO_2 is captured.

Only qualitative assessment of turning off capture in oxy-combustion plants was considered. The option of continuing to capture CO_2 while turning down the ASU and using stored oxygen in the boiler, which is discussed later, was expected to be more attractive than short term switching between oxygen and 'air-firing' modes.

The results of the analysis of turning off capture are summarised in Table 2. The specific emissions for peak power generation shown in this table are calculated in the following way:

$$Ep = \frac{Ev - Er}{Pv - Pr}$$

Where:
Ep is Emissions for peak generation, t/MWh
Er is Emissions from the reference plant operating with capture, t/h
Ev is Emissions from a plant venting CO_2-containing gases, t/h
Pr is Net power output of the reference plant with capture, MW
Pv is Net power output when venting CO_2-containing gases, MW

Specific costs for peak generation are calculated in a similar way.

Table 2 Turning off CO_2 capture

	NGCC	PC	IGCC
Increase in power output with no capture, %	15.9	27.4	6.4
Thermal efficiency, %			
Reference plant with capture	50.6	34.8	31.4
Plant with capability to turn off capture	50.2	34.2	31.1
Plant with capture turned off	58.6	44.3	33.5
Capital cost			
Change in cost per kW of normal output, %	+5.8	+3.9	+0.5
Change in cost per kW of peak output, %	-8.7	-18.5	-5.6
Cost of extra peak power capacity, €/kW	354	322	213
CO_2 emissions			
Tonnes CO_2 per MWh of extra peak power	2636	2944	10450

It can be seen that having the capability to turn off capture increases the capital cost of the plant (per kW of normal power output), mainly because of the need for greater steam turbine capacity, but the cost per kW of peak power output is lower. The net capital cost per kW of extra peak power generation capacity is relatively low, probably less than the cost of other types of peak generation capacity such as simple cycle gas turbines but the specific emissions of CO_2 per kWh of extra peak power generation are high, particularly for IGCC. Including the ability to turn off post combustion capture reduces the net efficiency of the plant during normal operations because the low pressure steam turbine is oversized to enable it to use the extra low pressure steam that is available when capture is turned off. The turbine therefore operates at non-optimum conditions when the capture plant is operating. To avoid this efficiency reduction a separate steam turbine could be installed to use the low pressure steam that is available when capture is turned off. This approach was adopted in the solvent storage cases described later.

The economic viability of turning off capture would depend on the carbon emissions cost, the number of hours per week that capture is turned off and CO_2-rich flue gas is vented and the peak electricity prices during the time when capture is turned off. The relationship between these parameters for a base load PC plant is shown in Figure 2. Peak power costs would be slightly lower for turning off capture in an NGCC than a PC plant.

The peak power price will be determined by the cost of alternative peak load generation techniques, including simple cycle gas turbines and energy storage (pumped hydro, compressed air energy storage, batteries etc). Determining the costs of these techniques was beyond the scope of this study but in Figure 2 of this overview the costs of a simple cycle gas turbine (SCGT) plant are included for comparison with the costs of turning off CO_2 capture. The SCGT plant was assumed to have an efficiency of 40% (LHV), a capital cost of €450/kW, and an emission cost of €50/t of CO_2. Two SCGT cases are shown, one based on natural gas at €8/GJ and the other based on distillate oil at the current price of €16/GJ.

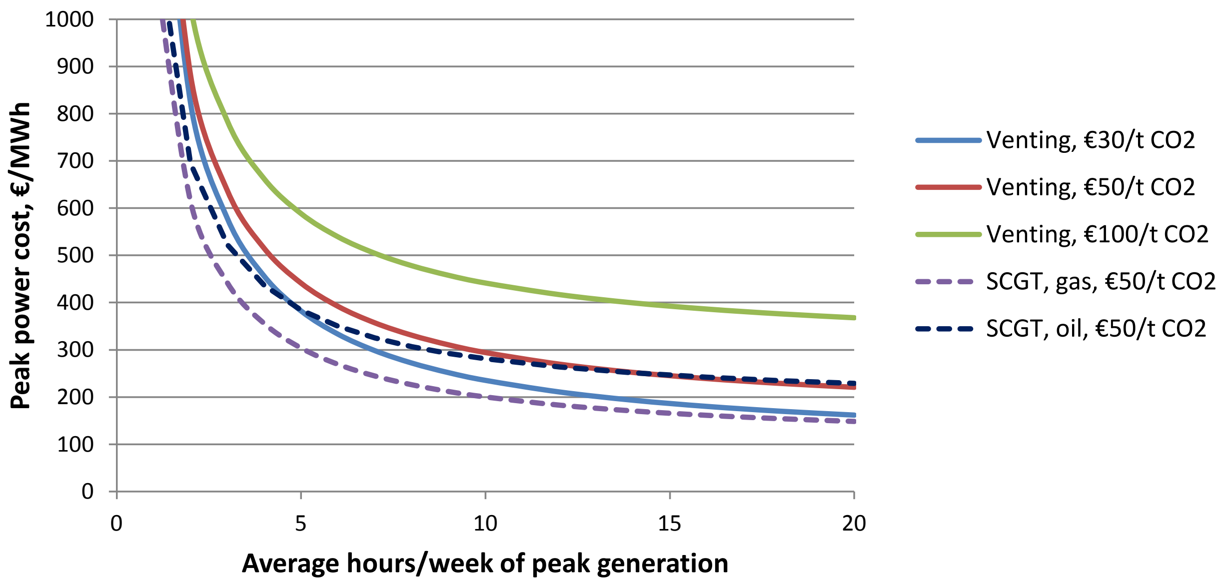

Figure 2 Economics of turning off CO_2 capture (PC plant)

The overall cost of generation increases as the number of hours per week that CO_2 capture is turned off is reduced because the fixed costs associated with turning off capture (Capex and O+M) are attributed to a lower number of MWh of peak power. It can be seen that for an emission cost of €50/t of CO_2, turning off capture is less economically attractive than an SCGT, although the costs are broadly similar if oil has to be used as the fuel for the SCGT. The economic advantage of the SCGT becomes greater at higher CO_2 emission costs, because the specific emissions associated with capture by-pass are higher than for an SCGT.

Solvent storage

Solvent from post combustion capture can be stored during times of peak power demand for regeneration during times of lower power demand. This reduces the requirement for other peak generation capacity. The extra generation during peak times would have low CO_2 emissions, unlike the alternatives of by-passing CO_2 capture as described earlier, or using peaking plants such as simple cycle gas turbines without CCS. Solvent storage in IGCC was not assessed in this study because the Selexol solvent would have to be stored at high pressure and it was expected that the costs would be high compared to other techniques e.g. liquid oxygen storage.

Foster Wheeler discussed the practicality of CO_2 solvent storage with some leading technology suppliers, including MHI, Aker Clean Carbon and Alstom. These companies all confirmed the technical feasibility of storing solvent, provided the temperature of CO_2-rich solvent is maintained at or slightly below the absorber bottom outlet temperature to avoid degassing. High rates of degradation are not expected, degradation would be mainly due to the reaction with oxygen, so nitrogen or CO_2 blanketing would always be considered. MEA-water solution that would be stored in capture plants is not flammable but solvent is toxic and the stores are potentially large, as discussed later, so it may not be acceptable at all locations.

Regeneration of stored solvent could take place during times of 'base load' operation or during times of low power demand when the power plant is operating at part load. The operating mode of the plant would determine the required capacities of the solvent storage tanks and the solvent regeneration and CO_2 compression equipment. If the plant is required to operate only at 'base load' the solvent regenerator and CO_2 compressor would need to be oversized to cope with regeneration of the solvent from 'peak load' operating hours. If the plant is expected to operate for some of the time at reduced load, the stored solvent could be regenerated during these times and the regenerator and compressor would not need to be oversized. If a plant is expected to regularly operate at substantially reduced load at night and at weekends, the solvent regenerator and CO_2 compressor could be undersized, i.e. they could be made smaller than in a normal base load power plant, thereby reducing capital costs. However, such a plant would not have the ability to operate at base load for long periods of time and this may not be attractive to the plant owner.

Two operating scenarios described below were assessed in this study as an illustration but it is recognised that in reality power plant operations will depend on many external factors which may change during the operating life of a plant. PC plants were assumed to be operated at higher load factors than NGCC plants at night and at the weekend because their lower marginal operating costs would put them higher up the operating 'merit order'. The 'weekly' and 'daily' scenarios involve different amounts of solvent storage and peak load operation.

1. Daily storage scenarios
    a. PC plant: Operation at peak load for two hours during the weekday day-time, normal full load for the remaining 14 hours of the day-time and 50% load for 8 hours of night-time and all weekend. Stored solvent is regenerated during the night-time.

b. NGCC plant: Operation at peak load for two hours during the day-time, normal full load for the remaining 14 hours of the day-time and shut-down during night-time and weekend. Stored solvent is regenerated during normal day-time operation.

2. Weekly storage scenarios
   a. PC plant: Operation at peak load for 16 hours during weekdays and operation at 50% load during 8 hours of night-time and all weekend. Stored solvent is regenerated during the night-times and weekend.
   b. NGCC plant: Operation at peak load for 16 hours during weekdays and shut-down or operation at the minimum load required for solvent regeneration during night-time and weekend.

In the weekly scenarios the 'peak' times are almost half of the total hours. For the PC plants, if solvent regeneration was completely switched off during peak times in these scenarios the amount of CO_2-laden solvent to be stored would be extremely large. Also the regenerator would have to be substantially larger than in the reference plant and it may be difficult to provide sufficient steam for the regenerators during the off-peak times when the plant is operating at 50% part load. In the weekly scenarios assessed in this study the solvent regeneration was therefore reduced by only 25% at peak times. Two alternatives were assessed:

1. Reduced regenerator size. The regenerator is about 85% of the size in the reference plant, which enables all of the stored solvent to be regenerated during off-peak times
2. 100% regenerator size. There is no reduction in the size of the regenerator, which would enable the plant to operate for long periods at 100% load if required. To minimise the capacity of the storage tanks the regenerator is operated at full capacity during the weekday night time, and it is operated at lower throughput during the weekends.

The lower capital cost of storage tanks and stored solvent in alternative 2 is greater than the extra cost of a larger regenerator. This lower capital cost and the greater flexibility to operate at full load means that alternative 2 is preferred, so results for this are presented in this overview.

In the NGCC weekly scenario, if solvent regeneration was completely switched off during peak times the amount of CO_2-laden solvent to be stored would be extremely large, although less so than in the PC plants because gas fired power plants have lower specific CO_2 production. It is possible to store 50% of the solvent during peak times without having to oversize the regenerator. Solvent is regenerated at off-peak time by operating one of the two gas turbines at minimum environmental load. As with the PC plant, the lowest cost and most flexible option is to have a 100% sized regenerator.

In the daily operating scenario, solvent regeneration is shut down completely during the 2 hours of peak operation and all of the CO_2–rich solvent produced during this time is stored. In the PC plants the stored solvent is regenerated during the night time when the plant is operating at 50% load. In the NGCC plants the stored solvent is regenerated during the remaining 14 hours of daytime operation, which requires the regenerator to be over-sized by about 14% compared to a capture plant without solvent storage. The NGCC plants shut down overnight and at weekend.

Solvent storage has very little effect of the thermal efficiency except for the NGCC weekly scenario, in which one of the gas turbines has to operate at minimum environmental load at off-peak times to regenerate solvent. The solvent storage tanks are conventional sized tanks as used at oil refineries but they are nevertheless large, particularly in the weekly scenario. As an example, in the NGCC daily scenario four tanks each of which is 27.4m diameter and 12.8m high are required.

Table 3 Storage of post combustion CO_2 capture solvent

Power plant type	**NGCC**	**PC**	**NGCC**	**PC**
Storage scenario	Weekly	Weekly	Daily peak	Daily peak
Hours per week of peak output	80	80	10	10
Increase in power output at peak times, %	6.2	4.8	12.1	22.2
Thermal efficiency, %				
Reference plant efficiency, 100% load	50.6	34.8	50.6	34.8
Reference plant time weighted average efficiency	50.6	33.6	50.6	33.6
Storage plant time weighted average efficiency	45.3	33.5	50.5	33.6
Capital cost				
Change in cost per kW of normal output, %	+19.6	+6.1	+9.3	+5.8
Change in cost per kW of peak output, %	+12.6	+1.2	-2.6	-13.5
Cost of extra peak generation, €/kW	3116	2891	752	589
Solvent storage				
Quantity of solvent storage, 10^3m^3	286	199	30	46

The overall economics of solvent storage are complex because there are substantial changes in the electricity output at various different times. An electricity price profile at different times is needed, which is beyond the scope of this study. However, an initial assessment of the economics can be made by comparing the capital cost of solvent storage and alternative means of generating peak load electricity. In the weekly scenario the capital cost per kW of additional peak generation capacity is greater than the cost of the reference power plant, which indicates that this scenario is unlikely to be attractive. In the daily scenario the capital cost per kW of additional peak generation capacity is less than the cost of the reference plant but it is probably higher than the cost of the leading alternative technology for peak load generation, namely simple cycle gas turbines. Solvent storage may be attractive in this scenario, depending on fuel prices, carbon emission costs and the electricity price profile.

Liquid oxygen and air storage

Storage of liquid oxygen (LOX) in oxy-combustion and IGCC plants can provide a boost to the peak power output by reducing the power consumption for oxygen production. During the times of peak power demand the power plant is operated at full load, the air separation unit (ASU) is operated at minimum load and the rest of the oxygen required by the power plant is taken from a LOX store. In the oxy-combustion plant the LOX is vaporised by condensing liquid air which is then stored and in the IGCC plant the stored LOX is vaporised using LP steam. During off-peak times the power plant is operated at part load but the ASU is operated at a higher load to enable the LOX store to be re-filled. Performance and cost data for PC oxy-combustion and IGCC plants with oxygen storage are shown in table 4.

An alternative that was evaluated in the report but which is not shown in this overview involves having a smaller capacity ASU which is operated at constant load. This option would reduce the capital cost and oxygen storage requirement but it would give a smaller boost to the power output at peak times. The plant would also not have the flexibility to operate at full load for long periods of time, similar to the post combustion cases with a reduced size solvent regenerator mentioned earlier.

The minimum efficient turndown of an ASU air compressor is 70% and the minimum turndown of the cold box is around 50%. In IGCC, turndown of the main ASU air compressor to 70%

would give only a marginal increase in net peak power output. The ASUs are therefore configured to have two smaller air compressors, one of which is turned off during the time of peak demand and the other is operated at 70% load. Having multiple compressors increases the capital cost but provides greater opportunity for high peak generation. Half of the compressed air for the ASU in the IGCC plants is provided by extraction from the gas turbine, which earlier studies and practical experience has shown results in relatively high efficiency, good operability and low costs. When the power plant is operating at part load, less air is available to the ASU from the gas turbine compressor. To operate the ASU at full load more air has to be provided by the ASU's own air compressors, so an additional compressor is provided for each ASU.

In the oxy-combustion case shown in table 4 there are two 50% capacity ASUs, each equipped with two 60% capacity main air compressors. During peak times one of the main air compressors per train is turned off but the ASUs are kept in operation because it is not feasible to shut down the ASU cold box due to its long start-up time. In the oxy-combustion plant only liquid oxygen and liquid air need to be stored but in the IGCC plant liquid nitrogen also has to be stored, as nitrogen is required for the gas turbine. Nitrogen accounts for more than half of the total storage volume.

Table 4 Storage of oxygen

Power plant type	**PC-oxy**	**IGCC**	**PC-oxy**	**IGCC**
Storage scenario	Weekly	Weekly	Daily	Daily
Hours per week of peak output	80	80	10	10
Power output				
Increase in output at peak times, %	5.3	7.7	5.8	10.5
Thermal efficiency, %				
Reference plant efficiency, 100% load	35.5	31.4	35.5	31.4
Reference plant time weighted average efficiency	34.0	29.5	34.0	29.5
Storage plan time weighted average efficiency	34.8	30.0	34.3	28.9
Capital cost, €/kW				
Change in cost per kW of normal output, %	+2.5	+2.7	+0.9	+1.4
Change in cost per kW of peak output, %	-1.5	-4.6	-4.6	-8.2
Cost of extra peak generation, €/kW	1573	928	381	336
Storage of liquid oxygen and nitrogen/air				
Quantity stored, $10^3 m^3$	12.1	24.0	0.8	3.4

The volumes of storage are much smaller than in the solvent storage cases but vessels have to operate at cryogenic temperatures.

The capital costs of peak generation are relatively low because unlike the earlier cases no additional power generation equipment has to be installed, instead the increased peak power is achieved by reducing the plant's ancillary power consumption. Although the capital costs per kW of normal power output increase, the costs per kW of maximum peak output decrease, particularly for the daily storage scenarios. The capital cost of the extra peak generation capacity in the daily storage scenarios is competitive with simple cycle gas turbines and the storage option has the advantage that extra peak generation has low CO_2 emissions. This preliminary analysis indicates that oxygen storage should be an attractive option for providing additional peak generation.

Hydrogen-rich gas storage

The flexibility of IGCC plants could be improved by storing surplus hydrogen-rich fuel gas produced during off-peak times. The stored hydrogen could be used to generate electricity at peak times or it could be supplied to other energy consumers. This would have the practical and economic advantages of enabling the gasification plant to continue to operate at full load at all times. The leading option for hydrogen storage would be underground salt caverns, which are a proven and relatively low cost technique for large scale hydrogen storage. Some liquid nitrogen would also be stored to satisfy the needs of the gas turbine. Performance and cost data are given in Table 5. The increase in peak power output per unit of gas turbine capacity is relatively small (3.3%) but the increase per unit of gasification plant capacity is greater (26.0%). The overall capital cost per kW of peak capacity is 8.5% lower than the reference IGCC plant. The capital cost of the extra peak generation capacity is negative because the capital cost of the plant is lower and the peak output is higher, although it should be noted that the plant would be unable to operate at continuous full load because of the under-sized gasification plant.

Table 5 Storage of hydrogen

Power plant type	**IGCC**
Storage scenario	Weekly
Hours per week of peak output	80
Increase in power output at peak times, %	
Per unit of gasifier capacity	26.0
Per unit of gas turbine capacity	3.3
Thermal efficiency, %	
Reference plant efficiency, 100% load	31.4
Reference plant time weighted average efficiency	29.5
Storage plant time weighted average efficiency	29.7
Capital cost, €/kW	
Change in cost per kW of normal output, %	-5.5
Change in cost per kW of peak output, %	-8.5
Cost of extra peak generation, €/kW	negative
Storage of hydrogen and nitrogen	
Quantity of hydrogen stored, $10^3 m^3$ working volume	100
Quantity of liquid nitrogen stored, $10^3 m^3$	7.2

The hydrogen storage volume is relatively small for a typical modern salt cavern store, for example about 5% of the capacity of a hydrogen storage cavern being built in Texas. This study focussed on coping with sort term (up to a week) variability in electricity demand. The relatively low cost of underground hydrogen storage means that this technique could also be cost effective for smoothing out longer term seasonal variability in electricity demand.

Another case was assessed in which the gasification and CCS is operated at continuous full load, a constant flow of high purity hydrogen for other consumers is maintained at all times and some of the hydrogen rich gas from the CCS plant is stored at off-peak times. Details of this case are provided in the main report.

Constant flow of CO_2 to transport and storage

Variation of the throughput of a CO_2 capture plant would result in variation of the flowrate of CO_2 to the transport pipeline and storage site. Little information is currently available on the ability of dense flow pipelines and storage wells to accept variable and intermittent CO_2 flows and the effects may be site specific. Two techniques for providing a constant flow of CO_2 were assessed,in case this should turn out to be required:

1. Buffer storage of compressed CO_2
2. Buffer storage of CO_2-rich solvent, combined with a reduced solvent regenerator capacity

In Case 1 it was assumed that CO_2 would be stored in cylindrical pressure vessels. If longer term storage was required and suitable geology was available near the power plant site it may be worthwhile considering an underground temporary buffer store.

Providing CO_2 buffer storage for the NGCC and PC plants with the 'weekly' operating scenario described earlier (in the section on solvent storage) would increase the plant capital cost by €30-40/kW. This cost could in principle be offset by a reduction in the size and cost of the CO_2 pipeline (and injection wells), for example in the NGCC case the cost savings for a 100km dedicated CO_2 pipeline would more than offset the cost of CO_2 storage. However if a small pipeline was built the plant would not be able to operate at continuous full load for long periods of time. The modest extra cost of installing a full capacity pipeline may be considered worthwhile to maintain the option to operate the plant at high load factors if required.

Case 2 (reduced capacity solvent regenerator and buffer storage of CO_2 capture solvent) was found to be substantially more expensive than Case 1 (storage of compressed CO_2).

Expert Review Comments

Comments on the draft report were received from seven reviewers who have expertise in the power industry, oxygen production, IGCC project development, and research on post combustion capture and CCS plant flexibility. IEAGHG and the contractor reviewed the comments and various detailed changes were made to the report. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard. Some reviewers emphasised that many operational issues still need to be considered in detail and more dynamic modelling and optimisation of the control of power plants and capture units is needed. This was emphasised more in the report.

Some reviewers expressed concerns that the load profiles originally assumed for the flexibility assessments may not be optimum as they resulted in excessive amounts of solvent storage, which raises economic, safety and regulatory concerns. To address these comments, additional cases involving short term peaking operation and substantially lower quantities of solvent storage were evaluated. More part load operation cases were also assessed and the oxy-combustion case with oxygen storage was modified to also include liquid air storage, to address reviewers' comments.

Conclusions

- CCS may impose additional constraints on the flexible operation of power plants but in general there are ways of overcoming these limitations. A plant with CO_2 capture may even be able to ramp up its net power output more quickly and produce more peak generation than a plant without capture, using the techniques considered in this study.

- The efficiency penalties for part load operation are expected to be somewhat greater for plants with CO_2 capture than plants without capture, for example around 3 percentage points at 50% load for a pulverised coal plant with post combustion capture compared to around 2 percentage points for a plant without capture.

- Increasing the power output by turning down or turning off the CO_2 capture unit may be an attractive technique for short periods, depending on the peak power price and CO_2 emission cost but preliminary analysis indicates that simple cycle gas turbines may be a lower cost option for peak load generation. Regulations would need to allow the resulting increase in CO_2 emissions, for example by averaging emission performance standards over a long period. Some additional equipment, particularly steam turbine capacity, would have to be installed to obtain the full benefit from turning down or turning off the capture unit, which would increase the capital cost. Turning off capture could increase the net power output by 27% for a pulverised coal fired plant and 16% for a natural gas combined cycle plant.

- Storing CO_2–rich solvent and regenerating it at a later time may be attractive as a way of increasing power plant ramp rates and for increasing the net power output during short term peaks in power demand. However, the large quantity of solvent that would have to be stored would mean that operating at peak output for longer periods of time would not be attractive. Plants could be built with a wide range of storage volumes, solvent regenerator sizes and peak power generation capacities; selecting the optimum would be a difficult commercial decision. Storing solvent could increase the net power output by 22% for a pulverised coal fired plant and 12% for a natural gas combined cycle plant.

- Liquid oxygen and air/nitrogen could be stored in oxy-combustion and IGCC plants to improve flexibility and increase net peak generation by 5-10%. From an economic perspective this is expected to be a relatively attractive option for short term peak power generation.

- Hydrogen produced in IGCC plants with pre-combustion capture could be stored for example in underground salt caverns, which are commercially proven. This would enable the gasification and CCS equipment to operate at continuous full load and only the combined cycle plant would need to operate flexibly to cope with variable power demand. This would be a significant practical and economic advantage for non-base load power generation. Underground hydrogen storage would be suitable for longer-term as well as short term storage, which could be an advantage particularly in electricity systems that include large amounts of variable renewable generation.

- Compressed CO_2 could be stored at capture plants to reduce the variability of flows of CO_2 to transport and storage, if this is found to be necessary. Buffer storage of CO_2 would enable a smaller capacity CO_2 pipeline to be built but this would constrain the ability of the power plant to operate at continuous full load, which may not be commercially attractive.

Recommendations

- IEAGHG should assess the ability of CO_2 transport and storage systems to accept variable and intermittent flows of CO_2.

- IEAGHG should undertake further work to determine the requirements for CCS plant flexibility, including collaboration where appropriate with other organisations that are undertaking modelling of electricity systems that include other low CO_2 technologies.

- IEAGHG should validate the methodology and results of this study when further information becomes available from plant dynamic modelling and pilot and demonstration plant operation.

- IEAGHG should propose further reviews and studies on CCS flexibility when appropriate.

IEA Greenhouse Gas R&D Programme

Operating Flexibility of Power Plants with CCS

FINAL REPORT

Job FWI No. 1-BD-0530 A

November 2011

FOSTER WHEELER

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SECTION D REVIEW OF FLEXIBILITY OF POWER PLANTS WITH CCS

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ABBREVIATIONS

AC	Alternate Current
AGR	Acid Gas Removal
ASU	Air Separation Unit
BES	Battery Energy Storage
BEDD	Basic Engineering Design Data
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BL	Battery Limits
BOP	Balance Of Plant
CAES	Compressed Air Energy Storage
CC	Combined Cycle
CCPP	Combined Cycle Power Plant
CCS	Carbon Capture and Storage
CFB	Circulating Fluid Bed
CPU	CO_2 Purification Unit
DC	Direct Current
DCAC	Direct Contact After Cooler
DLE	Dry Low Emission
DoD	Depth of Discharge
EOR	End Of Run
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement, Construction Management
ESP	Electro Static Precipitator
FBES	Flow Battery Energy Storage
FD	Forced Draft
FEED	Front-End Engineering and Design
FGD	Flue Gas Desulphurisation
FLA	Flooded Lead-Acid
FW	Foster Wheeler
FWH	Feed Water Heater
FWI	Foster Wheeler Italiana
GEE	General Electric Energy
GOX	Gaseous Oxygen
GT	Gas Turbine
H&M	Heat and Mass
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure
KO	Knock Out
LA	Lead Acid

LHV	Low Heating Value
LIN	Liquid Nitrogen
LOX	Liquid Oxygen
LP	Low Pressure
MAC	Main Air Compressor
MEA	Mono-Ethanol-Amine
MHI	Mitsubishi Heavy Industries
MP	Medium Pressure
MWe	Mega Watt electrical
MWth	Mega Watt thermal
NaS	Sodium-Sulphur
NEE	Net Electrical Efficiency
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NiCd	Nickel-Cadmium
NPO	Net Power Output
NG	Natural Gas
O&M	Operating and Maintenance
OTSG	Once-Through Steam Generator
PC	Pulverised Coal
PCS	Power Conversion System
PHES	Pumped Hydroelectric Energy Storage
PSA	Pressure Swing Adsorption
PBS	Polysulphide Bromide
PU	Process Unit
RH	Re-Heated
S/D	Shutdown
SCPP	Simple Cycle Power Plant
SCR	Selective Catalytic Reduction
SH	Super Heater
SMES	Superconducting Magnetic Energy Storage
SOR	Start Of Run
SRU	Sulphur Recovery Unit
ST	Steam Turbine
TGT	Tail Gas Treatment
TIC	Total Investment Cost
TSO	Tight Shut Off
UPHES	Underground Pumped-Hydroelectric Energy Storage
USC PC	Ultra Super Critical Pulverised Coal
VLP	Very Low Pressure
VR	Vanadium Redox
VRLA	Valve-Regulated Lead-Acid
WWT	Waste Water Treatment
ZnBr	Zinc Bromine

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INDEX

1 Background and objectives of the study

Power plants built in the 1990's and early years of the new millennium have been typically designed for base load operation, favouring higher efficiency and lower capital costs, with the main objective of minimizing the cost of electricity production. Nowadays, existing and new power plants must face the challenges of the liberalized electricity market and the requirement to cover intermediate and peak load constraints, so to respond to the daily and seasonal variation of the electricity demand. In this scenario, not only conventional natural gas combined cycles must be designed for flexible operation, but also coal-fired power plants, which are now generally required to operate in the mid merit market.

With this premise, IEA Greenhouse Gas R&D Programme has contracted Foster Wheeler (FW) to perform a study that assesses the potential flexibility of power plants with Carbon Capture and Storage (CCS). Most studies undertaken by several companies so far have assumed that these plant types will operate at base load in the near future, but it is now clear that they will need to be able to respond to the requirements of the new liberalized electricity market, otherwise it will not be possible to meet overall greenhouse gas abatement targets.

The main objectives of this study have been the following:

- Outline current capabilities of conventional coal and natural gas fired power plants, without CCS, to operate flexibly in response to the demand of the electricity market.
- Make a review of the information, available in the public domain, on the flexibility of the same power plants with carbon capture and storage for three leading capture technologies: pre, post and oxy-combustion.
- Identify factors that may constrain the operating flexibility of CCS processes, possible ways of overcoming these constraints and related cost implications.
- Make a techno-economic review of alternative energy storage techniques, like pumped hydropower, compressed air and batteries.

IEA GHG R&D Programme has already issued in the past years reports assessing natural gas and coal based power plants with leading CCS technologies, which have been considered as reference plants for the considerations of this work. Most of the information for the reference plants has been derived from the IEA GHG report "Water Usage and Loss Analysis in Power Plants without and with CO_2 Capture", completed by Foster Wheeler in 2010. Remaining information, relevant to the post-combustion capture process from natural gas-fuelled combined cycles, are partially taken from FW in-house design and partially from the IEA Report PH4/33, Nov 2004, Improvement in Power generation with post Combustion capture of CO_2.

FW like to acknowledge the following companies, listed in alphabetical order, for their fruitful support to the preparation of the report:

- Aker Clean Carbon;
- Alstom;
- Mitsubishi Heavy Industries (MHI);
- UOP.

2 Outline of operating flexibility of power plants without CCS

Most of the information available in the public domain refers to the combined cycles, especially in relation to the improvements made in the recent years for flexible operation. Much less information is available on operational flexibility of PC boiler plants, as well as IGCCs without CCS. This is because PC boiler and, moreover, IGCC plants have been generally designed to operate at base load, due to the lower weight of the variable costs (i.e. fuel) on the overall cost of electricity.

2.1 Natural Gas Combined Cycle (NGCC)

Depending on seasonal load and dispatch rank of the plant, driven by competition and fuel prices, the newly designed NGCC plants operate as cycling units over their lifetime, increasing load during the day or peak hours and reducing it to the minimum or shutting down during the night or when the electricity demand is low. In general, the operational flexibility of the combined cycle plants is characterized by the following main elements:

- Low technical minimum environmental load: this is the minimum load at which the Gas Turbine is able to operate while meeting the environmental limits, in particular NO_X and CO emissions. It is generally from 30% to 50% of the base load power production.
- Good efficiency at partial load: for newly designed plants the efficiency penalty corresponding to a load reduction down to 60% is only a few percentage points (2-3) lower than the base load operation, even if the expected impact on the cost of electricity is much higher (7-8%), as the cost for fuel consumption represents a significant portion of the economics of the plant.
- High cycling capability: recently built plants are generally characterized by fast start-up (45-55 min in hot conditions vs. 90 min of older plants) and shut down, fast load change and load ramps, low start-up emissions, high start-up reliability.
- Frequency control: it occurs whenever the electricity supply and demand are not in balance. Frequency control is generally made in three different steps: primary, secondary and tertiary. In many countries, the request for frequency control (at least the primary) is mandatory for NGCC power plants interconnected with the national grid, which are typically able to respond within a few seconds, restoring the nominal value of grid frequency.
- Low operating costs: this means high start-up efficiency or short start-up time.

In addition to the above, it is noted that a flexible plant opens up new business opportunities, like utilizing hourly and seasonal market arbitrage or participation in a peak load market. For this last opportunity, power production can be increased by Air chilling, Gas Turbine over-firing or HRSG post-firing.

For these plant types, the aero-derivative gas turbine technology has several features that provide further answers to the needs of the liberalized electricity market, in particular for their capability to participate in the peak load market and their possible use integrated with renewable energy sources.

2.2 Ultra Super Critical-Pulverized Coal (USC-PC) power plant

Nowadays, coal-fired plants are generally required to operate in the mid merit market, so a medium operating flexibility is also required for these plant types. In general, the operational flexibility of USC-PC boiler plants is characterized by the following main elements:

- Good cycling capability: Supercritical and ultra-supercritical PC boiler power plants show cycling capability much greater than conventional subcritical plants. In fact, subcritical plants use drum-type boilers that require a controlled heating, limiting the load change rates generally to 3% per minute. On the other hand, supercritical or ultra-supercritical facilities use once through steam generators that can achieve quick load changes, even up to 8%.
- Fast load response: 5% to 15% of the power output can be provided in few seconds by using the energy storage capacity of the steam/water. For limited time, following measures can be used: opening overload valve(s) or opening throttled turbine control valve(s), opening/closing a feed water supply valve to the LP feed water heaters, opening/closing of the steam supply valve to the final feed water heaters.
- Fast change rate: Typical ramp rates (%rated power/min) are: 2-3 from 30% to 50% load, 4-8 from 50% to 90% load, 3-5 from 90% to 100% load.
- Fast start-up: Typical start-up times are: <1 h (very hot start, <2h shutdown), 1.5-2.5h (hot start. 2-8h shutdown), 3-5 (warm start. 8-48h shutdown), 6-7 (cold start, >72h shutdown).
- Good efficiency at partial load: reduction of plant efficiency of supercritical units is about 2 percentage points at 75% load, compared to 4 percentage points reduction in efficiency for subcritical plants under comparable conditions.

2.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants show dispatch flexibility lower than other power plants, due to the inertia related to the process units (gasification, syngas cooling and conditioning line, etc.), as well as the Air Separation Unit (ASU), to generate and prepare the fuel at the conditions required by the gas turbine. As a matter of fact, gasification and syngas cleaning processes are chemical processing plants, operating best at design point condition and at steady-state conditions over long period of time, minimizing shutdown, start-up and changes of process conditions, as it takes time to re-adjust after upset condition.

These features are generally in contrast with the common requirements of a flexible operation. Furthermore, IGCC requires significantly longer time for start up, because of pre-heating requirements related to the gasifier, particularly for refractory-lined and less for slag wall type gasifiers, downstream unit pressurization and because of the deep cool-down sequence of the ASU. In general, the operational flexibility of IGCC plants is characterized by the following main elements:

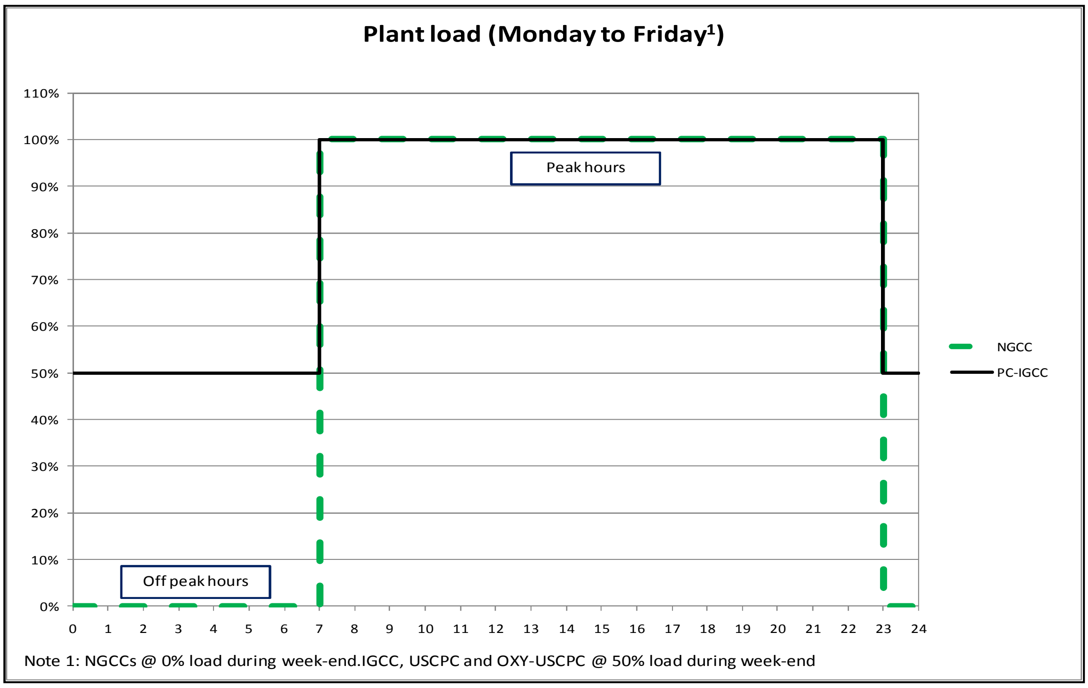
- Low cycling capability: although the load of the gas turbine can vary freely between 0 and 100% of base load, in practice the lower limit is around 50-60%. In fact, for syngas operation diffusion burners only are available. Below 60% of base load, the concentrations of NOx and CO in the flue gas increase drastically, potentially creating environmental issues. In addition, the minimum load achievable during night period is limited by the minimum turndown of the gasification and the Air Separation Unit and their inertia related to the syngas production. In order to increase plant flexibility some modification should be introduced in the plant design: syngas storage, oxygen/nitrogen storage, syngas/auxiliary fuel co-firing, chemicals and electricity co-production.
- Low change rate: load changes are generally conditioned by the gasification and the ASU: 3% per minute is the expected load change rate from the light off of coal to minimum capacity (generally 50%), while 5% is foreseen increasing the load from minimum to full capacity. Faster ramp rates can be achieved if the gas turbine co-fires syngas and natural gas, as the syngas generation plant can follow its own ramp rate while natural gas is added to the fuel mixture of the gas turbine.
- Long start-up: start-up time depends on the start-up of the single units or equipment, e.g. Gasification, Gas Turbine, ASU, as well as on the thermal integration of the various units, including the possible air integration between the Gas Turbine compressor and the ASU. A total time of about 80-90 hours is expected for the cold start-up of the entire IGCC, in case of no or partial air integration. An additional 10-20 hours will need to be added in case of full air integration.
  For a hot-start-up, the key factor is the ASU cold box temperature: start-up sequence lasts approximately 6 hours (instead of the 36-48 hours for "cold" start-up). Typical hot start-up and restart-up time after minor upsets for the gasification island is in the range from 6 to 8 hours, which is the minimum time required for de-pressurization and purging of the gasifier and downstream components.

3 Assessment of operating flexibility of power plants with CCS

The reference plants selected for the assessments of this study are the NGCC, IGCC, USC PC and Oxy-combustion plant. For the combined cycle-based alternatives (NGCC and IGCC), the design capacity of the plant is fixed to match the appetite (thermal requirement) of two F-class gas turbines at the reference ambient temperature of the study (9°C). For the boiler-based alternatives (USC PC and Oxy-combustion plant), the design capacity is selected by referring to a boiler size that could be currently engineered and built, corresponding to approximately 750-1000 MWe gross power production.
The economic data of each case have been derived from the data contained in the reference studies, after currency adjustment and cost level escalation.

For the reference plants with leading CCS technologies, the following sections identify the elements that may constrain the operating flexibility of the plant, discuss possible ways of overcoming them and assess performance and cost implications of flexible operation. Some elements are common to the different power plant types, while others are related to a specific technology only.

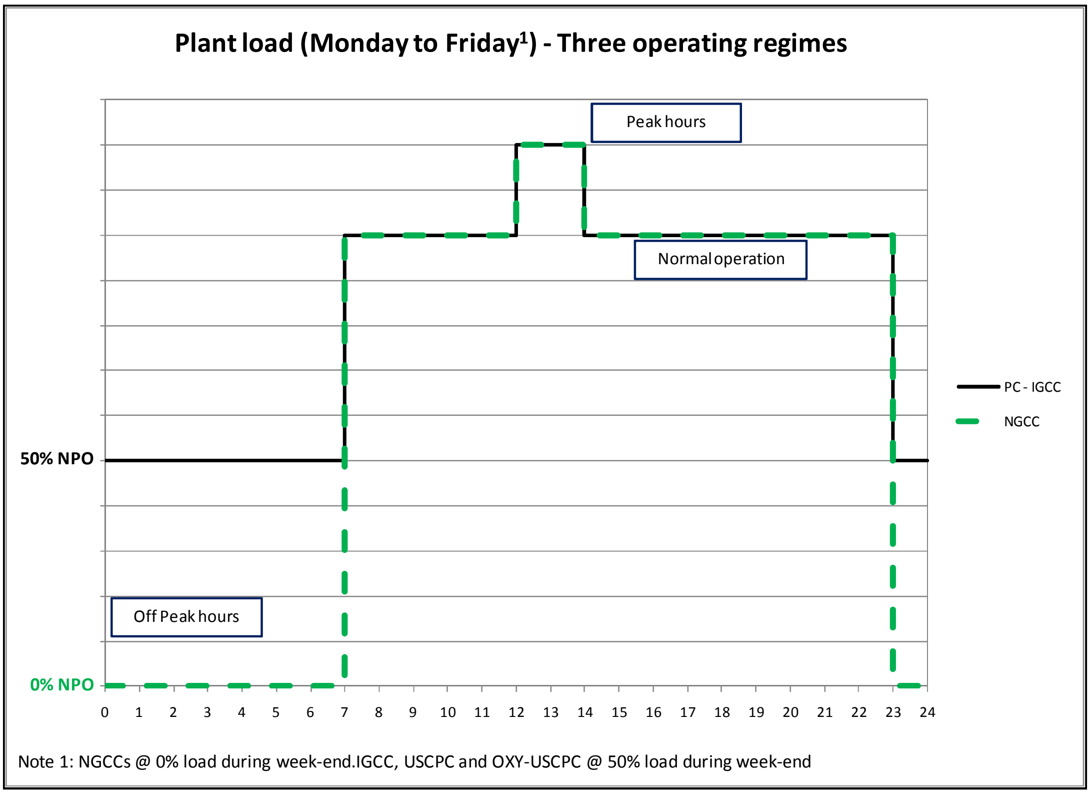
Figure 3-1: Load operation of power plants with CCS



Depending on the power plant type, these considerations are based on the assumption that plants will be requested to operate in the mid and peak merit market, in order to meet actual power market requirements. The trends assumed for the different power plants follow a weekly demand curve characterised by two operating regimes, as shown in Figure 3-1. Additional considerations have been made by considering alternative scenarios, as explained in the following:

- A weekly demand curve characterised by three operating regimes, with two hours per working day of peak electricity demand, as shown in Figure 3-2.
- An electricity market where the USCPC plant and the power train of the IGCC are shutdown analogously to the demand curve of the combined cycles.

Figure 3-2: Three regimes load operation of power plants with CCS



3.1 Thermal cycling of power plants with CCS

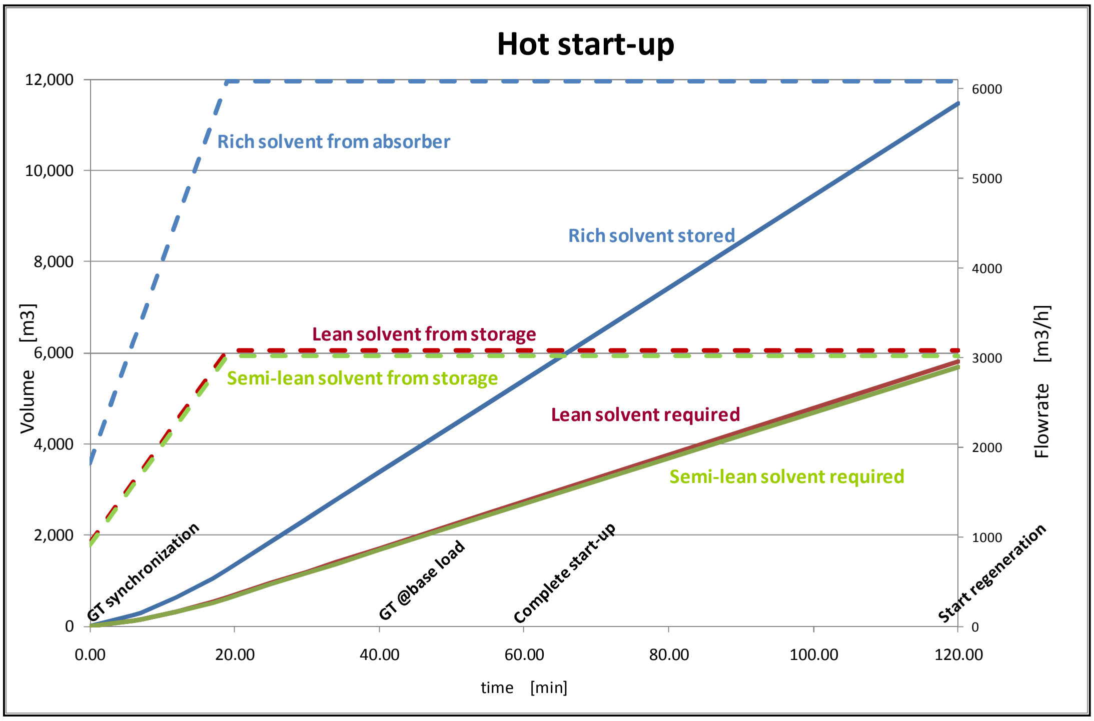
In general, the introduction of the CO_2 capture and compression facilities in power plants may impose additional constraints to a flexible operation, predominantly for the combined cycles and the USCPC plants with post-combustion capture, where certain equipment, like stripper and reboiler, may limit the capacity to make frequent start-ups/shut-downs, due to the time required to pre-heat the regeneration column and the related reboilers. For plants with other capture technologies, i.e. pre-combustion capture and cryogenic purification of oxy-combusted flue gases, this constraint is not present as the capture unit is generally capable to follow the transient operation of the other units.

For the NGCC and USCPC plants, to overcome this constraint it is possible to consider the storage of CO_2-laden solvent (Case 1a and 3a), which allows to decouple the Gas Turbine or the boiler island from the CO_2 capture unit during start-up. As an alternative, a small fired heater providing the heat required for preheating the regenerator column before the plant start-up could be installed, avoiding the need for solvent storage during this phase. However, with this solution a certain amount of CO_2 in the flue gas from the fired heater is released to the atmosphere.

Recently designed combined cycle plants can be started-up in 45-55 minutes, after night shutdown (hot start-up), or 2 hours after weekend shutdown (warm start-up), while recently designed USC PC plants can be started-up respectively in 120 minutes and less than 4 hours. On the other hand, the heating up of a regenerator column could require a few hours, once the steam is available from the steam cycle. In this case, solvent circulation in the CO_2 absorber can be started before gas turbine/boiler ignition so that, when gas turbine/boiler is started-up with its own ramp-up rate, the exhaust gases are fed to the absorption column and CO_2 is captured by lean solvent. As soon as steam from the HRSG/boiler is available at required pressure, the regeneration section can be heated up. It has been estimated that the regeneration section can be ready for operation at full load in 120 minutes, after gas turbine/boiler ignition during hot start-up, while 240 minutes are required in case of warm start-up.
In order not to limit the operating flexibility of the combined cycle with CCS, the strategy considered in Case 1a and 3a is that until the regenerator is not able to purify the CO_2-rich amine from the bottom of the absorber, rich solvent is sent to a storage tank, while lean amine and semi-lean amine are taken from other dedicated tanks.

The solid lines in Figure 3.1-1 show for Case 1a the solvent flowrate from/to the storage tanks during hot start-up, while the dashed lines represent the resulting required storage volume (similar trend is during warm start-up).

Figure 3.1-1: Case 1a (NGCC) – Stored solvent volume during hot start-up

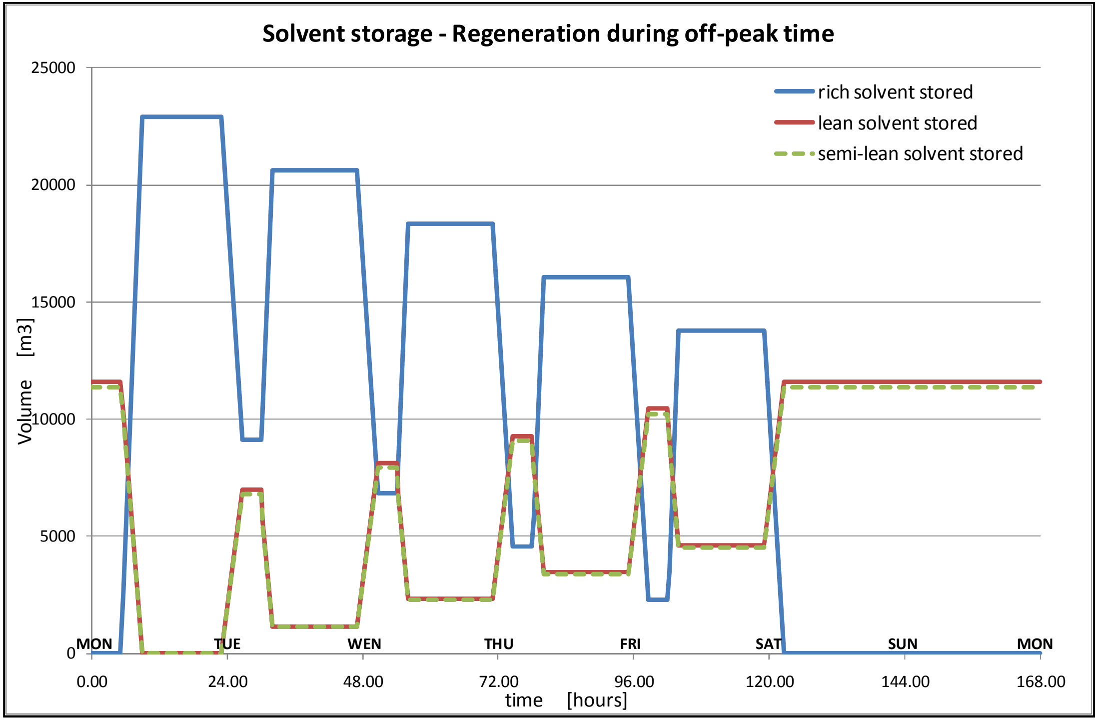


For the NGCC case, two alternatives have been assessed for the regeneration of stored rich solvent and refilling of lean and semi-lean amine storage tanks:

1. Regeneration during off-peak hours, maintaining the plant in operation at minimum environmental load, i.e. one gas turbine operated at about 40%, for approximately 3-4 hours per night in order to provide steam for the reboiler.
2. Regeneration during peak hours, when the plant is operated at full load, thus requiring an oversize of about 15% for the regeneration and compression units.

The first alternative is considered the most reasonable choice, because it has the lowest investment cost and the highest power production during peak demand period. However, higher variable and fixed operating costs will need to be considered during off-peak demand period, because the power plant is operated at minimum environmental load for the time required to regenerate rich solvent and refill lean solvent tanks. Figure 3.1-2 shows the dynamic trend of the stored solvent volume during the week. The design of the storage tanks is fixed by the amount of stored solvent required during warm start-up.

Figure 3.1-2: Case 1a (NGCC) – Stored solvent volume during the week



For the USCPC plant following a two regimes demand curve where the plant is required to be shutdown during low electricity demand period (Case 3a – Scenario 2), the regeneration of stored rich solvent and refilling of lean and semi-lean amine storage tanks is carried out when the plant is operated at full load, thus requiring an oversize of about 8.5% for the regeneration and compression units.
Figure 3.1-3 shows the dynamic trend of the stored solvent volume during the week. The design of the storage tanks is fixed by the amount of stored solvent required during warm start-up.

For the USCPC plant following a three regimes demand curve (Case 3a – Scenario 3), where the plant is shutdown during low electricity demand period and to cover two hours per working day of peak electricity demand, the regeneration of stored rich solvent and refilling of lean and semi-lean amine storage tanks is carried out during normal electricity demand, thus requiring an oversize of about 24% for the regeneration and compression units. Figure 3.1-4 shows the dynamic trend of the stored solvent volume during the week. The design of the storage tanks is fixed by the amount of solvent stored after peak demand period on Monday.

Figure 3.1-3: Case 3a (USC PC plant) - Scenario 2 - Stored solvent volume during the week

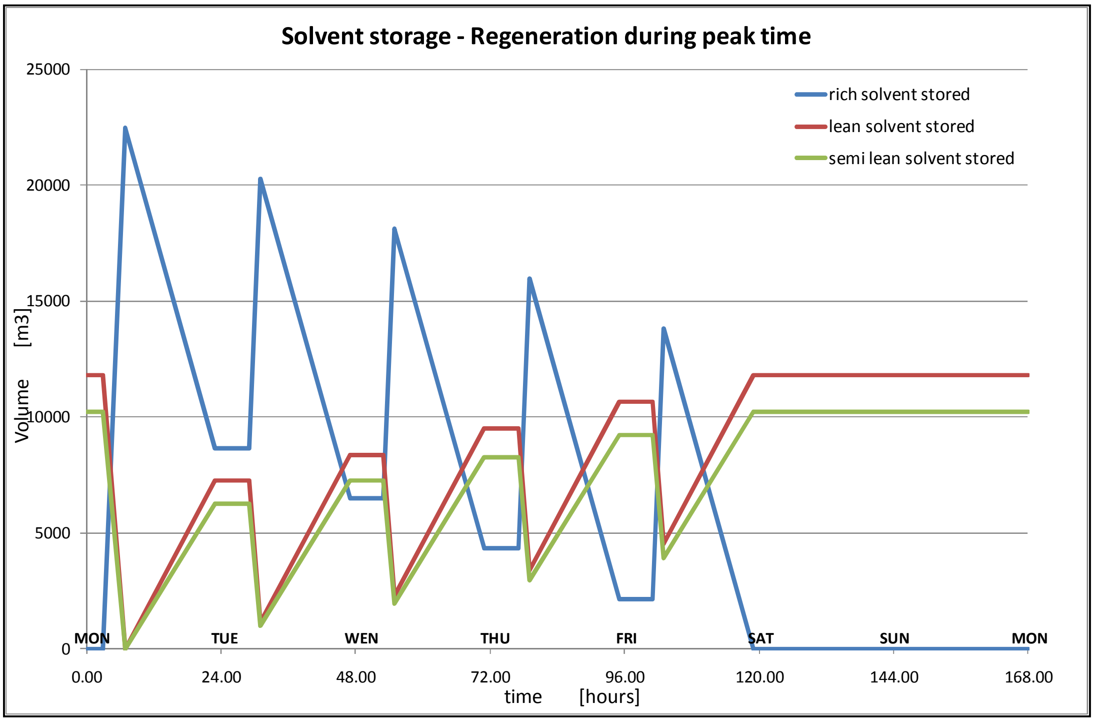
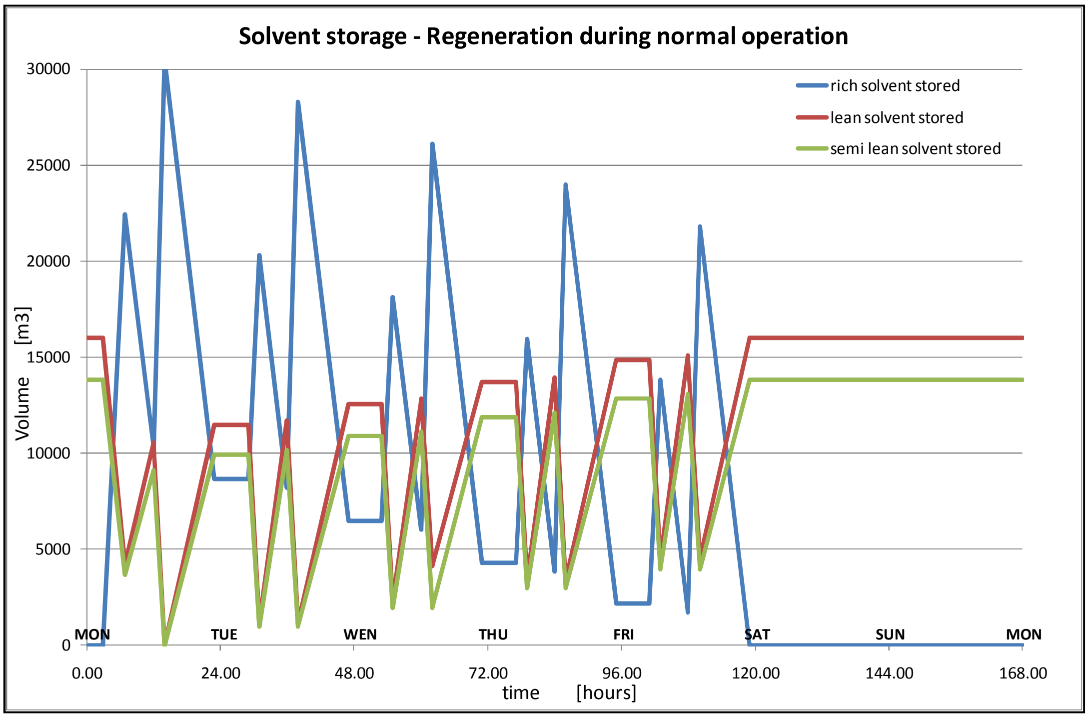


Figure 3.1-4: Case 3a (USC PC plant) - Scenario 3 - Stored solvent volume during the week



The following table summarizes the main performance and cost data of Case 1a and 3a (Scenario 2 and 3).

Table 3.1-1: Thermal cycling in NGCC – Performance and cost data summary (Est. accuracy: ±35%)

Tag	Plant type	Reference plant		Regeneration during off-peak		
		Performance	TIC, M€	Performance	Size (% of ref. plant) / Plant changes	TIC, M€
Case 1a	NGCC w post-comb	NPO=742MWe NEE=50.6%	726	Peak NPO=742MWe NEE=50.6% Off-peak (during regeneration) NPO=77MWe NEE=18.4%	Start-up ST 65MWe Condensing section 190%	783
					Rich solvent 2 x 12,500 m^3 (D: 31.1 m x H: 16.5 m)	
					Lean solvent 1 x 13,000 m^3 (D: 31.1 m x H: 17.1 m)	
					Semi Lean solv: 1 x 12,500 m^3 (D: 31.1 m x H: 16.5 m)	
Case 3a (Scenario 2)	USC PC w post-comb	NPO=666 MWe NEE=34.8%	1,513	Peak NPO=655MWe NEE=34.2% (Plant shutdown during off-peak)	Regeneration / compression section 108.5%	1,545
					Rich solvent 2 x 12,000 m^3 (D: 30.5 m x H: 16.5 m)	
					Lean solvent 1 x 13,000 m^3 (D: 31.1 m x H: 17.1 m)	
					Semi Lean solv: 1 x 12,000 m^3 (D: 30.5 m x H: 16.5 m)	
Case 3a (Scenario 3)	USC PC w post-comb	NPO=666 MWe NEE=34.8%	1,513	Peak NPO=808MWe NEE=42.2% Normal operation NPO=655MWe NEE=34.2% (Plant shutdown during off-peak)	Regeneration / compression section 124%	1,627
					New ST: 113 MWe Condensing section 145%	
					Rich solvent 2 x 17,300 m^3 (D: 36.6 m x H: 16.5 m)	
					Lean solvent 1 x 17,300 m^3 (D: 36.6 m x H: 16.5 m)	
					Semi Lean solv: 1 x 17,300 m^3 (D: 36.6 m x H: 16.5 m)	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost
Estimate accuracy: ±35%

It can be drawn that for power plants with CO_2 post-combustion capture, to maintain same thermal cycling capability as the conventional plants without capture, solvent storage is required, leading to an investment cost increase of about 8% and 2% with respect to the reference case, respectively for NGCC and USCPC boiler cases, considering a weekly demand curve with two operating regimes.
A higher investment cost, around 7.5% of the reference case, is required for the USCPC boiler case, when considering a weekly demand curve with three operating regimes.

3.2 CO_2 capture solvent storage

For NGCC and USC-PC power plants, the introduction of the post-combustion solvent washing process and the CO_2 compression unit may potentially limit their intrinsic capacity to operate flexibly. However, solvent storage can allow to decouple the operation of the absorption section from the regeneration and compression units, while continuously capturing the CO_2 from the flue gases. Solvent regeneration and compression, with their associated energy penalties, can then be made during low electricity demand periods. This feature has the potential for improving load following capabilities and overall economics of capture plants, because the electricity production can be maximized when the market requires a higher electricity generation.
Licensors of the most referenced solvent washing technologies, like Aker Clean Carbon, Alstom and Mitsubishi Heavy Industries have all confirmed the technical feasibility of solvent storage, either lean or laden, provided that the temperature of the rich solvent is maintained at or slightly below absorber bottom outlet temperature condition, to avoid degassing or venting of carbon dioxide and potential over pressure of the tank. Furthermore, high rates of solvent degradation in the rich storage tank are not expected; degradation would be mainly due to the reaction with oxygen, therefore nitrogen or CO_2 blanketing shall always be considered. In addition, solvent solution is not flammable at the concentration used in the capture plant and cannot be auto-ignited during different operating modes.
Furthermore, MHI owns a patent in the European Union, USA and Japan (EP 0537593B1), which is dedicated to the storing of solvent and regeneration during high power demand.

3.2.1 Solvent storage for plants with two operating regimes

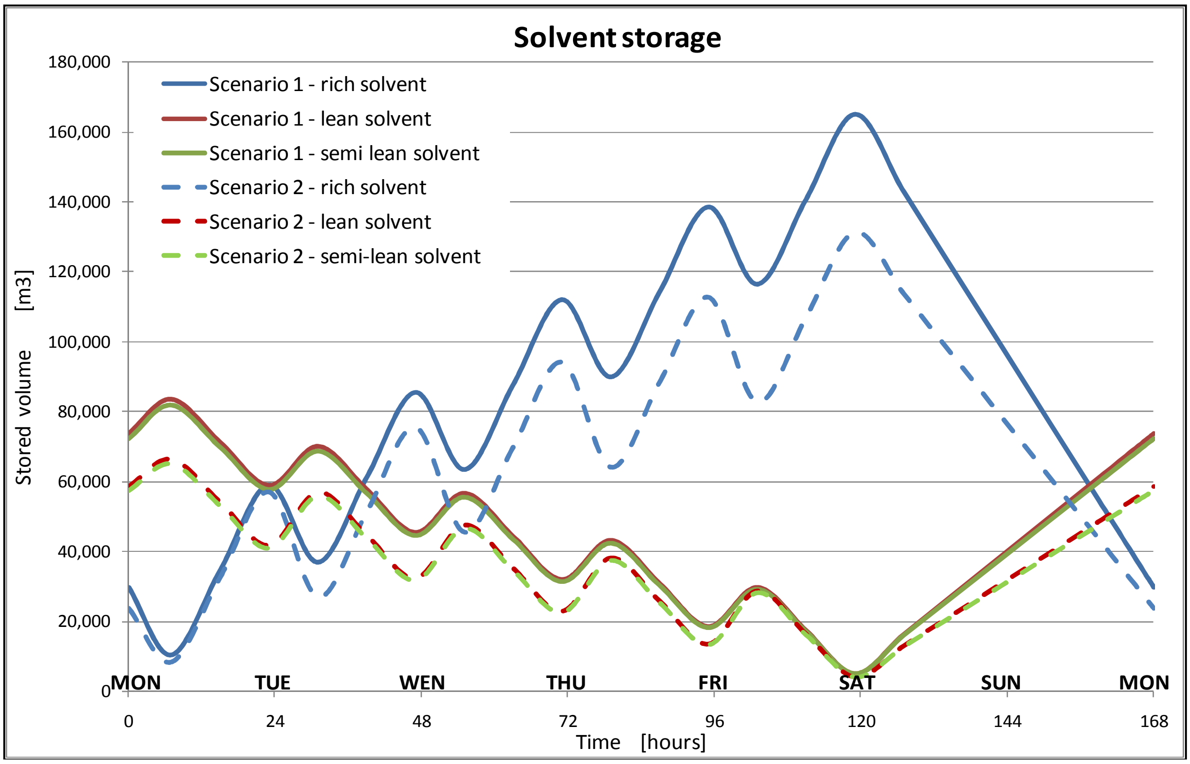
Cases 1b (NGCC plant) and 3b (USCPC plant) are based on a weekly demand curve characterized by two operating regimes, as shown in Figure 3-1. For these plants, to maximize energy production, rich solvent can be partially or even totally stored during the 80 hours per week of peak load operation, when the plant is at base-load, while the regeneration of stored solvent can be made during the remaining 88 hours per week of off-peak load operation, when the plant is required to operate at a partial load (50% NPO for USC-PC) or is shutdown (NGCC). With this strategy, the solvent flowrates from/to the storage have to be balanced in one week of operation.

During peak electricity demand, when the market requires maximum amount of electricity, the power plant is operated at base load by making full capture of the CO_2 from the flue gases in the absorber column, while only a certain amount of the CO_2-rich solvent from the absorber bottom is fed to the regenerator, the remainder being stored in dedicated storage tanks. As a consequence, part of the lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, so it is has to be taken from dedicated storage tanks.
During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the stripper can be operated in order to regenerate the rich solvent stored in the tanks, while refilling the lean amine storage tanks. The steam required for the regeneration is taken from the power island, thus implying that the combined cycle has to be operated at minimum environmental load, i.e. the shutdown required by the electricity demand curve is not possible for this plant type.

Different regeneration loads during high electricity demand period have been investigated in order to evaluate the most convenient operating condition. The resulting optimum regeneration loads are 50% and 25%, respectively for NGCC and USC-PC power plants, thus resulting in a significant increase of the net power output during peak hours, while avoiding the need for excessive storage volumes. For each plant, two possible scenarios have been considered:1) Reduced (i.e. lower than reference plant) size of the regeneration and compression section, resulting in 74% and 85% of the reference case, respectively for the NGCC and the USC-PC; 2) Same size as the reference plant, i.e. unchanged design.

Figure 3.2-1 shows the stored volumes of solvents during the week, for the scenarios considered in the NGCC plant (same trend is for the USC-PC case). The net volume of the storage tank is the difference between the maximum and the minimum volume of solvent stored during the week. It corresponds to the solvent stored during the weekend, from turndown of Friday night to ramp up of Monday morning. The solid line corresponds to the stored volume for scenario 1, while the dashed line corresponds to the stored volume for scenario 2. Although both scenarios are designed for the same regeneration load during peak time, storage tanks required for the second alternative are smaller because it is possible to maintain this section at base load during off-peak hours of the working days, while maintaining a lower load during the week-end, enough to avoid accumulation in the storage tanks.

Figure 3.2-1: NGCC –Stored solvent volume during the week



The following tables summarize the main performance and cost data of the two power plants. From the figures in the tables the following conclusions can be drawn:

- By introducing adequate solvent storage in the plant, the electricity production and the net electrical efficiency during peak demand period increase by about 5% to 6% with respect to the reference case.
- For the NGCC plant, the investment cost delta is about 20% higher than the reference case, both for the alternative with reduced regeneration and compression units design and the case with unchanged design. Cost delta variation for the USC-PC plant with respect to the reference plant is respectively 7%.
- When comparing the two alternatives, it follows that an unchanged design (scenario 2) is the most attractive choice. In fact, this alternative has both a wider operating flexibility and a slightly lower investment cost.

Table 3.2-1: Scenario 1 (lower size) – Performance and cost data summary (Estimate accuracy: ±35%)

Tag	Plant type	Reference plant		Scenario 1 (lower size)		
		Performance	TIC, M€	Performance	Storage tanks	TIC, M€
Case 1b	NGCC w post-comb	NPO=742 MWe NEE=50.6%	726	NPO=788 MWe NEE=53.7%	Rich solvent 2 x 87,500 m^3 (D: 81 m x H: 17 m)	885
					Lean solvent: 1 x 87,500 m^3 (D: 81 m x H: 17 m)	
					Semi Lean solvent: 1 x 87,500 m^3 (D: 81 m x H: 17 m)	
Case 3b	USC PC w post-comb	NPO=666 MWe NEE=34.8%	1,513	NPO=697 MWe NEE=36.4%	Rich solvent 2 x 71,600 m^3 (D: 73 m x H: 17 m)	1,627
					Lean solvent: 1 x 71,600 m^3 (D: 73 m x H: 17 m)	
					Semi Lean solvent: 1 x 63,600 m^3 (D: 69 m x H: 17 m)	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost

Table 3.2-2: Scenario 2 (full size) – Performance and cost data summary (Estimate accuracy: ±35%)

Tag	Plant type	Reference plant		Scenario 2 (full size)		
		Performance	TIC, M€	Performance	Storage tanks	TIC, M€
Case 1b	NGCC w post-comb	NPO=742 MWe NEE=50.6%	726	NPO=788 MWe NEE=53.7%	Rich solvent 2 x 71,600 m^3 (D: 73 m x H: 17 m)	868
					Lean solvent: 1 x 71,600 m^3 (D: 73 m x H: 17 m)	
					Semi Lean solvent: 1 x 71,600 m^3 (D: 73 m x H: 17 m)	
Case 3b	USC PC w post-comb	NPO=666 MWe NEE=34.8%	1,513	NPO=697 MWe NEE=36.4%	Rich solvent 2 x 47,700 m^3 (D: 60 m x H: 17 m)	1,605
					Lean solvent: 1 x 55,700 m^3 (D: 65 m x H: 17 m)	
					Semi Lean solvent: 1 x 47,700 m^3 (D: 60 m x H: 17 m)	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost.

3.2.2 Solvent storage for plants with three operating regimes

Cases 1f (NGCC plant) and 3e (USCPC plant) are based on a weekly demand curve characterized by the following three operating regimes:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (NGCC plant shutdown or USC PC generating 50% of net power output): night and weekend.

To maximize the energy production, the rich solvent is totally stored during the 2 hours per day of peak load operation, when either the gas turbines or the boiler are at 100%load. The power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are halted. A supplementary LP steam turbine has been considered to expand the additional steam available when the regeneration is halted; this avoided to over sizing the steam turbine for the total amount of steam, as well as the inefficient operation of the machine during normal operation.

For the NGCC case, as per the assumed electricity demand curve, the plant is fully shut down overnight and at the weekend, while the regeneration of stored solvent is made during the 14 hours per day of normal operation, thus requiring an oversize of the regeneration and compression section of approximately 14% to avoid any accumulation of the stored solvent.

For the USCPC case, the regeneration of stored solvent can be made during the 8 night hours per day of off-peak load operation, when the plant is required to operate at a partial load in order to produce 50% of the normal operation net production. This leads to a boiler load around 55% during the weekend and 61% during weekday night time, when the solvent stored during peak load operation has to be regenerated, while the regenerator and compression section operate at around 86%.

With this strategy, the solvent flowrates from and to the storage are balanced within each day of plant operation, leading to a size of the storage tanks that is smaller than the demand curve based on two operating regimes, as shown in the previous section.

The following tables summarize the main performance and cost data of the two power plants. From the figures in the tables the following conclusions can be drawn:

- By introducing adequate solvent storage in the plant, the electricity production and the net electrical efficiency during peak demand period increase from about 12% to 22% with respect to the reference case. For the NGCC plant, during normal operation the net power output is around 2% lower than the reference case, due to the oversize of the regenerator, which also corresponds to an increased pipeline diameter (400 mm vs. 350 mm)

- For the NGCC plant, the investment cost delta is about 9% higher than the reference case. Cost delta variation for the USC-PC plant is 6%.

Table 3.2-3: Daily cycle solvent storage – Performance and cost data summary

Tag	Plant type	Reference plant		Daily cycle solvent storage with an alternate demand curve		
		Performance/ pipe diam. (mm)	TIC, M€	Performance pipe diam. (mm)	Size (% of ref. plant) / Plant changes	TIC, M€
Case 1f	NGCC w post-comb capture	NPO=742MWe NEE=50.6% Pipeline D: 350	726 100km pipe: 167	Peak NPO=832MWe NEE=56.7% Normal operation NPO=729MWe NEE=49.6% Pipeline D: 400	Regeneration / compression section 114%	793 100km pipe: 185
					New ST: 77MWe Condensing section 195%	
					Rich solvent 2 x 7,600 m^3 (D: 27.4 m x H: 12.8 m)	
					Lean solvent: 1 x 7,600 m^3 (D: 27.4 m x H: 12.8 m)	
					Semi Lean solvent: 1 x 7,600 m^3 (D: 27.4 m x H: 12.8 m)	
Case 3e	USCPC w post-comb capture	NPO=666 MWe NEE=34.8%	1,513	Peak NPO=813 MWe NEE=42.5% Normal operation NPO=666 MWe NEE=34.8%	New ST: 91MWe New condenser 295 MWth	1,600
					Rich solvent 2 x 12,000 m^3 (D: 30.5 m x H: 16.5 m)	
					Lean solvent: 1 x 12,000 m^3 (D: 30.5 m x H: 16.5 m)	
					Semi Lean solvent: 1 x 10,100 m^3 (D: 27.4 m x H: 17 m)	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost
Estimate accuracy: ±35%

3.3 Constant CO_2 flowrate in transport pipeline

For each power plant assessed in the study, the cycling operation required to meet the variable grid demand leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating conditions in the pipeline. As a consequence, a two-phase flow or a significant change of the physical properties could occur in the pipeline, if pressure and temperature were not maintained within a limited range of variation with respect to the normal operation of the capture plant. Furthermore, for some applications like the Enhanced Oil Recovery (EOR) it would be preferred to have a pre-determined flow rate of CO_2, even if variable, rather than an unpredictable fluctuating stream. Two different options have been considered to avoid these issues:

- *Scenario 1* (CO_2 buffer storage): introduction of a CO_2 storage system, to maintain a constant CO_2 flowrate in the pipeline.
- *Scenario 2* (Reduced regenerator capacity, valid for post-combustion technologies): operation of the regeneration and compression sections at constant and reduced load. These sections are designed for a lower capacity, while solvent storage tanks compensate the difference between the absorber and the regenerator load.

Using above strategies, a constant CO_2 flowrate lower than peak production when the plant is operated at base load is sent to the external pipeline; then, it is possible to select a lower pipeline diameter, leading to a potential cost saving, depending on the overall length of the pipeline, though some costs associated with laying a pipe (e.g. access, earthmoving) are generally more dependent on length, rather than diameter.

For Scenario 1, Figure 3.3-1 shows a trend, typical for all plant types, of the whole volume of stored CO_2 during the week and the single vessel volume trend. The required net volume of the storage vessels is the difference between the maximum and the minimum volume of stored CO_2 during the week. From the graph, it can be drawn that it corresponds to the CO_2 accumulated during the weekdays and mainly discharged during the partial load operation from Friday night to Monday morning.

With reference to Scenario 2, Figure 3.3-2 shows a trend, typical for all plant types, of the stored volumes of rich, lean and semi-lean solvents during the week. The net volume of the storage tank corresponds to the difference between the maximum and the minimum volume of solvent stored during the week. It corresponds to the solvent stored during the weekend, from turndown of Friday night to ramp-up of Monday morning.

Table 3.3-1 and Table 3.3-2 summarize main performance and cost data of different plants. For each case, estimated cost of 100 km pipeline is also included in the figure.

Figure 3.3-1: Scenario 1 – Stored CO_2 volume during the week

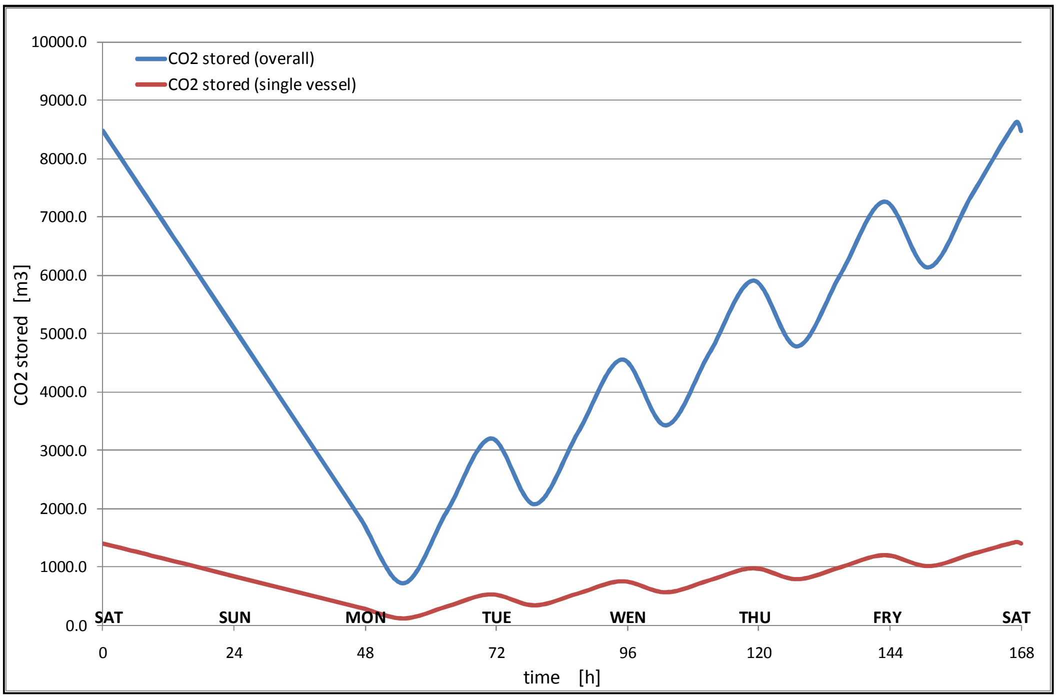


Figure 3.3-2: Scenario 2 –Stored solvent volume during the week

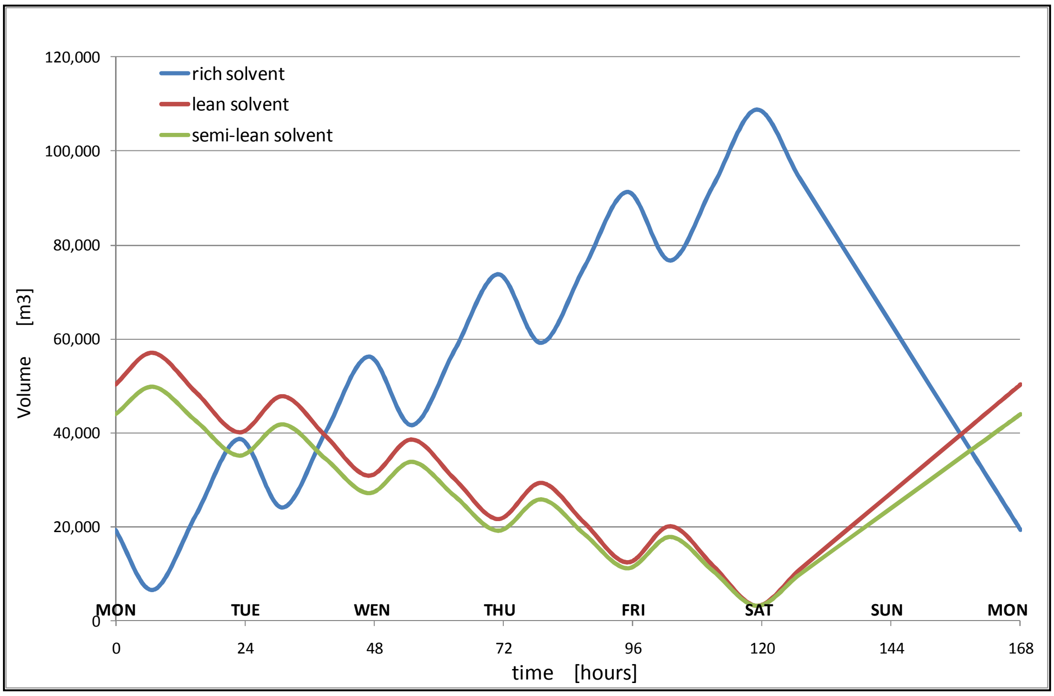


Table 3.3-1: Scenario 1 (CO_2 buffer storage) – Performance and cost data summary

Tag	**Plant type**	**Reference plant**		**Scenario 1 (CO_2 buffer storage)**		
		Performance/ pipe diam. (mm)	TIC, M€	Performance (peak hours)/ pipe diam. (mm)	CO_2 storage vessels	TIC, M€
Case 1d	NGCC w post-comb capture	NPO=742 MWe NEE=50.6% Pipeline D: 350	726 100km pipe: 167	NPO=742MWe NEE=50.6% Pipeline D: 250	6x1,535 m^3 (D: 8.7m, H: 26.1m)	748 100km pipe: 135
Case 2e	IGCC w pre-comb capture	NPO=730 MWe NEE=31.4% Pipeline D: 500	1,885 100km pipe: 206	NPO=732 MWe NEE=31.4% Pipeline D: 450	8x1,600 m^3 (D: 8.8m, H: 26.4m)	1,915 100km pipe: 195
Case 3c	USC PC w post-comb capture	NPO=666 MWe NEE=34.8% Pipeline D: 500	1,513 100km pipe: 206	NPO=666 MWe NEE=34.8% Pipeline D: 450	6x1,450 m^3 (D: 8.5m, H: 25.5m)	1,541 100km pipe: 195
Case 4c	Oxy-combustion USC PC	NPO=533MWe NEE=35.5% Pipeline D: 500	1,387 100km pipe: 206	NPO=536MWe NEE=35.7% Pipeline D: 400	6x1,325 m^3 (D: 8.3m, H: 24.9m)	1,408 100km pipe: 184

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost
Estimate accuracy: ±35%

Table 3.3-2: Scenario 2 (Lower regenerator/compressor size) – Performance and cost data summary

Tag	**Plant type**	**Reference plant**		**Scenario 2 (lower size)**		
		Performance/ pipe diam. (mm)	TIC, M€	Performance (peak hours)/ pipe diam. (mm)	Size (% of ref. plant) / Storage tanks	TIC, M€
Case 1d	NGCC w post-comb capture	NPO=742MWe NEE=50.6% Pipeline D: 350	726 100km pipe: 167	NPO=776MWe NEE=52.9% Pipeline D: 300	Regeneration section 62.5% Rich solvent 2 x 63,600 m^3 (D: 69 m x H: 17 m) Lean solvent: 1 x 63,600 m^3 (D: 69 m x H: 17 m) Semi Lean solvent: 1 x 63,600 m^3 (D: 69 m x H: 17 m)	838 100km pipe: 150
Case 3c	USCPC w post-comb capture	NPO=666 MWe NEE=34.8% Pipeline D: 500	1,513 100km pipe: 206	NPO=688 MWe NEE=36.0% Pipeline D: 450	Regeneration section 80% Rich solvent 2 x 55,700 m^3 (D: 65 m x H: 17 m) Lean solvent: 1 x 63,600 m^3 (D: 69 m x H: 17 m) Semi Lean solvent: 1 x 55,700 m^3 (D: 65 m x H: 17 m)	1,601 100km pipe: 167

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost
Estimate accuracy: ±35%

From the figures in the tables the following conclusions can be drawn:

- By introducing CO_2 buffer storage in the plant, overall performances during peak time are basically not affected, while the total investment cost increase (not including the pipeline) is marginal, ranging from 2% to 3% of the reference case. However, depending on the overall length, this investment increase may be offset by the lower cost of the pipeline.
- For the NGCC and the USC-PC alternatives, if solvent storage is introduced in the plant then the electricity production increases by about 3% to 5%, during peak hours, with respect to the reference case. On the other hand, the plant total investment cost is respectively 12% and 4% higher than the CO_2 buffer storage option (overall % increase equal to 15.4 and 5.8 respectively).

3.4 Hydrogen storage in IGGC plants with CCS

The operating flexibility and economics of the IGCCs can be improved if the plant is designed for the co-production of electricity and hydrogen (Case 2b) or if a buffer storage of hydrogen rich gas (Case 2c and 2f) is introduced in the plant. In this case, the syngas (or hydrogen) production line and CCS plant can operate constantly at full load, while the hydrogen-fired power plant follows the requirements of the flexible market (i.e. demand curve with two operating regimes).

In all the alternatives assessed in the study, part of the hydrogen rich gas from the CO_2 removal unit is fed to storage during low electricity demand periods, while it is used during electricity peak demand.

During *low electricity demand period* and for Cases 2b and 2c, the excess syngas production, obtained from the process units running at base load, is stored or used to produce hydrogen, while the power plant is operated with two gas turbines at their minimum environmental load, which is 60% of base production, corresponding to approximately 66% of fuel requirement. In Case 2f, as the plant is required to operate in island mode during off-peak demand period, only one gas turbine is in operation at its minimum environmental load.

For Case 2b, the amount of fuel required by the gas turbines is sent to the power island for electricity generation, while the remainder part from the AGR, corresponding to approximately 34% of the overall production, is split into two different streams: one is fed to a pressure swing adsorption (PSA) unit for high purity hydrogen production, while the other stream is sent to underground storage and used as feeding stream for the PSA during peak-hours operation, i.e. when all the syngas generated from the gasification island is dedicated to the power production. The PSA design capacity is selected to generate a constant hydrogen flowrate at plant battery limits, during the whole week of plant operation. It has been estimated that by storing approximately 48% of the de-carbonised fuel used for hydrogen production during off-peak demand period, then the PSA can be maintained at constant load, producing about 75,400 Nm^3/h of high purity hydrogen.

For Case 2c and 2f, fuel gas from/to the storage system has to be balanced during the cyclic weekly operation, in order to avoid any accumulation of fuel. The need of balancing the fuel gas fixes the design capacity of the whole syngas generation line, which results in 82% and 65% of the reference case, respectively for Case 2c and 2f.

During *high electricity demand period*, the power island is operated with the two gas turbines at base load. For Case 2b, hydrogen rich gas from the storage is fed to the PSA to generate a constant hydrogen flow, while for Case 2c and 2f, where the process units are designed for a lower capacity, the hydrogen rich gas from the AGR unit is integrated with the stored gas, to meet the thermal requirement of the two machines.

It is noted that, as the ASU and the power trains are maintained at different loads during the cyclic operation, the air integration between the ASU and the gas turbines may potentially represent a constraint for the flexible operation of the IGCC. In this case, an additional main air compressor shall be considered for operation during off-peak hours, as the air extracted from the gas turbines, operated at part load, is significantly lower than the amount required by the ASU, operated at base load.

Figure 3.4-1 shows the main hydrogen rich fuel flowrate on the whole week of plant operation and the related volumes of stored gas for Case 2b. From the graph, it can be concluded that a storage volume of about 100,000 m^3 is required for this alternative, leading to the selection of an underground storage, rather than storage in vessels. Also for Case 2c, the required storage volume is about 100,000 m^3, while twice of this volume is required for Case 2f; it is noted that for these cases an additional back-up volume of about 6,400 m^3 and 17,900 m^3 of liquid nitrogen respectively for Case 2c and 2f is required in the ASU, due to the lower size of this unit and to allow base load operation of the gas turbines.

Hydrogen storage is not a novel industrial application. In fact, over the last decades there have been several examples of underground storage, like:

- England, Teesside, Yorkshire: ICI has stored 1 million Nm^3 of nearly pure hydrogen in three salt caverns at about 400 m in depth. The caverns have operated successfully for many years, and they are now operated by SABIC.

- France, Beynes, Ile de France: Gaz de France has stored a gas with 50-60% hydrogen in an aquifer of 330 million Nm^3 capacity for nearly 20 years. No losses or safety problems have been recorded.
- Germany: 62% H_2 gas was stored in a salt cavern of 32000 m^3 at 80-100 bar
- Texas: Praxair is constructing a large underground hydrogen storage facility in salt caverns, to enable "peak shaving" of its hydrogen production.

Figure 3.4-1: Case 2b – Balance of syngas within the week

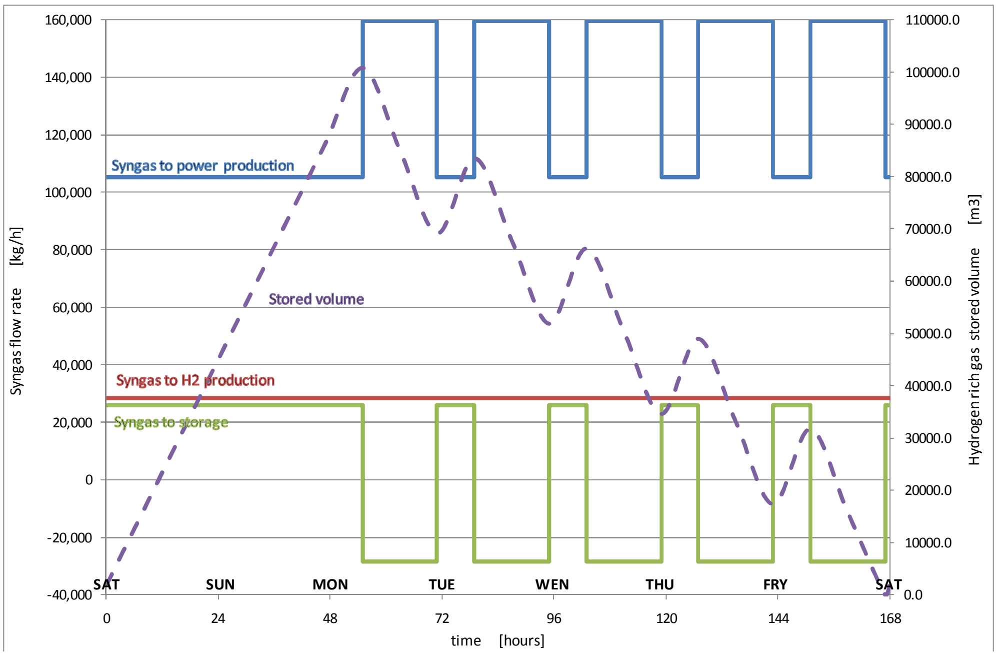


Table 3.4-1summarizes the main performance and cost data of the three cases. From the figures in the table it can be drawn the following:

- By introducing hydrogen storage in the plant, the electricity production during peak demand period increases by about 3% and 6% with respect to the reference case, respectively if the plant is required to generate the 50% of the net power output or to operate in island mode during low electricity demand period. In addition, the introduction of a PSA unit can allow to produce a significant amount of high purity hydrogen (75,400 Nm^3/h).
- For the hydrogen co-production alternative, the investment cost increase is about 3% of the reference case, while for the hydrogen storage case, the investment cost reduction is about 6% and 12.5%, respectively for Case 2c and 2f. These cost figures do not include cost for hydrogen storage, which depends both on the storage type (natural reservoir or mined cavern) and whether it is constant-pressure or variable-pressure storage. From literature data, it can be

derived that the expected cost for the hydrogen storage of these IGCCs plant may vary from 10 M€ to 50 M€ (twice for Case 2f), corresponding to a maximum of 3% (6%) of the overall plant cost.

Table 3.4-1: H_2 storage in IGCC plants – Performance and cost data summary (Est. accuracy: ±35%)

Tag	Plant type	Reference plant		H_2 storage in IGCC plants		
		Performance pipe diam. (mm)	TIC, M€	Performance (peak time) pipe diam. (mm)	Main changes	TIC, M€
Case 2b	IGCC w pre-comb capture	NPO=730MWe	1,885	NPO=750MWe	H_2 storage working volume: 100,000 m^3 H_2 prod.: 75,400 Nm^3/h	1,931 (w/o storage)
Case 2c	IGCC w pre-comb capture	NPO=730MWe Pipeline D: 500	1,885 100 km pipe: 206	NPO=754MWe Pipeline D: 450	PU % size of ref. plant: 82% H_2 storage working volume: 100,000 m^3	1,781 (w/o storage) 100 km pipe: 195
Case 2f	IGCC w pre-comb capture	NPO=730MWe Pipeline D: 500	1,885 100 km pipe: 206	NPO=774 MWe Pipeline D: 450	PU % size of ref. plant: 65% H_2 storage working volume: 200,000 m^3	1,651 (w/o storage) 100 km pipe: 195

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost; PU: Process Units

3.5 Oxygen storage in IGGC and oxy-USCPC power plants with CCS

The ASU significantly impacts the overall net electricity production of the plant, mainly due to its high auxiliary power demand. By reducing the energy requirement of this unit, at least during peak-demand hours, it is possible to increase the overall net power export during remunerative hours and improve the economics of the plant.

3.5.1 Oxygen storage for plants with two operating regimes

Two different design alternatives can be considered for either the IGCC or the oxy-combustion USCPC plant (Case 2a and Case 4b), both requiring adequate oxygen storage (as well as nitrogen storage for the IGCC), sized to cover production fluctuations of a cyclic operation, based on the electricity demand curve shown in section 3. The two scenarios assessed are the following:

- *Scenario 1* (partial load): ASU is operated at partial load during peak hours, while the rest of the plant runs at full load, thus reducing the auxiliary consumption and increasing the overall net electricity production.
- *Scenario 2* (reduced capacity): ASU is designed for a reduced capacity, with a consequent lower investment cost, while the plant load is changing in response to the variable electricity market requirements.

In both scenarios, oxygen from/to the storage system will need to be balanced during the weekly cyclic operation, in order to avoid any accumulation of the product. The need of balancing oxygen to/from the storage determines a relation between the ASU, running at low load during high electricity demand hours, and the other units, running at partial load during low electricity demand period. In fact, during off-peak operation the plant auxiliary demand and the resulting plant load strongly depend on the ASU load, which will need to ensure as a minimum the oxygen required by the plant to produce 50% of the daily power output, plus the oxygen sent to storage, necessary to fulfil the peak-hours demand.

For the oxy-combustion USCPC plant, during peak demand period compressed air is liquefied to provide the heat required for liquid oxygen from storage vaporisation. Liquid air is stored in pressurised vessel and vaporised during off-peak operation to replace the liquid oxygen sent to storage, in the main ASU exchanger.

Figure 3.5-1 shows the volume of stored oxygen during the week, for the two scenarios of Case 2a (similar trend is for Case 4b). The required net volume of the storage tank is the difference between the maximum and the minimum volume of stored oxygen during the week. From the graph, it can be concluded that it corresponds to the oxygen stored during the weekend, from the turndown of Friday night to the ramp up of Monday morning. A minimum oxygen storage volume corresponding to normal requirement of the plant, similarly to the reference plant, has been also considered while defining the tank size.

For the oxy-combustion USCPC plant, it is noted that oxygen storage has also been assessed in Case 4a of the study, in relation to the ramp rate of the Air Separation Unit, which is generally different, lower, than the one of a conventional boiler (typically 3% per min for vs. 4-5% per min for the PC boiler). In fact, by introducing a properly designed oxygen storage and vaporization system, it is possible not to affect the normal ramp-rate capacity of the boiler plant. The analysis showed that the difference between the ASU supply rate and the demand of the boiler is less than 10 tonnes of oxygen for each ramp-up phase. Therefore, the 200 tonnes back-up LOX storage tank and vaporiser system, already included in the reference design case, are also adequate to meet this requirement.

Table 3.5-1 and Table 3.5-2 summarize the main performance and cost data of the two power plants.

Figure 3.5-1: Case 2a –Stored Oxygen volume during the week

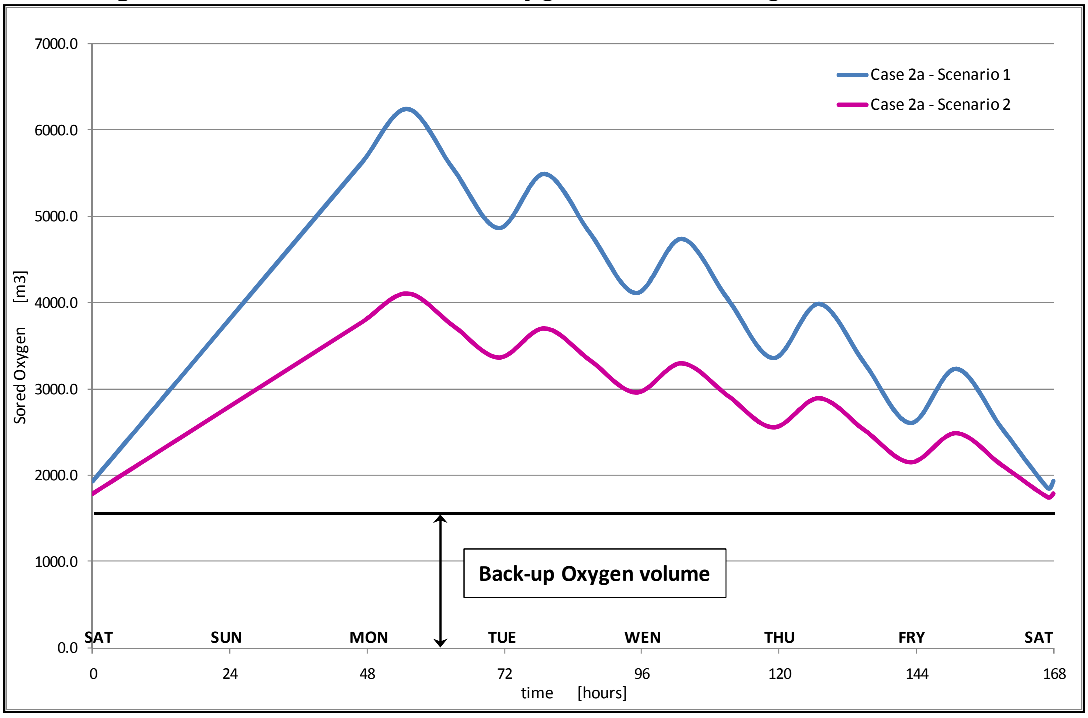


Table 3.5-1: O_2 storage (Scenario 1) – Performance and cost data summary (Estimate accuracy: ±35%)

Tag	**Plant type**	**Reference plant**		**Scenario 1 (ASU at partial load operation)**		
		Performance	TIC, M€	Performance (peak time)	Main changes	TIC, M€
Case 2a	IGCC w pre-comb capture	NPO=730MWe NEE=31.4%	1,885	NPO=786MWe NEE=33.9%	O_2 storage 1 x 6,500 m^3 (D: 27.4 m; H: 11 m)	1,937
					N_2 storage 1 x 17,500 m^3 (D: 43 m; H: 12 m)	
					New MACs.: 4 x 16 MWe	
Case 4b	Oxy-combustion USC PC w flue gas cryogenic purification	NPO=533MWe NEE=35.5%	1,387	NPO=561MWe NEE=37.4%	O_2 storage 1 x 10,500 m^3 (D: 33.5.1 m, H: 12.2 m)	1,422
					Liquid air vessel 4 x 1,600 m^3 (D: 8.8 m, H: 26.4 m)	
					2x60% Air compressors Booster compressor 1 x 1.4 MWe	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost; MAC: Main air compressor

Table 3.5-2: O_2 storage (Scenario 2) – Performance and cost data summary (Estimate accuracy: ±35%)

Tag	**Plant type**	**Reference plant**		**Scenario 2 (reduced ASU capacity)**		
		Performance	TIC, M€	Performance (peak time)	Main changes	TIC, M€
Case 2a	IGCC w pre-comb capture	NPO=730MWe NEE=31.4%	1,885	NPO=759MWe NEE=32.7%	O_2 storage: 1 x 4,200 m^3 (D: 20.4 m, H: 12.8 m) N_2 storage 1 x 6,500 m^3 (D: 27.4 m; H: 11 m) ASU size: 82.5% of reference plant New MACs.: 2 x 21 MWe	1,890
Case 4b	Oxy-comb. USCPC w flue gas cryogenic purification	NPO=533MWe NEE=35.5%	1.387	NPO=547MWe NEE=36.4%	O_2 storage 1 x 5,500 m^3 (D: 23.8 m, H: 12.8 m) Liquid air vessel 2 x 1,680 m^3 (D:9 m, H: 27 m) ASU size: 78% of reference plant Booster compressor 1 x 0.75 MWe	1,361

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost; MAC: Main air compressor

From the figures in the tables the following conclusions can be drawn:

- By introducing adequate oxygen (and nitrogen) storage in the plant and running the ASU at partial load, the electricity production during peak demand is about 5% and 8% higher than the reference case, respectively for Oxy-combustion and IGCC plant.
- For the IGCC plant, the investment cost delta is about 3% higher than the reference case by considering an ASU at partial load operation, while it is approximately 2.5% for the Oxy-combustion plant.
- By considering a lower-sized ASU (about 80% of the reference case), the electricity production is 3% and 4% higher than the reference case, respectively for the Oxy-combustion and the IGCC plant. Moreover, the total investment cost is about the same as the reference case for the IGCC, while for the Oxy-combustion power plant it is approximately 2% lower.

3.5.2 Oxygen storage for plants with three operating regimes

Cases 2g (IGCC plant) and 4d (Oxy-fuel plant) are based on a weekly demand curve characterized by the following three operating regimes:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (50% of net power output): night and weekend.

During normal and peak electricity demand the IGCC is operated at base load to maximise the electricity production, while during off-peak electricity demand, the plant is required to produce 50% of the overall net electricity production capacity.

For the two hours of peak electricity demand, the ASU is operated at its minimum load and oxygen from the ASU is integrated with the oxygen coming from the liquid storages, after vaporisation. The minimum load is represented by the minimum technical load of the ASU cold box. i.e. around 50% of the design capacity. For the IGCC case, the air required by the ASU to obtain the 50% oxygen production is derived from gas turbine compressors while, for the oxy-combustion plant, a dual train configuration has been considered for the main air compressor to avoid inefficient operation at a load lower than 70%.

The oxygen requirement during peak hours is balanced by the production during night time, following a daily cycle operation and avoiding any accumulation of the stored product, thus implying a lower storage tank volume with respect to the weekly storage cycle scenarios.

Table 3.5-3 summarizes the main performance and cost data of the two power plants. From the figures in the tables the following conclusions can be drawn:

- By introducing adequate oxygen (and nitrogen) storage in the plant and running the ASU at partial load, the electricity production during peak demand is about 6% and 10% higher than the reference case, respectively for the Oxy-combustion and the IGCC plant.
- For the IGCC plant, the investment cost delta is about 1.5% higher than the reference case, while it is approximately the same for the Oxy-combustion plant.

Table 3.5-3: O_2 storage (daily cycle) – Performance and cost data summary

Tag	**Plant type**	**Reference plant**		**Daily cycle LOX storage with an alternate demand curve**		
		Performance	TIC, M€	Performance (peak time)	Main changes	TIC, M€
Case 2g	IGCC w pre-comb capture	NPO=730MWe NEE=31.4%	1,885	NPO=806MWe NEE=34.7%	O_2 storage 1 x 2,000 m^3 (D: 15.2 m; H: 11 m)	1,910
					N_2 storage 1 x 1,450 m^3 (D: 13 m; H: 11 m)	
					New MACs.: 2 x 18 MWe	
Case 4d	Oxy-combustion USC PC w flue gas cryogenic purification	NPO=533MWe NEE=35.5%	1,387	NPO=564MWe NEE=37.5%	O_2 storage 1 x 600 m^3 (D: 9.1 m, H: 9.8 m)	1.399
					Liquid air vessel 1 x 230 m^3 (D: 4.8 m, H: 14.4 m)	
					2x50% Air compressors New air compressor 1 x 7MWe	

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost; MACs: Main air compressors; Estimate accuracy: ±35%

3.6 Operation without carbon capture and sequestration

Provided that design is adequately made, power plants with CO_2 pre or post-combustion capture can also be maintained in continuous operation without making the capture and compression of the carbon dioxide for transportation outside plant battery limits. Depending on possible low CO_2 emission allowance costs, as in the present market situation, this operating flexibility may improve the economics of the plants, because of the resulting higher power production in this operating condition.
However, a critical factor in determining whether a plant may be operated without capture is the acceptability of this approach to regulators.

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems (NGCC-Case 1e, USPC-Case3d), as it is possible to totally by-pass the CO_2 capture unit, directly releasing to atmosphere the flue gases from the boiler, similarly to conventional power plants without CO_2 capture. In this operating mode, the energy penalties related to the CO_2 capture and compression units, as well as the steam requirement for solvent regeneration, are avoided, leading to an overall higher plant net power production. However, this implies that the whole cycle has to be designed for accepting all the steam from the steam generation, when the capture plant is turned off.

For IGCCs with pre-combustion CO_2 capture processes (Case 2d), the Acid Gas Removal Unit cannot be shut down because it is necessary to remove at least the H_2S from the syngas, before combustion in the Gas Turbine, to meet the design environmental emission limits. In addition, fuel composition to the gas turbine cannot be changed dramatically (e.g. CO shift unit cannot be by-passed) because it is necessary to respect the maximum range variation of fuel properties (e.g. LHV, Wobbe index etc.) as tolerated by the machine.
However, it is possible to tune to a certain extent the CO_2 capture rate, and consequently the plant net power output, varying the solvent circulation flowrate in the AGR unit, in order to absorb completely the H_2S but not the CO_2. With this strategy, the capture rate range to which it is possible to operate is limited by both the AGR design and the gas turbine flexibility in accepting a variable fuel composition.

In the plant configuration assessed in Case 2d (IGCC), it has been considered that the AGR continues making the capture of the CO_2 from the syngas: part of it is used as diluent in the gas turbine for NOx reduction and power augmentation, while the remainder is released to atmosphere, thus saving the CO_2 compressor power demand. However, it is noted that the content of toxic components in the vented stream, in particular H_2S and CO, does not allow its direct release to atmosphere. To overcome this problem, the following two alternatives have been considered:

- Scenario 1: Different AGR unit design, to meet minimum H_2S and CO specification for direct venting of the stream.
- Scenario 2: Treatment and purification of the CO_2 in a system downstream the AGR unit, without changing the design of the reference case.

For Scenario 1, with respect to the AGR design of the reference plant, major design changes of this configuration are the following:

- Increased H_2S absorber height and additional solvent chiller to meet the H_2S specification in the CO_2 vent stream.
- Additional CO_2 flash drum and recycle compressor to remove enough CO and meet CO_2 vent stream specification.

As a consequence, these modifications lead to higher investment cost and higher steam and power consumptions of the unit, also when the plant is making full capture of the CO_2 for delivery to plant battery limits.

For Scenario 2, the main drawback for venting the CO_2 stream from the AGR is that the content of H_2S in the stream is higher than 100 ppmv, while the benchmark limit value is assumed to be 5 ppmv. Several purification methods, based on sulphur absorption on catalyst bed, are proposed by specialised vendors, to meet the H_2S specification in the venting stream. The main disadvantage of all these alternatives is the compression of the CO_2 vent stream up to at least 20 bar, as required by the upstream purification treatment. In fact, lower pressure of the feed stream leads to excessive volumes of the reactors, and, consequently, of the catalyst required for the purification treatment. To reduce also the CO and H_2 content in the CO_2 vent stream, an additional treatment is required, based on the catalytic oxidation of these components. As for the H_2S removal, the required amount of oxygen does not affect the ASU capacity. However, catalyst required for this purification treatment, typically based on platinum, can be poisoned by sulphur components.

The following table summarizes the main performance and cost data of the different power plants.

Table 3.6-1: Operation without CCS – Performance and cost data summary

Tag	Plant type	Reference plant		Flexible plant operation		
		Performance	TIC, M€	Performance	Design modification	TIC, M€
Case 1e	NGCC w post-comb	NPO=742MWe NEE=50.6%	726	**Without CCS** NPO=860MWe NEE=58.6% **With CCS** NPO=736MWe NEE=50.2%	Greater ST LP module and condenser	768
Case 2d	IGCC w pre-comb: Scenario 1: modified AGR design	NPO=730MWe NEE=31.4%	1,885	**Without CCS** NPO=777MWe NEE=33.5% **With CCS** NPO=722MWe NEE=31.1%	Taller H_2S absorber, additional chiller	1,895
Case 2d	IGCC w pre-comb: Scenario 2: treatment of CO_2 vent stream	NPO=730MWe NEE=31.4%	1,885	**Without CCS** NPO=747MWe NEE=32.2% **With CCS** NPO=730MWe NEE=31.4%	Absorption catalyst bed	1,909
Case 3d	USCPC w post-comb	NPO=666MWe NEE=34.8%	1,513	**Without CCS** NPO=848MWe NEE=44.3% **With CCS** NPO=655MWe NEE=34.2%	Greater ST LP module and condenser; Condensate preheating line; Additional SW pumps	1,572

Legend: NEE=Net Electrical Efficiency; NPO=Net Power Output; TIC=Total Investment Cost
Estimate accuracy: ±35%

From the figures in the table the following conclusions can be drawn:

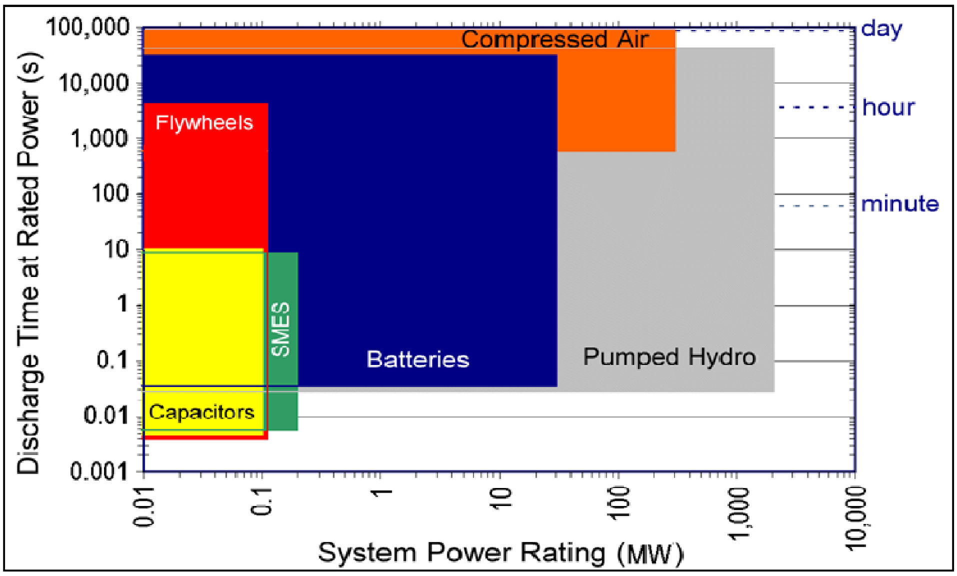
- For the two post-combustion cases, the plant performances are same as the conventional plants without capture, but this option slightly reduces the efficiency and increases the costs when operating the plant with CCS. This is not the case for the IGCC, due to the maximum range variation of fuel properties tolerated by the gas turbine.
- For the IGCC case, by considering an AGR design that meets minimum H_2S and CO specifications for direct release of the CO_2, the power production is 4% higher than the alternative with treatment and purification of the stream, while the investment cost is only marginally affected. However, a performance penalty shall be considered in normal operation with CO_2 capture, the power production being 8 MWe less than the reference case.
- By introducing a CO_2 purification unit in the IGCC plant, the performances of the reference case are not affected, but approximately 30 MWe power production are lost while releasing the CO_2 to atmosphere with respect to a modified AGR design. The total investment cost increase of the plant is about 1.3% higher than the reference case.

4 Alternative energy storage techniques

Some energy storage techniques, alternative to those discussed in the previous sections, are becoming a realistic option in response to the challenges of the liberalized electricity market and the need to cover intermediate and peak load constraints, as well as to follow the daily and seasonal variation of the electricity demand. There are currently several promising energy storage technologies, characterized by different power and storage capacities and reaction times, as shown in Figure 4-1:

- Pumped hydropower and compressed air energy storage, with large power and storage capacities;
- Battery energy storage device, with a wide range of power and storage capacity;
- Flywheels, superconducting magnetic energy storage (SMES), electrochemical capacitors, characterised by small power and/or storage capacities.

Figure 4-1: Capabilities of Existing Electricity Storage Technologies



Pumped hydroelectric energy storage (PHES) is the most mature and largest storage technique available, providing about 3% of the world's global generating capacity. PHES plants consists of two large reservoirs at different elevations and a number of pump and hydraulic turbine units. During off-peak electrical demand, water is pumped, using excess energy generated by other sources, from the lower reservoir to the upper reservoir, where it is stored. Once required, i.e. during high electricity

demand period, the water in the upper reservoir is released through the turbines, producing electricity.
The main disadvantage of a PHES facility is the requirement of two large reservoirs with a sufficient amount of hydraulic head between them. A new concept that may potentially overcome this drawback is Underground Pumped-Hydroelectric Energy Storage (UPHES), as the upper reservoir is at ground level and the lower reservoir below earth's surface.
PHES facilities are characterised by large power and storage capacities and fast reaction time, thus identifying load-levelling as the ideal application, though they can participate to peak load market and frequency control.

Compressed Air Energy Storage (CAES) cycle is essentially a variation of a standard gas turbine generation cycle, in which the air compression is separated from the combustion and steam generation cycle.
Air is compressed using off-peak electrical power, which is taken from the grid to drive a motor, and stored in large underground storage reservoirs. During peak demand period, the compressed air is released from the storage facility, heated and used to burn natural gas in the combustion chambers. The resulting combustion gas is then expanded in the turbine expander, generating electricity.
CAES is a very large scale storage technology with fast reaction time and then it is ideal for load following applications, ancillary services and renewable integration.
Two CAES plants are in operation today: a 290 MWe plant in Huntorf, Germany, and a 110 MWe plant in McIntosh, Alabama.

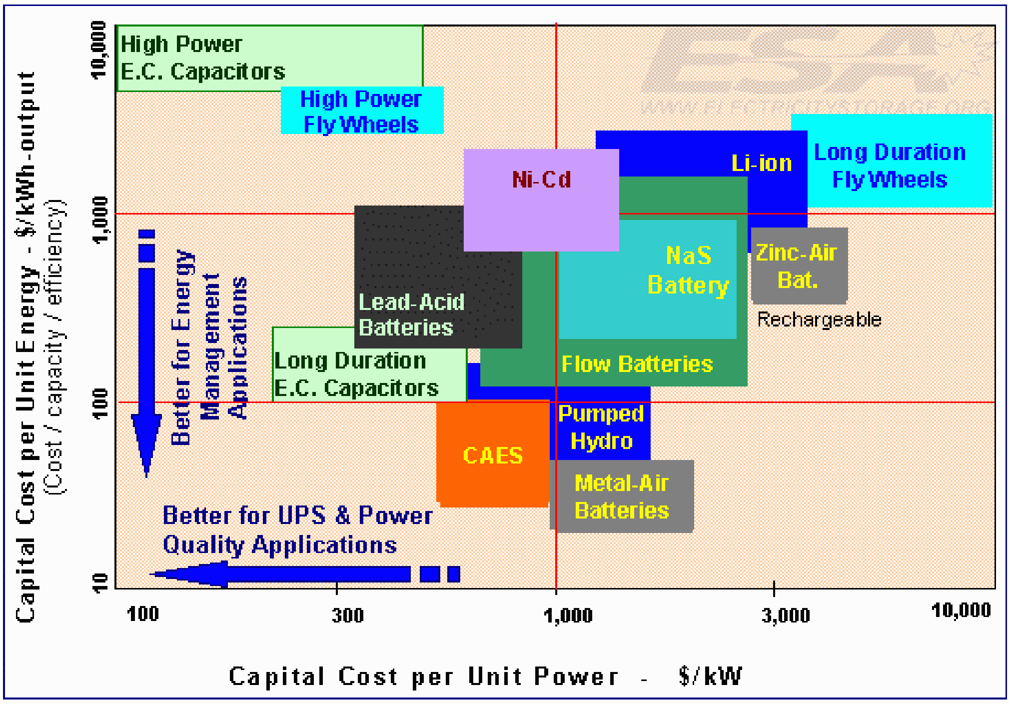
Battery Energy Storage (BES) systems store electric energy in electrochemical form in the same way as conventional batteries, though on a large scale. Two electrodes are immersed in an electrolyte, while a chemical reaction generates a current when required. In *Flow Battery Energy Storage (FBES)* two charged electrolytes are pumped to the cell stack where a chemical reaction occurs, generating a current when required.
Using a battery energy storage device, a Power Conversion System (PCS) is required to convert from alternating current (AC) to direct current (DC) while the energy device is charged, and vice versa, when the device is discharged.

Main characteristics of these technologies and their applications are also summarised in Table 4-1. Cost figures of the different storage technologies are shown in Figure 4-2. Cost ranges in this chart are referred to 2Q2001, so approximately 1.45 escalation factor should be considered for these data. Costs of these energy storage techniques might be varied, as a result of the normal technological development of last years.

Table 4-1: Main Energy storage technologies characteristics

Storage device	Storage medium	Power Capacity	Storage capacity	Remarks
Pumped-Hydroelectric Energy Storage	Mechanical	Large	Large	Load levelling, frequency regulation, peak generation
Compressed Air Energy Storage	Mechanical	Large	Large	Load following, frequency regulation, voltage control
Lead-Acid Battery	Chemical	Medium	Medium	Back up power, USP system. Life: 5 y, 250-1,000 cycles
Nickel-Cadmium Battery	Chemical	Medium	Medium	storage for solar gen., engine start. Life: 10-15 y, 1,000-3,500 cycles
Sodium-Sulphur Battery	Chemical	Medium	Medium	Load management, Power quality Life: > than others; 2,500 cycles
Vanadium Redox Flow Battery	Chemical	Medium	Medium	Integration of renewable resources. Life: 7-15 y, 10,000 cycles
Flywheels	Mechanical	Small	Small	USP system, Integ. of wind farms
Supercapacitor Energy Storage	Electrical	Small	Small	Power quality
Superconducting Magnetic Energy Storage	Magnetic	Small	Small	Integration of renewable resources, Transmission upgrade deferral

Figure 4-2: Costs of Existing Electricity Storage Technologies



5 Summary findings

The primary conclusions that can be drawn from the considerations made in this study are the following:

- Conventional NGCC and USCPC-based power plants without CCS show respectively a high and medium operating flexibility, generally allowing thermal cycling operation, rapid load changes and start-ups, as well as good efficiency at partial load. On the other hand, IGCC's show lower dispatch flexibility, due to the inertia of the process units to generate and prepare the fuel at the conditions required by the gas turbine.
- For the reference plants with leading CCS technologies, there are additional constraints that may limit the flexible operation. However, depending on the specific characteristics of the power plant and their weekly demand curve, there are possible ways of overcoming these limitations, as reported in the following:
  - ✓ Thermal cycling of power plants with CCS: for NGCC and USCPC plants with frequent start-ups/shut-downs, to maintain the same thermal cycling capability as the conventional plants without capture, solvent storage shall be made, leading to an investment cost increase of about 8% and 2% of the reference case, respectively for NGCC and USCPC. For IGCC and Oxy-combustion USC PC plant types, there are no specific constraints to follow a weekly demand curve consisting of 100% load during the daytime and 50% load at evenings and weekends ('two regimes operating curve').
  - ✓ CO_2 capture solvent storage: for NGCC and USC-PC power plants, solvent storage allows to decouple the operation of the absorption section from the regeneration and compression units, while continuously capturing the CO_2 from the flue gases. This feature improves load following capabilities and overall economics of capture plants, because the electricity production is maximized when the market requires a higher electricity generation. Considering a 'two regimes operating curve' as described above, it has been estimated that the net electrical efficiency increases by about 5% to 6% with respect to the reference case, while the investment cost delta is about 20% and 7% higher, respectively for the NGCC and the USCPC plant. On the other hand, considering a 'three regimes demand curve' that includes also two hours per working day of peak demand, an electrical efficiency increase of about 12% (NGCC) and 22% (USCPC) is achieved by halting the regeneration during these two hours, while for the rest of the daytime the plant is operated as in the reference conditions; this leads to an investment cost delta of about 9% and 6%, respectively for the NGCC and the USCPC plant.
  - ✓ Constant CO_2 flowrate in transport pipeline: cycling operation leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating

conditions in the pipeline. To avoid this problem in a 'two regimes operating curve', ***CO_2* buffer storage** can be considered in the plant, leading to unchanged performance and cost increase from 2% to 3% of the reference case. However, depending on the overall length, this investment increase may be offset by the lower cost of the pipeline. For the NGCC and the USC-PC alternatives, ***solvent storage*** can be also considered, leading to an electricity production increase from 3% to 5%, during peak hours, with respect to the reference case. On the other hand, the plant total investment cost is respectively 12% and 4% higher than the CO_2 buffer storage option.

- ✓ Hydrogen storage in IGGC plants with CCS: considering a 'two regimes operating curve', power production during peak demand period and investment cost are about 3% higher than the reference case, while also producing 75,400 Nm^3/h of high purity hydrogen. Alternatively, without hydrogen production it is possible to produce the same amount of power, while reducing the investment cost by about 6%, due to the reduced size of the main process units. In both cases, from literature data it is expected that cost of hydrogen storage may vary from 10 M€ to 50 M€, corresponding to a maximum of 3% of the overall plant cost. Hydrogen storage also allows operating the combined cycle at partial load or in island mode during low electricity demand period, while the syngas generation line is operated at full load; in this case the combined cycle of the IGCC can be operated as a conventional NGCC plant, following a weekly demand curve consisting of 100% load during the daytime and island mode operation at evenings and weekends.
- ✓ Oxygen storage in IGGC and oxy-USCPC power plants with CCS: considering a 'two regimes operating curve', with adequate oxygen (and nitrogen) storage and running the ***ASU at partial load*** the electricity production during peak demand is about 5% and 8% higher than the reference case, respectively for Oxy-combustion and IGCC plant. The additional investment cost ranges from 2% to 3%. Alternatively, if ***lower-sized ASU*** (about 80% of the reference case) is considered, the electricity production is 3% and 4% higher than the reference case, while the total investment cost is almost unchanged. On the other hand, considering a 'three regimes demand curve', an electrical efficiency increase of about 6% and 10% is achieved running the ASU at part load for two hours per working day of peak load operation, respectively for Oxy-combustion and IGCC plant. The investment cost is about 1.5% higher than the IGCC reference case, while it is almost the same for the oxy-combustion USCPC.
- ✓ Operation without carbon capture and storage: provided that design is adequately made, power plants with CO_2 pre or post- combustion capture can also be maintained in continuous operation without capturing the carbon dioxide. Depending on possible low CO_2 emission allowances costs, this

operating flexibility may improve the economics of the plants because of the resulting higher power production. With respect to the reference case, the investment cost increase is marginal for the IGCCs, while it is about 4% and 6% respectively for the USC-PC and the NGCC power plants.

- Several promising energy storage technologies, characterized by different power and storage capacities and reaction times, are becoming a realistic option in response to the challenges of the liberalized market. These are: pumped hydropower, compressed air energy storage, battery energy devices, flywheels, superconducting magnetic energy storage (SMES), electrochemical capacitors.

In summary, it can be stated that power plants with leading CCS technologies will be able to respond to the requirements of the new liberalized electricity market. For IGCC and oxy-USPC plants, the oxygen storage is of primary importance, while for post-combustion capture plants the key factor is solvent storage, whose technical feasibility has been already confirmed by the main licensors of the technology. Furthermore, for IGCC plants the option of hydrogen storage may lead to additional advantages.

In broader and more general terms, it can be concluded that performances of flexible CCS plants during peak hours are often better than those of base load plants and in most cases the investment cost increase is not excessive. Therefore, flexible plants with leading CCS technologies have the potential for opening new business opportunities and improving the overall economics of the project.

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PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME : GENERAL INFORMATION
FWI CONTRACT : 1-BD-0530 A

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CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

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SECTION B

INDEX

1. Background and objectives of the study

Power plants built in the 1990's and early years of the new millennium have been typically designed for base load operation, favouring higher efficiency and lower capital costs, with the main objective of minimizing the cost of electricity production. Nowadays, existing and new power plants must face the challenges of the liberalized electricity market and the requirement to cover intermediate and peak load constraints, so to respond to the daily and seasonal variation of the electricity demand. In this scenario, not only conventional natural gas combined cycles must be designed for flexible operation, but also coal-fired power plants, which are now generally required to operate in the mid merit market.

With this premise, IEA Greenhouse Gas R&D Programme has contracted Foster Wheeler (FW) to perform a study that assesses the potential flexibility of power plants with Carbon Capture and Storage (CCS). Most studies undertaken by several companies so far have assumed that these plant types will operate at base load in the near future, but it is now clear that they will need to be able to respond to the requirements of the new liberalized electricity market, otherwise it will not be possible to meet overall greenhouse gas abatement targets.

The main objectives of this study have been the following:

- Outline current capabilities of conventional coal and natural gas fired power plants, without CCS, to operate flexibly in response to the demand of the electricity market.
- Make a review of the information, available in the public domain, on the flexibility of the same power plants with carbon capture and storage for three leading capture technologies: pre, post and oxy-combustion.
- Identify factors that may constrain the operating flexibility of CCS processes, possible ways of overcoming these constraints and related cost implications.
- Make a techno-economic review of alternative energy storage techniques, like pumped hydropower, compressed air and batteries.

IEA GHG R&P Programme has already issued in the past years reports assessing natural gas and coal based power plants with leading CCS technologies, which have been considered as reference plants for the considerations of this work. Most of the information for the reference plants has been derived from the IEA GHG report "Water usage and loss Analysis in Power plants without and with CO_2 capture", completed by Foster Wheeler in 2010. Remaining information, relevant to the post-combustion capture process from natural gas-fuelled combined cycles, are partially taken from FW in-house design and partially from the IEA Report PH4/33, Nov 2004, Improvement in Power generation with post Combustion capture of CO_2.

FW like to acknowledge the following companies, listed in alphabetical order, for their fruitful support to the preparation of the report:

- Aker Clean Carbon;
- Alstom;
- Mitsubishi Heavy Industries (MHI);
- UOP.

2. Project design bases

This section describes the general design and cost estimating criteria, used as common basis for the techno-economic assessment on the operating flexibility of power plants with leading CCS technologies. Main criteria only are reported in the following sections, as taken from the reference studies.

2.1. Feedstock specification

The feedstock characteristics of the different power plant types are listed hereinafter.

2.1.1. Coal

	Eastern Australian Coal
	Proximate Analysis, wt%
Inherent moisture	9.50
Ash	12.20
Coal (dry, ash free)	78.30
Total	100.00
	Ultimate Analysis, wt% (dry, ash free)
Carbon	82.50
Hydrogen	5.60
Nitrogen	1.77
Oxygen	9.00
Sulphur	1.10
Chlorine	0.03
Total	100.00
Ash Fluid Temperature at reduced atm., °C	1350
HHV (Air Dried Basis), MJ/kg (*)	27.06
LHV (Air Dried Basis), MJ/kg (*)	25.87
Grindability, Hardgrove Index	45

(*) based on Ultimate Analysis, but including inherent moisture and ash.

2.1.2. Natural Gas

	Composition, vol%
- Nitrogen	0.4
- Methane	83.9
- Ethane	9.2
- Propane	3.3
- Butane and C5	1.4
- CO_2	1.8
Total	100.0
- Sulphur content (as H_2S), mg/Nm3	4
LHV, MJ/Nm^3	40.6
Molecular weight	19.4

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reverses.

2.2. Products and by-products

The main products and by-products of the plants are listed here below, together with their main specifications.

2.2.1. Electric Power

Voltage:	380	kV
Frequency:	50	Hz
Fault duty:	50	kA

2.2.2. Carbon Dioxide

The Carbon Dioxide characteristics at plant B.L. are the following:

Status:	supercritical
Pressure:	110 bar g
Temperature:	20 – 50 (2)

Purity:	
H_2S content:	0.1% wt (max)
CO content:	0.1% wt (max)
Moisture:	< 50 ppmv
N_2 content:	to be minimized (1)

(1) High N_2 concentration in the CO_2 product stream has a negative impact for CO_2 storage, particularly if CO_2 is used for Enhanced Oil Recovery (EOR). N_2 degrades the performance of CO_2 in EOR, unlike H_2S, which enhances it.

(2) Depending on the alternative of the study. Refer to the case-specific report in section E.

Capture rate : not less than 85%.

2.2.3. Sulphur (IGCC plant alternative)

Sulphur characteristics at IGCC plant B.L. are the following:

Status:	solid/liquid
Colour:	bright yellow
Purity:	99.9 % wt. S (min)
H_2S content:	10 ppm (max)
Ash content:	0.05 % wt (max)
Carbonaceous material:	0.05 % wt (max)

2.2.4. Hydrogen (IGCC plant alternative)

Hydrogen characteristics are suitable for Refinery users.

H_2	99.5 % vol. (min)
N_2 + Ar	balance, % vol.
Pressure at B.L.	24 barg
Temperature	40 °C

2.3. Environmental limits

The environmental limits set up for each plant are outlined hereinafter.

2.3.1. Gaseous emissions

The overall gaseous emissions from the plant shall not exceed the following limits:

	NGCC plants (1) **Case 1**	**IGCC plants (1)** **Case 2**	**USC PC plant (2)** **Case 3-4**
NO_x(as NO_2)	≤ 50 mg/Nm^3	≤ 80 mg/Nm^3	≤ 200 mg/Nm^3
SO_x(as SO_2)	-	≤ 10 mg/Nm^3	≤ 200 mg/Nm^3
CO	-	≤ 50 mg/Nm^3	-
Particulate	-	≤ 10 mg/Nm^3	≤ 30 mg/Nm^3

Note: (1) @ 15% O_2 volume dry
(2) @ 6% O_2 volume dry

2.3.2. Liquid effluent

Characteristics of waste water discharged from the plant shall comply with the limits stated by the EU directives:

- 1991/271/EU
- 2000/60/EU

The main continuous liquid effluent is the sea cooling water return stream from the open-loop cooling water circuit of the plant.

Possible effluent from the Waste Water Treatment shall be generally recovered and recycled back to the plant as process water, where possible, or discharged to the sea/river.

2.3.3. Solid wastes

The solid wastes of the IGCC plant are:
- Slag, which is potentially saleable to the building industry
- Filter cake, which contains some toxic compounds.

The solid wastes of the USC PC plant are:
- Bottom ash;
- Fly Ash.

Other potential solid wastes are typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). However, in the IGCC plants, the wastewater sludge is recovered and recycled back to the Gasification Island to be processed by the Gasifiers.

2.4. NGCC - plant features

2.4.1. Capacity

Plant production capacity is approximately 800 MWe, based on the use of two F-class gas turbines.

2.4.2. Unit Arrangement

Unit 3100	Gas Turbine
Unit 3200	HRSG
Unit 3300	Steam Turbine
Unit 4000	CO_2 Amine Absorption
Unit 5000	CO_2 compression
Unit 6000	Utility & Offsites

2.4.3. Minimum turndown

Gas Turbines can run at full-speed-no-load. However, the minimum load at which the Gas Turbine is able to operate, still meeting the environmental limits, in particular NO_X and CO emissions, is around 40%.

The minimum stable operating load of the CO_2 capture plant is around 30% of the flue gases entering the unit.

2.5. IGCC - plant features

2.5.1. Capacity

The gasification capacity, i.e. the coal flow rate of the IGCC Complex has been fixed to match the appetite of the two F-Class gas turbines in the combined cycle, at the reference ambient temperature of the study.

Air Separation Unit capacity is defined by oxygen requirements of the IGCC Complex (mainly the gasifiers requirement plus the marginal consumption of Sulphur Recovery Unit). ASU is also requested to produce nitrogen at different levels of pressure to be supplied to the IGCC complex.

Sulphur Recovery Unit consists of two trains at 100% capacity. The Tail Gas Treatment consists in a Hydrogenation step plus gas scrubbing sections and a dedicated compressor to recycle the stream back to the AGR Unit. This Unit is designed for 100% of the max tail gas production of the SRU.

2.5.2. Unit Arrangement

Unit 900	Coal Handling and Storage
Unit 1000	Gasification
Unit 2100	ASU
Unit 2200	Syngas Treatment and Conditioning Line
Unit 2300	AGR
Unit 2400	SRU & TGT
Unit 2500	CO_2 Compression and Drying
Unit 3000	Power Island
Unit 4000	Utility & Offsites

2.5.3. Minimum turndown

The Gasification Unit is composed of four gasifiers, thus allowing to operate at low loads with respect to the IGCC design capacity, the minimum turndown of the single gasifier being 50%.

Most other Units are based on twin trains (50% capacity each) thus limiting the events causing the shutdown of the entire IGCC Complex or of the entire Gasification Island.

The minimum stable operating load of each Gas Turbine on syngas is 20% as far as electrical generation is concerned, thus corresponding to 10% of the IGCC capacity. In practice, the minimum load at which the Gas Turbine is able to operate, still meeting the environmental limits, in particular NOx and CO emissions, is around 60%.

2.6. USC-PC - plant features

2.6.1. Capacity

Boiler capacity has been selected in order to have 830 MWe gross power production.

2.6.2. Unit Arrangement

Unit 100	Coal and Ash Handling

Unit 200	Boiler Island
Unit 300	FGD and Gypsum Handling Plant
Unit 400	DeNOx Plant
Unit 500	Steam Turbine
Unit 600	CO_2 Amine Absorption
Unit 700	CO_2 compression
Unit 800	Utility and offsite

2.6.3. Minimum turndown

The minimum stable operating load of the boiler is 30% as far as duty is concerned.

The minimum stable load of the Steam Turbine is around 20% as far as electrical generation is concerned. The Steam Turbine can stably maintain such load if the rated steam conditions are maintained.

The minimum stable operating load of the CO_2 capture plant is around 30% of the flue gases entering the unit.

In conclusion, the overall plant minimum turndown is expected around 30%.

2.7. USC PC oxy-combustion power plant - Plant Operation

2.7.1. Capacity

Boiler capacity has been selected in order to have 740 MWe gross power production.

2.7.2. Unit Arrangement

Unit 100	Coal and Ash Handling
Unit 200	Boiler Island
Unit 500	Steam Turbine
Unit 600	Air Separation Unit
Unit 700	CO_2 compression and inerts removal
Unit 800	Utility and offsite

2.7.3. Minimum turndown

The minimum stable operating load of the boiler is expected to be around 30% as far as duty is concerned.

The minimum stable load of the Steam Turbine is around 20% as far as electrical generation is concerned. The Steam Turbine can stably maintain such load if the rated steam conditions are maintained.

The minimum stable operating load of the CO_2 compression and purification section is expected to be around 30% on the basis of the flue gases inlet flowrate.

In conclusion, the overall plant turndown is expected around 30%.

2.8. Location

The site is a Greenfield location on the NE coast of The Netherlands.

The plant area is assumed to be close to a deep sea, thus limiting the length of the sea water lines (both the submarine line and the sea water pumps discharge line). The site is also close to an existing harbour, equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

2.9. Climatic and Meteorological Information

The conditions marked (*) shall be considered reference conditions for plant performance evaluation.

- atmospheric pressure: 1013 mbar (*)

- relative humidity

average:	60	%	(*)
maximum:	95	%	
minimum:	40	%	

- ambient temperatures

minimum air temperature:	-10	°C	
maximum air temperature:	30	°C	
average air temperature:	9	°C	(*)

2.10. Cost estimating basis

The following sections describe the main cost estimating basis used to make the economic assessment of the various cases.

2.10.1. Estimate methodology

The investment cost estimate of the reference cases has been derived from the data contained in the reference studies. For each alternative, the following methodology has been applied:

- Currency adjustment (US$ to Euro): capital cost conversion has been made in the reference estimating year, i.e. taking into account the currency exchange rate of that period. Currency adjustment has been necessary for the NGCC and the USC PC cases.
- Cost level escalation: escalation from reference estimate cost level to 1Q2011 has been made using FW in-house multiplicative factors.

With this methodology, the investment cost estimate of the reference cases has been made in Euro, 1Q2011 cost level and in the Netherlands. Then, on the basis of a case-specific sized equipment list, showing equipment or unit added or modified with respect to the reference case, the investment cost of direct materials has been made by means of program runs performed with K-Base, a commercial software from AspenTech. For the other costs (construction, engineering, etc.) the same percentages with respect to the direct materials as per the reference cases have been applied.

It is noted that FW shall not be regarded has having reviewed and endorsed the original cost estimate made by other engineering companies for the reference cases.

For estimating the investment cost of the CO_2 pipeline, the updated cost calculation computer program for CCS system developed by Woodhill Engineering has been used (IEA Report Number 2009/3). The cost level has been updated to 1Q2011, using FW in-house multiplicative factors.

2.10.2. Estimate accuracy

Estimate accuracy is in the range of ±35%.

2.10.3. Contingency

Contingency is included in the estimate as a percentage of the installed costs. 7% of the installed costs is assumed for most of the units, excluding ASU, CO_2 compression and BoP, as 5% factor is used in this case.

2.10.4. License fees

2% of the installed plant cost is assumed to cover process/patent fees, consultant services other than EPC Contractor's services, fees for agents, legal and planning costs.

2.10.5. Owner's cost

5% of the installed plant cost is assumed to cover the Owner's cost.

2.11. Operation and Maintenance

Operating and Maintenance (O&M) costs include:

- Chemicals
- Catalysts
- Solvents
- Raw Water make-up
- Direct Operating labour
- Maintenance
- Overhead Charges.

O&M costs are generally allocated as variable and fixed costs.
Variable costs depend on the plant operating mode, e.g. peak or off-peak operation, capturing or venting CO_2 etc. as they depends on the plant operating load. They can be expressed as €/h.
Fixed operating costs are essentially independent from the plant operating mode. They can be expressed as €/y.

2.11.1. Variable costs

The variable costs are mainly derived from the IEA GHG report "Water usage and loss Analysis in Power plants without and with CO_2 capture", completed by Foster Wheeler in 2010. Remaining information, relevant to the post-combustion capture process from natural gas-fuelled combined cycles, are mainly derived from the IEA Report PH4/33, Nov 2004, Improvement in Power generation with post Combustion capture of CO_2.

For part load operation, the variable costs have been considered proportional to the plant load. This assumption has been considered a reasonable simplification, at the level of the details if this study.

2.11.2. Fixed costs

The fixed costs of the different power plants include the following items:

Direct labour

The yearly cost of the direct labour is calculated assuming, for each individual, an average cost equal to 60,000 €/y. The number of personnel engaged is directly derived from reference studies and is reported hereinafter.

Case 1: NGCC with CCS	62 operators
Case 2: IGCC with CCS	128 operators
Case 3: USC PC with CCS	130 operators
Case 4: Oxyfuel	136 operators

Administrative and general overhead

All other company services not directly involved in the operation of the plant fall in this category, such as:

- Management
- Administration
- Personnel services
- Technical services
- Clerical staff.

These services vary widely from company to company and are also dependent on the type and complexity of the operation.

Based on EPRI, Technical Assessment Guide for the Power Industry, an amount equal to 30% of the direct labour cost has been considered. This figure is in accordance with reference studies.

Maintenance

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the plant. Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected Supplier, this type of evaluation of the maintenance cost is premature at this stage of the study.

For this reason the annual maintenance cost of the plant is normally estimated as a percentage of the installed capital cost of the facilities. The same percentage of the reference studies has been used for each case, as listed hereinafter:

Case 1: NGCC with CCS	2.7%
Case 2: IGCC with CCS	3.6%
Case 3: USC PC with CCS	3.8%
Case 4: Oxyfuel	4.0%

2.12. Software Codes

For the development of the study, three software codes have been mainly used:

- PROMAX v2.0 (by Bryan Research & Engineering Inc.): flue gas amine sweetening process for CO_2 removal.
- Gate Cycle v6.0.3 (by General Electric): Simulator of Power Island used for Steam Turbine and Preheating Line simulation.
- Aspen HYSYS 2006.5 (by AspenTech): Process Simulator used for CO_2 compression and drying.

3. Basic Engineering Design Data

Scope of the Basic Engineering Design Data is the definition of the common bases for the design of the process and utility units included in the different power plants, as listed in the following.

NGCC plant with post-combustion capture

Power Island, including:
- Gas Turbines;
- Heat Recovery Steam Generators;
- Steam Turbine;
- Electrical Power Generation.

Process Units, including:
- CO_2 capture plant
- CO_2 compression and drying

Utility and Offsite Units, providing utility fluids to other units, including:
- Sea Cooling Water and Machinery Cooling Water systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant & Instrument Air systems;
- Waste Water Treatment;
- Fire fighting system;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

Coal IGCC plant with pre-combustion capture

Process Units, including:
- Coal Handling and Storage;
- Gasification Island;
- Air Separation Unit;
- Syngas Treatment and Conditioning Line;
- Acid Gas Removal Unit;
- Sulphur Recovery and Tail Gas Treatment;
- CO_2 Compression and Drying.

Power Island, including:
- Gas Turbines;
- Heat Recovery Steam Generators;

- Steam Turbine;
- Electrical Power Generation.

Utility and Offsite Units, providing utility fluids to other units, including:

- Sea Cooling Water and Machinery Cooling Water systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Solid (Slag & Filtercake) Handling;
- Sulphur Storage and Handling;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

USC PC power plant with post-combustion capture

Process Units, including:

- Storage and Handling of solid materials, including:
  - Coal storage and handling
  - Ash and solid removal and handling
- Boiler Island
- Flue Gas Desulphurisation and Gypsum handling plant
- DeNOx plant
- CO_2 capture plant (for cases with CO_2 capture)
- CO_2 compression and drying (for cases with CO_2 capture)

Power Island, including:

- Steam Turbine and condenser;
- Preheating Line;
- Electrical Power Generation.

Utility and Offsite Units, providing utility fluids to other units, including:

- Sea Cooling Water and Machinery Cooling Water systems;
- Cooling Water/Machinery Cooling Water Systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

USC PC oxy-combustion power plant

Process Units, including:

- Storage and Handling of solid materials, including:
  - Coal storage and handling
  - Ash and solid removal and handling
- Boiler Island
- Air Separation Unit
- CO_2 compression and inerts removal

Power Island, including:

- Steam Turbine and condenser;
- Preheating Line;
- Electrical Power Generation.

Utility and Offsite Units, providing utility fluids to other units, including:

- Sea Cooling Water and Machinery Cooling Water systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

3.1. Units of measurement

The units of measurement are in SI units.

3.2. Climatic and Meteorological Information

Reference is made to section 2.9 for main data. Other data:

Sea water supply temperature and salinity

average (on yearly basis):	12	°C
maximum average (summer):	14	°C
minimum average (winter):	9	°C
salinity:	22	g/l

3.3. Project Battery Limits design basis

3.3.1. Electric Power

High voltage grid connection:	380 kV
Frequency:	50 Hz
Fault duty:	50 kA

3.3.2. Process and Utility fluids

The streams available at plant battery limits are the following:

NGCC plant with post-combustion capture
- Natural gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- CO_2 rich stream.

Coal IGCC plant with pre-combustion capture
- Coal;
- Natural gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- Sulphur product;
- CO_2 rich stream.

USC PC power plant with post-combustion capture
- Coal;
- Natural gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- CO_2 rich stream.

USC PC oxy-combustion power plant
- Coal;
- Natural gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- CO_2 rich stream.

3.4. Utility and Service fluids characteristics/conditions

Following sections list utilities and service fluids distributed inside the plant.

3.4.1. Cooling Water

The plant primary cooling system is seawater in once through system.

Sea Cooling Water (primary system)

Source : sea water in once through system
Service : for steam turbine condenser and CO_2 compression unit, machinery cooling water-cooling.
Type : clear filtered and chlorinated, without suspended solids and organic matter.

Supply temperature:

- average supply temperature (on yearly basis): 12 °C
- max supply temperature (average summer): 14 °C
- min supply temperature (average winter): 9 °C
- max allowed sea water temperature increase: 7 °C

Return temperature:

- average return temperature: 19 °C
- max return temperature: 21 °C

Operating pressure at Users inlet: 0.9 barg
Max allowable ΔP for Users: 0.5 barg

Design pressure for Users: 4.0 barg
Design pressure for sea water line: 4.0 barg
Design temperature: 55 °C
Cleanliness Factor (for steam condenser): 0.9
Fouling Factor: 0.0002 h °C m^2/kcal

Machinery Cooling Water (secondary system)

Service : for machinery cooling and for all plant users other than steam turbine condenser and CO_2 compression exchangers.
Type : demiwater stabilized and conditioned – water cooled

Supply temperature:

- max supply temperature: 17 °C
- min supply temperature: 13 °C
- max allowed temperature increase: 12 °C
- design return temperature for fresh cooling water cooler: 29 °C

Operating pressure at Users:	3.0	barg
Max allowable ΔP for Users:	1.0	bar
Design pressure:	5.0	barg
Design temperature:	50	°C
Fouling Factor:	0.0002	h °C m^2/kcal

3.4.2. Waters

Potable water

Source : from grid
Type : potable water

Operating pressure at grade:	0.8	barg (min)
Operating temperature:	Ambient	
Design pressure:	5.0	barg
Design temperature:	38	°C

Raw water

Source : from grid
Type : potable water

Operating pressure at grade:	0.8	barg (min)
Operating temperature:	Ambient	
Design pressure:	5.0	barg
Design temperature:	38	°C

Plant water

Source : from storage tank of raw water
Type : raw water

Operating pressure at grade:	3.5	barg
Operating temperature:	Ambient	
Design pressure:	9.0	barg

Design temperature: 38°C

Demineralized water

Type : treated water (mixed bed demineralization)

Operating pressure at grade:	5.0	barg
Operating temperature:	Ambient	
Design pressure:	9.5	barg
Design temperature:	38	°C

Characteristics:

- pH		6.5÷7.0	
- Total dissolved solids	mg/kg	0.1	max
- Conductance at 25°C	µS	0.15	max
- Iron	mg/kg as Fe	0.01	max
- Free CO_2	mg/kg as CO_2	0.01	max
- Silica	mg/kg as SiO_2	0.015	max

3.4.3. Steam, Steam Condensate and BFW

NGCC plant with post-combustion capture
Steam

The following figures show the steam characteristics at the HRSG battery limits.

	Pressure, barg		**Temperature, °C**	
	Norm	**Design**	**Norm**	**Design**
High Pressure **(HP)**	123	134	560	580
Medium Pressure **(MP)**	31	35	328	353
Low Pressure **(LP)** (1)	3.8	6.0	236	261

Coal IGCC plant with pre-combustion capture
Steam

These conditions refer to the Process Units. Inside Power Island the steam levels are different even if interconnected to the Process.

Table 3.4-1: Process Units steam conditions

	Pressure, barg			Temperature, °C	
	Max	**Min**	**Design**	**Norm**	**Design**
High Pressure **(HP)** Nominal Pressure: 160 barg	170	160	187	353	370
Medium Pressure **(MP)** Nominal Pressure: 40 barg	43	40	47	256	270
Low Pressure **(LP)** Nominal Pressure: 6.5 barg	8	6.5	12	175	250
Very Low Pressure **(VLP)** Nominal Pressure: 3.2 barg	4	3.2	12	152	250

In the table above:
- The maximum value indicates the steam generation pressure to be adopted for steam generators in the Process Units.
- The minimum pressure indicates the steam pressure available for steam users.
- The normal Temperature indicates the *saturation T* corresponding to the Max Pressure indicated.

Cold condensate

Type: condensate from Power Island (plus demineralized water make up)

Supply:
- Operating pressure at Users: 16 barg
- Operating temperature: 21 °C
- Design pressure: 22 barg
- Design temperature: 50 °C
- Fouling Factor: 0.0001 h °C m^2/kcal

Return:
- Operating pressure: 9.9 barg
- Operating temperature: 95
- Design pressure: 22.8 barg
- Design temperature: 130 °C
- Fouling Factor: 0.0002 h °C m2/kcal

Steam Condensate from process, utility and off site units

Steam condensate will be flashed within process units whenever possible to recover steam and piped back to the condensate collection header.
The condensate collection header shall have the following characteristics:

Operating pressure for other Units B.L.:	1	barg
Operating temperature:	94	°C
Design pressure:	12.0	barg
Design temperature:	250	°C

Boiler Feed Water

The main characteristics of the Boiler Feed Water at Units B.L. are shown in the following table.

Table 3.4-2: **Boiler Feed Water at units B.L.**

	Pressure, barg	**Temperature, °C**
	Normal	**Normal**
Boiler Feed Water, Very Low Pressure **(BWV)**	15	120
Boiler Feed Water, Low Pressure **(BWL)**	15	160
Boiler Feed Water, Medium Pressure **(BWM)**	60	160
Boiler Feed Water, High Pressure **(BWH)**	195	160

USC PC power plant with post-combustion capture
Steam

The main characteristics of the Steam at Boiler B.L. are shown in the following table.

Table 3.4-3: Steam conditions

HP SH		**Cold RH**	**Hot RH**	
P, bar	**T, °C**	**T, °C**	**P, bar**	**T, °C**
289	600	363	59	620

Boiler Feed Water

The Boiler Feed Water is available at Boiler B.L. at 300°C.

3.4.4. Instrument and Plant Air

Instrument air

Operating pressure		
- normal:	7.0	barg
- minimum:	5.0	barg
Operating temperature:	40	°C (max)
Design pressure:	10.0	barg
Design temperature:	60	°C
Dew point @ 7 barg:	-30	°C

Plant air

Operating pressure:	7.0	barg
Operating temperature:	40	°C (max)
Design pressure:	10.0	barg
Design temperature:	60	°C

3.4.5. Nitrogen (IGCC plant)

Low Pressure Nitrogen

Supply pressure:	6.5	barg
Supply temperature:	15	°C min
Design pressure:	11.5	barg
Design temperature:	70	°C
Min Nitrogen content:	99.9 % vol.	

Medium Pressure Nitrogen (Syngas dilution)

Supply pressure:	30	barg
Supply temperature:	210	°C
Design pressure:	35	barg
Design temperature:	240	°C
Min Nitrogen content:	98 % vol.	

Medium Pressure Nitrogen (GT injection)

Supply pressure:	26	barg
Supply temperature:	213	°C
Design pressure:	35	barg
Design temperature:	240	°C
Min Nitrogen content:	98 % vol.	

3.4.6. Oxygen

Oxygen for the gasifier has the following characteristics at unit B.L:

Supply pressure:	82	barg
Supply temperature:	35	°C
Design pressure:	99	barg
Design temperature:	70	°C

Oxygen for the oxy-combustion boiler has the following characteristics at unit B.L.:

Supply pressure:	0.6	barg
Supply temperature:	16	°C
Design pressure:	3.5	barg
Design temperature:	50	°C

Purity:	95.0	% mol. O_2 min
	3.5	% mol Ar
	1.5	% mol N_2
H_2O content :	1.0	ppm max
CO_2 content :	1.0	ppm max
HC as CH_4 (number of times the content in ambient air):	5	max

Oxygen for Sulphur plant

Supply pressure at IGCC BL:	5.0	barg
Supply temperature:	15	°C min
Design pressure:	8.0	barg
Design temperature:	50	°C
Purity:	95	% mol. O_2 min

3.4.7. Chemicals

Caustic Soda

A concentrated (50% by wt) NaOH storage tank is foreseen and used to unload caustic from trucks.
Concentrated NaOH is then pumped and diluted with demineralized water to produce 20% by wt NaOH accumulated in a diluted NaOH storage tank.
The NaOH solution is distributed within plant with the following characteristics:

Supply temperature, °C	Ambient
Design temperature, °C	70
Supply pressure (at grade) at unit BL barg	3.5
Design pressure barg	9.0
Soda concentration wt %	20

Hydrochloric Acid

Two concentrated (20% by wt) HCl storage vessels are foreseen and used to unload hydrochloric acid from trucks.
Concentrated HCl is pumped to users where is firstly diluted if necessary.

Supply temperature, °C	Ambient
Design temperature, °C	70
Supply pressure (at grade) at unit BL barg	2.5
Design pressure barg	5.0
Hydrochloric concentration wt %	20

The following chemicals are used in the Waste Water Treatment plant:

Chemical	Quality
H_2O_2	98% wt
Polyelectrolyte	0.1%wt
Ferrous Sulphate	20%wt
Sulphuric acid	98%wt

Chemical for DeNOx

Aqueous ammonia will be used as reducing agent in this application with the following characteristics:

NH_4OH: with NH_3 concentration 25% by weight (commercial grade)

The following chemicals are used in the Waste Water Treatment plant:

Chemical	Quality
H_2O_2	98% wt
$FeCl_3$	40% wt
Polyelectrolyte	0.1% wt
Phosphoric acid	85% wt

3.4.8. Electrical System

The voltage levels foreseen inside the plant area are as follows:

	Voltage level (V)	*Electric Wire*	*Frequency (Hz)*	*Fault current duty (kA)*
Primary distribution	33000 ± 5%	3	50 ± 0.2%	31.5 kA
MV distribution and utilization	10000 ± 5% 6000 ± 5%	3 3	50 ± 0.2% 50 ± 0.2%	31.5 kA 25 kA
LV distribution and utilization	400/230V±5%	3+N	50 ± 0.2%	50 kA
Uniterruptible power supply	230 ± 1% (from UPS)	2	50 ± 0.2%	12.5 kA
DC control services	110 + 10%-15%	2	-	-
DC power services	220 + 10%-15%	2	-	-

3.5. Plant Life

The Plant is designed for a 25 years life, with the following considerations:

- Design life of vessels, equipment and components of equipment will be as follows:
  25 years for pressure containing parts;
  5 years for replaceable parts internal to static equipment.
- Design life of piping will be 10 years.
- For rotating machinery a service life of 25 years is to be assumed as a design criterion, taking into account that cannot be applicable to all parts of machinery for which replacement is recommended by the manufacturer during the operating life of the unit, as well as to small machinery, machines on special or corrosive/erosive service, some auxiliaries and mechanical equipment other than rotating machinery.

3.6. Codes and standards

The project shall be in accordance to the main International and EU Standard Codes.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME: REVIEW OF FLEXIBILITY OF POWER PLANTS WITHOUT CCS
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APPROVED BY : L. MANCUSO

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INDEX

1 Introduction

This section provides an overview of the current capabilities of conventional coal and gas fired power plants, without Carbon Capture and Storage (CCS), to operate flexibly. Some of the data included in this section are available in the public domain, others originate from Foster Wheeler's in-house information.

The main objective of this investigation is to highlight how plants without CO_2 capture and storage can operate in the actual electricity market, responding to the normal daily and seasonal variability of the electricity demand. Then, on the basis of the information shown in this section, it will be evaluated how CCS affects the plants operation, in order to understand if and to what extent these plant types can operate in the new flexible electricity market (refer to section D).

Therefore, this section focuses on the main features related to the flexibility of conventional power plants, like: cold and hot start-up and shut-down times, operating load range and the impact of variable and low load operation on plant efficiency, equipment lifetime and operating costs. These considerations are mainly referred to the Combined Cycle, PC and IGCC plants.

It is to be noted that most of the information available in the public domain refer to the combined cycles, especially in relation to the improvements of plant flexibility, due to the latest developments of the technology. Vice versa, much less information is available on the operating flexibility of PC boiler plants, as well as IGCC's. This is because PC boiler and, moreover, IGCC plants have been designed to operate mainly at base load, due to lower weight of the variable costs (i.e. fuel) on the overall cost of electricity.

2 Combined cycle operating flexibility

Nowadays, existing and new combined cycle power plants must face with the challenges of the liberalized electricity market. Further on, also the compliance with more stringent environmental requirements is becoming more and more important, introducing additional constraints on the plant operation.

Typically, combined cycle power plant built in the 1990's and early years of the new millennium have been designed for base load operation, favouring higher efficiency and lower capital costs, with the main objective of minimizing the cost of electricity production.

Today, a number of operating combined cycle plants are used to cover intermediate and peak load constraints. Therefore, new plants shall be designed for cycling load regimes, to meet recent power market requirements for fluctuating operation, so to cover the daily and seasonal variation of the electricity demand.

Drivers for this new operating philosophy are the risks related to the floating of the fuel and electricity prices, combined with a generating capacity of the power industry in the developed countries that exceeds the actual market demand, particularly in the current scenario of the global economic crisis.

Depending on seasonal load and the dispatch rank of the plant, driven by competition and fuel prices, the newly designed NGCC plants operate as cycling units over their lifetime, increasing load during the day or peak hours and reducing it to the minimum or shutdown during the night or when the electricity demand is low.

As a matter of fact, high flexibility becomes a must for the design and operation of combined cycles, also considering that advanced cycling capability and high efficiency are required at base, as well as at partial loads.

Figure 2-1 shows a possible daily behaviour of the electricity demand. This trend can be typical for many countries, though it may slightly change or having differences in timing in other locations. For example, UK has a shorter morning peak and has generally no need for air conditioning, while there is an earlier evening peak for and early dinner.. In the recent years, the use of Natural Gas Combined Cycles (NGCC) has been increased to cover both variable electricity demand, during day and night (or during the different seasons), and load regulation all over the entire period.

In general, it can be stated that operational flexibility of the combined cycle plants requires:

- A lower and lower technical minimum environmental load;
- Good efficiency at partial load operation;
- High cycling capability (e.g. fast start-up and shut down, fast load change and load ramps, low start-up emissions, high start-up reliability);
- Frequency control;
- Low operating costs (high start-up efficiency or short start-up time).

It is also noted that a flexible plant opens up new business opportunities, like utilizing hourly and seasonal market arbitrage, participation in ancillary energy markets or peak load market. Of course, a power plant designed to meet these market requirements shows an investment cost higher than a traditional base-load plant.

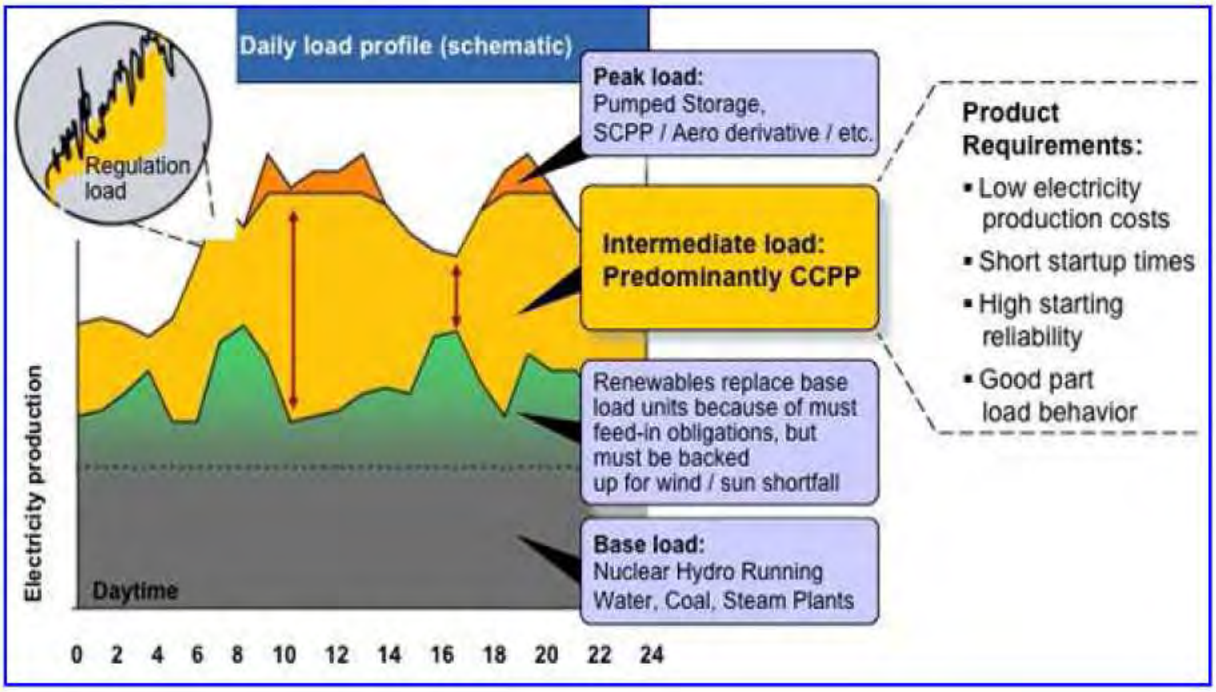

Figure 2-1. Typical daily electricity demand curve

2.1 Technical minimum environmental load

The technical minimum environmental load is defined as the minimum condition at which the Gas Turbine is able to operate, still meeting the environmental limits, in particular NO_X and CO emissions.

Actually, the minimum environmental load is generally related to the limits on the NO_X emission, as shown in the following Figure 2-2, which illustrates NO_X behavior as a function of the gas turbine load.

The CO behavior is similar, though the limit on the minimum load imposed by the CO emission would a little less stringent than the limit on NO_X emission. In fact, the CO tent to be more stable down to lower loads, increasing extremely quickly up to very high figure.

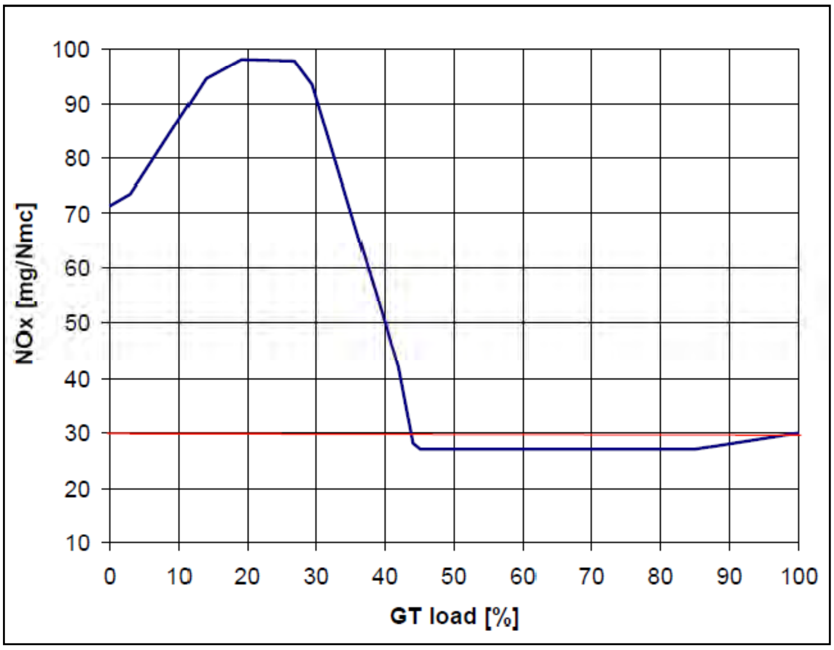

Figure 2-2. NO_X emission changes with GT load

The most recent Gas Turbine designs have tried to reduce the technical minimum environmental load, because this allows to:

- Run the plant in a wider range of production loads. In this way the GT and, consequently the entire combined cycle, can better follow the daily or seasonal electricity demand variations, while meeting the environmental limits.
- Limit the economic losses during the non remunerative hours, like night hours, through the possibility of running the GT at low load and being able to increase load suddenly, to follow grid services. Otherwise, plant shall be shutdown, to limit economic losses, but in this case it cannot be ramped up so quickly, when required.
- Reduce the emissions during the plant start-up phase.

Depending on the Gas Turbine manufacturer, it can be stated that nowadays the technical minimum environmental load is generally in the range between 30% and 50% of the base load power production.

2.2 Partial load operation

The combined cycle power plants put in operation in the 1990's and in the early years of new millennium have been designed for an optimum operation (highest efficiency) at base load. Therefore, their efficiency at partial load is significantly lower than the base-load point. This is intrinsic for the technology, as even at "full-speed-no-load" mode, the power requirement of the GT compressor is significant.

As new plants are requested to operate both at base-load and at partial load over their lifetime, power production shall be optimized along the daily and seasonal floating behavior, to improve the overall economics also when the electric power demand is low.

Figure 2-3 shows the typical net overall plant efficiency vs. GT load for newly designed power plants.

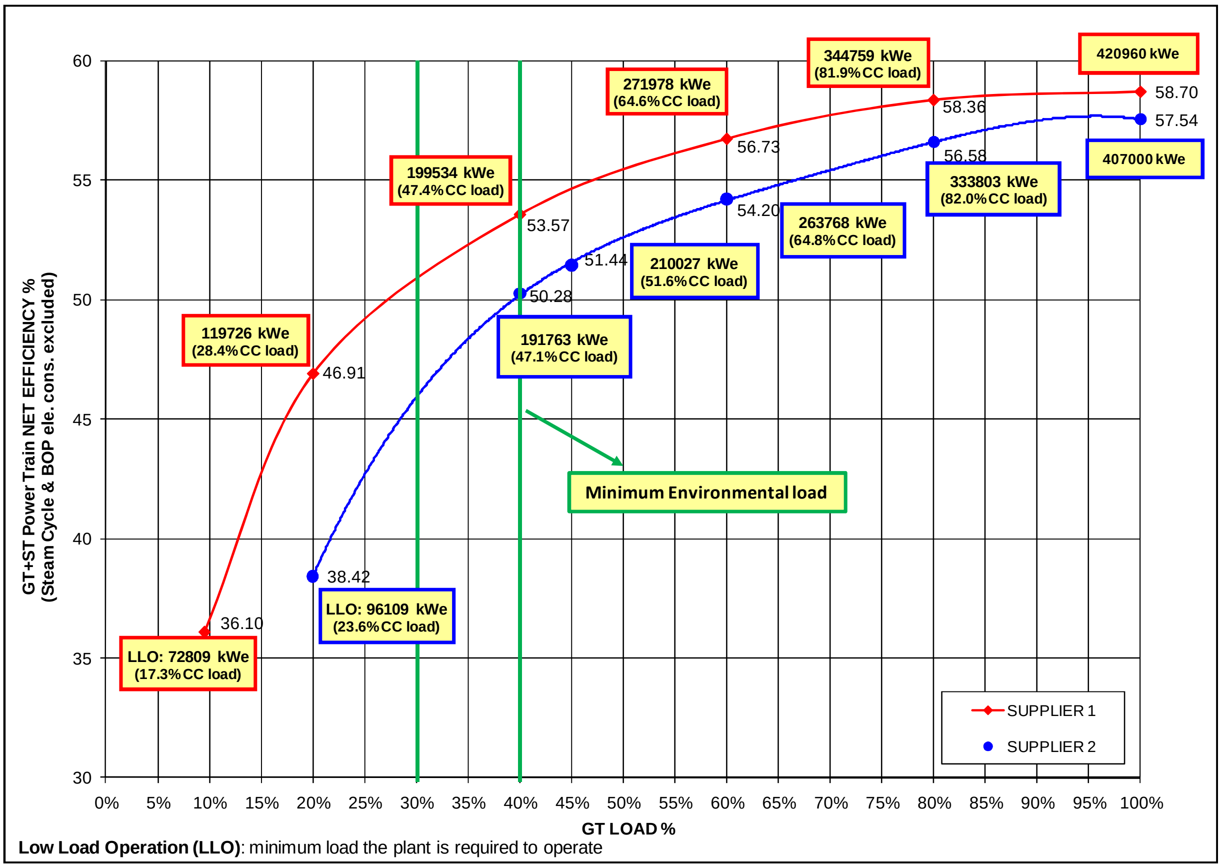

Figure 2-3. Overall plant efficiency vs. GT load

It can be noted that the efficiency reduction at partial load is relatively low, as the plant achieves an overall efficiency of 55-56% even at 60-65% of the load. Actually, the efficiency penalty corresponding to a load reduction down to 60% is only a few percentage points (2-3%) lower than the base load operation, even if the expected impact on the cost of electricity is much higher (7-8%), as the cost for fuel consumption represents a significant portion in the economics of a natural gas combined cycle.

2.3 Start-up and cycling capability

As an answer to the changed market requirements, and in particular to the daily trend of electricity demand, cycling capability in combined cycle power plants shall be optimised to fulfil the nightly and weekend load reductions or shutdowns. In addition, time required for the subsequent hot start-up (after night shutdown) and warm start-up (after week-end hours shutdown) shall be reduced as much as possible. The cold start-up times after an extended outage (generally longer than 120 h) shall be also low, even if it is usually of low importance as it is generally required few times per year.

For a combined cycle designed to meet these requirements, the economics of the plant are significantly improved because of the following reasons:

- Possibility to follow the seasonal or daily market trend.
  A flexible plant can be shutdown in case the electricity prices do not cover the variable costs and run when operation is economically convenient. These plants take advantage from high prices of electricity, while not operating when electricity prices are low, i.e. would result in an economic loss.
- Higher electricity production during the hours of remunerative service of the plant and greater ability to follow the load changes requirements.
- Reduced start-up costs through fuel saving, because of the short gas turbine operation in non-profitable loads, i.e. at low efficiency and through fast change over from steam bypass operation to combined cycle operation.
- Reduced NO_X and CO emissions, as lower time is required to reach the technical minimum environmental load.
- Capability to participate in ancillary services markets.
  A fast load changing plant can participate in markets for spinning reserve, which means that the plant must provide a guaranteed output in a specified period of time, as well as in hour-reserve markets, where the output must be available after one hour. These operating conditions may be an option to the nightly shutdown.

Table 2-1 compares the typical start-up times of plants built in the 1990's (base-load) with those of most recent designs for flexible operation. To achieve this reduced start-up time and high cycling capability, some improvements in plant design have been introduced in the last years. This is the result of a significant work made on some of the key features of these plants, which limited their operative flexibility in the past years, like:

- Gas Turbine and Steam Turbine ramp restrictions;
- Heat Recovery Steam Generator ramp restrictions;
- Vacuum system and steam chemistry.

Table 2-1. Comparison of start-up times

Start-up type (to full load)	Base-load plants (1990's)	Flexible plants (recent design)
Hot start (night S/D)	90 min	45-55 min
Warm start (weekend S/D)	200 min	120 min
Cold start (120 hours)	250 min	180 min

A key element to optimise the unit start-up process and to significantly increase the load output during start-up is the use of final-stage, high-capacity attemperators in the high pressure and medium pressure reheat steam lines, so to adjust steam temperature end meet the steam turbine requirements.

In the past years, the steam temperature was controlled by varying the gas turbine load and, consequently, the exhaust gases temperature and flowrate. The introduction of final SH and RH steam attemperators has allowed to decouple the gas turbine from the steam turbine start-up and to increase the load output of the gas turbine during start-up, keeping the steam temperature constant and optimal for the operation of the steam turbine. In fact, steam turbine loading ramp is normally limited by temperature transients, not by pressure and/or mass fluctuations.

Because of this decoupling, it is possible to start-up quickly the gas turbine, while the steam turbine is put in operation with its dedicated, slower ramp. Moreover, it is also assured a much greater cycling capability for the entire power plant, as this can follow the load variations with the gas turbine first and then with the steam turbine.

On the other hand, the use of once through steam generators (e.g. Benson design), typically for small-scale power plants, has further reduced the restrictions on the temperature and pressure transients, thus improving the operational flexibility both during start-up and load changes. The Benson design, in fact, eliminates the high

pressure thick wall drum and allows an unrestricted gas turbine start-up, including a high number of fast start-up and load changes.
In the steam drum of a conventional HRSG, in order to reduce the inertia relevant to wall drum, the steam generator hold-up shall be significantly reduced, so to decrease drum size and thicknesses. This helps to reduce the inertia in the HRSG, due to the excessive thickness of the drum, designed to operate at high pressure.

Another key element that reduces the start-up duration of the combined cycles is the possibility to avoiding HRSG cooling when the plant is not in operation. In fact, by reducing heat losses, it is possible to reduce considerably the restart-up time. Also, automated drains and vents shall be installed to minimize steam losses during the shutdown phases.

Moreover, in order to minimize heat losses due to natural convection phenomena, two actions can be taken: to consider an insulated breeching between the steam generator and stack, as well as to install a stack damper to minimize the HRSG cooling for natural convection.

The installation of a stack damper, as a matter of fact, also limits the velocity of the HRSG pressure decreasing during a plant shutdown. In case of nightly shutdown (8 hours) the installation of the damper is absolutely recommended, as also shown in Figure 2-4.

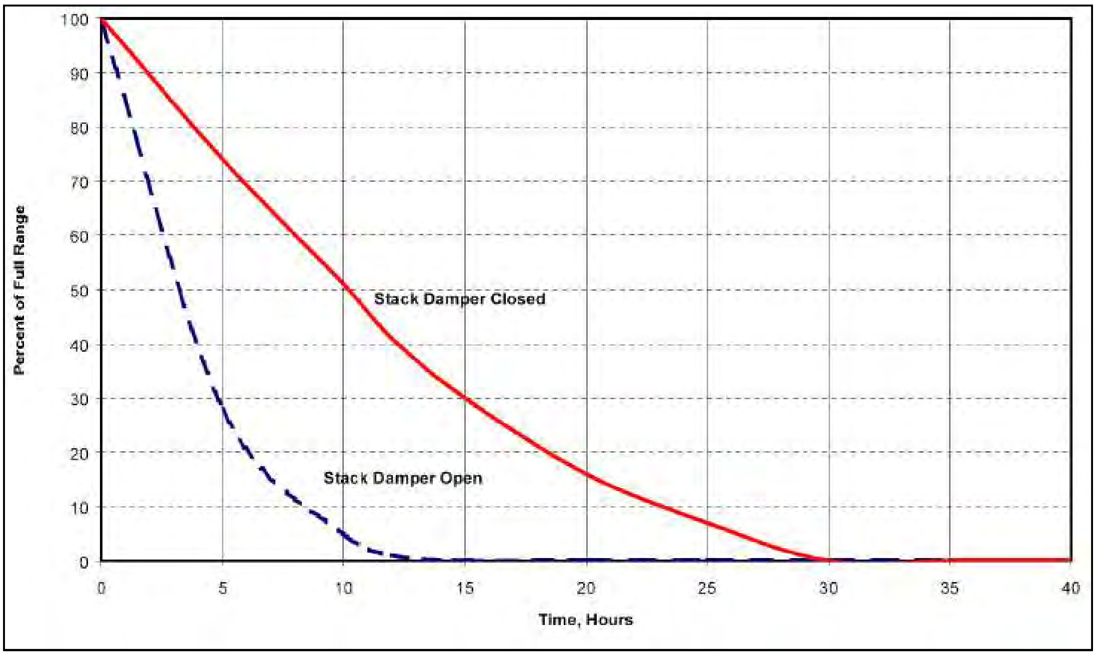

Figure 2-4. HRSG Pressure profile during shutdown

Some manufacturers also provide active measures to keep steam generator warm during hot start-up, introducing an auxiliary boiler that generates low pressure steam to be circulated in a sparging system in the steam drum components, to keep them warm.

A further element to reduce the start-up duration is to maintain the vacuum condition overnight, to prevent air inlet into the condenser hot-well. To achieve this, an auxiliary boiler providing steam to the steam turbine gland system during shutdown and mechanical vacuum pump for evacuating the condenser before the Gas Turbine start-up may be used. This alternative shall be evaluated carefully, as the steam extracted from the condenser shall be either vented (with consequent loss of demineralized water) or condensed in the gland steam condenser (with consequent necessity to keep in operation condensate pumps).

By introducing the above-mentioned design changes in the combined cycles, the start-up sequence of recent plants has been optimised, in order to reduce its duration and allow fast start-up in accordance to the actual market requirements. A qualitative trend that shows both the past and improved start-up curves is also shown in Figure 2-5.

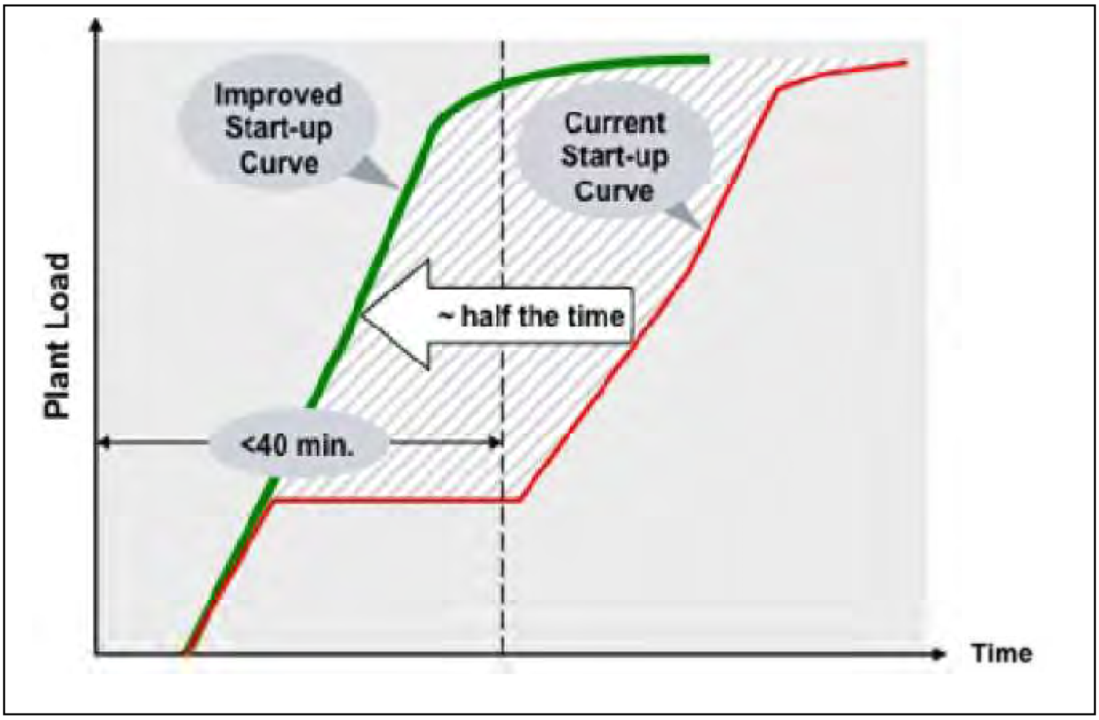

Figure 2-5. Sequential plant start-up concept

Typical load change rates for the whole combined cycle during hot start-up sequence are reported in Table 2-2.

Table 2-2. Ramp rates for combined cycle power plant

Load range	**Ramp rates** % rated power / min
0% to 40% GT load (GT at minimum environmental load)	3 – 5
HRSG pressurisation	1 – 2
40% to 85% GT load	4 – 6
85% to 100% GT load	2 – 3

In the past years, the plant start-up was performed through the steps described in the following:

- ✓ The Gas Turbine was accelerated and synchronized to the grid at the minimum load of about 20%, although the environmental limits on emissions were not met.
- ✓ The exhaust gases were passed through the HRSG and steam production dumped directly to the condenser through full capacity bypass stations. At the same time, the steam turbine and steam piping were warmed-up, while steam characteristics were adjusted to meet the turbine requirements.
- ✓ The pressurisation of the HRSG in the start-up sequence begun when the gas turbine was at the minimum technical load required to produce steam at an acceptable temperature for the steam turbine, i.e. about 20%.
- ✓ When all preconditions were fulfilled, then steam turbine was accelerated and synchronised, and steam was taken over until the bypass stations were closed (operation in fix pressure mode).
- ✓ Finally, Gas Turbine loads were increased up to full load and the Steam Turbine followed the increased steam production. At higher loads, the Steam Turbine was operated in sliding pressure mode.

In Figure 2-6, the “old” start up sequence is shown. After the GT start up, HRSG pressurisation and ST synchronisation was carried on with the GT at its minimum load, corresponding to about 20%. This was the figure selected in order to allow the pressurisation of the HRSG at low pressure, and the preheating and synchronisation of the ST with a correct steam temperature (about 400°C).

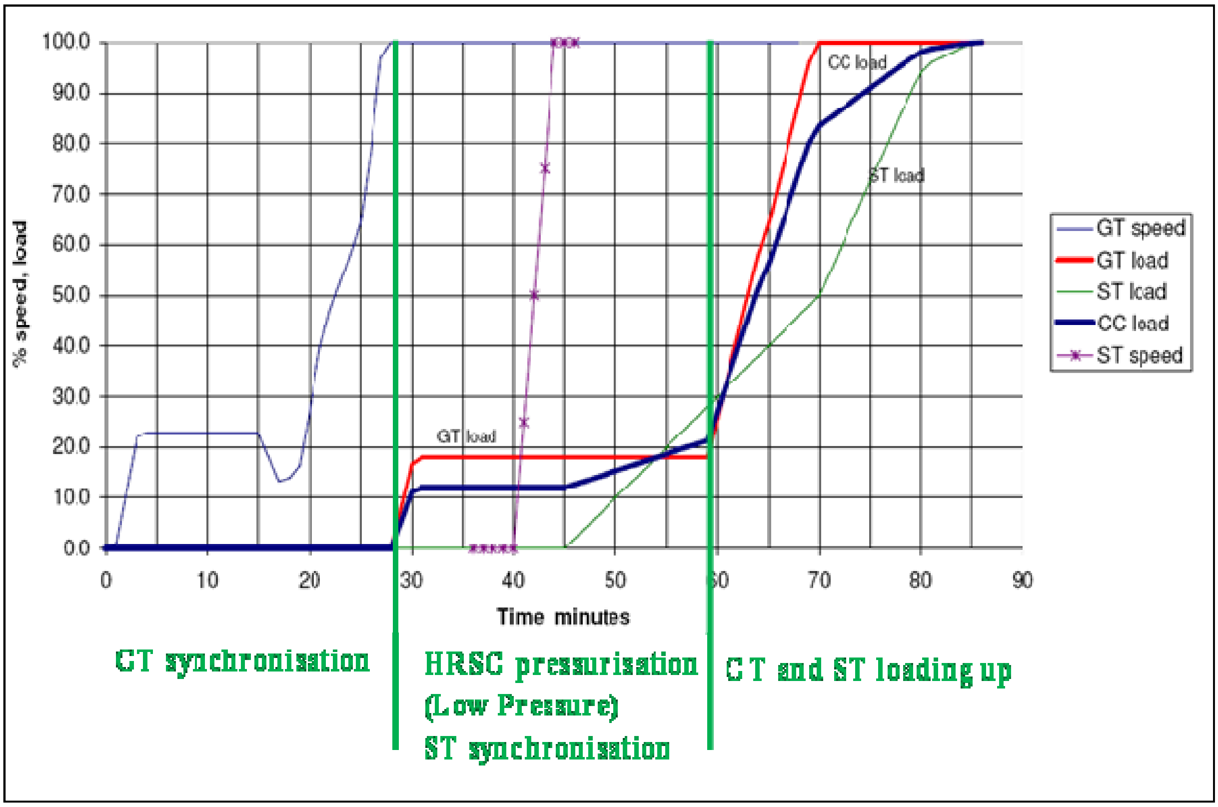

Figure 2-6. "Old" start-up sequence

In newly designed power plants (refer to Figure 2-7), the pressurisation of the HRSG in the start-up sequence begins when the gas turbine is at the technical minimum environmental load (approx 40%), in order to reduce start-up emissions.

At this load, with respect to the older start-up sequence, a larger amount of steam is generated in the HRSG, at a temperature higher than the one acceptable by the steam turbine. As a consequence, an increased size of the bypass valves and final attemperators for high pressure steam and hot reheat steam are required. In fact, after the synchronisation with the grid, the GT is loaded continuously with its maximum allowable load ramp up to base load, while by means of final steam attemperators and bypass, the steam turbine is started-up following its dedicated, slower, load increasing rate. This procedure can allow a total plant start-up time around 45-55 minutes, versus 90 minutes of the older plants.

Figure 2-6 and Figure 2-7 highlight the different minimum load during the old and the new start-up sequence, as a result of higher minimum technical environmental load of the gas turbine. The reduced start-up time achieved with the new start-up sequence is not shown in these graphs.

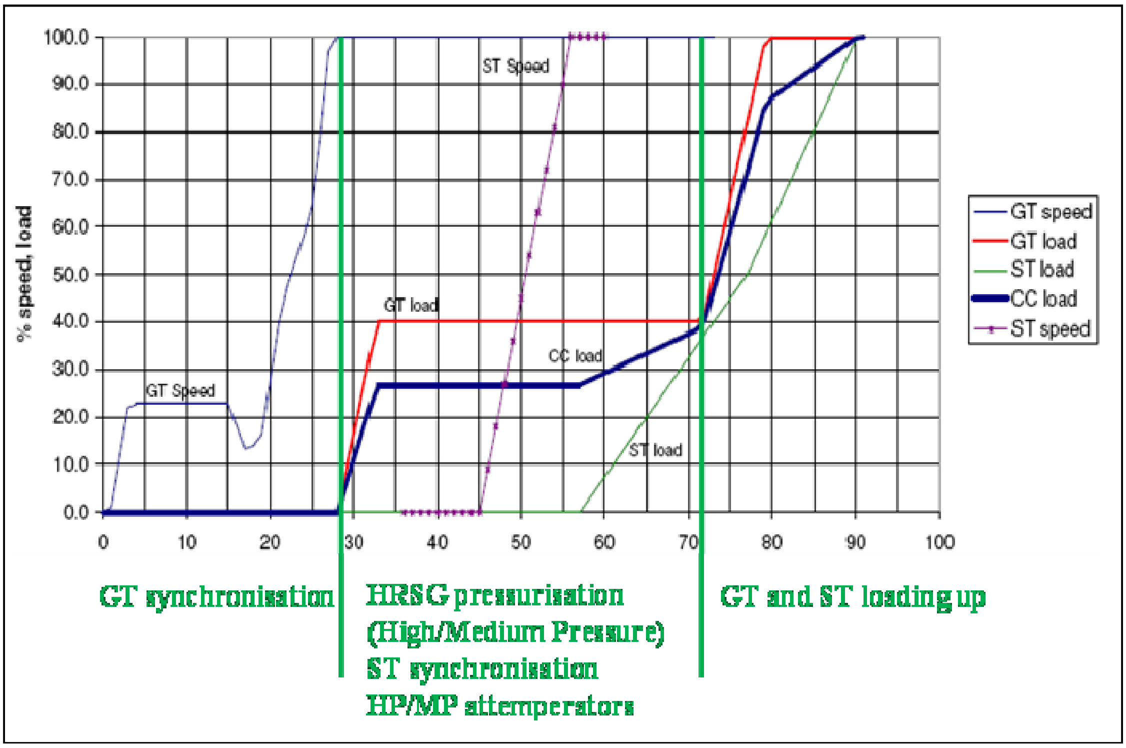

Figure 2-7. “New” start-up sequence

Recently, some of the major gas turbine and combined cycle Vendors, like Alstom, GE Energy, MHI and Siemens, have officially presented the flexibility features of the next-generation plants, which can be summarized as follows:

- GE Energy claims that its last package, the “FlexEfficiency 50”, will ramp up at a rate of 51 MW per minute, while maintaining the emission limits of 50 ppm NOx, while going from hot start to full rated power in 28 minutes (85% load in less than 20 minutes). The combined cycle part load efficiency will be greater than 60% down to 87% of the plant’s base load power output. The CCPP will turn down to 40% of its load while maintaining the emission limits, thus corresponding to a minimum environmental load for the gas turbine of 30%.
- The new Siemens’ H Class unit achieved the highest base load operational efficiency of 60.75%. The combined cycle is capable of ramping up at 35 MW per minute. The plant can operate stably at load lower than 20% of the rated power output, with an efficiency typical of peak load power plants.

- Alstom is claiming a base load efficiency of 61% and the best all-round efficiency over the entire load range, achieved with their last GT26. The combustion system is designed to operate over a wide range of Wobbe Index range, maintaining the NOx emission under 25 ppm at 15%O_2 dry from 100% down to 40% of the combined cycle base load power output, as well as at the low parking point. Alstom also claim a ramp up rate of 350 MW in 15 minutes from low load.
- MHI J series gas turbine achieves a gross thermal efficiency exceeding 60%, but MHI aims to reach 61% later this year. The combined cycle is characterised by a part load efficiency of 55% at 50% load.

2.4 Grid services

Grid services are traded as independent products in liberalized energy market. They are necessary to guarantee grid stability because a stable electrical grid frequency is essential to assure the efficient and safe operation of the electrical users.

Frequency changes occur whenever the electricity supply and demand are not in balance. Frequency control is generally made in three different steps:

- Primary frequency control: it avoids grid instability, keeping the grid frequency inside a narrow range of acceptable values;
- Secondary frequency control: it restores the nominal value of grid frequency;
- Tertiary frequency control: it restores the reserve in case the entire margin kept by plants participating to the secondary frequency control has been used. It may require the start-up of warm stand-by plants.

In many countries, some of the frequency response capabilities (at least the primary) are mandatory for power plants interconnected with the national grid. They must be able to respond quickly, i.e. within a few seconds after a first limited variation in grid frequency. Active reserve to be guaranteed by power plants connected to the grid corresponds to a certain percentage of their net power output production, depending on the local legislations.

The participation in market for optional spinning reserves can significantly increase the plant economics, provided that the plant is able to fulfil the grid requirements.
The earnings in these markets normally are split in a payment for the capability to provide the power (availability fee) and a payment for effectively generated and delivered power (utilization fee), which is normally significant higher than the daily market price fluctuations.

Nowadays, depending on the requirement of the grid, plant owners can optimise their load profile participating both in ancillary service markets and power markets.

2.5 Peak load market

Power production in combined cycle power plants can be increased during peak electricity demand hours, by:

- Air chilling.
- Gas Turbine over-firing.
- HRSG post-firing.

Participation in the peak load market increases the economic value of the plant, as the electricity price increases when the demand for a service is at its highest.

2.5.1 Air chilling

The Gas Turbine efficiency and power generation decreases when the ambient temperature increases, as the inlet volumetric air remains constant and consequently the mass flowrate results lower.

Since spot market prices for power generally increases in summer, in countries where the peak power demand is in this season, the reduced gas turbine output at high temperatures affects the economics of a power plant.

One solution to this problem is to install gas turbine inlet air cooling, in order to reduce the temperature at the GT air intake and improve the performance of the machine.

The three most common options for inlet air cooling are: *evaporative cooling*, *refrigeration chillers* and *inlet fogging*.
In evaporative cooler and inlet fogging the air cooling is achieved by means of water vaporisation in the GT air intake duct and therefore humidification and refrigeration of the air at GT compressor inlet. Evaporative cooler and inlet fogging typically exhibit a low capital cost per marginal increase in power output, but become less effective as the relative humidity of the inlet air increases.

In the system based on chillers, instead, the air at GT intake is cooled down by means of chilled water heat exchangers. Although chillers can increase the gas turbine power output, independently from the ambient air relative humidity levels, they have higher capital costs with respect to the previous systems. Moreover, the energy requirements for chillers are significantly higher than the evaporative cooling and fogging system, affecting the overall power plant performance. Finally, the use of chillers leads to the increase of heat load for cooling system and therefore higher investment cost and plot plan requirements.

2.5.2 Gas Turbine over-firing

Over-firing of the gas turbine consists of operating the Gas Turbine at peak load conditions, corresponding to a production capacity a few percentage points higher than the base load. This can be done during peak electricity demand hours, in order to increase the electricity production for a limited time, when required by the market.

During this operation the metal temperatures of some components increase, so prolonged operation at peak load leads to more frequent maintenance and replacement of hot-gas path components, thus increasing the plant operating costs.

2.5.3 HRSG post-firing

Steam generation, and consequently steam turbine power output, can be increased, if required during peak load hours, by firing additional fuel in the post-firing system of the Heat Recovery Steam Generator. This reduces the overall plant efficiency, but increases the net plant electricity production and, therefore, allows the plant covering the higher production requirements, when needed.

The post firing system acts directly on the steam generation and the steam turbine performance and, therefore, the increase/decrease ramp rates are much lower if compared with the gas turbine or the over-firing mode, as they are significantly limited by the steam system inertia.

The addition of post firing in HRSG leads to the increase of the investment cost both of the HRSG itself and of the steam turbine, which shall be greater size, in order to expand the higher steam flowrate.

2.6 Aeroderivative gas turbine

The aeroderivative gas turbine technology has several features that provide an answer to the needs of the liberalized electricity market, in particular for their capability to participating in the peak load market and their possible use as integrated with a renewable energy source.

These machine types have an efficiency generally greater than 40%, which is among the highest value for simple cycle applications, and can reach full power in 5-10 minutes, depending on the gas turbine generator size. They are also capable to follow

the grid power demand trend with ramp rates of up to 50 MW/min, thus allowing the plant to reach the target load within few seconds.
In addition, these turbines do not require maintenance activities longer than other machines, even for cyclic operation, i.e. with daily start-up and shutdowns.
Another key advantage of this technology is the flexibility to accept a wide range of liquid and gaseous fuels, also meeting stringent emission limits by using a Dry Low Emission (DLE) combustion system.

The characteristics listed above make the aeroderivative gas turbines particularly suited for the flexible operation of a power plant, including daily start and stop operation, peaking application and grid stabilization during demand changes, as well as to provide power during forced outage of major power plants.

Another natural application of these machines is in conjunction with renewable energy sources, as wind or solar farms, which by their intrinsic nature are intermittent.

3 PC boiler operating flexibility

As an answer to the new electrical grid requirements, similarly to the conventional natural gas combined cycle power plants, coal-fired plants are required to operate in the mid merit market. Therefore, a medium operating flexibility is also required for these plant types. In fact, making reference to Figure 2-1, while NGCC plants are required to cover peak load electricity demands, for which a high operating flexibility is required, coal power plants are generally required to participate to the first step of variable electricity demand only.
However, it ha to be noted that the relative required flexibility of coal and gas plant may vary in the future, depending on the plant location and on coal/gas price differential.

A PC boiler power plant, in particular if based on supercritical and ultra-supercritical technologies, provides flexibility in dispatching power greater than other coal-fired technologies. In general, it can be stated that operational flexibility for PC boiler power plants consists in:

- Load cycling capability
- Fast start-up
- Good efficiency at partial load
- Low turndown load.

3.1 Cycling capability

Higher cycling capability and good efficiencies at partial load can be achieved with full-arc admission on the HP steam turbine, operating in a sliding pressure mode, i.e. without limitation due to the low-cycle fatigue for the pressure valves. In fact, because of the high level of steam partialisation at steam turbine inlet, it is possible to keep the boiler in operation at supercritical pressure, avoiding excessive pressure fluctuations on boiler side.

Supercritical and ultrasupercritical PC boiler power plants show an operating flexibility that is much greater than conventional subcritical power plants. In fact, subcritical plants use drum-type boilers that are limited in their load change rate due to the boiler drum, component that requires a controlled heating, due to the very high wall thickness. This limits the load change rates generally to 3% per minute.

On the other hand, supercritical or ultrasupercritical facilities use once through steam generators that can achieve quick load changes, even up to 8% when the turbine is suitable designed, and are much more suitable for quick start-up.

In general, a fast load response of 5% to 15% of the power output can be provided in few seconds by using the energy storage capacity of the steam/water cycle (e.g. providing a hold up in the steam drum in subcritical boiler allows increasing the plant load response). The following quick controlling measures can be used for a limited time, until the normal operating conditions are restored:

- Opening overload valve(s) or opening throttled turbine control valve(s).
  In case of need of quick power generation increase, the plant can be operated with overload and throttle valves partially closed in order to have the possibility to open them when required. This implies the normal operation of the plant with penalized performance;
- Opening/closing a feedwater supply valve to the LP feedwater heaters;
- Opening/closing of the steam supply valve to the final feedwater heaters.

Typical load change rates for a supercritical PC boiler power plant are reported in Table 3-1, over a wide load range from minimum to full load (i.e. from about 25-30% to 100% output).

Table 3-1. Ramp rates for supercritical PC boiler power plant

Load range	**Ramp rates** % rated power / min
30% to 50% load	2 – 3
50% to 90% load	4 – 8
90% to 100% load	3 – 5

In case of full-load rejection, prolonged operation of the supercritical PC boiler is possible, using the main and reheat bypass systems. The boiler load is operated at the minimum PC boiler stable load (about 25-30%), while the turbine generator provides the unit's auxiliary load, bypassing the excess steam. The power plant, operating in this so-called stand-by mode, is ready for the re-synchronization at any time.

3.2 Start-up

Start-up in advanced plants with supercritical, once-through steam generators consists mainly of three phases, as described here below.

In the first phase, the boiler circulation is established through the water/steam separator.

In the second step, main steam is supplied through the main steam bypass station to the cold reheat line and hot reheat steam is bypassed through the dedicated bypass station into the condenser hot well.

Finally, the steam turbine is started-up by controlled switch-over from bypass to turbine operation.

Typical cold start-up to full load sequence of a supercritical PC boiler power plant is shown in Figure 3-1.

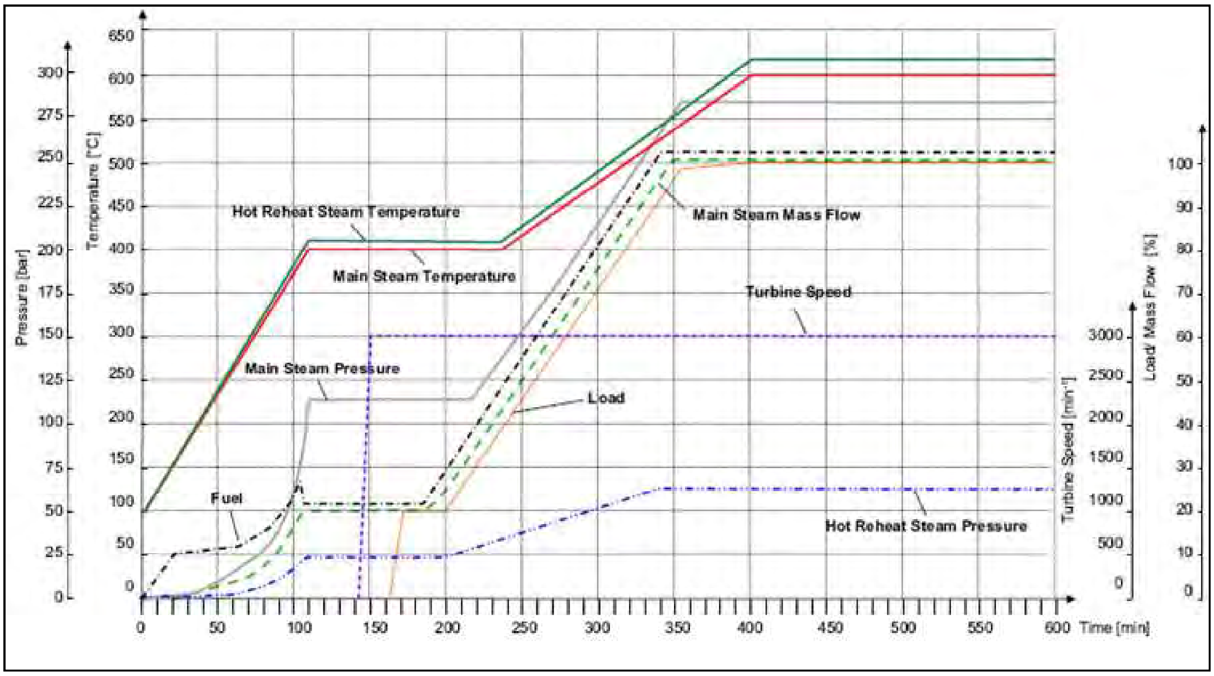

Figure 3-1. Cold PC boiler power plant start-up

After a nightly shutdown, a medium-large scale pulverized coal power plant can reach the minimum load (about 30%) in about 30-40 minutes, after boiler ignition, and then reach full load capacity in about 70-90 minutes.

Typical start-up times for a supercritical PC boiler power plant to reach full load operation are reported in Table 3-2.

Table 3-2. Start-up times for supercritical PC boiler power plant

Start-up type	Start-up time
Very Hot start (<2 hours shutdown)	< 1 h
Hot start (2 to 8 hours shutdown)	1.5 – 2.5 h
Warm start (8 to 48 hours shutdown)	3 – 5 h
Cold start (>72 hours shutdown)	6 – 7 h

3.3 Partial load operation

Depending on the technology, net efficiencies of PC boiler power plants is within the range from 38% for subcritical boiler to a maximum of 46% for supercritical plant (most recent designs), for average European temperatures of the cooling water (15-20 °C).

In addition, efficiencies of supercritical and ultra-supercritical power plants are less affected by partial load operation. In fact, public available data show reductions in plant efficiency of supercritical units of about 2% at 75% load, compared with 4% reduction in efficiency for subcritical plant under comparable conditions.

This is related to the lower heat input required to reach the same outlet temperature at supercritical conditions, with respect to subcritical conditions, e.g. the heat required to reach 540°C at subcritical pressure (180 bar) is 100 kJ/kg lower than supercritical condition. Whit the boiler operating at partial load, the steam pressure decreases in accordance to the sliding operation of the steam turbine. In subcritical boiler, this leads to an increase of the heat required for generating the same amount of steam, as the heat of vaporization increases. This does not affect the partial load operation of a supercritical boiler, as long as the steam pressure is maintained above critical condition.

4 IGCC operating flexibility

An IGCC plant generally shows a dispatch flexibility lower than the Combined Cycle or the PC boiler power plants, due to the inertia related to the process units (Gasification, syngas cooling and conditioning line, etc.) and the Air Separation Unit (ASU) to generate and prepare the fuel at the conditions required by the gas turbine.

As a matter of fact, the gasification and syngas cleaning processes are generally operated as chemical process plants, i.e. at a steady-state operation over long period of time, minimizing shutdown, start-up and changes of process conditions.

In addition, for IGCC plants, there are general difficulties for a flexible operation, as the syngas generation is intrinsically made for an immediate use in either power or chemical units.

These features are generally in contrast with the common requirements of a flexible operation. Furthermore, IGCC requires significantly longer time to start up the plant, because of pre-heating requirements related to the gasifier, downstream unit pressurization and because of the deep cool-down sequence of the Air Separation Unit.

4.1 IGCC start-up and shut-down

The IGCC start-up time depends on the start-up of the single units or equipment, e.g. Gasification, Gas Turbine, ASU, etc, as well as on the thermal integration of the various units, including the possible air integration between the Gas Turbine compressor and the ASU.

First build IGCC (Buggenum, Puertollano) was designed for 100% air integration between the GT and the ASU, facing with several problems during the first years of operation and demonstrating low flexibility, limited efficiency gain, low investment cost reduction. As a matter of fact, newly designed IGCC's have no or partial air integration between these two units. It is FW opinion that the optimum degree of air integration is typically approximately 50%.

4.1.1 Cold start-up: partial or no air integration between ASU and gas turbine

The following description makes reference to the typical start-up sequence of an IGCC plant, shown in Attachment 1 at the end of this section.

Generally, the integration between ASU and Gas turbine is partial, i.e. only part of the compressed air required by the ASU is provided by extraction from the GT compressor discharge. The remaining part is provided by a dedicated Main Air Compressor (MAC) in the ASU.

In this configuration, the ASU cool-down and start-up sequence can be optimized according to its own requirements, as air flowrate during cool-down sequence is not (or only partially) limited by the air extracted from the Gas Turbine. ASU typically reaches its minimum load in about 36 hours.

In theory, the ASU cool-down sequence could begin with its own MAC, without the start-up of the gas turbine, if electrical import is possible in the plant. The Gasification unit can be then started-up as soon as Nitrogen and Oxygen from the ASU are available.

GT is ignited firing natural gas (or generally back-up fuel) to reach the synchronization speed. At this point, the load is increased up to a percentage (approx. 50%), still firing natural gas, which allows making the steam generation for overall plant start-up.

When the gas turbine reaches this load, it is possible to feed extracted air, if any, to the ASU, to ramp it up to 100%, following the O_2 and N_2 requirements gasification unit.

The gas turbine partial load is maintained at least for the time required for the start-up of the combined cycle; this phase requires the HRSG to be heated and pressurised and the steam turbine to be heated, accelerated and synchronized, while produced steam is by-passed to the condenser. Then, the steam turbine load increases up to its minimum load, the by-pass valves close and the steam turbine operates in sliding pressure.

When the Steam Turbine is running stable at minimum load, the gas turbine can be maintained at partial load (thus limiting natural gas consumption and CO_2 emissions) or increased up to design load (thus reducing ASU start-up time due to additional air available from compressor, increasing plant power output, but increasing also natural gas consumption).

As the ASU operates at minimum stable load and consequently the nitrogen system becomes fully available, the start-up sequence of the Gasification Units is initiated. A typical time of 24 – 48 hours can be assumed for filling, pressurizing and preheating the main systems of the gasification island.

The process units downstream the gasification island can be started-up as soon as the syngas from the scrubber is available at the required conditions, in particular composition and pressure.

At this point, the gasification is operating at around 50% capacity and it is possible to switch over the Gas Turbine and, if required, the HRSG post-firing system from natural gas to syngas operation.

The Gas Turbine allowable load range for this operation is generally in line with the syngas production in the Gasification Unit, operating at low load. The excess syngas produced by the gasification during start-up is sent to flare.

A total time of about 80-90 hours is expected for the cold start-up of the entire IGCC plant on syngas.

4.1.2 Cold start-up: 100% air integration between ASU and gas turbine

In case of full air integration between the GT and ASU, the gas turbine is the first main equipment to be started-up. It is ignited firing natural gas (or generally back-up fuel) to reach the synchronization speed. At this point, the load is increased up to a percentage, still firing natural gas, which allows making the steam generation for the plant start-up (approx. 50%).

When the gas turbine is at this load, it is possible to feed extracted air to the ASU, which then begins the cool-down sequence of the unit. The minimum air quantity sent to ASU in the cool-down phase has an impact in the ASU start-up time, because reduced air causes a longer start-up time.

In addition, ASU air requirement during cool down is not constant, but increases as long as the cold box temperature decreases. In this case, the gas turbine load has to be increased up to a value depending on the ASU air requirements.

At the end of the cool-down phase, that requires about 48 hours, the ASU begins to produce stably nitrogen and oxygen.

As the ASU operates at minimum stable load and consequently the nitrogen system becomes fully available, gasification start-up can begin.

The rest of the plant start-up follows the same procedures as described in the previous section.

A total time of about 100 hours is expected from the cold start-up up to base load operation of the entire IGCC plant on syngas.

4.1.3 Hot start-up considerations

The cold start-up sequences described in the previous sections occur after a long plant shutdown or planned maintenance. A hot-start sequence can occur after a main unit trip that led other units and/or whole complex shutdown. The complex is restarted allowing a shorter sequence in case the trip cause can be solved in short time.

In this case, the power train start-up sequence will not require some of the steps described before, in particular the steps relevant to HRSG warm-up and pressurization can be avoided, also the Steam Turbine heating is quicker.

The main parameter that influences ASU start-up time is the cold box temperature. To allow a shorter start-up time, sometimes are applied auxiliaries systems and procedures (e.g. liquid nitrogen circulation) that can reduce the cold box temperature increase. Without considering these additional devices, ASU unit "hot" start-up sequence lasts in approximately 6 hours (instead of the 36-48 hours required for "cold" start-up).

Typical hot start-up and restart-up time after minor upsets for the gasification island is in the range from 6 to 8 hours, which is the minimum time required for de-pressurization and purging of the gasifier.

4.2 IGCC load changes

The load change rate of the gasification is mainly conditioned by the ramping rate of the coal feed system. In fact, the dense flow control in the pneumatic transport is the main critical aspects during coal feed system load changes, thus limiting the whole gasification unit ramp-up rates. In case of slurry feed system the load changes could be less critical.

Gasification ramp rate is expected to be about 5% of full capacity per minute. Load changes during start-up differ from load changes during normal operation: 3% per minute is the expected load change rate from the light off of coal to minimum capacity, while a slightly higher rate is foreseen increasing the load from minimum to full capacity (expected change rate 3-4% per minute).

The load change ramps of the power train equipment (GT, HRSG and ST) are in accordance with the Natural Gas Combined Cycle power plants standard figures.

The expected normal load change of the ASU is approximately 3-5% per minute, depending on Vendor, keeping purity of products in the whole range from minimum turndown to full capacity. During emergencies, load can be generally reduced by 5% per minute.

4.3 IGCC partial load operation

4.3.1 Air Separation Unit

The turndown of an ASU is limited by the air compressors, rather than the distillation columns in the cold box. The normal turndown for a single train ASU is generally around 70%, without affecting machines efficiency. If lower turndown were required, two alternative configurations could be adopted:

- Introducing an air recycle system the MAC operates always at a load between allowable ranges, but the air flowrate sent to the distillation columns can be adjusted by opportunely acting on the recycle system. This solution has a negligible impact on ASU overall investment costs, but has a significant impact on the ASU performance at reduced load. In fact, when the recycle is in operation and ASU is operating at partial load, the compressor is still running at high load, without reduction of the electric power consumption.
  For maximum efficiency, the normal operating range of the plants shall be maintained in the range of operation of the compressor.

- A second alternative can be the selection of a multiple train configuration. With 2x50% compressors, it is possible to turn-down easily ASU to 50% just operating with a single compression train, without impact on unit performances.
  In this case the minimum turndown of the unit will be around 35%, when only one train is in operation at minimum load. On the other hand, it will be generally impossible to run between 50% and 70%, without venting or recycling air as both trains will need to run in this range.

This second alternative, that shows higher degree of flexibility, involve a greater investment cost related to the introduction of a second train. The flexibility can be further increased by considering an even higher number of compression trains, but the heavier impact on plant overall investment costs would discourage this solution.

Although for economical reasons the ASU suppliers are trying to increase as much as possible the maximum size of the single train, the selection of a 2x50% ASU trains configuration is often driven by the maximum size of the single ASU train in commercially available, compared to the Oxygen requirements of a large scale IGCC.

4.3.2 Gasification Unit

The minimum turndown of the gasification unit is generally around 50%. However, considering the possibility to reduce the gasification pressure because of the lower pressure drops in the downstream sections (lower flow during turndown) a turndown of 40% is generally achieved, while keeping the syngas pressure constant at gas turbine inlet.

As for ASU, the gasification technology Licensors are trying to increase as much as possible the maximum size of single gasifier for economical reasons. Nevertheless, the selection of a 2x50% gasification trains configuration is still often driven by the maximum size of the gasifier commercially available.

These turndown values are in line with the minimum capacity that can be handled by the process units located downstream the gasification (syngas cooling and conditioning line and Acid Gas Removal).

4.3.3 Power Plant

Partial load behavior and efficiency of the power train equipments (GT, HRSG and ST) are in accordance with the conventional combined cycle power plant figures, shown in Section 2 of this report.

The Gas Turbine is characterized by a very high flexibility as it can stably operate in a wide load range. Although the switchover from natural gas (or any other back-up fuel) to syngas operation and vice versa shall be done inside a specific Gas Turbine load range (typically around 40-60%), there are no limitations on GT operation on both fuels from its minimum load (approx 20%) up to base load.

The HRSG and relevant post-firing are characterized by a very high flexibility as they can stably operate in all the load ranges of the Gas Turbine.
The HRSG flexibility limit is defined by the minimum drum pressure that is generally around 60% of normal operating pressure: below this value the velocities in pipes becomes too high for HRSG continuous operation. This can be solved by acting on the Steam Turbine control valves. In fact, throttling the control valves the pressure at ST bowl can be decoupled from the pressure upstream the ST, and therefore at the steam drum. In this way steam drum and HRSG can operate at a proper pressure level that avoid any issue on pipes velocities and exchange surfaces, while the steam turbine pressure profile decreases remaining in line with the reduced flowrate at partial load.

In general, it can be stated that with Gas Turbine in operation up to 40% load, HRSG can operate above its minimum required pressures; with GT in operation at minimum stable load, the thermal input to HRSG is lower and could be too low to operate the steam drums above the minimum pressures, without throttling the steam turbine control valves.

The Steam Turbine gives no limitation to the Gas Turbine and HRSG operation, as far as minimum turndown is concerned.

4.4 IGCC flexible operation

Due to the reduced possibility of operating the process units and the ASU in a flexible way, because of their sensible thermal and volumetric inertia, the IGCC flexible operation is strongly reduced and mainly limited to the operation of the power island.

4.4.1 Cycling operation

In theory, to operate flexibly the IGCC, the syngas production and consequently the gas turbine load should be reduced during nightly hours to follow the daily electricity demand. However, the minimum load achievable during night period is limited by the minimum turndown of the gasification and the Air Separation Unit.

As highlighted in Figure 4-1, the Gas Turbine high cycling capabilities cannot be exploited due to the flexibility constraints of the syngas generation plant, in particular for the lower ramp rate of the gasification unit and the ASU.

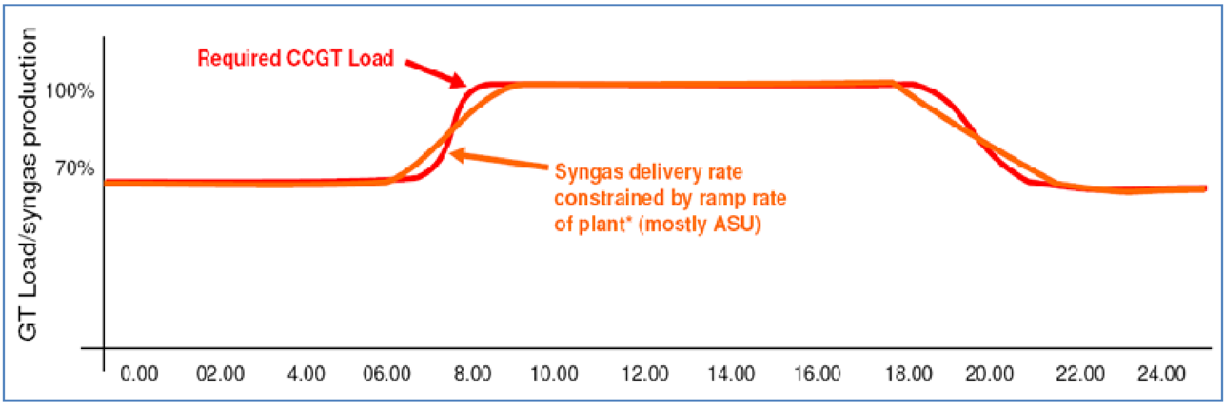

Figure 4-1. Daily load trend

As described above, the IGCC in its base configuration is not suitable for a flexible operation, so the plant is typically designed for operation at base load, due to the significant inertia related to the syngas generation sections (Gasification, ASU and syngas treatment).

Although, in principle, the load of the gas turbine can vary freely between 0 and 100% of base load (nominal electrical capacity of the gas turbine), in practice the lower limit is around 50-60%.
In fact, at this moment, for syngas operation, only diffusion burners are available. Below 60% of base load, the concentration of CO in the flue gas increases drastically, potentially creating environmental issues, while NOx can be generally controlled by injecting a significant amount of either steam or water in the machine.

In order to increase the plant flexibility some modification can be introduced in the plant design, as described in the following sections, though impacting on the plant overall investment costs.

4.4.2 Syngas storage

Syngas storage may allow the process plant to operate continuously at base load during the low electricity demand periods (nightly hours and weekends), while it can be used when demand is higher. In this way, the power production follows the daily demand trend, taking the benefits of the high cycling operation capabilities given by the gas turbine and the combined cycle.

However, the increase of the investment cost related to the syngas storage facilities may be significant, as well as accurate considerations shall be made in relation to safety.

It is noted that in case of a gasification that operates at a pressure significantly higher than the minimum required by the gas turbines, the syngas generation line (from gasification to AGR) itself can provide a small syngas storage.

4.4.3 Oxygen / Nitrogen storage

ASU strongly affects the plant net electricity exported to the grid, due to the electricity demand of the related compressors. Therefore, flexibility in the net power production can be achieved reducing the ASU auxiliary power consumptions, when higher electricity production is required.

By oversizing the ASU with respect to the normal production needs, additional O_2 and N_2 can be produced during period of low electricity requirements from the market, providing storage of both liquid products and resulting in an increased auxiliary demand. Vice versa, when the market requires a higher electricity generation, the ASU can be operated at partial load (or it can be shutdown, depending on the products hold-up foreseen), while the rest of the plant is running at full load. This reduces the auxiliary consumptions and increases the net electricity exported to the grid.

The increase of investment cost is related to the extra-capacity required by the ASU and both products storage facilities.

A different approach could be to reduce the size of the ASU (lower capital cost), while operating the plant at an average load lower than the base load and cover the production fluctuations by using the product storage.

4.4.4 Syngas / Natural gas co-firing

In IGCC plants, it is possible to run the gas turbine in Syngas and NG co-firing mode. This allows to operate the power plant and the syngas generation plant independently, thus enhancing the overall plant flexibility.

The entire IGCC complex can be designed to produce only part of the syngas required to satisfy the appetite of the gas turbine, which can then be saturated by firing NG.

In this way, depending on the ratio between syngas and NG fired in the gas turbine, high plant flexibility can be achieved, taking advantage from the power island capabilities.

In this configuration, syngas generation plant investment cost is reduced as it is designed for a lower production, but on the other hand plant economics are affected by the significant consumption of natural gas.

4.4.5 Chemical and electricity coproduction

An IGCC complex can be designed in order to co-produce electricity and chemicals, like methanol, hydrogen and so on. Significant benefits can be achieved by opportunely integrating electricity and chemical production lines. This scheme can give to the plant the flexibility to increase the production of chemicals or electricity, depending on market requirements.

In particular, in case of hydrogen production, this can be sold or stored during low electricity demand periods and fed to the gas turbine during peak load operation. Main constraints for this alternative are related to the capability of the gas turbine to vary the hydrogen load and the local availability of geological structures suitable for hydrogen storage.

The main options for storing hydrogen are as a compressed gas (above ground or underground), as a liquid or in metal hydrides. Generally for these specific applications, underground storage is the best solution in relation to the very large volumes of hydrogen to be stored for long periods.
In fact, aboveground compressed gas storage and the metal hydride option are not suitable to large quantities of hydrogen, due to very high costs, while liquid hydrogen has specific applications related to high storage energy density, but requires very expensive cryogenic facilities.

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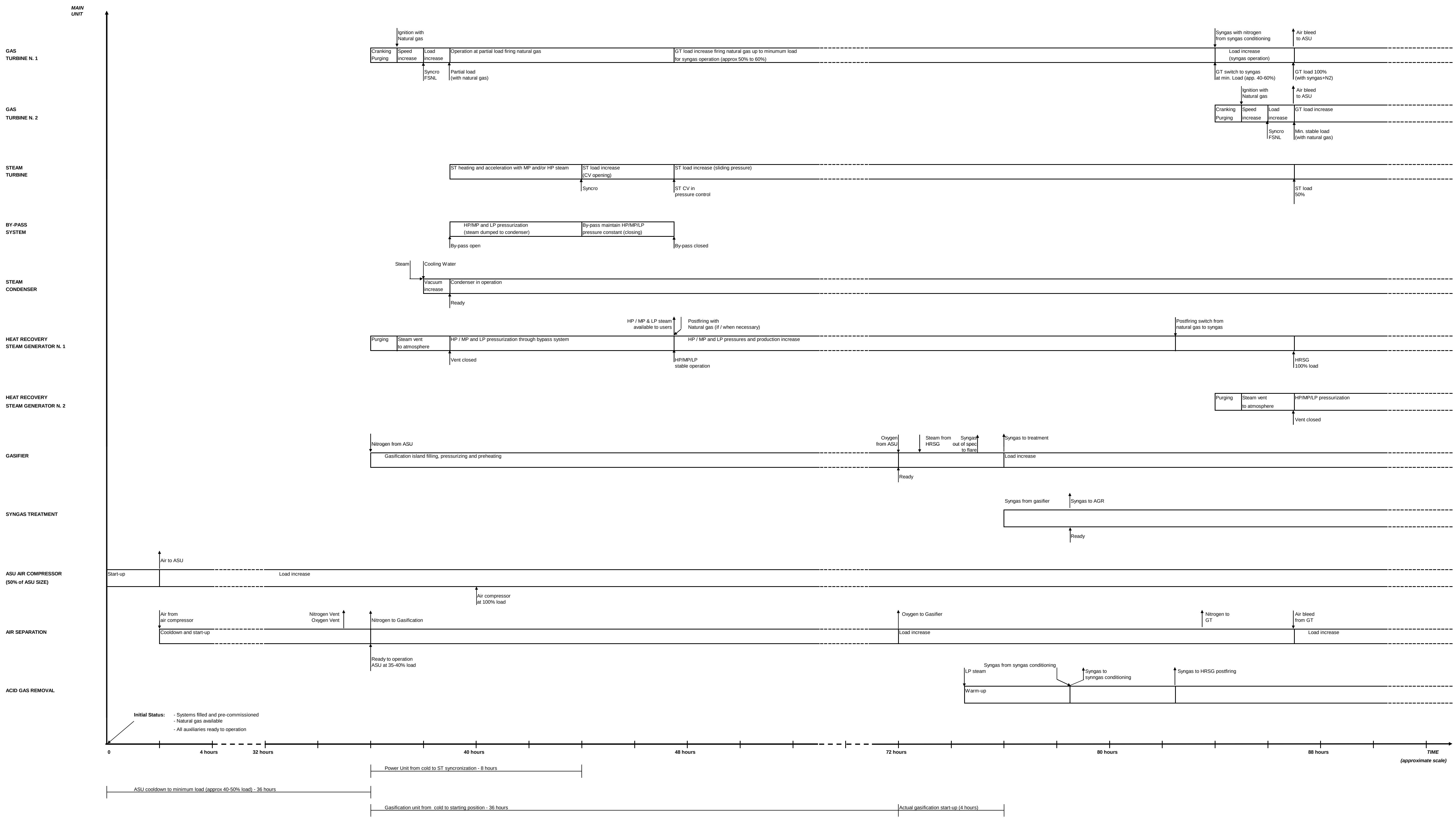
6 Attachments

Attachment C.1 – IGCC start-up sequence (typical)

Cold Start-up sequence

IGCC - partial integration between Gt and ASU



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SECTION D

INDEX

1 Introduction

Scope of this section is to make a review of the information, available in the public domain, on the flexibility of power plants with carbon capture and storage for three different capture technologies: pre, post and oxy combustion.

In general, it can be stated that the available information focuses on two main different aspects related to the capability of these plants to operate flexibly, as discussed in the following.

The first aspect refers to the possibility to change the power output in response to the variable electricity demand of the grid and the relevant impact of the CO_2 capture plant on the operational flexibility of the whole power plant. Particular attention is placed on technical issues, such as the ability of plant to start-up, shut-down and ramp up or down output rapidly, that characterize the suitability of the plant to act as a flexible mid-merit plant.

The second aspect refers to the variability of CO_2 emissions costs: until the cost of emitted CO_2 is fluctuating around low values, as in the present market conditions, it may be economically convenient not capturing the CO_2, rather than limiting the plant flexibility.

Most publications focus on the post-combustion CO_2 capture and compression units in pulverised coal boiler power plants and conventional combined cycles. These works mainly assess possible ways, like solvent storage and absorber bypass, for reducing or avoiding the energy penalty related to the operation of the CO_2 capture and compression units during peak electricity demand period.

Only a limited amount of information is available on the additional constraints that limit the power plant flexibility with CO_2 capture and storage, in terms of cycling rate, start-up and shutdown time and partial load performance.

Strategies for operating flexibly the IGCC plant with pre-combustion capture, identified in available papers and presentations, include oxygen and nitrogen storage, intermediate storage of de-carbonised hydrogen-rich gas and co-production of electricity and hydrogen or other chemicals. Many of these strategies are similar to those identified in Section C of this report, as the addition of the CO_2 capture does not represent a major modification of the plant configuration. In fact, minor changes are required in the IGCC in order to make the capture of the produced carbon dioxide.

In the oxy-fuel combustion, many aspects are still under investigation as the technology is relatively recent with respect to pre and post combustion CO_2 capture. Significant amount of information is available on the boiler start-up and the changeover from air to oxygen fired mode, as well as on the possibility to switching off the CO_2 purification section when additional electricity is required.

A few publications have been made on the dynamics of the CO_2 transport pipeline systems. No information is available on the impact of flexible operation of the upstream units on storage systems because, up to now, the commercial applications of CO_2 storage (e.g. Weyburn and Sleipner) are operated as a base load, i.e. no specific flexibility is required.

2 Post-combustion capture

Post-combustion capture is the technology normally applied for the CO_2 capture in conventional PC (or CFB) boiler and natural gas combined cycle power plants. Published information on the flexibility of these plant types mainly focuses the attention on the flexible operation of coal-fired boiler power plants, but their contents are also valid for the natural gas combined cycles, though there are potentially important differences in the design of the two plants.

In general, in order to improve the flexibility of fossil-fired power plants with CO_2 capture, changes in operating procedures shall be identified, in response to the daily electricity grid demand and prices variation. In most works, the following alternatives are considered and investigated for these plant types:

- Varying the CO_2 capture rate, depending on electricity prices and CO_2 costs;
- Turning on and off the CO_2 capture plant;
- Providing solvent storage to decouple plant operation (boiler or GT) from the CO_2 capture, allowing the power plant to increase/decrease load, following its own ramp up/down rates.

All the possibilities require extra investment costs, related to the over-sized capacity of some units in the power plant or to the additional equipment necessary for a specific operating mode.

These solutions allow to generate extra power, when required, or to store solvent and decouple the plant operation from the CO_2 capture unit, thus meeting the same objective.

To estimate if the increased plant revenues associated with the improved plant flexibility and the capability to offer ancillary services are economically convenient, i.e. if the benefits recompense the additional investment cost, is not an easy task, as the analysis is strongly dependent on the future market conditions, which are unpredictable.

2.1 Impact of post-combustion capture on power plant capabilities

2.1.1 Start-up time and cycling capability

In general, it is expected that post-combustion capture facilities do not limit start-up times of the power plant, since flue gas can be released to the atmosphere. However, in electricity markets where there is a cost related to the CO_2 emissions, releasing carbon dioxide during start-up is an important additional cost that should be as much as possible reduced, compatibly with the plant start-up requirements. This issue could be avoided with moderate amounts of solvent storage, in order to allow the decoupling of the boiler (or GT) from the CO_2 capture unit during start-up or when fast overall plant load changes are required.

With this configuration, the CO_2 capture column can be put in “stand-by” operation, with full amine circulation, waiting feed gas from the boiler (or the GT). Therefore, the amine is initially circulated to the absorption column by-passing the regeneration section, without any flue gases entering the column. When boiler (or GT) is put in operation with its own ramp-up rate, the exhaust gases pass through the absorption column where the CO_2 capture is made. During the first phases, when the ratio between gas and liquid is lower than the design conditions, the CO_2 capture will likely be lower than the nominal. Until the power island is not able to provide a stable amount of steam for the regeneration, the rich amine can be stored in a dedicated storage tank while, simultaneously, the lean amine is taken from an equally-sized lean amine tank.

Once the steam cycle is started-up and LP steam is available, the regeneration section can be put in operation in accordance to its own ramp rate. The storage tanks shall be sized properly, taking into account the duration of these transients.

However, since the steam cycle and the CO_2 capture plant are thermally integrated, the power plant output and the overall plant efficiency is influenced by the required steam extracted for solvent regeneration. Therefore, some constraints to the power plant start-up could occur, depending on the ability of the plant to handle variable steam flows in the Steam Turbine, mainly in relation to its minimum stable load.

The same configuration with rich and lean storage tank can promote the cycling operation of power plants, because the regeneration and compressions can be completely decoupled from the absorption column.

Regarding the CO_2 compressors, it can be stated that these machines do not add specific constraints on plant capabilities to change loads, or, more in general, to the plant flexibility. Ramp up and down rates depend on compressor type, e.g. “in-line” or “integral-gear” centrifugal, but they are typically very short, in the order of a few seconds.

It seems that other aspects on flexibility have not been investigated yet. For example, a relatively narrow band of temperatures of the steam used for solvent regeneration is acceptable, without affecting the characteristics and properties of the solvent itself. However, it is expected that steam supply pressures and temperatures can be appropriately regulated, also when a boiler is operated under sliding pressure conditions.

2.1.2 Partial load operation

Power plant efficiency is reduced in power plants with CCS when operating at partial load, mainly due to the compressor power consumptions and the steam required for the solvent regeneration that is extracted from the steam turbine.

In fact, as explained in Section C, the minimum load for a stable and efficient operation of a compressor is around 70-75%. Below this value, a recirculation of compressed stream is necessary to keep the machine in operation, thus impacting its efficiency. Moreover, the lower the load of the Steam Turbine, the higher the penalty related to the LP steam extraction at constant pressure for solvent regeneration.

As a consequence, it is essential for the economics of the plant to identify those operating conditions, in terms of solvent circulation and lean/rich loading, that correspond to the lowest heat requirement at the regenerator reboiler.

When the boiler is required to operate at partial load, then flue gas mass flow and composition vary with respect to the base load operation. At lower load, the flue gas mass flow decreases and, as a consequence of the increased air ratio in the boiler, CO_2 content decreases while oxygen content increases.
These changes in the flue gas conditions influence the liquid to gas (L/G) ratio in the absorber. In fact, the optimum L to G ratio, corresponding to the minimum heat demand of the reboiler for solvent regeneration, while maintaining a constant CO_2 capture rate, tends to decrease when decreasing unit load. Therefore, when CO_2 capture unit is operating at partial load, lower specific steam consumption is required in the reboiler.

Moreover, the higher oxygen content in the flue gases entering the CO_2 capture section has a negative impact on the amine degradation rate and unit operation. In fact, one of the main concerns with the amine-based solvents is the high-level of corrosion and degradation in the presence of oxygen, as well as of other impurities (e.g. SOx, NO_2, etc). This characteristic leads to the need of addition of inhibitors in the solvent, to counteract the oxygen activity. These inhibitors also protect the equipment against corrosion and allow for use of conventional materials of construction, mostly carbon steel. Therefore, the design of CO_2 capture section and specification of such inhibitors shall be properly made, taking into account the operation at partial load where O_2 content in flue gases increase.

With respect to the plant without CCS, the energy penalty associated with the steam extraction from the steam cycle increases at partial load, mainly due to the increasing of throttling losses in the steam turbine extraction. In fact, in order to have a constant extraction pressure for the LP steam used in the regeneration section, the steam extraction from the turbine shall be properly controlled. It can be done throttling the steam at LP section inlet, with the effect of decoupling LP steam inlet pressure from LP section bowl pressure. The lower the plant load, the heavier the steam throttling for having a constant pressure and the higher the efficiency penalty of the steam turbine. Therefore, the Steam Turbine and in particular the LP module shall be optimized, taking into account this operating mode.

This efficiency penalty is more evident for retrofitted power plants, because constraints on the steam pressure for solvent regeneration have not been considered in the steam turbine design, so heavy throttling is required when plant operates at partial load. However, retrofitting the power cycle of an existing plant with let-down back pressure turbines would lead the steam cycle to achieve performances close to the new-build power cycle with CCS. These subjects have been more deeply investigated in IEA GHG report 2011/02.

Another aspect that partially affects the overall plant efficiency at partial load is the compressor behaviour. Typical efficient turndown of CO_2 compressor with electric drivers, operating at constant discharge pressure, is approximately 70-75% of full load. If throughput is reduced below this limiting load, the CO_2 capture plant can continue operating, but it is associated to an extra power required per unit of CO_2 captured, as the stable operation of the CO_2 compression system requires flow recycle.
No significant issues, with the exception of efficiency penalties, are expected to maintain discharge pressure at part load, as long as recycling CO_2 is used to ensure that compressor throughput remains in the manufacturer’s allowable operating range.

It is to be noted that, in most power plants applications, often multiple train of CO_2 compressions are required. In this case, when the plant operates at partial load, it would be possible to turn off one or more compression trains, so that any remaining operating compressor has a throughput higher than 70-75% of full load.

Although for economical reasons the compressors suppliers are trying to increase as much as possible the maximum size of the single machine, the selection of a 2x50% compression trains configuration may be driven not only by turndown reasons, but also by the maximum size of the compressors available in the market.

Further investigations are required for other potential changes in plant efficiency at variable loads. For example, waste heat rejected in the CO_2 compression process is supposed to be used to provide heat, where possible, within the power cycle. However, as long as CO_2 capture plant load is varied, the potential for heat transfer between the compression section and the steam cycle could also vary, with associated impacts on power plant efficiency.

2.2 Tuning capture level

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems, which generally offers the ability for flexible or on/off operation.

The on/off operation is based on the possibility to totally by-pass the CO_2 capture unit, when required or economically convenient. It allows the plant to have the possibility of saving the energy required for CO_2 capture and compression when it is preferred to increase the plant output in response to the electric grid demand, though releasing CO_2 to atmosphere.

Nevertheless, this operating option requires that the power plant is properly sized to handle the increased steam flow in the low pressure steam turbine module and condenser. Alternatively, if no margins on LP steam section are considered, the boiler operating load has to be reduced in line with the steam cycle capacity constraints, but in this configuration the plant is not exploited at its maximum capacity.

On the other hand, for retrofitted plants, sufficient capacity in critical items like the low pressure (LP) steam turbine and generator is available and increased net power can be produced, when the capture plant is bypassed.

For new plants, designed for CCS, some areas of plant including the low pressure turbine section, condenser and generator will require appropriate design to accommodate the large variation in flows associated with tuning the CO_2 capture rate. Therefore, investors have to decide whether any expected increase in revenues associated with the additional power exported when the CO_2 capture is bypassed is sufficient to justify the related extra capital cost.

As a matter of fact, the relevant profitability of these operating options depends on the selling price of both the electricity and the CO_2. If electricity prices are high and/or CO_2 prices are low, it might be economically attractive to bypass the post-combustion capture unit. When CO_2 prices increase, the breakeven point in terms of electricity selling price required for the plant to switch from CO_2 capture to no capture mode is also increased.

For low CO_2 prices, the plant would not capture the CO_2, regardless of the electricity selling price, unless other constraints (e.g. environmental law) require this operation. Alternatively, the CO_2 capture unit can be kept in warm stand-by, with amine continuously circulating, without feeding steam to the reboiler. In this case, the stresses related to the on/off unit operation are avoided, but some of the O&M costs shall be taken into account. On the other hand, this operating option allows a quicker re-start up of the unit, when the CO_2 capture is required, by feeding the steam to the reboiler.

In addition, it is noted that by turning down or off the post combustion capture unit it is possible to ramp-up the steam turbine more quickly than the ramp rate of a conventional coal fired boiler, which generally limits the capacity of the steam turbine for these plant types. From this point of view, the load-tuning of the capture unit could increase the rate at which the power output is ramped-up, resulting in an operating flexibility of the boiler plants with CCS higher than the plants without CCS.

2.3 Rich-solvent storage

Providing solvent storage tanks for rich solvent from the CO_2 absorber allows continuously capturing the CO_2 from the flue gas flow, delaying most of the energy penalty requirements associated with the CO_2 capture and compression units.

During peak demand periods, when electricity selling prices are high, power plants could operate removing the CO_2 from the flue gas in the absorber column as during base load operation, but with the solvent regeneration and CO_2 compression processes halted.

In this way, the rich solvent containing CO_2 leaves the absorber column and is temporarily stored in solvent storage tanks, avoiding the majority of the energy penalty for the amine capture process, which is related to the steam extracted from the steam cycle and to the CO_2 compression. Typically, when lower electricity selling prices reduce the revenues of the plant output, the rich stored solvent can be regenerated.

To allow the delayed regeneration, while maintaining the power plant in operation at full load, over-sizing of the regenerator section of the CO_2 capture plant, i.e. stripper and reboiler, and of the compression train is required, implying an additional investment cost.

If no over-sizing were provided, when the stored solvent has to be regenerated, the power plant should be in operation at partial load, while the compression train and the reboiler are in operation at base load. The selection of this solution shall be based on careful market evaluation, to assess if expected cycling operation of the plant is in line with such behaviour of the capture plant.

Accordingly to the information provided by the main technology Licensors, the dynamic modelling of the post combustion capture unit has been performed, even if not to deeply investigate the decoupled operation of the regenerator and absorber sections. However, no particular critical aspects are foreseen by main technology Licensor to operate independently both the absorber and the regenerator between their minimum and maximum load.

Available information on chemical stability of solvent for CO_2 capture highlights that degradation of amine solution increases when increasing temperature and CO_2 loading. As a consequence, rich solvent degradation is possible, when stored, so further investigation with referenced Licensors of this technology is recommended.

3 Pre-combustion capture

Pre-combustion capture process is the typical technology considered for the application in IGCC power plants.

The addition of the CO_2 capture in IGCC plants affects its design only marginally. With reference to the syngas treatment and conditioning line, a complete new section is required to make the CO shift reaction and increase the CO_2 and hydrogen content of the fuel, which is sent to the AGR after cooling.

With respect to the traditional AGR configuration for the removal of H_2S only, the addition of CO_2 capture has the following main impacts on the unit design:

- ✓ Addition of one or multiple CO_2 absorber columns, supported by different ancillary equipments like solvent circulation pump, solvent chiller, flashing system etc.
- ✓ Increase of electrical consumption (of about 7-8 times), due to the higher solvent circulation rate for the CO_2 absorption and to the required higher refrigeration duty;
- ✓ Reduction of the heat input (about 25-35%) in to the solvent regeneration section;
- ✓ Improvement of performance in terms of H_2S removal: H_2S present in the feed gas is almost totally removed.

Finally, the CO_2 compression section shall be added downstream the AGR unit.

Gasifiers and IGCC have very different operating characteristics with respect to pulverised coal-fired boilers and natural gas combined cycle power plants, as well as very different behaviours versus the variable electricity demand. As in the case without CO_2 capture, a large flexible operation of IGCC plants with CCS is not achievable.

3.1 Impact of pre-combustion capture on power plant capabilities

3.1.1 Start-up and cycling capability

As described in section C, the IGCC in its base configuration is not generally suitable for a flexible operation and the plant is typically designed for operation at base load, due to the significant inertia related to the syngas generation sections (Gasification, ASU and syngas treatment).

It is expected that the modifications described in the AGR unit do not impact on the overall plant operation in terms of flexibility. The ramp rates and start-up times of AGR, in fact, are not affected by the equipment added for the CO_2 capture, as the new column and the flash separators do not add particular constraints.

As per the AGR unit, also the CO_2 compression does not introduce specific constraints on plant flexibility, both during start-up and during normal operation, because the inertia of the gasification, ASU and process units are significantly higher than the CO_2 compression.

In order to increase the plant flexibility, some modifications similar to those described for the plant without CO_2 capture can be introduced with a significant impact on the overall investment cost of the plant.

For example, storage options could provide opportunities for flexible operation of IGCC plants. Liquid oxygen or nitrogen storage might be useful to decouple ASU from the rest of the plant. Moreover, interim storages of raw or decarbonised syngas (or hydrogen) can allow the gasifier to run at constant load while the combined cycle provides flexibility.

Also, to improve IGCC flexibility and cycling capabilities, the possibility to co-produce different products can be considered. In fact, in the IGCC with CO_2 capture syngas is converted mainly into hydrogen by means of shift reaction of CO and water into hydrogen and CO_2 and subsequent CO_2 removal. These intermediate products, such as hydrogen rich gas or shifted syngas, can be used, instead of being fed to the gas turbine for electricity generation, for the production of chemicals or carbon based fuels. In this case, the overall flexibility of the plant may increase as there is the possibility to switch from one product to another, depending on the market demand fluctuations.

In IGCC with CO_2 capture, the possibility to couple the electricity generation plant with chemical plants is higher than plants without CO_2 capture, due to the presence of such intermediate products that are suitable for the production of a wide range of chemicals.
It has to be noted that, depending on the intermediate product and its final use, the overall CO_2 capture rate can vary significantly.

3.2 Hydrogen co-production and storage

IGCC can be designed to co-produce electricity and hydrogen in order to provide a greater operating flexibility with respect to the conventional IGCC.

IGCC scheme remains practically unchanged up to the AGR section. Syngas at AGR outlet, with a hydrogen molar content of approximately 85% is then split into two streams: one is sent to the gas turbine for electricity generation in a combined cycle, while the other is fed to the hydrogen production unit.

The hydrogen production line is capable of operating as much as possible independently from the power line, allowing the gasification, syngas treatment, CO_2 capture, transport and storage equipment to operate at base load, while the power plant operates flexibly in response to the electricity demand.

This can be made possible by storing either the decarbonised hydrogen-rich gas or high purity hydrogen.

In the first alternative, part of the hydrogen rich gas from the CO_2 removal is fed to the storage during low electricity demand periods (nightly hours and weekends), and is subsequently used during electricity peak demand.

In the other alternative, the hydrogen-rich gas is fed to an additional pressure swing adsorption (PSA) unit to produce high purity hydrogen and a tail gas stream consisting of hydrogen and impurities in the de-carbonised fuel. Hydrogen can be sold or stored during low electricity demand periods and fed to the gas turbine during peak load operation. Main constraints for this alternative are related to the capability of the gas turbine to vary the hydrogen load and the local availability of geological structures suitable for hydrogen storage.

The main options for storing hydrogen are as a compressed gas (above ground or underground), as a liquid or in metal hydrides. Generally for these specific applications, underground storage is the best solution in relation to the very large volumes of hydrogen to be stored for long periods.
In fact, aboveground compressed gas storage and the metal hydride option are not suitable to large quantities of hydrogen, due to very high costs, while liquid hydrogen has specific applications related to high storage energy density, but requires very expensive cryogenic facilities.

3.3 AGR (CO_2 capture) shutdown

Unlike in the post combustion CO_2 capture processes, the Acid Gas Removal Unit cannot be shut down completely, as it is needed at least to remove the H_2S from the syngas stream, before being fed to the Gas Turbine, to meet the environmental limits. On the other hand, if necessary it could be possible to avoid the separation of the CO_2 from the syngas, by properly designing the AGR in order to have the possibility to by-pass the CO_2 absorption column only.

A net power plant power production increase of 10-15% is expected in case CO_2 is not captured and compressed.
In fact, as no CO_2 is separated, the CO_2 compressor is shutdown avoiding significant power consumption. In addition, part of the CO_2 that has not been captured from the syngas, may act as diluent in the gas turbine for the control of NOx production and therefore nitrogen diluent would not be (partially or totally) required for the Gas Turbine, leading to a power saving because of the nitrogen compressor shutdown or operation at low load.

On the other hand, the CO_2 would be released to atmosphere from the combined cycle stack, similarly to an IGCC without CO_2 capture. Therefore, this solution could be followed if the cost of emitted CO_2 were fluctuating around low figures as in the present market conditions, as it may be economically convenient release the CO_2 rather than limit the plant flexibility in electricity generation.

4 Oxy-fuel combustion technology

Oxygen fired process is based on the combustion of pulverized coal (or other primary fossil fuels) using as oxidizing medium a mixture of oxygen and recycled CO_2 rich flue gas, instead of air.

As no nitrogen is fed to the furnace, the flue gases consist mainly of CO_2 (70-80%wt), water (10-15%wt) and inerts. After cooling, for removing the moisture condensate, approximately 65% to 70% of flue gas is recycled and mixed with oxygen to form a primary and secondary flue gas recycle stream that support coal combustion in the boiler.
The balance of the total exhaust gas from the boiler is fed to a CO_2 purification and compression unit, where the water and inerts are removed. Then, purified CO_2 can be sent to storage.

Design features, and consequently flexibility, of the oxy-combustion plants are in line with those of conventional air-fired boiler plants, as described in the previous section.

The capability of this technology to operate flexible is mainly affected by constraints on the Air Separation Unit and the CO_2 purification and compression plant, as far as minimum turndown, start-up time and ramp rates are concerned.

As for the IGCC and the conventional PC boiler power plants with amine-based CO_2 capture, the possibility of varying the power production in response to the changes in the electrical grid demand, tuning the internal power consumption, is investigated in the next sections.

4.1 Flexibility feature

4.1.1 Start-up sequence

One of the main features of the oxy-fuel power plants is that start-up and shutdown is made in air firing combustion mode. This allows to make the start-up of the boiler in air mode, while cooling down the Air Separation Unit.

The maximum load level that can be achieved with air firing is dependent on the load which the burners accept. In fact, in order to minimise uncontrolled emissions from the plant during switch over to oxy-fuel, it is advisable to operate at the lowest possible load, which generally is about 30%.

In the air-firing phase, the boiler load is increased to the minimum stable load using a back-up fuel (typically fuel-oil). At the same time, the steam turbine is heated, accelerated, synchronized and ramped up to minimum load. Boiler exhaust gases are sent to the stack, without being treated in the CO_2 processing unit.

When both the boiler and the steam turbine are in operation at minimum stable load and oxygen from the air separation unit is generated at the required purity, the combustion mode is changed from air to oxygen and simultaneously the flue gas recirculation is started.

While increasing the plant load, also the switch over from back-up fuel to coal (or other primary fuels) is carried out. At the same time, CO_2 compression unit is started-up. When plant load is increased to an acceptable value for the compressors, flue gas is fed to the CO_2 purification and compression section.

4.1.2 Start-up time

Typical start-up time for the Air Separation Unit necessary to reach the required oxygen purity, in this case 95%, are summarised in the following Table 4-1.

Table 4-1. Start-up times for ASU in oxy-fuel plant

Initial condition	Start-up time
After defrost	36 hours
After 24 hours shutdown	6 – 8 hours
After 16 hours shutdown	4 – 6 hours
After 8 hours shutdown	3 – 5 hours
Less that 1 hour shutdown	Less than 1 hour

It has to be noted that, as the burners in the furnace are able to operate also under air-firing, hence with an oxygen purity of approximately 23%wt., it is possible during the transient to supply oxidizing agent to the boiler system, even with oxygen content lower than the design specification of 95%. This can be achieved by properly adjusting the recycle ratio in order to provide the correct temperature control and oxygen excess into the boiler. The only detrimental effect will be a reduction of plant capture performance and therefore on the amount of CO_2 that can be captured, due to the inert content increase into the gases fed to the CO_2 purification system.

It is noted out that the total time required to start-up the oxy-fuel power plant and change from air firing to oxy firing is not yet shown in literature data.

4.1.3 Ramp rates

Main limitation in cycling operation of the oxy-fuel combustion plant is given by the Air Separation Unit ramp rate.
The maximum ramp rate for an ASU is typically 3% per min, while for the boiler it is generally 6% per min. Therefore, a plant ramp rate in line with the boiler capacity can be achieved by using a dedicated and properly designed oxygen storage.

4.1.4 Turndown

Air Separation Unit turndown depends mainly on Main Air Compressor (MAC). These compressors operate efficiently in the range 70-100% of maximum flow. The cryogenic air distillation equipment is able to turn down at lower load, maintaining a constant oxygen recovery. This characteristic gives flexibility to operate efficiently in the range 70% to 100% with a single train configuration. Considering multiple train configuration, efficient operation is possible even at lower load.

If it is required to run below 70%, this has an impact on the machine's efficiency, as the following operational modes could be required:

- Recycling a portion of the compressed air back to the inlet of the main air compressor;
- Venting a portion of the produced oxygen;
- Producing a certain quantity of liquid oxygen for backup storage, if foreseen.

CO_2 compressor systems are capable of efficiently turning down to about 70% of full flow at constant discharge pressure. Operation at lower load can be achieved using a multiple train configuration or recycling part of the CO_2.

4.2 Tuning power consumptions

As for conventional PC boiler plant with post-combustion capture, reducing the internal power consumption, when electricity prices are high, allows to follow the seasonal or daily market trend and participate in ancillary services markets, therefore increasing the remunerability of the plant.

In oxy-fuel power plants, the power consumption related to the CO_2 purification (including compression) and to the cryogenic separation of oxygen in ASU is significant.

Therefore, to reduce energy penalty, a possibility is to change the boiler operation from oxy fired to a traditional air fired, when electricity demand rises. This approach can be followed depending on the variability of CO_2 emissions cost: until the cost of emitted CO_2 remains low, as in the present market conditions, it could be economically convenient to release the CO_2, rather than limit the plant flexibility.

Currently, the oxy-fuel power plants are designed to allow flexible operation both in air and oxy-modes.

The main parameter influencing the boiler capability for a flexible and efficient operation in both firing modes is the flue gas recirculation flowrate, as some boiler design features, like furnace surfaces and boiler cross-sectional area, and operating parameters, like the combustion temperature, depend on the amount of flue gases in furnace.

Operation with high flue gas recirculation and an oxygen concentration around 30% leads to a flue gas amount in the combustion chamber that replaces the combustion air in the conventional boiler.

The flue gas treatment system downstream the boiler has to be sized for the proper flue gas flowrate, to achieve full capacity operation in both firing modes.

Also, providing liquid oxygen storage would temporarily avoid the operation of the ASU, increasing the electricity exported to the grid with the plant still operating at full load. In fact, by over-sizing the ASU, it is possible to produce extra O_2 during periods of low electricity requirements from the market, providing storage of liquid product, while increasing the auxiliary consumptions. When the market requires a higher electricity generation, the ASU can be operated at partial load, while the rest of the plant is running at full load. This reduces the auxiliary consumptions, increasing the net electricity exported to the grid.

The increase of investment cost is related to the extra-capacity required for the ASU and oxygen storage facilities.

On the other hand, the alternative of storing the CO_2 rich stream (upstream CO_2 purification) for avoiding the energy penalty associated to the CO_2 compression, without increasing CO_2 emissions from the plant, is more difficult and it has not been evaluated yet.

5 Summary of flexibility characteristics of the basic plants

The overleaf table summarizes the expected flexibility characteristics of the basic plants with and without CCS, excluding solvent and oxygen storage, CO_2 venting and other forms of energy storage, as assessed in the next sections of the report.

Flexibility features summary table

	Turndown	Cycling capability: Start-up to full load	Cycling capability: Ramp rates	Part load efficiency
NGCC	Low Load Operation: 15-25% CC load (10-20% GT load) Minimum Environmental Load: 40-50% CC NPO (30-40% GT load)	Hot start-up: 45-55 min Warm start-up: 120 min Cold start-up: 180 min	**35 - 50 MW/minute max** **Hot start-up load change rate:** - 0-40% GT load: 3-5%/min - HRSG pressurisation: 1-2%/min - 40-85% GT load: 4-6%/min - 85-100% GT load: 2-3%/min	Approx. constant efficiency up to 85% GT load 2-3 percentage points less @ 60% CC load
with CCS	Post combustion unit minimum load: 30% CO_2 compressor minimum efficient load: 70%	Regenerator preheating: - hot start-up: 1-2 h - warm start-up: 3-4 h	Same as plant w/o CCS	Same as plant w/o CCS
IGCC	Minimum Environmental GT Load: 60% PO Process unit minimum load: 50% ASU cold box minimum load: 50% ASU compressor minimum efficient load: 70%	Cold start-up: 80-90 h Gasification hot start-up: 6-8 h ASU hot start-up: 6 h	Gasification ramp rate: 3-5%/min ASU ramp rate: 3%/min	Gross electrical efficiency: 2 percentage points less @ 70% CC load
with CCS	CO_2 compressor minimum efficient load: 70%	Same as plant w/o CCS	Same as plant w/o CCS	Same as plant w/o CCS
USC PC	Minimum boiler load: 25-30%	Very hot start-up: < 1h Hot start-up: 1.5-2.5 h Warm start-up: 3-5 h Cold start-up: 6-7 h	30-50% load: 2-3%/min 50-90% load: 4-8%/min 90-100% load: 3-5%/min	Subcritical boiler: 4 percentage point less @ 75% load Supercritical boiler: 2 percentage point less @ 75% load
with CCS	Post combustion unit minimum load: 30% CO_2 compressor minimum efficient load: 70%	Regenerator preheating: - hot start-up: 1-2 h - warm start-up: 3-4 h	Same as plant w/o CCS	Same as plant w/o CCS
Oxy combustion				
Air-firing mode	Minimum boiler load: 25-30%	Very hot start-up: < 1h Hot start-up: 1.5-2.5 h Warm start-up: 3-5 h Cold start-up: 6-7 h	30-50% load: 2-3%/min 50-90% load: 4-8%/min 90-100% load: 3-5%/min	Subcritical boiler: 4 percentage point less @ 75% load Supercritical boiler: 2 percentage point less @ 75% load
Oxy-firing mode	ASU cold box minimum load: 40-50% ASU compressor minimum efficient load: 70% CO_2 compressor minimum efficient load: 70%	Start-up in air-firing mode, ASU start-up completed in approx. 36 h	ASU ramp rate: 3%/min	Same as plant in air-firing mode

6 CO_2 transport

The safe CO_2 transport requires maintaining the CO_2 in a stable phase, selected depending on boundary conditions and transport and storage section optimisation design, avoiding risks associated with the change in CO_2 phase, because of temperature and pressure variations.

Flexible operation of the upstream units, frequent start-up or shutdown and load changes lead to fluctuation of the captured CO_2 flowrate. This shall be taken into account in the design of the pipeline, in order to avoid change of the CO_2 physical state.

6.1 Flexible operation

During shutdown of a CO_2 capture plant, the pressure in the pipeline tends to drop, while approaching the external conditions.

In this case, a two-phase flow or a significant change of the physical properties could occur in the pipeline during shutdown or cycling mode operation of the capture plant, unless the pipeline is properly designed to maintain the pressure above the critical conditions of the CO_2. For this reason, the pipeline shall be adequately designed with proper heat insulation and TSO valves.

6.2 CO_2 pipeline start-up

Start-up process of the CO_2 pipeline consists in filling and pressurisation of the entire pipeline volume. The entire process can take several days to be completed, depending on the starting pressure and density condition.

During the start-up process, the CO_2 physical state changes from gas phase to the final liquid or supercritical phase, depending on the design conditions selected. Filling and pressurisation process is slow when the CO_2 is in gas and two-phase condition, while becomes much quicker when the pipe fluid is entirely in the dense liquid phase.

As CO_2 pipeline start-up may have a significant duration, plant shall be started-up independently and CO_2 shall be fed into the pipeline progressively, achieving its pressurisation while keeping closed the connection to the storage. Once the line pressure is at the required values, the downstream block valve can be open and CO_2 flow to storage.

7 CO_2 storage

In the public domain, there are only few information available on the effect of varying the CO_2 injection rate in underground reservoirs, because of the flexible operation of the power plants.

Nowadays, this subject is becoming more and more important because underground storage may be used as an intermediate storage that smoothes the variability of the CO_2 flowrate from the power plant, while delivering a constant CO_2 stream to end-users, like depleted oil fields (for EOR) or other industrial processes.

In general, it can be stated that the implications of varying injection rates are site-specific, as they depend on the type of storage formation (saline aquifers, depleted oil and gas fields, salt caverns), the reservoir and seal characteristics (dimension, shape, porosity, permeability, salinity, etc.).

To investigate the effects of variable CO_2 supply, storage modelling would be required to simulate the variable injection of CO_2 in a reservoir, because no specific flexibility has been required to the existing storage applications.

Evaluations have been made on the CO_2 migration in the reservoir and the pressure built-up as a function of the distance from the injection wells. Preliminary results show that the extent of CO_2 migration in the reservoir is not dependent on the injection rate variability or the extent of confinement of the storage reservoir.

Near the injection well, pressure build-up increases with time, steadily in the case of constant injection, but periodically in case of variable injection, as the pressure buildup in the reservoir increases with the amount of CO_2 injected, and the trend of reservoir pressure variation is directly proportional to that of the CO_2 injection rate.
It has to be noted that for cases of variable injection near the injection well, the pressure variation cycles amplitude decrease as injection proceeds with time. This is related to the compressibility of CO_2, which causes the system to be more flexible as more CO_2 is injected with time. However, it is possible to maintain both pressure and temperature within certain limits if the mass flow is reduced by closing off some of the well injectors.

In addition, the periodic variations of reservoir pressure due to periodic variations of CO_2 injection rate fades away as the distance from the injection well increases, increasing steadily with time with the amount of stored CO_2.

However, further investigations are required to assess in detail the storage ‘flexible’ operation. In particular, the effects of the injection rate variation on how the gas occupy the pore space and consequently on the reservoir capacity, injection and withdrawal maximum rate.

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9 Attachments

Attachment D.1 – Underground hydrogen storage

Attachment D.2 – CO_2-rich solvent storage

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
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INDEX

1 Introduction

Scope of this attachment is to make a high-level techno-economic review of the published information on the underground large-scale hydrogen storage facilities. Main technical characteristics of different type of underground storage reservoirs have been investigated, focusing on various topics like storage capacity, gas containment, operating pressures and possible constraints on gas delivery and injection rates. Specific investment and operating costs ranges are also provided.

The review is based on data available in the public domain, because main operators of hydrogen storage facilities have decided of not supporting this study, in order not to disclose business confidential information.

2 Underground hydrogen storage

Natural gas bas been stored underground since 1916 and much of the experience is directly applicable to hydrogen. Nowadays, there are already twenty-three salt caverns being used for natural gas or hydrogen storage in the UK. In France there are at least fifteen underground storage sites for natural gas, either in salt caverns or in aquifers, for a total available capacity of 110 TWh, i.e. about 30% of their current annual demand.

Over the last decades there have been several examples of underground storage of pure hydrogen or syngas:

- England, Teesside, Yorkshire: the British company ICI has stored 1 million Nm^3 of nearly pure hydrogen in three salt caverns at a depth of about 400 m. The caverns have operated successfully for many years, and they are now operated by SABIC.
- France, Beynes, Ile de France: the gas company Gaz de France has stored a gas with 50-60% hydrogen in an aquifer of 330 million Nm^3 capacity for nearly 20 years. No gas losses or safety problems have been recorded.
- Russia: pure hydrogen was stored underground at 90 bars for the needs of the aerospace industry.
- Germany: 62% H_2 gas was stored in a salt cavern of 32,000 m^3 at 80-100 bar.
- Czechoslovakia: 50% H_2 syngas was stored in an aquifer.

Furthermore, Praxair is constructing a large underground hydrogen storage facility to enable "peak shaving" of its hydrogen production. This facility, located in Texas, will utilize a salt cavern and will be the first of its kind in the industrial gases industry. Connected to the Praxair’s hydrogen pipeline network, which serves large consumers in Texas and Louisiana, it will significantly increase the availability of hydrogen during periods of peak demand.

As a matter of fact, the main current operators of large hydrogen storage systems are actually Praxair and SABIC.

3 Underground storage options

Facilities for the underground storage of gases fall into two main categories:

- *Porous media storage*, either in partially depleted oil or gas fields or aquifers, in which the gas occupies the naturally occurring pore space between mineral grains or crystals in sandstones or porous carbonates;
- *Cavern storage*, in which the gas is contained in excavated or solution-mined cavities in dense rock.

Both the storage categories have to satisfy two main requirements: providing sufficient storage capacity and containment of the stored gas.
In porous media storage, these requirements are met by a porous reservoir rock and an overlying confining enclosure, whereas in cavern storage, capacity is achieved from the chamber volume with containment provided by the impermeable host rock surrounding the cavern.
Several factors may influence the capacity and containment capability for a given storage mode, in particular storage pressure. As most host rock lithologies are not absolutely impermeable, the lower limiting pressure for some forms of underground storage is related to the hydrostatic pressure gradient, while the upper limiting pressure is related to the ultimate overburden pressure gradient. The overburden pressure is the load of the rock column and, when approached, may result in hydraulic fracturing, or lifting, of the overburden.

Most existing underground storage facilities for natural gas have maximum operating pressures in the range of 70 to 170 bar, although there are facilities operating at both extremes, from a low pressure of 10 bar to a maximum of more than 270 bar.

As the storage pressure increases, a lower volume capacity is required for a given quantity of stored gas. On the other hand, a number of factors limit the maximum depth and pressure desirable for underground storage, including the costs of drilling wells or sinking shafts, the cost of compression, and the geothermal gradient, because high storage temperatures partially offset the volumetric efficiency gained by greater pressure. Except in the case of depleted fields, the higher cost of exploration at greater depth also is a limiting factor, whereas the depth of storage caverns in salt is limited by the rheological properties of salt.

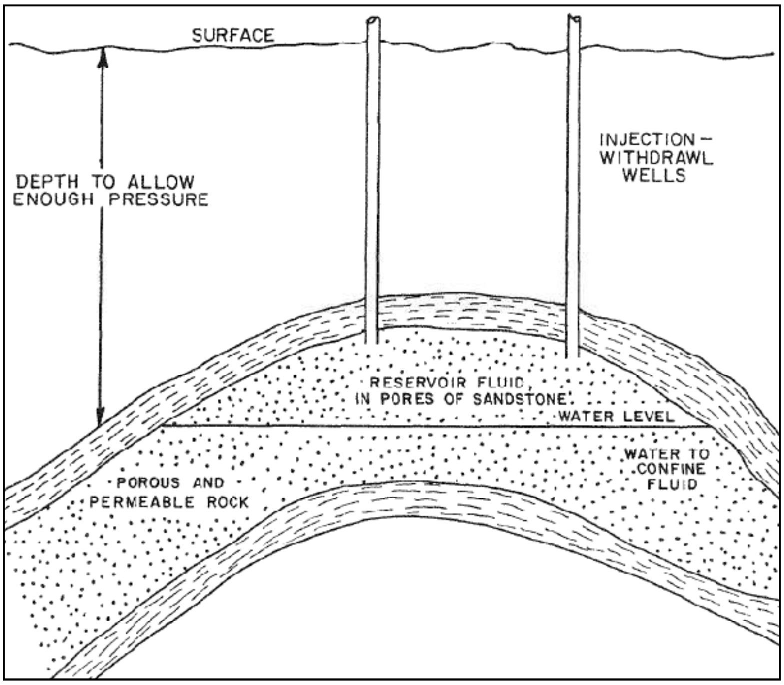
Depending on the mechanism adopted for withdrawing the gas from the reservoir, the storage can be at constant or variable pressure.
If water entries in the previously gas-filled portion of the reservoir, the reservoir operates at essentially constant pressure. If volumetric expansion occurs during the withdrawal cycle, the reservoir pressure drops down.

3.1 Porous media storage

An underground storage in porous-media requires the following features, as shown in Figure 3.1-1:

- A stratum of porous rock, usually sand or sandstone, at 150-900 m below the surface, sufficiently porous to provide a reasonable storage volume and sufficiently permeable to provide an adequate injection and withdrawal rate;
- A caprock of adequate thickness, overlying the reservoir;
- A suitable dome-shaped geological structure such as the anticline, that provides structural closure to limit lateral and vertical upward movement of the gas, together with an underlying gas/water contact, that prevents downward movement of the gas.

Figure 3.1-1: Elements of porous media underground storage



During operation, a minimum base gas or 'cushion gas' has to be maintained in the reservoir. The cushion gas is a volume of gas that remains as permanent inventory in the storage reservoir to maintain adequate pressure and deliverability rates.
In the case of hydrogen storage, a cushion gas of different nature, such as natural gas, can be used to displace a hydrogen-rich gas, but only if gas stratification can be maintained between cushion gas and hydrogen, by avoiding inter-diffusion or "fingering". Nevertheless, this would also require an efficient gas separator (membrane or PSA) in the gas station at ground level.
Whether this mixing should be encouraged or discouraged depends also on the use of the stored gas. If hydrogen will be used as a chemical feedstock, then high purity is required, thus limiting the amount of mixing that can be tolerated.

3.1.1 Depleted natural gas or oil field storage

The oldest, most widespread and most economical mode of underground gas storage is the re-injection of gas into existing fields, partially depleted by prior production. For natural gas storage, the use of such fields is advantageous, because it virtually eliminates exploratory cost and risk and because these fields normally contain sufficient residual gas to fulfil all or part of the base gas requirement.
Conversion to storage may require only the reworking of wells and the installation of compressor facilities. In the case of hydrogen storage, the presence of residual natural gas may be more of a problem than a benefit, because until it is fully displaced, mixing of the natural gas and hydrogen results in the production of gas characterised by a widely varying heating values.

3.1.2 Aquifer storage

In case no suitable depleted field is located near the market area or the pipelines facilities, it has been possible to develop similar fields, converting natural aquifer to gas storage reservoirs, by injecting gas to displace water from a portion of the aquifer.

A natural aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance.
The base gas may represent from one-third to two-thirds of the total field capacity.
Deliverability rates may be enhanced by the presence of an active water drive.

3.2 Cavern storage

Unlike depleted field and aquifer storage systems, cavern storage involves large open, void spaces to be filled with gas.
Underground manmade caverns are mined with access to the surface with wells. The most common type of cavern is the solution-mined cavern in salt domes, often found in form of layers that can be hundreds of meters thick. Alternatively caverns can be drilled in hard-rocks. Furthermore, efforts have been made to use abandoned mines to store compressed gas.

One important advantage of the cavern storage is that it is geologically feasible in many areas where porous-media storage is not. An additional advantage is that there is no limitation on gas deliverability, with respect to the porous-media storage where withdrawal rates are limited by the permeability of the reservoir formation and the number of wells available. Finally, cushion gas requirements are relatively low.
On the other hand, a more complex structural analysis is therefore required to establish feasibility. For example, if the pressure in the cavity is allowed to drop significantly below ambient pressure, a collapsing stress situation is created, which might result in loss of structural integrity of the storage volume. The cavern pressure has to be maintained above a safety limit, providing a proper amount of cushion gas or replacing the drawn off gases with water.

Two approaches can be followed to design a gas storage cavern: constant-pressure and variable-pressure design.

Constant-pressure or pressure-compensated design requires to keep the cavern partially filled with water, providing a connection with a surface water or brine pond, as shown in Figure 3.2-1. The pressure is kept constant by the hydraulic head of water that connects the water in the cavern to a reservoir at the surface, while the working volumes changes. During withdrawal periods, water is allowed to enter the chamber and displace the stored gas. The water level is lowered in the cavern during gas injection, as water is returned to the surface pond through the shaft that connects the cavern with the reservoir.

Reservoirs for compensated cavern storage do not always require surface ponds and can be designed as an underground chamber above the storage cavern, as shown in Figure 3.2-2. This water-compensating pressure system of cavern storage operates with a minimal volume of base gas, as the water maintained the pressure in the cavern providing the driving force to displace the gas during withdrawal operation.

Figure 3.2-1: Pressure-compensate storage caverns

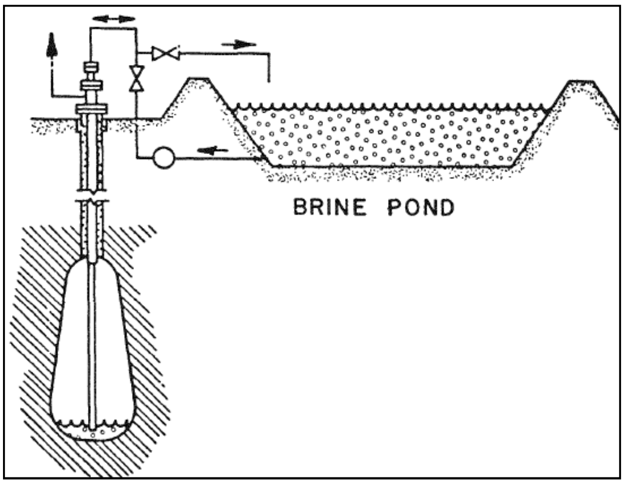
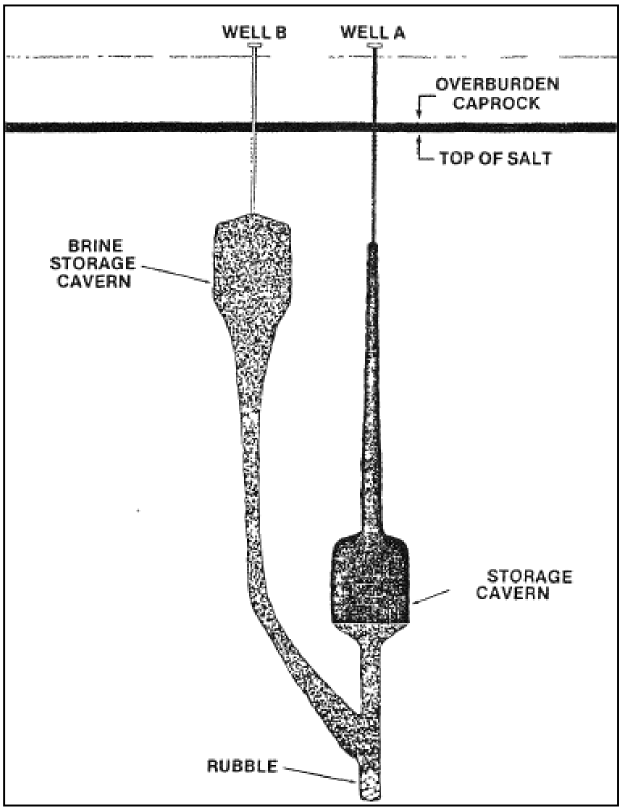
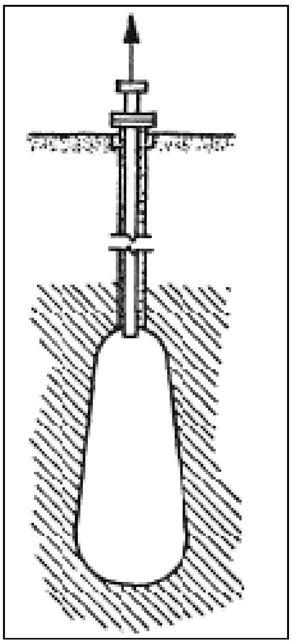


Figure 3.2-2: Pressure-compensate storage caverns with underground brine reservoir



The variable-pressure cavern shown in Figure 3.2-3 is a closed system in which the storage pressure is determined by the amount of gas stored in the cavern. Pressure fluctuates as the gas inventory changes. Maximum storage pressure is established by hydrostatic pressure. Minimum storage pressure can be determined by pipeline or compressor input pressures.

Figure 3.2-3: Variable-pressure storage caverns



3.2.1 Solution-mined salt caverns

Mines-solution cavern in salt domes is the most common type of manmade cavern storage. The cavern is created dissolving the salt layer with fresh water and removing the brine via a single well, which is used both for gas injection and withdrawal.

Salt caverns can be both vertically mined or horizontally mined, depending of the salt layer thickness. If the salt layer is between 60 to 100 metres thick, a horizontal drilling with solution mining techniques is preferred for storing the required volume of hydrogen, with respect to a collection of smaller and inter-connected vertical solution-mined caverns.

Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity. Base gas requirements are relatively low and can be totally recovered with brine injection.

4 Underground hydrogen storage cost

Underground storage is the most inexpensive mean of storing large quantities of gaseous hydrogen. In fact, underground hydrogen gas storage is estimated about two orders of magnitude cheaper than tank storage considering the cost per Nm^3 of stored hydrogen.

Capital costs vary depending on whether there is a suitable natural cavern or rock formation, or whether a cavern must be mined. Using abandoned natural gas wells is the cheapest alternative, followed by solution salt mining and hard rock mining. Prices are set from 5 $/kg to 40 $/kg (2007 year basis, IEA GHG Report 2007-13).

One additional expense for underground storage is the value of the cushion gas that remains when the storage system is at the end of its discharge cycle. As hydrogen is relatively expensive commodity, the cost of the cushion gas is a very significant part of the capital charges for such large storage reservoirs. However, as the cavern has a cycling operation, the initial cushion gas cost is amortized.

The operating costs for underground storage are limited to the energy and maintenance costs related to compressing the gas into underground storage and possibly boosting the pressure coming back out.

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FOSTER WHEELER

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME	:	CO_2-RICH SOLVENT STORAGE
FWI CONTRACT	:	1-BD-0530 A

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INDEX

1 Introduction

Scope of this attachment is to provide some preliminary information on the possibility of storing CO_2-rich solvent for later regeneration in post combustion capture plants.

The following main aspects have been evaluated, based on the information provided by leading Licensors of post combustion solvent-washing processes:

- Feasibility of storing CO_2 rich solvent;
- Storage operating conditions to avoid degradation rate;
- Maximum storage time to avoid solvent degradation;
- Safety and potential risks of such a storage.

FW like to acknowledge the following leading post combustion capture technology Licensors, listed in alphabetical order, for the useful information provided on the above topics:

- Aker Clean Carbon;
- Alstom;
- Mitsubishi Heavy Industries (MHI);

It has also to be mentioned that MHI owns a patent in the European Unit, USA and Japan (EP 0537593B1), which is dedicated to the storing of solvent and regeneration during high power demand.

2 CO_2-rich solvent storage

Storing CO_2 rich solvent should not provide too many technical challenges. The main concern is related to the large solvent storage volumes required, that would lead to a significant investment cost and large area dedicated to the storage tanks.
In fact, storage capacities and sizes represent the main limiting factors to the delayed regeneration, strongly affecting the minimum load of the regenerator during high electricity demand.

The storage operating conditions shall be selected in order to maintain the CO_2 loading of the rich solvent, without releasing gaseous CO_2 in the tank, and to avoid solvent degradation rate.

The solvent shall be generally stored at ambient temperature condition, up to a temperature slightly below the solvent outlet temperature from the absorber (40°C). Higher temperature should be avoided as may lead to release of the dissolved CO_2.

On the other hand, an excessive cooling of the solvent should not be allowed, as some solvents will become very viscous and even precipitate solids at low temperatures. In addition, this may increase the heat required to regenerate the solvent, affecting plant performance.
The same temperature conditions are recommended also for the lean and semi-lean solvent storage tanks.

High rates of solvent degradation in the storage tank are not expected at this temperature condition. As solvent degradation is mainly related to possible reaction with oxygen, the storage tanks should be blanketed with nitrogen/CO_2 to minimize air exposure. Floating roof storage tanks can be a suitable solution for this application. If the tank is maintained oxygen-free, no limitation is expected to the storage time.
It has to be noted that solvent degradation could be a critical aspect only for amine-based solvent, while no degradation is possible for ammonia-based solvent. To deal with this aspect, most technology Licensors use specific chemical agents as additives for the amine-based solvents.

Storing the solvent in these conditions, minimise the potential safety risks associated with the CO_2-rich solvent storage. In fact, at normal low operating temperature the vapour pressures of rich amines are low. Maintaining the rich solvent slightly below absorber bottom outlet temperature condition, the degassing of the CO_2 and consequent possible over-pressurisation of the storage tank are avoided. However, the tank vent stream should be fed back to the absorber.

Potential corrosion due to the CO_2 presence in vapour phase should be considered in the selection of the tank construction materials.
The use of stainless steel would result in an excessive cost for the tank, due to its dimensions. Alternatively, tanks can be made of concrete or carbon steel with a suitable internal coating to prevent corrosion.

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SECTION E

INDEX

1 Introduction

Scope of this Section E is to summarize the main technical information of reference cases of leading CO_2 capture processes, which will then be used to make an outline assessment of their operating flexibility.

Most of the information included in this section is derived from the IEA GHG report "Water usage and loss Analysis in Power plants without and with CO_2 capture", completed by Foster Wheeler in year 2010, which already identified reference plants for leading technologies. Remaining information, relevant to the post-combustion capture process from natural gas-fuelled combined cycles, are partially taken from FW in-house information and partially from the IEA Report PH4/33, Nov 2004, Improvement in Power generation with post Combustion capture of CO_2.

For each CO_2 capture process, the main technical and economical information like process description, utility consumption and performance data, investment and operating costs are collected in dedicated sub-sections, as listed below:

- **Section E.1**: Natural Gas Combined Cycle (NGCC) power plant, with post-combustion capture of the carbon dioxide.
- **Section E.2**: Integrated Gasification Combined Cycle (IGCC) power plant, fed with bituminous coal with pre-combustion capture of the produced carbon dioxide.
- **Section E.3**: Ultra Super Critical Pulverised Coal (USC-PC) power plant, fed with bituminous coal and with post-combustion capture of the produced carbon dioxide.
- **Section E.4**: USC-PC oxy-fuel plant, fed with bituminous coal and with cryogenic purification of the flue gases for carbon dioxide removal.

For the combined cycle alternatives, the design capacity of the plant is fixed to match the appetite (thermal requirement) of two F-class gas turbines.
For the boiler-based alternatives (USC PC and Oxy-combustion plant), the reference case design capacity is selected by referring to a boiler size that could be currently engineered and built, corresponding to approximately 750-1000 MWe gross power production.
The economic data of each case have been derived from the data contained in the reference studies, by currency adjustment and cost level escalation (further details are shown in Section B).

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SECTION E.1

INDEX

1 Introduction

The present case 1 refers to a combined cycle power plant, based on two natural gas fired gas turbine, with post-combustion CO_2 capture unit.

The IEA GHG study 'Improvement in power generation with post combustion capture of CO_2" has been taken as a reference for the configuration and performances of the CO_2 capture and compression units below described. In particular, units description, process schemes and performance data have been taken directly from reference study report.
All data relevant to power island are based on FWI in-house information.

The main features of the combined cycle power plant, case 1, are:

- Combined cycle, based on two natural gas fired, F-class gas turbines.
- Removal of CO_2 from the gas turbine exhaust gases, using a generic MEA-based chemical solvent process.
- CO_2 compression and drying.

Reference is made to the attached Block Flow Diagram of the plant.

The arrangement of the main process units is:

Unit		Trains
3000	F-class Gas Turbine	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Acid Gas Removal	
	Absorber	3 x 33%
	Stripper	1x100%
5000	CO_2 compression and drying	1x100%

2 Process Description

2.1 Overview

This description should be read in conjunction with block flow diagrams and process flow diagrams attached in the following paragraph 3.

Case 1 is a combined cycle power plant, based on two natural gas fired gas turbine, with post-combustion CO_2 capture unit. The design is a market based design.

2.2 Unit 3000 – Combined Cycle

The combined cycle is mainly composed of one F-class gas turbine (U-3100), one Heat Recovery Steam Generator (HRSG, U-3200) generating steam at three levels of pressure, and one steam turbine (U-3300), water-cooled and condensing type.

2.2.1 Unit 3100: Gas Turbine

Natural gas from the distribution grid is fed to the two Gas Turbines, at minimum 34 barg. Natural gas is pre-heated to 191°C, using pre-heated MP Boiler Feed Water from the HRSG, and then combusted in the Gas Turbine to produce electric power (280 MWe). The combustion system of the gas turbine is Dry Low NOx type, so no steam or water injection is required for NOx control from the machine.

The exhaust gases from the Gas Turbine are conveyed to the Heat Recovery Steam Generator (U-3200), located downstream of the machine and connected by means of an exhaust duct.

2.2.2 Unit 3200: Heat Recovery Steam Generator

Gas Turbine exhaust gases enter the Heat Recovery Steam Generator for generating steam at three pressure levels, with medium pressure reheating. After steam generation, the flue gases are sent to the CO_2 removal unit (U-4000).

The following coils are faced by the flue gases when horizontally flowing inside the HRSG:

- HP superheater 2nd section and MP steam re-heater 2nd section; coils are placed in parallel arrangement.
- HP superheater 1st section and MP steam re-heater 1st section; coils are placed in parallel arrangement;

- HP evaporator;
- MP superheater;
- HP economiser 2^{nd} section;
- LP superheater;
- MP evaporator;
- MP economiser and HP economiser 1^{st} section; coils are placed in parallel arrangement;
- LP evaporator with integrated deaerator;
- Condensate pre-heater.

Cold condensate coming from the Water Cooled Condenser is mixed with the condensate from the gas heater and then fed to the condensate pre-heater coil. After the preheating section (144°C), hot condensate and condensate recovered from the CO_2 regenerator reboiler are fed to the degassing tower of the LP Steam Drum.

The LP Steam drum liquid level is maintained by controlling the hot condensate flowrate through a dedicated control valve. The LP steam drum operating pressure is sliding, according to minimum steam pressure requirement of the reboiler in the CO_2 removal unit. Generated steam is superheated in the LP superheater coil and sent to the LP section of the Steam Turbine at a temperature of 236°C.

The boiler feed water for the HP and MP is directly taken from the LP steam drum and delivered to the relevant sections by means of dedicated HP and MP boiler feed water pumps.

HP boiler feed water flows through the HP economizer coils and feeds the HP steam drum. Level in the HP steam drum is maintained by adjusting the position of the relevant BFW control valve through a three-element logic: steam drum level, steam and feed water flowrates.

The HP steam drum operating pressure is sliding, according to ambient conditions and cycle load, with a normal operating value of 128 barg. Generated steam is superheated in the HP superheater coils and sent to the HP section of the Steam Turbine.
To control the maximum value of the HP superheated steam final temperature (560°C maximum), an intermediate attemperator is foreseen. Cooling medium is HP BFW taken on the HP BFW pumps discharge and adjusted through a dedicated temperature control valve.

MP boiler feed water flows through the MP economizer coil and feeds the MP steam drum. Level in the MP steam drum is maintained by adjusting the position of the relevant BFW control valve through a three-element logic: steam drum level, steam and feed water flowrates.

The MP steam drum operating pressure is sliding, according to ambient conditions and cycle load, with a normal operating value of 32 barg. Generated steam is superheated in the MP superheater coil and mixed with the exhaust steam of the HP section of the Steam Turbine. The resulting stream is fed to the re-heater coils and sent to the MP section of the Steam Turbine.

To control the maximum value of the MP reheated steam final temperature (560°C maximum), an intermediate attemperator is foreseen. Cooling medium is MP BFW taken from the MP BFW pumps and adjusted through a dedicated temperature control valve.

In case of high level inside steam drums during start-up phases, drum overflows can be discharged to the Intermittent Blow Down Drum through dedicated overflow lines with relevant control valves.

Cycle water quality is controlled by injection of chemicals and steam drums blow-downs. Continuous blow-down is foreseen for HP and MP steam drums, while intermittent blow-down has been foreseen for HP, MP and LP steam drums.

Angle valves are used to control continuous blow-down to the Continuous Blow-down Drum, balanced with LP steam drum. Steam fraction from blow down flashing is recovered to the LP steam system while the remaining liquid fraction is cooled down against machinery cooling water and sent to the Intermittent Blow Down Drum. Intermittent blow-downs are collected in the Intermittent Blow-down Drum as well. Steam fraction from blow down flashing inside the Intermittent Blow-down Drum is discharged to the atmosphere through the relevant vent line, while the remaining liquid fraction is sent to the waste water treatment system through the drain line.

2.2.3 Unit 3300: Steam Turbine and Condenser

The High Pressure (HP) steam entering the HP module of the Steam Turbine comes from the two Heat Recovery Steam Generators (Unit 3200). The HP ST admission valves adjust their stroke to maintain the HP Steam Drum operating pressure above a minimum value, depending on GT load and ambient conditions, to ensure the proper separation of steam and water in the generation drum of the HRSGs. Therefore, pressure at the steam turbine inlet is sliding, according to the process conditions of Unit 3200.

Exhaust steam from the HP module of the ST (31 barg and 366°C) is mixed with the MP steam generated in the evaporator of the HRSGs and then fed to the reheating coils of Unit 3100. Reheated MP steam is delivered to the MP module of the Steam Turbine. The MP module of the Steam Turbine is normally floating, depending on the STG hydraulic.

Superheated LP steam is produced in Unit 3200 and sent to the LP steam header to feed the process. Since the LP steam generated by the HRSGs is not enough to satisfy the requirement of the regenerator reboiler, an LP steam extraction (3.2 barg) from the crossover of the MP/LP modules of the Steam Turbine is foreseen to meet the process demand. The LP admission valves adjust their stroke to maintain the minimum pressure requirement of the reboiler in the CO_2 removal unit. The LP steam directed to the reboiler is successively cooled with MP BFW.

The wet steam at the outlet of the LP module of the Steam Turbine is routed to the water-cooled steam condenser which is of shell and tube type. The cooling medium in the tube side of the surface condenser, is sea cooling water.

The condensate is extracted from the steam condenser by means of two condensate pumps (one in operation and one spare). The condensate is then used to condense the steam from the vacuum ejectors. Then, the condensate is pumped back to the HRSGs.

2.3 Unit 4000 – CO_2 Amine Absorption

The flue gases from the HRSGs, at a temperature of about 125°C, are cooled against de-carbonised flue gases, coming from the top of the absorbers and directed to the stack.

Cooled flue gas flows into a direct contact quench coolers (three streams), where it is contacted with cooled, circulating water. This adiabatic saturation process cools the gas. The cooled gas is blown into three MEA absorbers arranged in a parallel configuration, where it is contacted in a first packed bed with a countercurrent flow of semi regenerated MEA. Further contact takes place in the second bed with lean, fully regenerated MEA. CO_2 is absorbed from the flue gas and the gas stream is then cooled in a direct contact quench bed at the top of the absorber. Some of the heat of reaction of amine with CO_2 is removed by pump around coolers which reject the heat to cooling water.
Before leaving the column, the gas is scrubbed with make up water to remove any entrained MEA and the gas is then discharged to atmosphere from the top of the absorbers via a short stack section mounted on the absorber top. The gas is

discharged to atmosphere at about 120°C, after been reheated with the hot flue gases from the power island.

Rich amine is pumped from the bottom of the absorbers and is split into two streams. The first is heated in a cross exchanger with hot stripper bottoms and the preheated rich amine flows to the stripper. The other part of the stream is flashed to produce steam, which is used in the stripping column and this reduces the amount of steam needed in the reboiler. The rich amine prior to being flashed is heated in a pair of exchangers (semi-lean MEA cooler where it is cross exchanged with hot flashed semi-lean amine from the flash drum and Flash preheater which is heated by hot stripper bottoms on their way to the amine cross exchanger). This flash, as well as producing additional stripping steam, partially desorbs carbon dioxide and creates a semi-lean amine stream which is introduced back into the absorber first mass transfer bed.

The fully stripped amine stripper bottoms are re-introduced into the second absorber bed after they have been cooled, finally, in the lean solvent cooler.

Hot rich MEA is regenerated in the stripping column, which has a stripping and rectification section. Flash steam plus some CO_2 from the amine flash drum is used in the top rectifying section of the column. Column traffic in the lower section is created by vertical thermosyphon reboilers arranged around the base of the stripping column. These reboilers are heated by condensing the steam extract from the IP/LP cross over in the power island. Condensate at saturation conditions is returned to the power island deaeration system.

Overhead vapour from the column passes through a disentrainment section and into the column overhead condenser where it is cooled with sea water.

A two-phase mixture of water and carbon dioxide vapour is disengaged in the overhead accumulator and some of the water is returned to the column as reflux. The excess condensed water is pumped to storage. This water is very clean, so it can be partially used as make-up water in the CO_2 capture plant to reduce the overall water consumption. The excess has to be treated before discharging it to the sea.

Periodically some of the circulating amine is sent to the reclaimer, where it is distilled with sodium carbonate to break down some of the heat stable salts, which are formed from the reaction of trace impurities with the MEA. The heavy residues remaining after this batch regeneration are pumped away for disposal.

MEA is made up into the system from the amine storage tanks.

A schematic Process Flow Diagram is attached in the following paragraph 3.

2.4 Unit 5000 – CO_2 Compression and drying

The compression and dehydration unit consists of one compression package, including one electrically driven multi-stage compressor, a dehydration unit and a centrifugal pump. The CO_2 compressor is a centrifugal, multi stage machine. The system includes anti-surge control, vent, inter-coolers (versus cooling water), knockout drums and condensate draining facilities as appropriate.

CO_2 as produced by the AGR section is required to be compressed and then pumped to 110 barg, prior to export for sequestration, as per the battery limit definition. The incoming stream to the CO_2 compression and dehydration unit is at a pressure of 1.5 bar.

CO_2 is initially compressed at 10 bar and then routed through the dehydration unit, where humidity water is removed and the gas is dried. The dehydration is carried out via a solid desiccant, like Activated Alumina and Molecular Sieves. The dehydration unit is composed of two beds and in normal operation one bed is used for drying, while the water-saturated bed is regenerated using a small part (ca.10%) of the dry product gas.

The dry product gas used for regeneration is part of the CO_2 coming from the bed in drying step. This stream is preheated and fed in counter-current to the bed in regeneration step. The wet CO_2 stream is then cooled and compressed back to the drying section inlet. The condensed water is separated in a flash drum downstream the cooling and drained together with the water coming from the other separators in CO_2 compression.

The dried CO_2 (99.97%vol) is compressed in the last stages of the compressor, then liquefied at 30°C against cooling water, pumped up to 110 barg and finally sent to the outside battery limits of the plant.

2.5 Utility Units

This comprises all the systems necessary to allow operation of the plant and export of the produced power.

The main utility units are the following:
- Sea Cooling water
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

3 Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagram of the combined cycle power plant, Case 1, and the schematic Flow Diagram of Units 2000, 3000, 4000 are attached to this section.

The H&M Balances relevant to the scheme attached are shown in paragraph 4.

BLOCK FLOW DIAGRAM

IEA GHG

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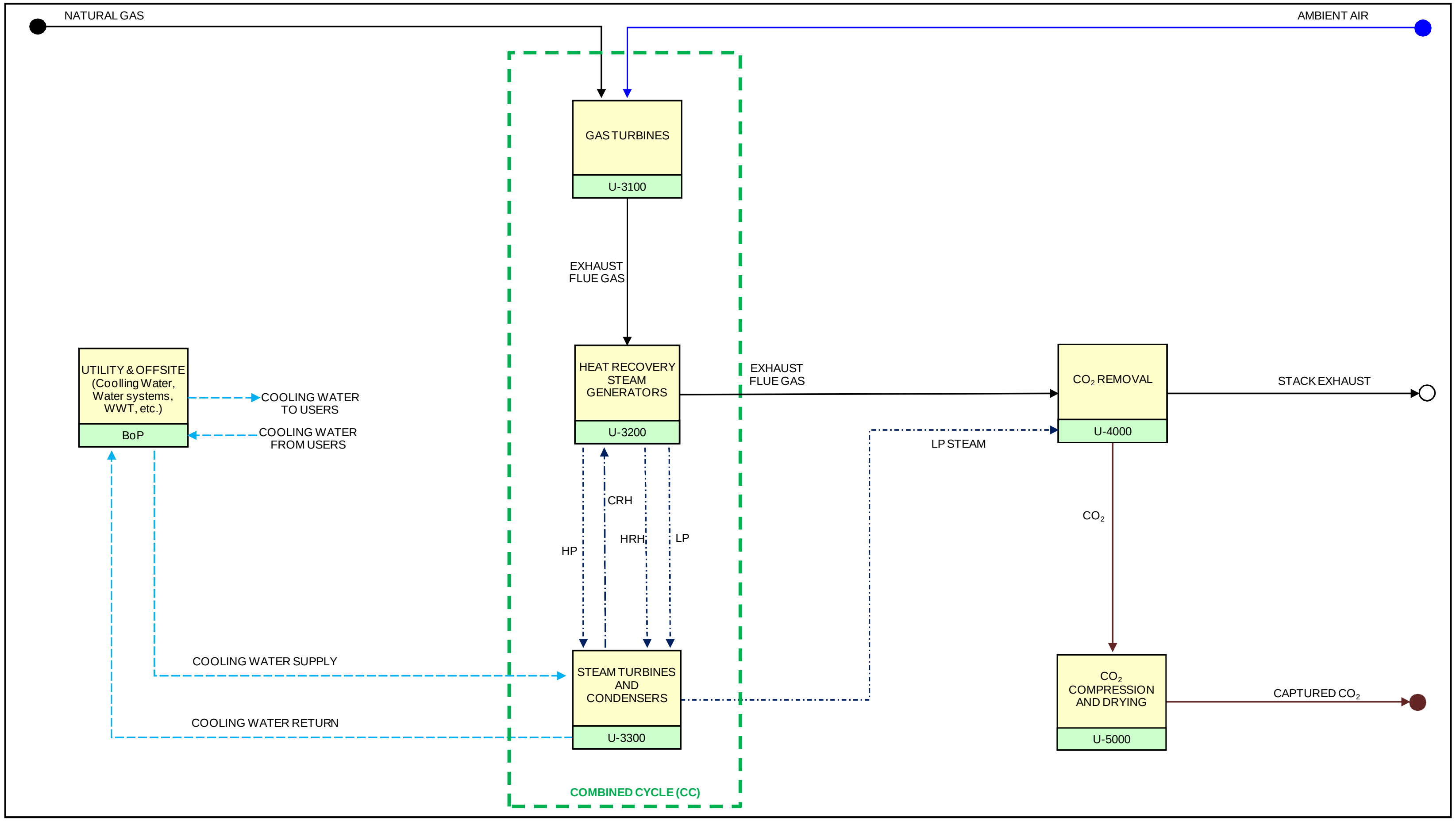
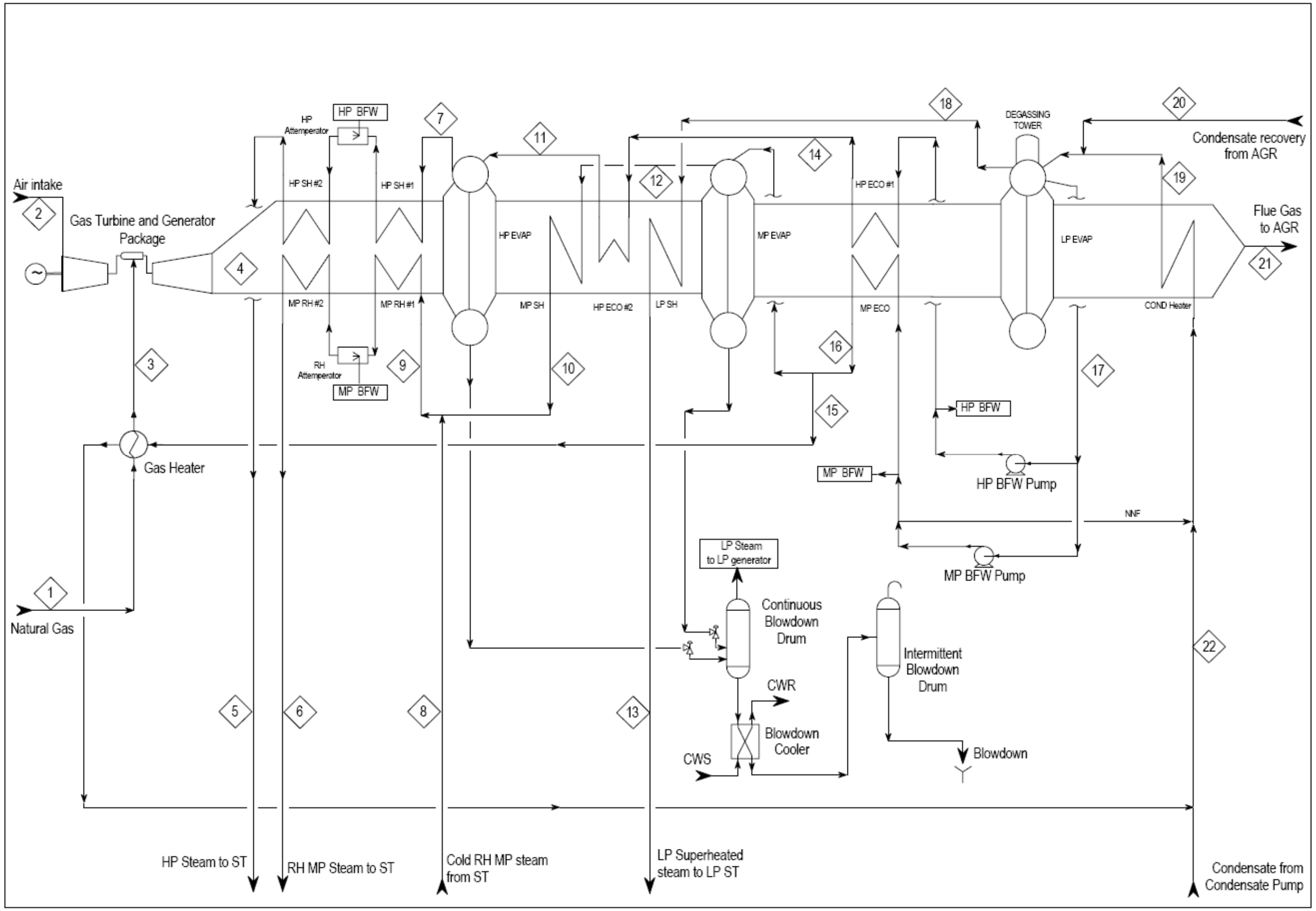
OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS

Section E.1 – Capture Plant definition – Case 1: NGCC with CCS




Air intake
Gas Turbine and Generator Package
Gas Heater
Natural Gas
HP Attemperator
HP BFW
RH Attemperator
MP BFW
HP SH #2
HP SH #1
MP RH #2
MP RH #1
HP EVAP
MP SH
HP ECO #2
LP SH
MP EVAP
HP ECO #1
MP ECO
DEGASSING TOWER
LP EVAP
COND Heater
Condensate recovery from AGR
Flue Gas to AGR
HP BFW Pump
MP BFW Pump
NNF
LP Steam to LP generator
Continuous Blowdown Drum
Intermittent Blowdown Drum
CWR
CWS
Blowdown Cooler
Blowdown
HP Steam to ST
RH MP Steam to ST
Cold RH MP steam from ST
LP Superheated steam to LP ST
Condensate from Condensate Pump
1
2
3
4
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6
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8
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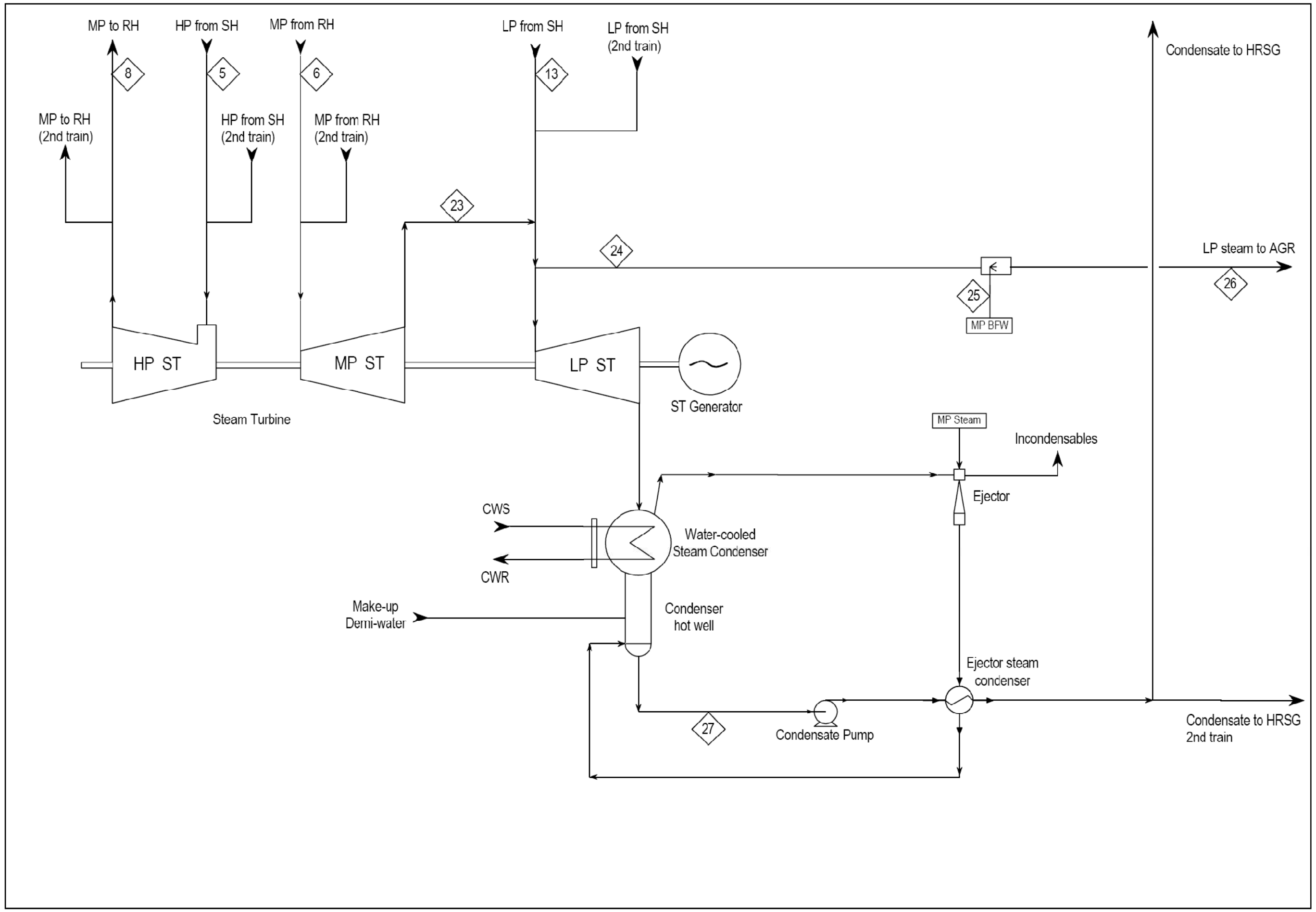
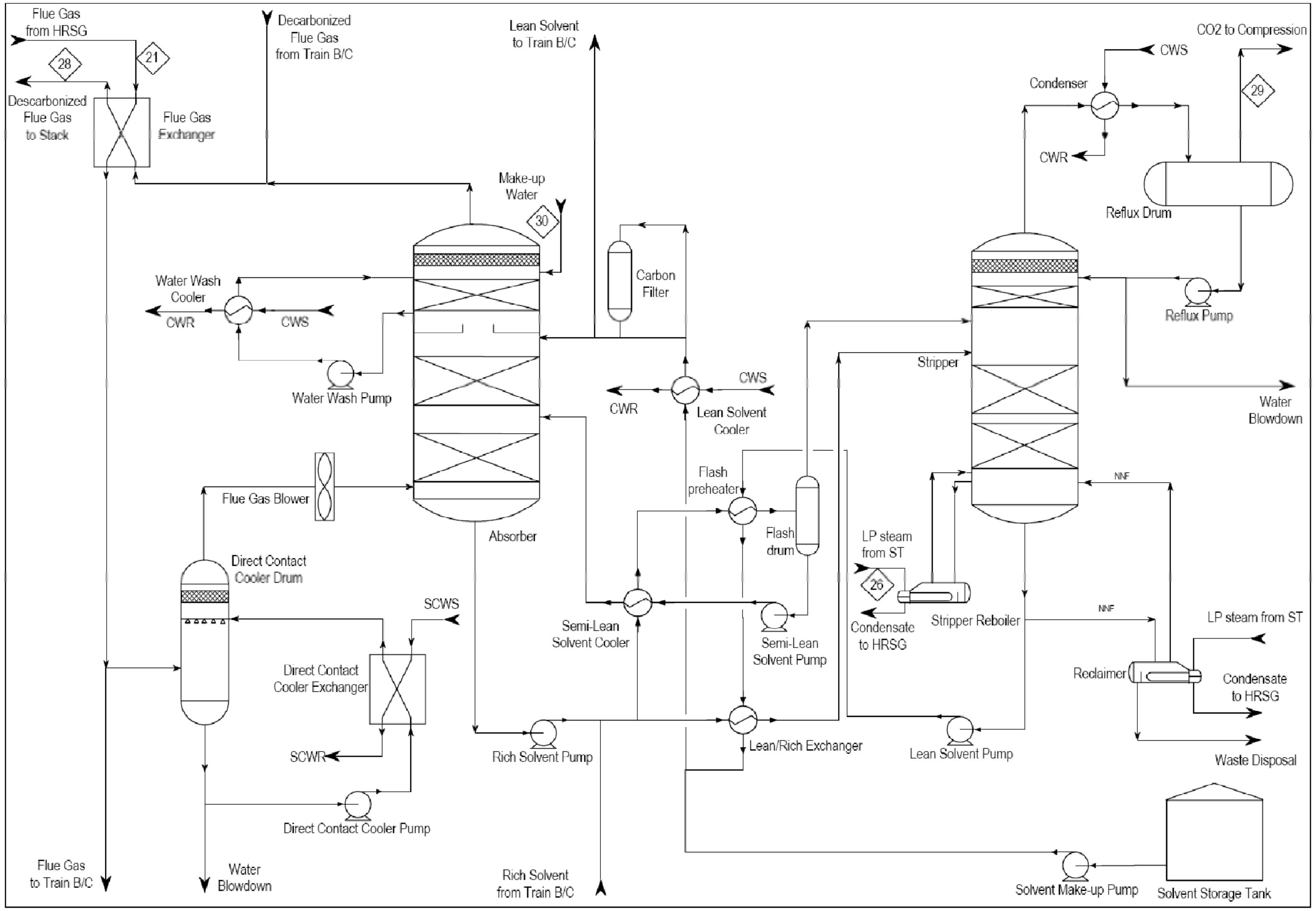
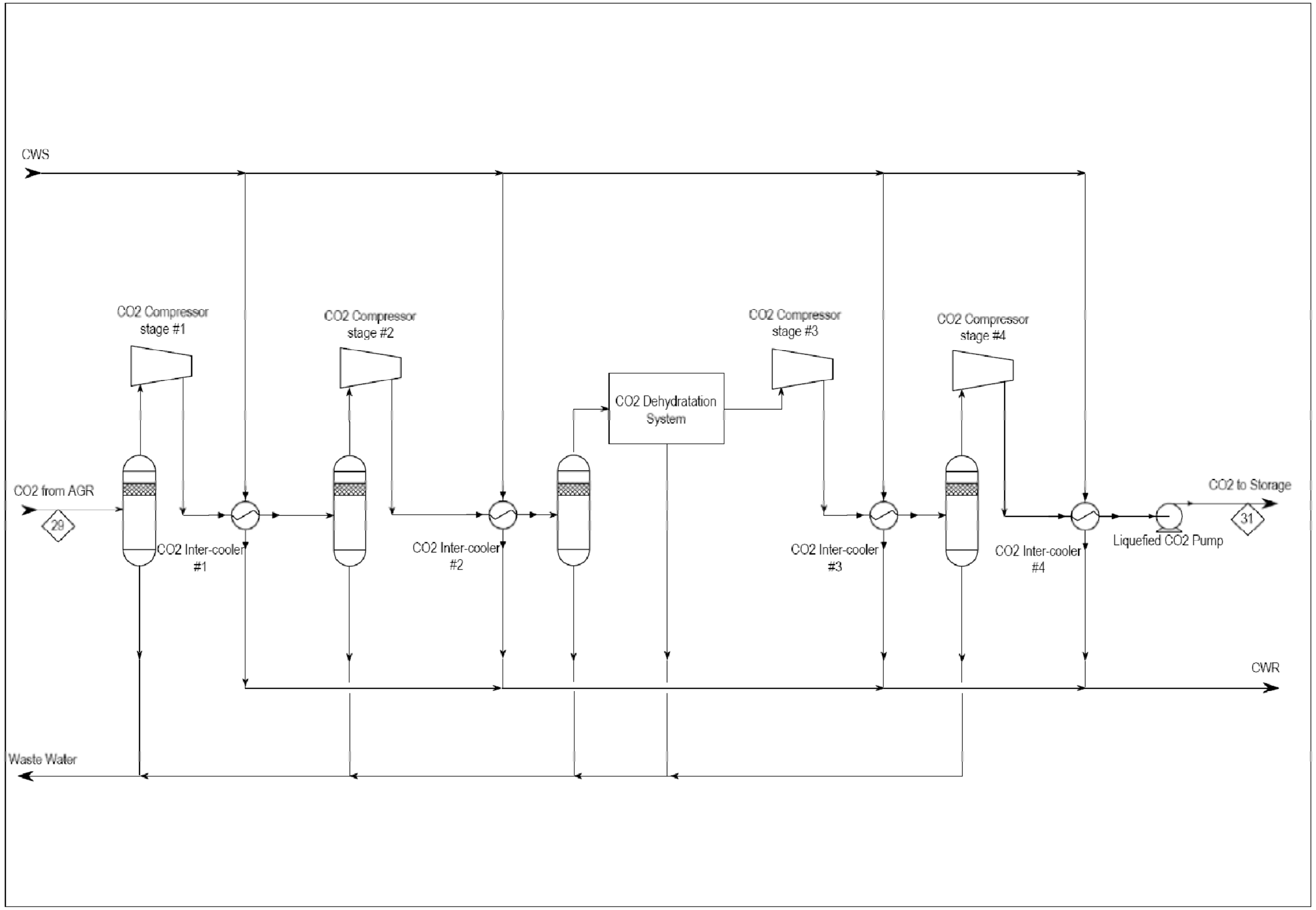
22


MP to RH
HP from SH
MP from RH
LP from SH
LP from SH (2nd train)
Condensate to HRSG
8
5
6
13
MP to RH (2nd train)
HP from SH (2nd train)
MP from RH (2nd train)
23
24
LP steam to AGR
25
26
MP BFW
HP ST
MP ST
LP ST
ST Generator
Steam Turbine
MP Steam
Incondensables
Ejector
CWS
Water-cooled Steam Condenser
CWR
Make-up Demi-water
Condenser hot well
Ejector steam condenser
27
Condensate Pump
Condensate to HRSG 2nd train


Flue Gas from HRSG
21
28
Decarbonized Flue Gas to Stack
Flue Gas Exchanger
Decarbonized Flue Gas from Train B/C
Lean Solvent to Train B/C
CO2 to Compression
CWS
Condenser
29
CWR
Reflux Drum
Make-up Water
30
Carbon Filter
Water Wash Cooler
CWR
CWS
Water Wash Pump
Reflux Pump
Stripper
Water Blowdown
CWS
CWR
Lean Solvent Cooler
Flash preheater
Flash drum
Flue Gas Blower
Absorber
Direct Contact Cooler Drum
SCWS
Semi-Lean Solvent Cooler
Semi-Lean Solvent Pump
LP steam from ST
26
Condensate to HRSG
Stripper Reboiler
NNF
LP steam from ST
Direct Contact Cooler Exchanger
Reclaimer
Condensate to HRSG
SCWR
Rich Solvent Pump
Lean/Rich Exchanger
Lean Solvent Pump
Waste Disposal
Direct Contact Cooler Pump
Flue Gas to Train B/C
Water Blowdown
Rich Solvent from Train B/C
Solvent Make-up Pump
Solvent Storage Tank


CWS
CO2 Compressor stage #1
CO2 Compressor stage #2
CO2 Compressor stage #3
CO2 Compressor stage #4
CO2 Dehydratation System
CO2 from AGR
29
CO2 Inter-cooler #1
CO2 Inter-cooler #2
CO2 Inter-cooler #3
CO2 Inter-cooler #4
Liquefied CO2 Pump
CO2 to Storage
31
CWR
Waste Water

4 Heat and Material Balance

The Heat and Material Balance, referring to the Flow Diagrams attached in the previous paragraph 3, is attached hereafter.

The H&M balance makes reference to the schemes attached to paragraph 3.

HEAT & MATERIAL BALANCES

CLIENT:	IEA	PROJECT No. :	1-BD-0530-A
LOCATION :	Operating flexibility of power plants with CCS	REFERENCE DIAGRAM	
PROJECT NAME:	Netherlands	PFD n°	
REVISION	0		
DATE	16/03/2011		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

Case 1

N°	STREAM DESCRIPTION		FLOW RATE [kg/h] (Note 1)	TEMP. [°C]	PRESSURE [bara]	ENTHALPY [kJ/kg] (Note 2)
1	Natural Gas	(Note 1,3)	56319	9	35.0	-
2	Air to Gas Turbine	(Note 1,4)	2319011	9	amb	-
3	Heated Natural Gas	(Note 1,3)	56319	191	34.9	-
4	Gas Turbine Exhaust	(Note 1,5)	2375330	626	1.03	-
5	HP steam to Steam Turbine	(Note 1)	305870	557	119.9	3500
6	Hot Reheat steam to Steam Turbine	(Note 1)	347056	557	29.9	3586
7	HP steam from HP Steam Evaporator	(Note 1)	305870	330	128.5	2666
8	Cold Reheat steam from Steam Turbine	(Note 1)	302220	364	31.9	3144
9	Cold Reheat steam to Reheaters	(Note 1)	347056	359	31.9	3132
10	MP steam from MP Superheater	(Note 1)	44836	324	31.9	3049
11	HP BFW from HP Economizer #2	(Note 1)	307399	323	139.5	1475
12	MP steam from MP Steam Evaporator	(Note 1)	44836	239	33.1	1033
13	LP steam to Steam Turbine	(Note 1)	20916	232	4.2	2927
14	HP BFW from HP Economizer #1	(Note 1)	307399	235	141.4	1016
15	MP BFW to Gas Heater	(Note 1)	73731	232	34.1	1000
16	MP BFW from MP Economizer	(Note 1)	118792	232	34.1	1000
17	BFW from LP Evaporator	(Note 1)	426191	154	5.3	649
18	LP steam from LP Steam Evaporator	(Note 1)	20917	154	5.3	2751
19	Condensate from Condensate Heater	(Note 1)	263854	144	8.0	607
20	Condensate recovery from AGR	(Note 1)	205657	140	4.2	589
21	Flue Gas to AGR	(Note 1, 5)	2375330	125	1.01	-
22	Condensate to HRSG	(Note 1)	263854	59	8.0	248
23	LP steam from Steam Turbine MP module		698411	281	4.2	3028
24	Hot LP steam to AGR		366288	278	4.2	3021
25	MP BFW for desuperheating		45025	155	41.6	656
26	LP steam to AGR		411313	155	4.2	2762
27	Condensate from Condenser		380246	21	0.025	88
28	Flue gas to gas heater	(Note 5)	4750660	125	1.01	-
29	Decarbonised fuel to stack	(Note 6)	4614890	110	1.01	-
30	CO2 to compression	(Note 7)	264862	38	1.48	-
31	Compressed CO2 to BL	(Note 8)	259844	26	110	-
32	Absorber make-up water		131090	38	1.01	158

NOTES :
1) Flowrates refers to single train
2) Only for water streams (steam, BFW, Condensate and DH).
3) Composition: N_2: 0.4%; CH_4: 83.9%; C_2H_4: 9.2%; C_3H_8: 3.3%; n-C_4H_{10}:1.4%; CO_2: 1.8%,
4) Composition: H_2O: 0.68%; O_2: 20.86%; N_2: 77.57%; Ar: 0.89%.
5) Composition: CO_2: 4.16%; H_2O: 8.15%; O_2: 12.21%; N_2: 74.62%; Ar: 0.86%
6) Composition: CO_2: 0.62%; H_2O: 12.21%; O_2: 12.14%; N_2: 74.18%; Ar: 0.85%
7) Composition: CO_2: 95.475%; H_2O: 4.489%; O_2: 0.008%; N_2: 0.026%; Ar: 0.001%
8) Composition: CO_2: 99.97%; N_2: 0.03%

5 Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter, for base load operation and partial load operations, considering both gas turbines in operation at minimum environmental (40%) and efficient (70%) load and at the load corresponding to a net power output around 50% of the base load production.

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - WATER CONSUMPTION SUMMARY - NGCC with CO_2 capture - Base load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			1020	
3200	**Heat Recovery Steam Generator Package**			18	
3300	**Steam Turbine and Generator Package**			550	
	Water-cooled Steam Condenser		5.0		28356
4000	**CO_2 Absorption and Amine Stripping**	131.5		2580	19117
5000	**CO_2 Compression and Recovery System**				5933
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	7274
	BALANCE excluding CCS	5.5	0	1663	35630
	BALANCE including CCS	137.0	0	4243	60680

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	
CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
Sep-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

CASE 1 - WATER CONSUMPTION SUMMARY - NGCC with CO_2 capture - 50% NPO

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			460	
3200	**Heat Recovery Steam Generator Package**			12	
3300	**Steam Turbine and Generator Package**			370	
	Water-cooled Steam Condenser		5.0		14178
4000	**CO_2 Absorption and Amine Stripping**	85.9		1560	12069
5000	**CO_2 Compression and Recovery System**				4153
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	4246
	BALANCE excluding CCS	5.5	0	917	18424
	BALANCE including CCS	91.4	0	2477	34646

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - WATER CONSUMPTION SUMMARY - NGCC with CO_2 capture - Minimum environmental load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			410	
3200	**Heat Recovery Steam Generator Package**			12	
3300	**Steam Turbine and Generator Package**			360	
	Water-cooled Steam Condenser		5.0		14178
4000	**CO_2 Absorption and Amine Stripping**	82.3		1460	11465
5000	**CO_2 Compression and Recovery System**				4153
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	3972
	BALANCE excluding CCS	5.5	0	857	18150
	BALANCE including CCS	87.8	0	2317	33769

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME PROJECT: OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS LOCATION: Netherlands FWI Nº: 1- BD 0530 A	Rev: 0 Sep-11 ISSUED BY: NF CHECKED BY: PC APPR. BY: LM

CASE 1 - WATER CONSUMPTION SUMMARY - NGCC with CO_2 capture - Minimum efficient load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**600**	
3200	**Heat Recovery Steam Generator Package**			**14**	
3300	**Steam Turbine and Generator Package**			**410**	
	Water-cooled Steam Condenser		**5.0**		**14178**
4000	**CO_2 Absorption and Amine Stripping**	**95.5**		**1810**	**13665**
5000	**CO_2 Compression and Recovery System**				**4153**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**4987**
	BALANCE excluding CCS	**5.5**	**0**	**1099**	**19165**
	BALANCE including CCS	**101.0**	**0**	**2909**	**36983**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - ELECTRICAL CONSUMPTION SUMMARY - NGCC with CO2 capture - Base load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**4042**
3300	**Steam Turbine and Generator Package**	**475**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**26200**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5345**
	BALANCE excluding CCS	**11042**
	BALANCE including CCS	**55542**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - ELECTRICAL CONSUMPTION SUMMARY - NGCC with CO2 capture - 50% NPO

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**530**
3200	**Heat Recovery Steam Generator Package**	**2940**
3300	**Steam Turbine and Generator Package**	**360**
4000	**CO2 Absorption and Amine Stripping**	**11900**
5000	**CO2 Compression and Recovery System**	**18340**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor…)**	**3015**
	BALANCE excluding CCS	**6845**
	BALANCE including CCS	**37085**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - ELECTRICAL CONSUMPTION SUMMARY - NGCC with CO2 capture - Minimum environmental load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**470**
3200	**Heat Recovery Steam Generator Package**	**2720**
3300	**Steam Turbine and Generator Package**	**340**
4000	**CO2 Absorption and Amine Stripping**	**11400**
5000	**CO2 Compression and Recovery System**	**18340**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor…)**	**3005**
	BALANCE excluding CCS	**6535**
	BALANCE including CCS	**36275**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1 - ELECTRICAL CONSUMPTION SUMMARY - NGCC with CO2 capture - Minimum efficient load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**690**
3200	**Heat Recovery Steam Generator Package**	**3160**
3300	**Steam Turbine and Generator Package**	**380**
4000	**CO2 Absorption and Amine Stripping**	**13300**
5000	**CO2 Compression and Recovery System**	**18340**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**3045**
	BALANCE excluding CCS	**7275**
	BALANCE including CCS	**38915**

Notes: (1) Minus prior to figure means figure is generated

6 Overall performance

The table summarizing the Overall Performance of the combined cycle power plant, case 1, is attached hereafter for base load operation and partial load operations, considering both gas turbines in operation at minimum environmental (40%) and efficient (70%) load and at the load corresponding to a net power output around 50% of the base load production.

CASE 1 - OVERALL PLANT PERFORMANCE					
		Ref case	50% NPO	Minimum efficient load	Minimum environmental load
		2GT @ 100%load	2GT @ 45%load	2GT @ 58%load	2GT @ 40%load
PLANT THERMAL INPUT					
Natural Gas Flowrate	t/h	112.6	68.0	78.8	63.9
Natural Gas LHV	MJ/kg	46.90	46.90	46.9	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	885.8	1027.3	832.3
PLANT ELECTRICAL OUTPUT					
Electric Power Output at Generator					
Gas Turbine	MWe	561.0	252.4	326.6	224.4
Steam Turbine	MWe	238.5	162.0	179.9	155.2
Total	**MWe**	**799.5**	**414.4**	**506.5**	**379.6**
Gross Electrical Efficiency (LHV basis)	%	54.5	46.8	49.3	45.6
Auxilliary Electrical Consumption					
Power Plant	MWe	5.7	3.8	4.2	3.5
Balance of Plant	MWe	5.3	3.0	3.0	3.0
CO_2 Capture	MWe	18.3	11.9	13.3	11.4
CO_2 Compression	MWe	26.2	18.3	18.3	18.3
Electric Power Consumption of the Plant	MWe	55.5	37.1	38.9	36.3
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**376.6**	**466.7**	**342.6**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	42.5	45.4	41.2
CO_2 EMISSION					
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	4192.0	4861.6	3938.8
CO_2 to storage	kmol/h	5903.2	3563.2	4132.4	3348.0
Removal efficiency	%	85.0	85.0	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**7.7**	**8.9**	**7.2**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.073**	**0.069**	**0.076**

7 Environmental Impact

The natural gas combined cycle power plant, case 1, is designed to produce power with post-combustion capture of the carbon dioxide.
The gaseous emissions and liquid effluents from the power plant are summarized in the present paragraph.
Plant will not emit any solid effluent.

7.1 Gaseous Emissions

7.1.1 Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases of the Power Island, proceeding from the combustion of the natural gas in the gas turbines.

The following Table 7-1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 7-1. Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	631
Flow, $Nm^3/h^{(1)}$	1,844,380
Temperature, °C	120
Composition	(%vol)
N_2 + Ar	76.65
O_2	12.71
CO_2	0.60
H_2O	10.04
Emissions	$mg/Nm^{3\,(1)}$
NOx	40
CO	40
Particulate	10

(1) Dry gas, O_2 content 15%vol

7.2 Liquid Effluent

A small Waste Water Treatment Unit is foreseen to treat the blowdown from the CO_2 capture unit. The water effluent from WWT, together with the demi water plant eluates, are disposed outside Power Plant battery limit.
Sea water in open circuit is used for cooling.

The return stream Water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 81.000 t/h
- Temperature : 19 °C
- Cl_2 : <0.05 ppm

8 Equipment List

The list of main equipment and process packages is included in this paragraph.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
FOSTER WHEELER		DATE	mar-01			
		ISSUED BY	NF			
		CHECKED BY	PC			
		APPROVED BY	LM			

EQUIPMENT LIST

Unit 3100 - Gas Turbine - NGCC with CO_2 capture, case 1

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
		PACKAGES							
1	PK-3101	Gas Turbine and Generator Package (1)	9FB	281 MWe					
2	PK-3101	Gas Turbine and Generator Package (1)	9FB	281 MWe					
		HEAT EXCHANGERS		Surface [m²]		Shell / Tube	Shell / Tube		
1	E-3101	Gas Heater	Shell & tube	1600	N.A.	51 / 40	255 / 220		
2	E-3101	Gas Heater	Shell & tube	1600	N.A.	51 / 40	255 / 220		

Note

1) *Including:* *Gas Turbine equipped with:*
- *DLN burners*
- *Inlet Guide Vanes*

Air intake system
Lube oil system
Hydraulic/pneumatic control system
Starting system
Fire fighting system
Natural gas system
Compressor cleaning system
Exhaust gas duct and expansion joint
Drainage system
Electrical generator and relevant auxiliaries
Final Gas Separator

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	mar-01			
		ISSUED BY	NF			
		CHECKED BY	PC			
		APPROVED BY	LM			

EQUIPMENT LIST
Unit 3200 - HRSG - NGCC with CO_2 capture, case 1

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
		PACKAGES							
1	PK-3201	**Heat Recovery Steam Generator Package**	Horizontal Natural circ.						
2	PK-3201	**Heat Recovery Steam Generator Package**	Horizontal Natural circ.						
1	PK-3202	**Continuous emission monitoring system**							*Monitoring of NOx, CO, O2, H2O, CO_2, Particulate*
2	PK-3202	**Continuous emission monitoring system**							*Monitoring of NOx, CO, O2, H2O, CO_2, Particulate*
		DRUMS		**D x H [mm]**					
		TRAIN 1							
1	D-3201	HP steam drum	Horizontal		N.A.	134	334		*Included in PK-3201-1*
1	D-3202	MP steam drum	Horizontal		N.A.	35	245		*Included in PK-3201-1*
1	D-3203	LP steam drum	Horizontal		N.A.	6	165		*Included in PK-3201-1 (Equipped with deaerator tower)*
		TRAIN 2							
2	D-3201	HP steam drum	Horizontal		N.A.	134	334		*Included in PK-3201-2*
2	D-3202	MP steam drum	Horizontal		N.A.	35	245		*Included in PK-3201-2*
2	D-3203	LP steam drum	Horizontal		N.A.	6	165		*Included in PK-3201-2 (Equipped with deaerator tower)*
	D-3204	**Continuos Blowdown Drum**	Vertical	1000 x 2000	N.A.	6	165		
	D-3205	**Intermittent Blowdown Drum**	Vertical	1260 x 2520	N.A.	Atm	100		*Peak temperature for short term (10 min): 330°C*

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		APPROVED BY	LM			

EQUIPMENT LIST
Unit 3200 - HRSG - NGCC with CO_2 capture, case 1

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
		HEAT EXCHANGERS		**Surface [m²]**		**Shell / Tube**	**Shell / Tube**		
		TRAIN 1							
1	E-3201	HP superheater 2nd section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3202	Reheater 2nd section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3203	HP superheater 1st section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3204	Reheater 1st section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3205	HP evaporator	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3206	MP superheater	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3207	HP economizer 2nd section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3208	LP superheater	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3209	MP evaporator	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3210	MP economizer	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3211	HP economizer 1st section	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3212	LP evaporator	Coil		N.A.				*Included in PK-3201 - 1*
1	E-3213	Condensate preheater	Coil		N.A.				*Included in PK-3201 - 1*
		TRAIN 2							
2	E-3201	HP superheater 2nd section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3202	Reheater 2nd section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3203	HP superheater 1st section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3204	Reheater 1st section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3205	HP evaporator	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3206	MP superheater	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3207	HP economizer 2nd section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3208	LP superheater	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3209	MP evaporator	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3210	MP economizer	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3211	HP economizer 1st section	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3212	LP evaporator	Coil		N.A.				*Included in PK-3201 - 2*
2	E-3213	Condensate preheater	Coil		N.A.				*Included in PK-3201 - 2*
-	E-3214	**Blowdown Cooler**	Plate	1.4	N.A.	6 / 6	165 / 50		

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EQUIPMENT LIST
Unit 3200 - HRSG - NGCC with CO_2 capture, case 1

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
		DESUPERHEATERS							
		TRAIN 1							
1	DS-3201	HP attemperator	Water spray		N.A.				*Included in PK-3201 - 1*
1	DS-3202	MP attemperator	Water spray		N.A.				*Included in PK-3201 - 1*
		TRAIN 2							
2	DS-3201	HP attemperator	Water spray		N.A.				*Included in PK-3201 - 2*
2	DS-3202	MP attemperator	Water spray		N.A.				*Included in PK-3201 - 2*
		PUMPS		**Q [m^3/h] x H [m]**					
		TRAIN 1							
1	P-3201 A/B	**HP Boiler Feed Water Pump**	Centrifugal	340 x 1600	2000	191	165		*One spare; electrical motor; variable frequency driver*
1	P-3202 A/B	**MP Boiler Feed Water Pump**	Centrifugal	130 x 407	250	51	165		*One spare; electrical motor; variable frequency driver*
		MISCELLANEA							
1	STK-3201	Stack		H: 50 m D: 7 m	N.A.				*Included in PK-3201 - 1*
2	STK-3201	Stack		H: 50 m D: 7 m	N.A.				*Included in PK-3201 - 2*

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EQUIPMENT LIST

Unit 3300 -Steam Turbine and Condenser - NGCC with CO_2 capture, case 1

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
PK- 3301	**Steam Turbine and Generator Package**		240 MWe					*Including:* *Steam turbine* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Gland steam condenser* *Electrical generator and relevant auxiliaries*
PK- 3302	**Steam Condenser Package**							*Including:* *Water-cooled steam condenser* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
PK- 3303	**Steam Turbine Bypass System**							*Including:* *MP dump tube* *LP dump tube* *HP/MP Letdown station* *MP Letdown station* *LP Letdown station*

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EQUIPMENT LIST

Unit 3300 -Steam Turbine and Condenser - NGCC with CO_2 capture, case 1

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	STEAM TURBINES							
ST- 3301	Steam turbine	Condensing Full reheat	240 MWe					*Included in PK-3301* *HP admission: 610 t/h @ 119 barg* *Hot reheat admission: 700 t/h @ 29 barg* *LP admission: 42 t/h @ 3.2 barg* *LP extraction from crossover: 367 t/h @ 3.2 barg*
	HEAT EXCHANGERS							
E- 3301	Water-cooled Steam Condenser		230 MWth					*Included in PK-3302*
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3302 A/B	**Condensate pump**	Centrifugal Vertical	475 x 146	280	19	110		*One spare, electric motor*

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EQUIPMENT LIST

Unit 4000 - CO_2 Amine Absorption Unit - NGCC with CO2 capture, case 1

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [℃]	Materials	Remarks
	DCC circulation pumps	centrifugal	4000 m3/h x 10 m	160 kW			casing: CS; internals: 12%Cr	three pumps in operation; one spare
	Wash water pumps							
	Rich amine pumps	centrifugal	2030 m3/h x 66 m	600 kW				three pumps in operation; one spare
	Reflux pump							
	Stripper bottoms pump	centrifugal	3000 m3/h x 56 m	670 kW				
	MEA pumps							
	Surplus water pump							
	Flue gas blowers	axial	15 MWe					
	Amine filter package							
	Soda ash dosing							
	Reclaimer							
	DCC towers							
	Packing							
	Absorption towers							
	Stripper							
	Packing for stripper							
	Semi lean flash drum							
	Ohd accumulator							
	MEA storage							
	Surplus water tankage							
	DCC cooler	shell and tube	87 MW th; 5500 m2				tubes: titanium shell: CS	Sea water heat exchanger
	Water wash cooler							
	Cross exchangers							
	Flash preheater							
	Overhead stripper condenser	shell and tube	70 MW th; 1300 m2					Sea water heat exchanger
	Stripper reboiler	kettle	125 MW th; 2000 m2				shell/tubesheet: KCS; tubes: SS 304L	heat exchanger with steam, 2 exchangers in parallel, 2000 m2 each
	Lean solvent cooler							

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EQUIPMENT LIST

Unit 5000 - CO_2 compression and inerts removal - NGCC with CO2 capture, case 1

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [℃]	Materials	Remarks
	Compression package							
	Compressor	4 stage compressor	69,300 Nm3/h x overall β = 58; β per stage = 2.8	motor = 13 MW each machine			SS	2 x 50% machines (69'300 Nm3/h each)
	Intercoolers	Shell & tube						steam condensate heat exchanger
	Intercoolers	Shell & tube	6 MWth each; 215 m2 each				tubes: titanium shell: SS	8 sea water heat exchanger
	Dryer							
	CO2 pumps	centrifugal	160 m3/h x 350m	180 kW			SS	2 operating + 2 spare

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EQUIPMENT LIST

Unit 6000 - Utility Units - NGCC with CO2 capture, case 1

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [℃]	Materials	Remarks
	Demin water storage tankage							
	Raw water and firewater storage							
	Plant air compression skid							
	Emergency diesel generator system							
	Closed loop water cooler	plate	59 MW th				plates: titanium frame: SS	sea water heat exchanger
	Blowdown water sump							
	Condensate return pump							
	Demin water pump							
	Sea water pumps	submerged	15000 m3/h x 20m	1250 kW			casing, shaft: SS; impeller: duplex	4 pumps in operation + 1 spare
	Sea water circulation pumps							
	Close loop CW pumps	centrifugal	4500 m3/h x 20m	355 kW			CS	1 pumps in operation + 1 spare
	Oily water sump pump							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	Waste water treatment plant							
	Seawater chemical injection							
	OWS							
	Sea water inlet/outlet works							
	Bulk MEA storage							
	MEA pumps							
	Amine pumps							
	Buildings							
	Electrical equipment							

9 Investment cost

The main cost estimating bases are shown in section B of this report. This section details the investment cost of the following units or blocks of units:

Unit 3000 Combined cycle
Unit 4000 CO_2 Amine Absorption
Unit 5000 CO_2 compression
Unit 6000 Utility & Offsite units

The overall investment cost of each unit is split into the following items:

- **Direct Materials:** including equipment and bulk materials;
- **Construction**: including mechanical erection, instrument and electrical installation, civil works, buildings and site preparation;
- **Other Costs:** including temporary construction facilities, solvent, chemicals, training, commissioning and start-up costs, spare parts;
- **EPC services:** including Contractor's home office services and construction supervision.

ESTIMATE SUMMARY

CASE 1 - NGCC WITH CARBON DIOXIDE CAPTURE (REFERENCE CASE)

Contract : 1-BD
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : May-11
Rev. : 0

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	182,440,000	48,380,000	19,610,000	15,720,000	266,150,000	
2	CONSTRUCTION	85,840,000	68,720,000	13,650,000	87,120,000	255,330,000	
3	OTHER COSTS	18,660,000	9,130,000	2,180,000	7,110,000	37,080,000	
4	EPC SERVICES	39,410,000	19,830,000	5,980,000	15,870,000	81,090,000	
	TOTAL INSTALLED COST - EURO	326,350,000	146,060,000	41,420,000	125,820,000	639,650,000	
5	CONTINGENCY	22,840,000	10,220,000	2,070,000	6,290,000	41,420,000	
6	LICENSE FEES	6,530,000	2,920,000	830,000	2,520,000	12,800,000	
7	OWNER COSTS	16,320,000	7,300,000	2,070,000	6,290,000	31,980,000	
	TOTAL INVESTMENT COST - EURO	**372,040,000**	**166,500,000**	**46,390,000**	**140,920,000**	**725,850,000**	

10 Operating and Maintenance Costs

The Operating and Maintenance Costs of this case are summarised in the following table. Fixed costs have been considered constant, independently from the plant operating mode, and are expressed as M€/y.
Variable costs, expressed as €/h, are evaluated for base load operation during peak hours, as the NGCC power plant is shut down during off peak hours.

Case	1
Description	NGCC with CCS
Fixed costs	
Maintenance	17.59
Operating Labour	3.72
Labour Overhead	1.12
Insurance & local taxes	12.79
Total fixed cost, M€/y	35
Variable costs (without fuel)	
	peak operation
Make up water	0
Chemicals and consumables	740
Total variable cost, €/h	740

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME	:	CAPTURE PLANT DEFINITION – CASE 2: IGCC WITH CCS
FWI CONTRACT	:	1-BD-0530 A

ISSUED BY	:	N. FERRARI
CHECKED BY	:	P. COTONE
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION E.2

INDEX

1 Introduction

The present Case 2 refers to a GEE IGCC power plant, fed with bituminous coal, and with pre-combustion capture of the produced CO_2.

The IEA GHG study 'Water usage and loss Analysis in Power plants without and with CO_2 capture' has been taken as a reference for the configuration and performances of the plant here below described. In particular, Plant description, process schemes and performance data have been taken directly from reference study report.

The main features of the GEE IGCC plant, case 2, are:

- High pressure (65 bar g) GEE Gasification (formerly Texaco);
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- Single stage dirty shift;
- Separate removal of H_2S and CO_2.

The separate removal of acid gases, H_2S and CO_2, is based on the Selexol process.
The degree of integration between the Air Separation (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and syngas dilution for NOx control are achieved with injection of compressed N_2 from ASU to the Gas Turbines.
The Sulphur Recovery (SRU) is an O_2 assisted Claus Unit, with Tail gas catalytic treatment (SCOT type) and recycle of the treated tail gas to AGR.

Reference is made to the attached Block Flow Diagram of the plant.

The arrangement of the main process units is:

Unit		Trains
1000	Gasification (Water treatment unit	4 x 33 % 2 x 66%)
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line Syngas Expansion	2 x 50% 1 x 100%
2300	AGR	1 x 100%
2400	SRU	2 x 100%

	TGT	1 x 100%
2500	CO_2 Compression and Drying	2 x 50%
3000	Gas Turbine (PG – 9351 - FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

2 Process Description

2.1 Overview

This description should be read in conjunction with block flow diagrams and process flow diagrams attached in the following paragraph 3.

Case 2 is an IGCC power plant, based on GEE gasification technology, fed with bituminous coal and provided with CO_2 capture unit. The design is a market based design.

2.2 Unit 1000 – Gasification Island

The Gasification Unit employs the GEE Gasification Process to convert feedstock coal into syngas. Facilities are included for scrubbing particulates from the syngas, as well as for removing the coarse and fine slag from the quench and scrubbing water.

The Gasification Unit includes the following sections:

- Coal Grinding/Slurry Preparation
- Gasification
- Slag Handling
- Black Water Flash
- Black Water Filtration

The following description refers to a single train.

2.2.1 Coal Grinding/Slurry Preparation

The Coal Grinding & Slurry Preparation System provides a means to prepare the coal as a slurry feed for the gasifier. Coal is continuously fed to the Coal Weigh Feeder, which regulates and weighs the coal fed to the Grinding Mill. Grey water from Black Water Filtration is used for slurrying the coal feed. Slurrying water is added to the grinding mill with a feed ratio controller to control the desired slurry concentration. The Grinding Mill may also utilize coal dust recovered by dust collection systems in the coal storage areas. The Grinding Mill is either a rod type or ball type with an overflow discharge. The Grinding Mill reduces the feed coal to the design particle size distribution.

Slurry discharged from the Grinding Mill passes through a coarse screen and into the Mill Discharge Tank, and is then pumped into the Slurry Run Tank. The Slurry Run

Tank holds enough capacity to sustain full rate operation of the gasifier train during routine maintenance of the Grinding Mill. Coal slurry is pumped from the Slurry Run Tank to the Gasifier by the Slurry Charge Pumps, which are high pressure metering pumps. These pumps supply a steady, controlled flow of slurry to the Gasifier Feed Injector.

A below grade Grinding Area Sump is located centrally within the Coal Grinding and Slurry Preparation section to allow for handling of drains and spills in this area.

2.2.2 Gasification

The Gasifier is a refractory-lined vessel capable of withstanding high temperatures and pressures. The coal slurry from the Slurry Run Tank and oxygen from the Air Separation Plant react in the gasifier at very high temperatures (approximately 1400 °C) and under conditions of insufficient oxygen to produce syngas. Syngas consists primarily of hydrogen and carbon monoxide with lesser amounts of water vapor, carbon dioxide, hydrogen sulfide, methane, and nitrogen. Traces of carbonyl sulfide (COS) and ammonia are also formed. Ash, which was present in the coal, melts in the gasifier and transforms into slag.

Hot syngas and molten slag from the Gasifier flow downward into a water filled quench chamber, where the syngas is cooled and the slag solidifies. Raw syngas then flows to the Syngas Scrubber for removal of entrained solids. The solidified slag flows to the bottom of quench chamber, where the Slag Crusher is located. The coarse fraction of the slag is then removed from the quench section through a water-filled lockhopper system, after being ground through the Slag Crusher.

The Feed Injector is protected from the high temperatures prevailing in the gasifier by cooling coils through which cooling water is continuously circulated. Feed injector cooling water is stored in the Feed Injector Cooling Water Drum and pumped by the Feed Injector Cooling Water Pump to the Feed Injector Cooling Water Cooler and then to the feed injector cooling coils. After the cooling water exits the cooling coils, it flows to the Feed Injector Cooling Water Drum by gravity.

Syngas from the Gasifier quench chamber is fed to a Nozzle Scrubber. In the Nozzle Scrubber, the syngas is mixed with a portion of the Syngas Scrubber bottoms in order to wet the entrained solids so they can be removed in the Syngas Scrubber. The spray water is supplied by the Syngas Scrubber Circulating Pump.

The water/syngas mixture enters the Syngas Scrubber, where all of the solids are removed from syngas. Process condensate from the Syngas Treatment and Conditioning Line is fed into the Syngas Scrubber to remove particulates in the syngas. Then, the syngas from the overhead of the Syngas Scrubber is routed to the Syngas Treatment and Conditioning Line.

The Syngas Scrubber bottoms stream contains all the solids, which were not removed in the Gasifier quench chamber. In order to reduce the amount of solids recycled to the Nozzle Scrubber and Gasifier quench ring, a portion of the scrubber bottoms stream is sent to the Black Water Flash Section.

2.2.3 Slag Handling

The Slag Handling System removes the majority of solids from the gasification process equipment. These solids are made up from the coal ash and unconverted coal components that exit the gasifier in the solid phase.

Coarse slag and some of the fine solids flow by gravity from the Gasifier quench chamber into the Lockhopper. Flow into the Lockhopper is assisted by the Lockhopper Circulation Pump which takes water from the top of the Lockhopper and returns it to the Gasifier quench chamber. After the solids enter the Lockhopper, the particles settle to the bottom. Thus, the Lockhopper acts as a clarifier, separating solids from the water. Solids are collected in this manner for a set period of time, typically about 30 minutes.

When the solids collection time is over, the Lockhopper is isolated from the quench chamber and depressured. Then, the solids, which have accumulated in the Lockhopper, are flushed with water into the Slag Sump. The water flush is then discontinued and the Lockhopper is filled with water and repressured, and the next solids collection period begins.

In the Slag Sump, slag settles onto a submerged conveyor, which drags the slag out of the water. It is passed over a screen, which allows surface water to drain. The slag is then transported by trucks to offsite for disposal. The water removed from the slag is pumped by the Slag Sump Overflow Pump to the Vacuum Flash Drum in the Black Water Flash Section.

Water used to flush the Lockhopper of collected solids is supplied to the Lockhopper Flush Drum from the Grey Water Tank in the Black Water Filtration Section. The water is cooled in the Lockhopper Flush Water Cooler so that the water in the Lockhopper will be cool at the start of the solids collection period and not get excessively hot during the solids collection period.

2.2.4 Black Water Flash

The purpose of the Black Water Flash Section is to recover heat from the black water, as well as to remove dissolved syngas. Gas evolved from the flashes is routed to the Sulfur Recovery Unit, since it contains traces of hydrogen sulfide and ammonia. The cooled and flashed black water is sent to Black Water Filtration.

Black Water from the Gasifier quench chamber and the Syngas Scrubber is first routed to the LP Flash Drum. The overhead vapor is first used to heat the grey water return from the Black Water Filtration Section before it is condensed by the LP Flash Condenser. Then, both of the vapor and condensate are routed to the Vacuum Pump Knockout Drum. From the LP Flash Drum, the black water stream goes to the Vacuum Flash Drum along with the black water from the Overflow Slag Sump. The Vacuum Flash Drum flashes out additional dissolve gases and liquid of which most of the liquid is condensed by the Vacuum Flash OH Condenser and separated in the Vacuum KO Drum. Then, both of the vapor and condensate are routed to the Vacuum Pump Knockout Drum. Most of entrained gas in the black water is removed in the Vacuum Pump Knockout Drum and flows to the Sulfur Recovery Unit. Any liquid condensed in this vapor stream is also removed in Vacuum Pump Knockout Drum and flows to the Grey Water Tank.

2.2.5 Black Water Filtration

The Black Water Filtration Section processes flashed black water from the Black Water Flash Section. The flashed black water from the Vacuum Flash Drum is sent to the LP Settler, where the suspended solids are settled at the bottom of the tank. The solids-free overflow is sent back to the Grey Water Tank, and the underflow is pumped by the LP Settler Bottom Pump to the Rotary Filter. The solids are removed, and the filtrate is sent to the Grey Water Tank. The filter cake is removed for disposal.

The water in the Grey Water Tank is essentially free of particulates. Some portion of the grey water is pumped by the LP Grey Water Return Pump to the Lockhopper Flush Drum, to the Coal Grinding Section and to offsite. The HP Grey Water Return Pump pumps grey water to the Grey Water Heater and then to the Syngas Scrubber.

2.3 Unit 2100 – Air Separation unit

This Unit is treated as a package unit supplied by specialised Vendors.

The Air Separation Unit is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

The oxygen produced is delivered to the Gasification Island to be used as reaction oxidant. A small quantity is also used by the Sulphur Recovery Unit. As a byproduct, nitrogen is obtained and it is almost integrally routed to the gas turbines of the combined cycle for power augmentation and NOx control.
The Plant consists of two air separation trains and at the same time is able to produce additional oxygen and nitrogen products to maintain the desired inventories in the storage systems of liquid and gaseous products used as back-up; these systems are common to both trains.
ASU is partially integrated with the gas turbines.
The streams listed in Table 2-1 are produced according to the requirement of GEE technology.

Table 2-1. ASU product

	Product	Use	Details
1	Oxygen	C	High Pressure Gaseous Oxygen for Gasifiers
2	Oxygen	C	Low Pressure Gaseous Oxygen for Sulphur Recovery Claus Units
3	Nitrogen	C	Medium Pressure Gaseous Nitrogen for Syngas Dilution at Gas Turbines
4	Nitrogen	C	Very High Purity Low Pressure Gaseous Nitrogen for blanketing, equipment purging, etc
5	Nitrogen	D	Very High Purity High/Low Pressure Gaseous Nitrogen for Purging under Gasifiers and Gas Turbine Shutdown
6	Air	C	Low Pressure Dry Gaseous Air to Plant and Instrument Air System

Note: (1) C = Continuous
D = Discontinuous

The Air Separation Unit capacity is defined by the required oxygen production (sum of flowrates to the gasification island and to the sulphur plant).

When the gasification operates at full load, 50% of the air required by the ASU to obtain the design oxygen production is derived from both gas turbine compressors; the integration between the gas turbines operation and the ASU is achieved at a level where 50% of the atmospheric air is compressed with selfstanding units and the difference comes already pressurized from the compressors of the gas turbines in the combined cycle.

The air extracted from the gas turbine at high temperature is cooled by exchanging heat with nitrogen for syngas dilution before being fed to the Air Separation Unit.

The continuity of supply of oxygen and nitrogen to the IGCC Plant is extremely critical.
The Air Separation Unit can be considered as an essential service since in case of complete failure it will result in the entire IGCC Complex not being available. For this reason two 50% Air Separation trains are installed and no equipment, except for the back-up systems, is shared between these two production trains.
In addition a liquid oxygen storage equivalent to at least 12 hours of a single ASU train and a back-up system shall be provided. This storage is sufficient to cover the majority of the ASU emergency failures ensuring a high availability (more than 98%).
In order to refill these systems in the time periods specified, ASU is “overdesigned” above the normal oxygen and nitrogen requirements at 100% IGCC operation.
The liquid oxygen storage facilities have two pumps and one vaporiser during the period necessary to reach the steady flowrate of the back-up vaporiser, a gaseous buffer tank with a capacity of at least two minutes of 50% ASU design capacity shall ensure the required oxygen flowrate.
The liquid storage is suitable to ensure low pressure nitrogen required for purging, blanketing etc. for 12 hours continuous operation of the IGCC Complex, and a safe shutdown in case of gasifier failure.

2.4 Unit 2200 – Syngas Treatment and Conditioning line

Saturated raw syngas from Unit 1000, at approximately 240°C and 62 bar g enters Unit 2200. The syngas is first heated in E-2201 by the hot shift effluent and then enters the Shift Reactor R-2201, where CO is shifted to H_2 and CO_2 and COS is converted to H_2S. The exothermic shift reaction brings the syngas temperature up to 434°C.
A single stage shift, containing sulphur tolerant shift catalyst (dirty shift), is used, being this sufficient to meet the required degree of CO_2 removal.
The hot shifted syngas is cooled in a series of heat exchangers:

- E-2201 Shift feed product exchanger
- E-2202 HP Steam Generator
- E-2203 MP Steam Generator
- E-2204 LP Steam Generator
- E-2205 VLP Steam Generator

Process condensate collected in the cooling process of the syngas is accumulated in D-2204 and from there pumped back to the syngas scrubber of Unit 1000.

The final cooling step of the syngas takes place in E-2206, preheating cold condensate. The process condensate separated after this step is routed to Unit 4000, Sour Water Stripper, being heavily contaminated, the remaining part is accumulated in D-2204.
Up to this point Unit 2200 is split into two parallel lines, each sized for 50% capacity of the total syngas flow because of the size limitation of the exchangers involved. Downstream D-2203 Unit 2200 is a single line for 100% capacity.
Cold syngas flows to Unit 2300 and returns to Unit 2200, as clean syngas, after H_2S and CO_2 removal.
Clean syngas is preheated in E-2207 with VLP steam and then reduced in pressure, down to 26 bar (g) in the Expander EX-2201, generating electric energy. Expanded clean syngas is heated in E-2208 with VLP steam and sent to Unit 3000 gas turbines.

2.5 Unit 2300 – Acid Gas Removal (AGR)

The removal of acid gases, H_2S and CO_2, where required, is an important step of the IGCC operation. In fact, this unit is not only capital intensive and a large consumer of energy, but also is a key factor for the control of the environmental performance of the IGCC. The right selection of the process and of the solvent used to capture the acid gases is important for the performance of the complex.
Several different technologies are commercially available for acid gas removal. They can be grouped in 3 categories. The physical solvents, which capture the acid gas in accordance with the Henry's law; the chemical solvents, which capture the acid gas with a chemical reaction with the solvent, and the mixed solvents, which display both types of capture, physical and chemical. The first group is obviously favoured by a high partial pressure of the acid gas in the syngas, while the second group is less sensitive to the acid gas partial pressure.

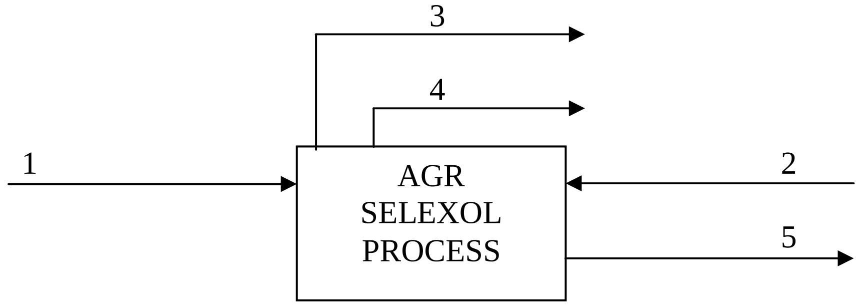
In the present case 2, this Unit utilises Selexol as acid gas solvent (physical solvent). A single train configuration that enhances the acid gases concentration without using Nitrogen from Air Separation Unit is considered.

Unit 2300 is characterised by a high syngas pressure (55 bar g) and an extremely high CO_2/H_2S ratio (183/1).

The interfaces of the process are the following, as shown in the Process Flow Diagram attached to the following paragraph 3:

<u>Entering Streams</u>
1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

<u>Exit Streams</u>
3. Treated Gas to Expander
4. CO_2 to compression.
5. Acid Gas to Sulphur Recovery Unit



The Selexol solvent consumption, to make-up losses, is 120 m^3/year.

The proposed process matches the process specification with reference to concentration of the treated gas exiting the Unit. In fact, the H_2S+COS concentration is 4 ppm. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of the solvent that is cooled down by a refrigerant package (Power consumption = 32% of the overall AGR power requirement) before flowing to the CO_2 absorber.
The CO_2 removal rate is more than 91% as required, allowing to reach an overall CO_2 capture of 85% with respect to the carbon entering the IGCC.

These excellent performances on both the H_2S removal and CO_2 capture are achieved with a large power consumption.

The acid gas H_2S concentration is 19% dry basis, more than suitable to feed the oxygen blown Claus process.

Together with CO_2 exiting the Unit, the following quantities of other components are sent to the final CO_2 destination, after compression:

- 262 kmol/h of Hydrogen, corresponding to 1,8% vol and to an overall thermal power of 17,7 MWt, i.e. more than 5,8 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 92 ppmvd.

2.6 Unit 2400 – SRU and TGT

This Unit is a Package Unit supplied by specialised Vendors.

The Sulphur Recovery Section consists of two trains each sized for a production of 66.8 t/day and normally operating at 50%.

The Sulphur Recovery Unit (SRU) processes the main acid gas from the Acid Gas Removal, together with other small flash gas and ammonia containing offgas streams coming from other units. SRU consists of two Claus Units, each sized for approx. 100% of the max sulphur production in order to assure a satisfactory service factor. Low pressure oxygen from ASU may be used as oxidant of Claus reaction.
The required recovery of sulphur from the entering streams is 95% minimum @ EOR, (95.5% minimum @ SOR); it is obtained by means of thermal reactor plus two Claus catalytic reactors.
Each train is equipped with its own liquid sulphur product degassing facilities whereby each train sulphur pit (48 h minimum total hold up) is divided into separate zones for collection from condensers etc. in the unit and for degassing (24 h hold up) plus transfer to liquid sulphur storage.
The Tail Gas Treatment Unit (TGT) is designed as a single train, capable of processing 100% tail gas resulting from the possible SRU operating modes.
A complete hydrogenation of SO_2, residual COS, CS_2 and elemental sulphur is achieved. After quenching tail gas is recycled back to the Acid Gas Removal (Unit 2300) by means of two tail gas recycle compressors (one operating, one spare).
In case a small quantity of hydrogen is needed for tail gas hydrogenation, back-up hydrogen containing gas (syngas) is available at SRU/TGT battery limit.

The catalyst selection shall be adequate to convert HCN and COS, in order not to accumulate them through the tail gas recycle to the solvent wash unit.
Ammonia contained in the feed gas streams to the Unit shall be completely destroyed.

However, due to the recycle of tail gas to the Acid Gas Removal, the sulphur recovery achieved in the IGCC Complex is significantly higher (more than 99%).

2.7 Unit 2500 – CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.

CO_2 as produced by the AGR section is required to be compressed up to 110 bar g prior to export for sequestration, as per the IEA battery limit definition. CO_2 at these conditions is a supercritical fluid.

The incoming stream of Unit 2500 flows from Unit 2300, Acid Gas Removal, and is the combination of three different streams delivered at the following pressure levels:

- MP stream : 27 barg
- LP stream : 10 barg
- VLP stream : 0,5 barg

All of these streams require treating to remove water and compression. These requirements are matched using the flow scheme described below.
The stream at lowest pressure is compressed to intermediate pressure and routed to the molecular sieve drier, together with the stream at intermediate pressure, and the higher pressure stream which has been letdown to intermediate pressure. The letdown duty is available for powergen or turbine duty, but has been used adiabatically to cool the combined drier outlet to reduce the compressor power. The total combined stream at intermediate pressure is then dried in the molecular sieve dryers to remove the water to ensure no free water in CO_2 service. The final CO_2 moisture content of the product stream is less than 1 ppm. The dryers are provided as 2x50% units, each with 2x100% absorption beds, which are electrically regenerated. Total quantities of water removed are small, and are of sufficient quality for recycle to the steam system after appropriate dissolved gas removal. A buffer drum is provided to smooth the returned water flow from the batch dryers. The main equipment of the Drying Unit are as follows:

- Feed Heater
- 3 x Absorption Beds
- Aftercooler
- Water KO Drum
- After Filter (cartridge type)
- Recycle Blower
- Regeneration Heater
- Moisture Analyser

The dry gas is cooled against the incoming letdown service and routed to the compressors as 2x50% streams. The study is based on compressor information provided by Nuovo Pignone.
The compressor system recommended is of the following type:

- 2x50% machines (API 617);
- Between bearing design (NP 2MCL526 + gearbox + BCL405/A or equivalent);
- Auto-transformer with appropriate taps for start-up operation;
- 2 casings, 3 stages, dry gas seals;

- Speed: 9600 rpm;
- intermediate pressure inlet (different depending on cases);
- 110 bar g outlet.

It is noted that for the CO_2 flow rate required for compression, these machines are currently available on the market.

The product stream sent to final storage is composed of CO_2 and H_2+N_2 coabsorbed. The main properties of the stream are as follows:

- Product stream : 626 t/h.
- Product stream : 110 bar.
- Composition :

	%wt
CO_2	99,4
N_2	0,3
H_2	0,1
Others	0,2
TOTAL	100,0

2.8 Unit 3000 – Power Island

The Process Flow Diagram of this Unit is attached to the following paragraph 3.

The power island is based on two General Electric gas turbines, frame 9351 FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.

For the configuration of the present case 2, the integration between the Process Units and the Power Island consists of the following interfaces:

- Compressed Air : air extracted from the Gas Turbine is delivered to the Air Separation Unit;
- Dilution nitrogen : excess nitrogen from ASU is delivered to GT for NOx control and power augmentation;
- HP steam (160 barg) : steam imported from Syngas Treatment and Conditioning Line.
- HP steam (85 barg) : steam exported to the Gasification Island users.
- MP steam (40 barg) : steam imported from Syngas Treatment and Conditioning Line. A small quantity is also generated in the Sulphur Recovery Unit.

- LP steam (6,5 barg) : steam imported from Syngas Treatment and Conditioning Line. A small quantity is also generated in the Sulphur Recovery Unit.
- VLP steam (3,2 barg) : steam imported from Syngas Treatment and Conditioning Line.
- BFW : HP, MP, LP, VLP Boiler Feed Water is exported to the Process Units to generate the above mentioned steam production.
- Process Condensate : All the condensate recovered from the condensation of the steam utilised in the Process Unit is recycled back to the HRSG after polishing in Unit 4200, Demi Water/Condensate Recovery.
- Condensate from ST : All the Condensate from the Condenser is exported to the polishing unit (Unit 4200), pre-heated in the Syngas Cooling and Conditioning Line and recycled back to the HRSG.

During normal operation, the clean syngas, coming from Unit 2200 – Syngas Treatment and Conditioning Line, is heated up to 170°C against MP BFW in the syngas final heater 1/2-E-3101 dedicated to each Gas Turbine. Before entering each machine the hot syngas goes through dedicated final separator 1/2-D-3101 in order to protect the Gas Turbine from liquid entrainment, mainly during cold start-up. Finally, the hot syngas is burnt inside the Gas Turbine to produce electric power; the resulting stream of hot exhaust gas is conveyed to the Heat Recovery Steam Generator located downstream each Gas Turbine.
Compressed air is extracted from the Gas Turbines and delivered to ASU (refer to paragraph 2.3)
MP nitrogen coming from ASU is injected into the Gas Turbines for NOx abatement and power output augmentation.

The flue gas stream at a temperature of about 600°C flows through the following coils sequence inside the HRSG:

- HP Superheater (2nd section);
- MP Reheater (2nd section);
- HP Superheater (1st section);
- MP reheater (1st section);
- HP Evaporator;
- HP Economizer (3rd section);
- MP Superheater
- MP Evaporator;
- LP Superheater;

- HP Economizer (2nd section)/MP Economizer (2nd section) (in parallel);
- LP Evaporator;
- HP economizer (1st section)/MP Economizer (1st section)/LP Econ. (in parallel);
- VLP Evaporator.

The flue gas is cooled down to about 129°C and then discharged to the atmosphere with stream coming from the other HRSG through a common stack.
The condensate stream, extracted from the Steam Condenser E-3303 by means of Condensate Pumps P-3301 A/B/C, is sent as Cold Condensate to the Polishing Unit, located in Unit 4200 – DM Water / Condensate Recovery System.
Demineralized water makeup is mixed to the polished stream and finally is sent to the IGCC Process Units where it is heated up by recovering the low temperature heat available.
The Hot Condensate coming back from IGCC process units enters the VLP steam drum which is equipped with the degassing tower operating at a temperature of 120°C.
Degassed Boiler Feed Water for HP, MP, LP and VLP services is directly taken from deaerator and delivered to the relevant sections by means of dedicated pumps. HP BFW from deaerator is delivered to the HP economizer coils by means of the HP BFW pumps 1/2-P-3203 A/B (two pumps for each HRSG with one pump in operation and one in hot stand-by), flows through the HP Economizer coils and feeds the HP Steam Drum.
From the outlet of the 1st section of the HP Economizer coils a portion of hot water is exported at a temperature level of about 160°C to the IGCC Process Units as HP BFW.
The largest portion of the generated steam is superheated in the HP Superheater coils and sent to the HP module of the common Steam Turbine together with HP Superheated steam coming from the second HRSG.
The saturated HP Steam bypassing the HP Superheater coils is letdown and mixed with a portion of the HP Superheated Steam to achieve the characteristics required by the HP Steam Users of the IGCC.
To control the maximum value of the HP Superheated Steam final temperature, a desuperheating station, located between HP Superheater coils, is provided. Cooling medium is HP BFW taken on the HP BFW pumps discharge and adjusted through a dedicated temperature control valve.
The exhaust steam from the HP module of the Steam turbine is split between the two HRSGs. Each stream feeds an MP header, and it is mixed with the MP Superheated steam coming from the relevant HRSG section.
MP BFW from deaerator is delivered to the MP Economizer coils of each HRSG by means of the MP BFW Pumps 1/2-P-3202 A/B (one operating and one in standby), flows through the MP Economizer coils and feeds the MP Steam Drum. From the outlet of the 1st section of the MP Economizer coils a portion of hot water is

exported at a temperature level of about 160°C to the IGCC Process Units as MP BFW.
Generated MP steam is partially diverted to the IGCC Process Units, while the remaining portion is superheated in the MP Superheater coil and mixed to the exhaust steam coming from the HP Module of the common Steam Turbine. The resulting stream is fed to the Reheater coils and the Reheated Steam is delivered to the MP module of the Steam Turbine together with the Reheated Steam coming from the second HRSG.

To control the Reheated steam final temperature, a desuperheating station, located between Reheater coils, is provided. Cooling medium is MP BFW taken on the MP BFW pumps discharge and adjusted through a dedicated temperature control valve.
The exhaust steam coming from the MP Module of the common Steam Turbine is mixed to the LP Superheated Steam and delivered to the LP Module of the Steam Turbine.

LP BFW from deaerator is delivered to the LP Economizer coil by means of two LP BFW Pumps 1/2-P-3201 A/B (one operating and one in stand-by), flows through the LP Economizer coil and feeds the LP Steam Drum.
Before entering the LP Steam Drum, a portion of hot water is exported at a temperature level of about 120°C to the IGCC Process Units as LP BFW.
Most of the produced steam returns to the Power Island as saturated steam through the LP Steam distribution network.

The wet steam at the outlet of the LP module of the Steam Turbine is routed to the steam condenser. The cooling medium in the tube side of the surface condenser is seawater in once through circuit.
Continuous HP, MP and LP blowdown flowrates from HRSGs are manually adjusted by means of dedicated angle valves; they are sent to the dedicated blowdown drum together with the possible overflows coming from HRSGs Steam Drums.
After flashing, recovered VLP steam is fed to the VLP steam drum while the remaining liquid is cooled down against cold condensate by means a dedicated Blowdown Cooler and delivered to the atmospheric blowdown drum.
Intermittent HP, MP and LP blowdown flowrates from HRSGs are manually adjusted by means of dedicated angle valves and sent to the dedicated atmospheric blow-down drum.
In case of Steam Turbine trip, live HP Steam is bypassed to MP manifold by means of dedicated letdown stations, while Reheated Steam and excess of LP steam are also let down and then sent directly into the condenser neck.
When the clean syngas production is not sufficient to satisfy the appetite of both Gas Turbines it is possible to cofire natural gas or to switch to natural gas one or both Gas Turbines. This could happen in case of partial or total failure of the Gasification/Gas Treatment units of the IGCC and during start-up.

2.9 Utility Units

This comprises all the systems necessary to allow operation of the plant and export of the produced power.

The main utility units are the following:

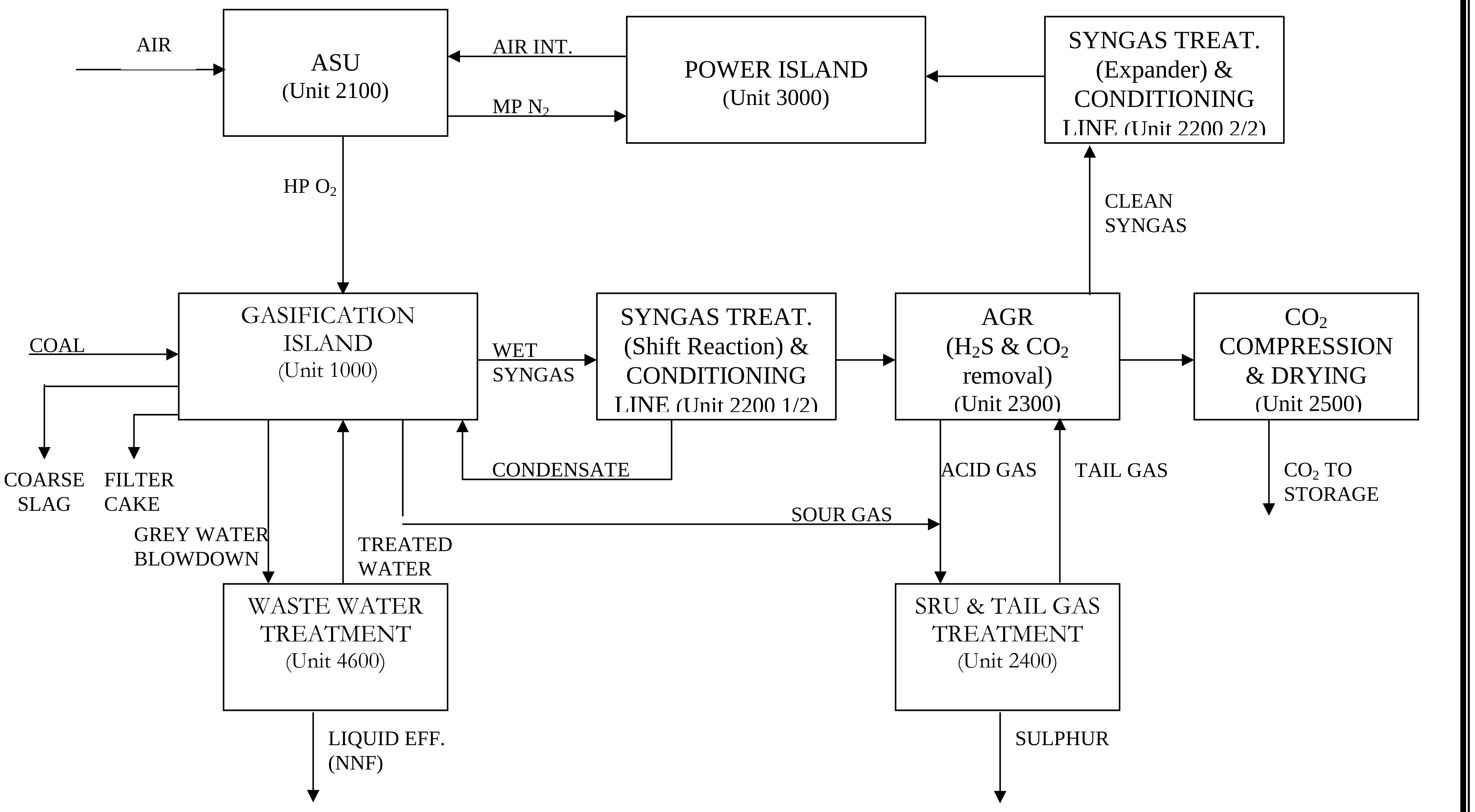
- Sea Cooling water
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

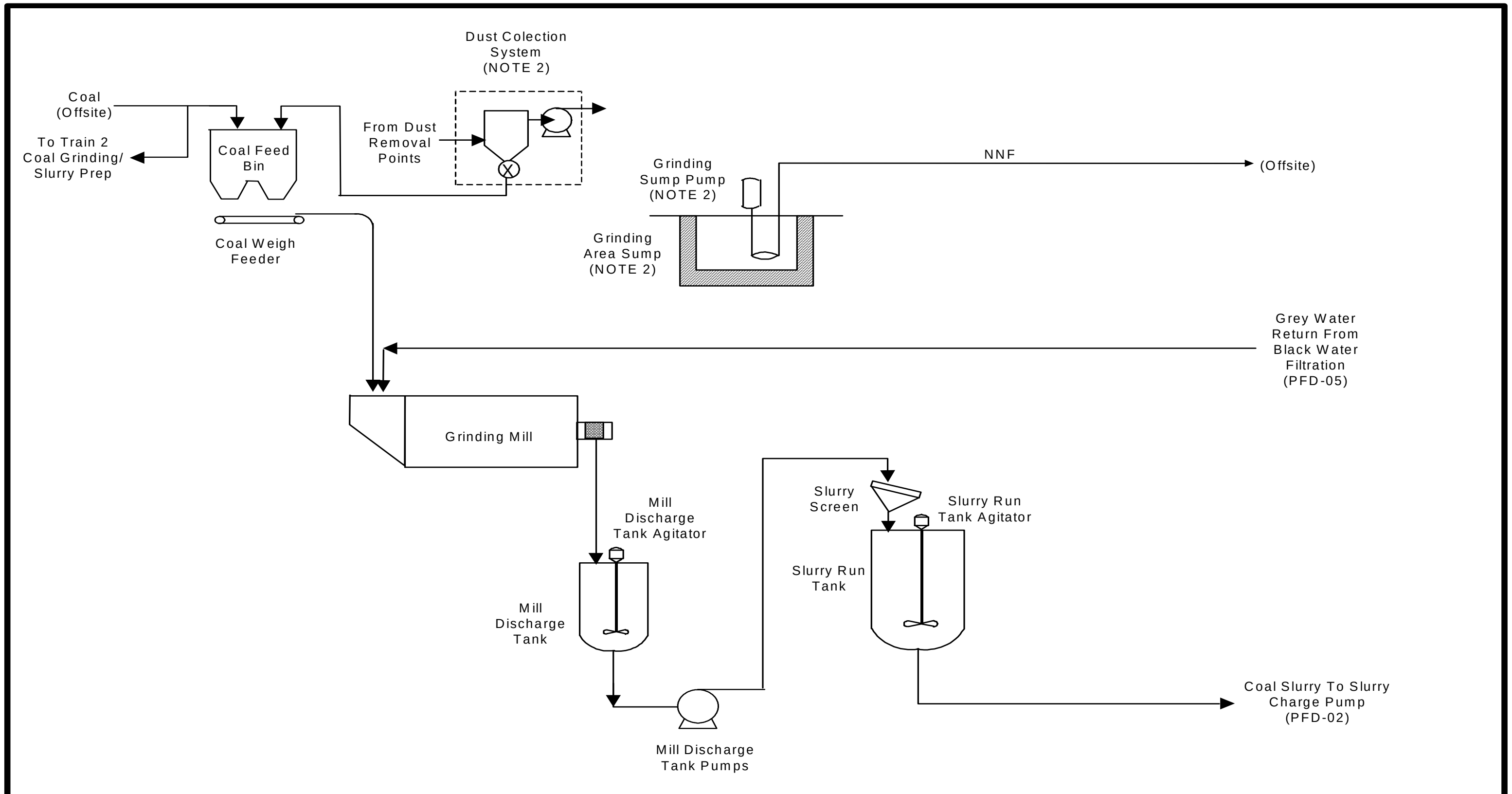
3 Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagram of the GEE IGCC, Case 2, and the schematic Flow Diagrams of Units 2100, 2200, 2300 and 3000 are attached hereafter.

The H&M balances relevant to the scheme attached are shown in paragraph 4.

CASE 2 – GEE IGCC COMPLEX BLOCK FLOW DIAGRAM





TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

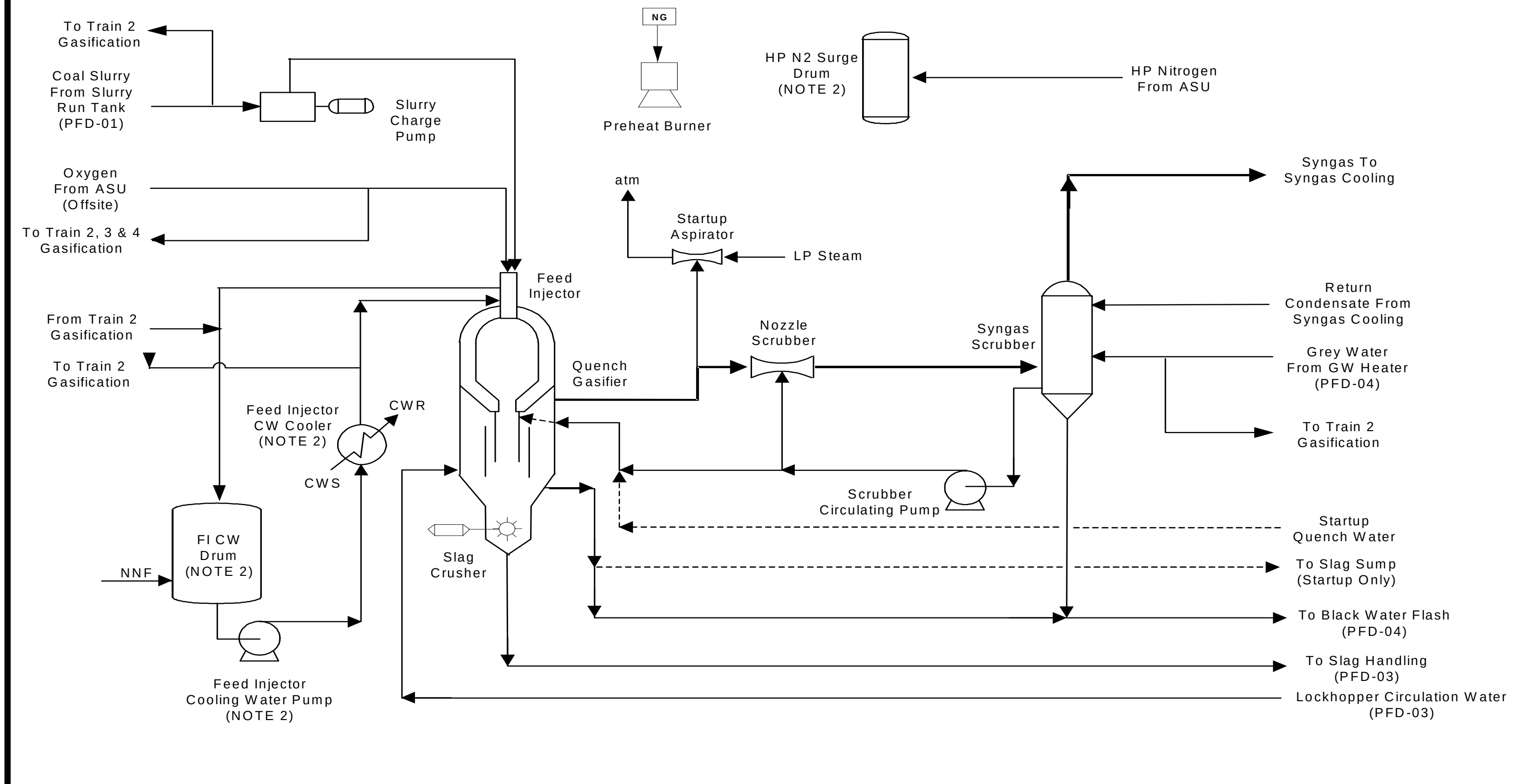
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

2. THE GRINDING SUMP AND DUST COLLECTION SYSTEM ARE COMMON TO ALL TRAINS.

TEXACO GASIFICATION POWER SYSTEMS

COAL GRINDING/SLURRY PREP SECTION

DRAWN	DATE	PROJECT NO.		REV.
DESIGNER	DATE			
CHECKED	DATE	DRAWING NO.	PFD-01	
APPROVED	DATE			



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

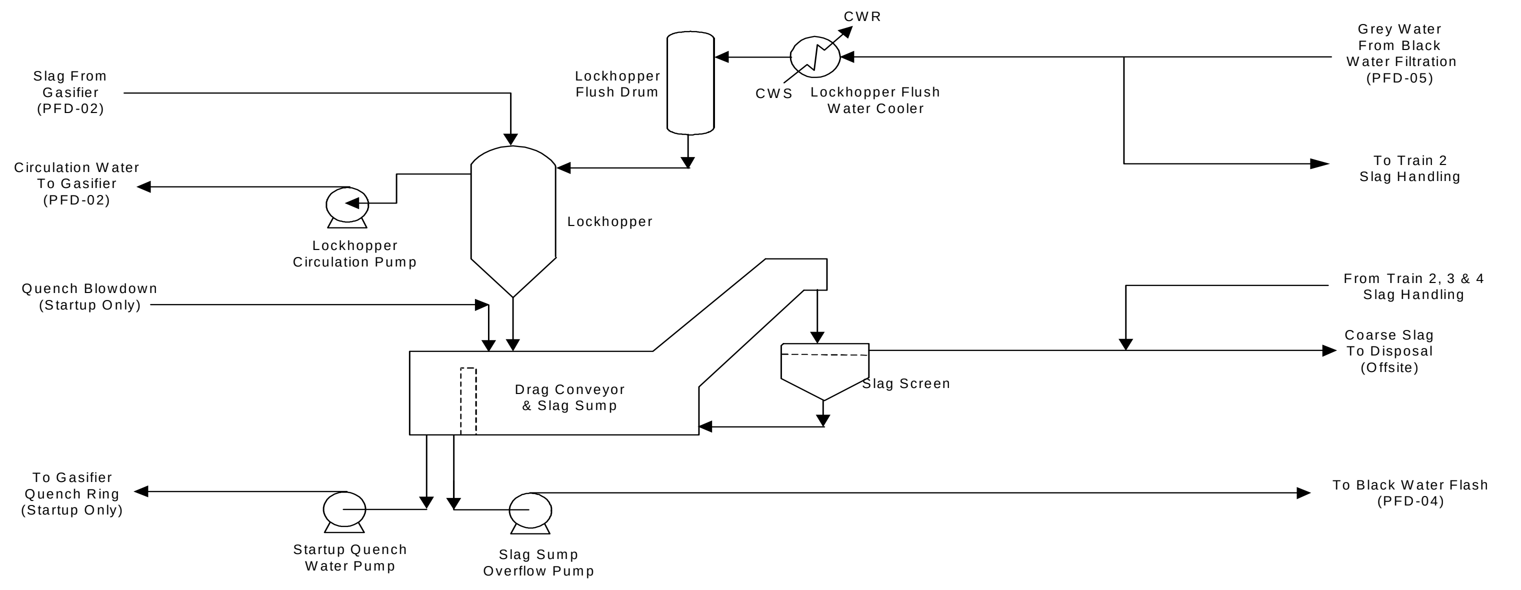
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. FOUR TRAINS AT 33.3% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

2. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED FOR HP N2 SURGE DRUM, FI CW DRUM, FI CW PUMP, AND FI CW COOLER.

TEXACO GASIFICATION POWER SYSTEMS

GASIFICATION SECTION

DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-02	
APPROVED	DATE		



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

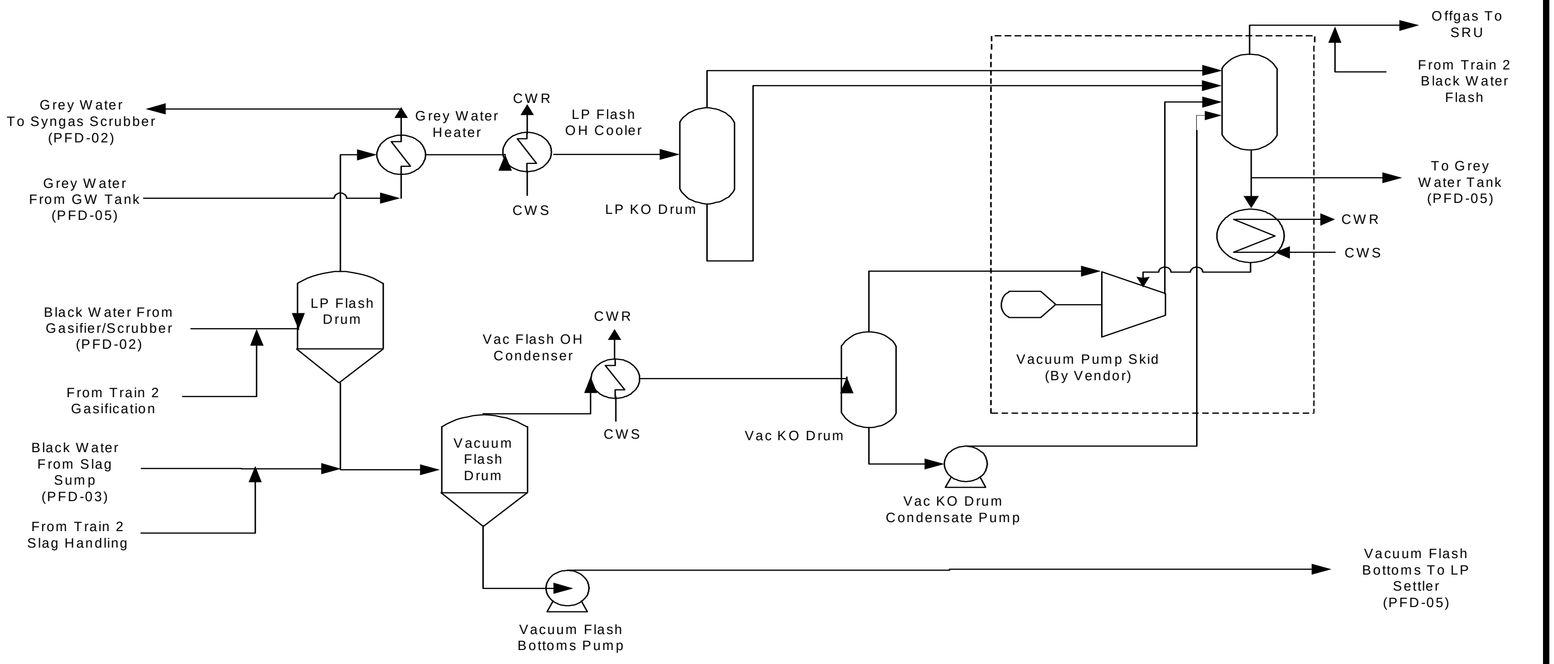
NOTES:

1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. FOUR TRAINS AT 33.3% CAPACITY ARE REQUIRED.

TEXACO GASIFICATION POWER SYSTEMS

SLAG HANDLING SYSTEM

DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-03	
APPROVED	DATE		



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

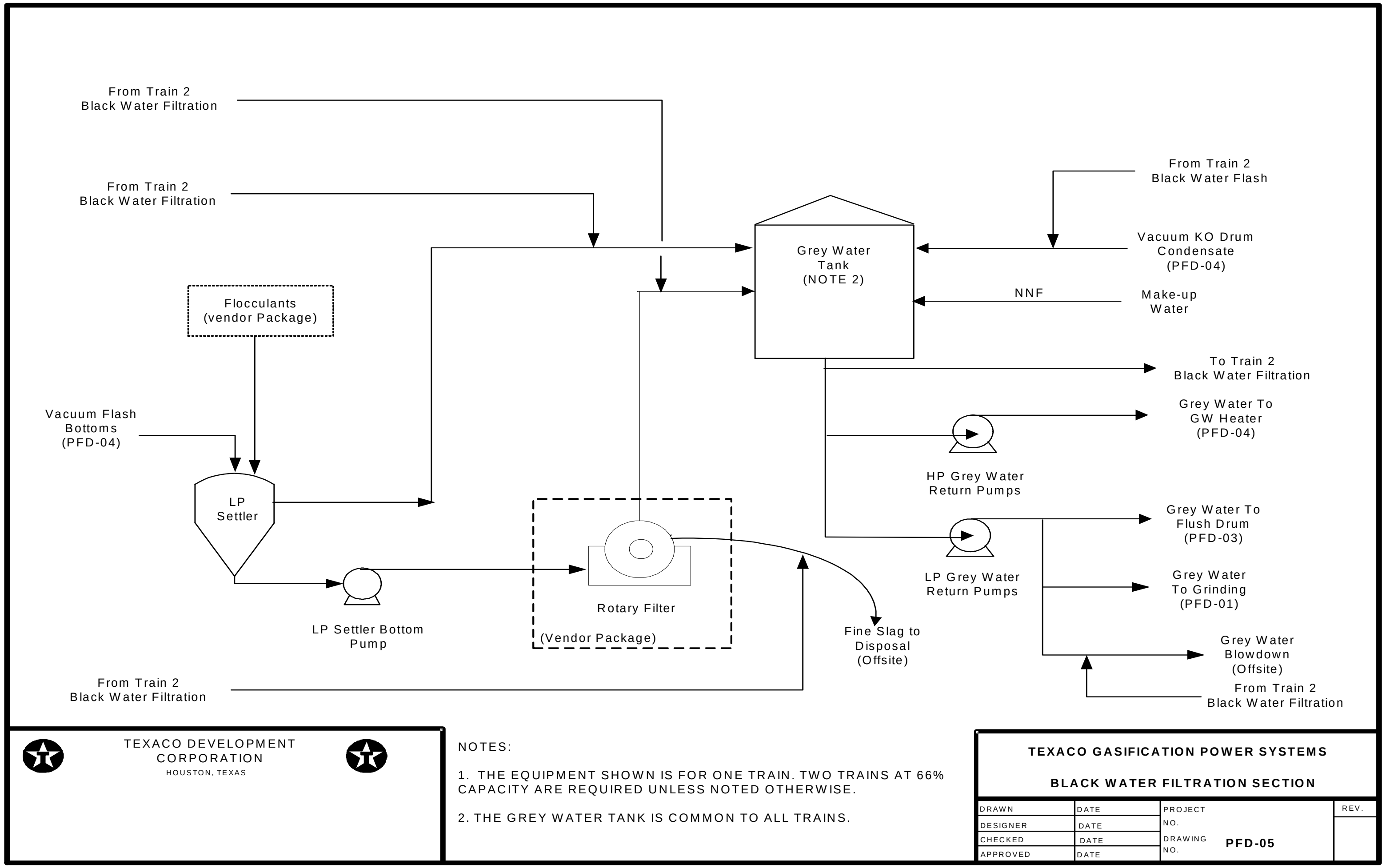
NOTES:

1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

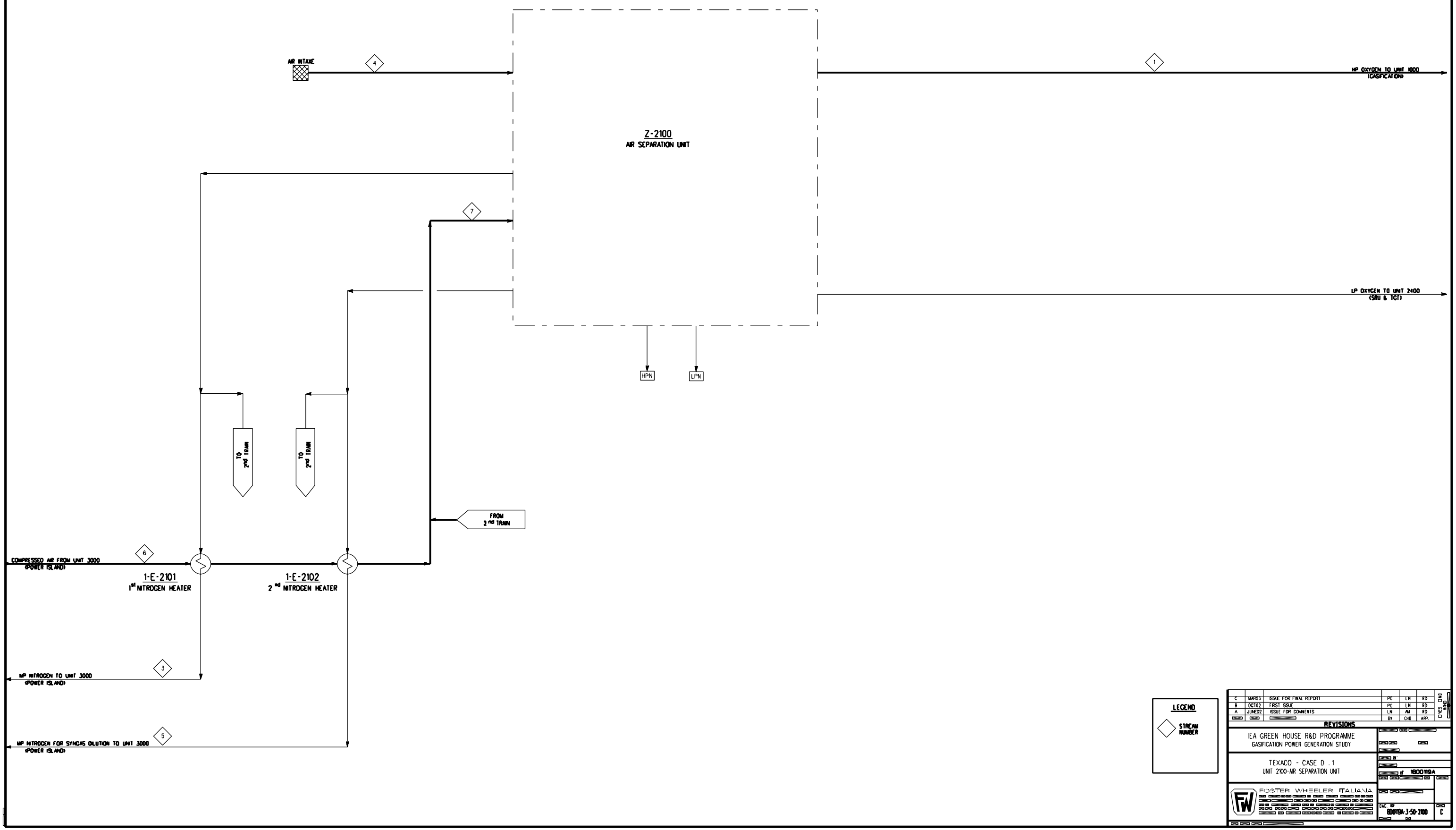
TEXACO GASIFICATION POWER SYSTEMS

BLACK WATER FLASH SECTION

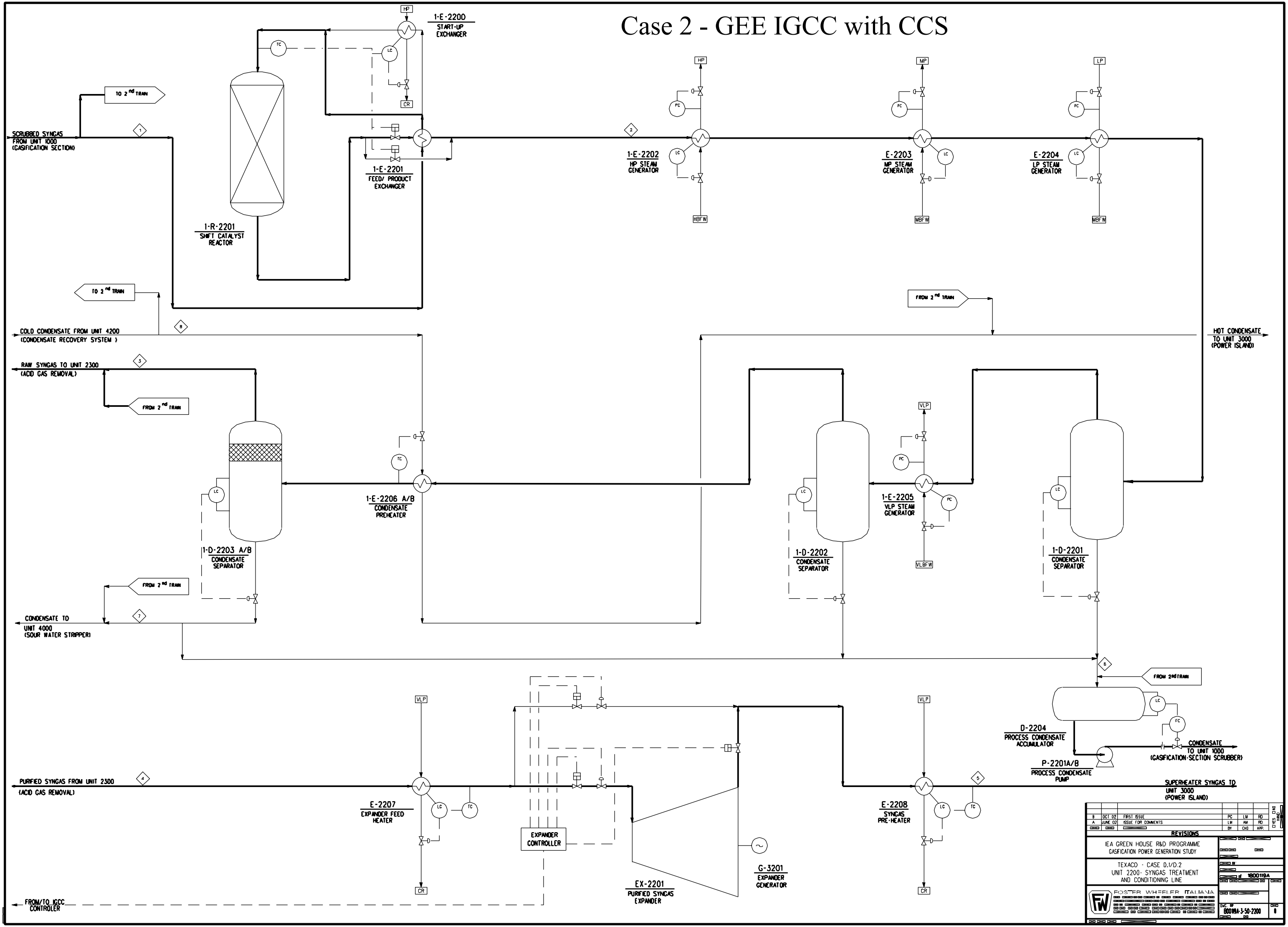
DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-04	
APPROVED	DATE		


From Train 2
Black Water Filtration
From Train 2
Black Water Filtration
From Train 2
Black Water Flash
Grey Water
Tank
(NOTE 2)
Vacuum KO Drum
Condensate
(PFD-04)
NNF
Make-up
Water
Flocculants
(vendor Package)
To Train 2
Black Water Filtration
Vacuum Flash
Bottoms
(PFD-04)
Grey Water To
GW Heater
(PFD-04)
HP Grey Water
Return Pumps
LP
Settler
Grey Water To
Flush Drum
(PFD-03)
LP Grey Water
Return Pumps
Grey Water
To Grinding
(PFD-01)
Rotary Filter
LP Settler Bottom
Pump
(Vendor Package)
Fine Slag to
Disposal
(Offsite)
Grey Water
Blowdown
(Offsite)
From Train 2
Black Water Filtration
From Train 2
Black Water Filtration
TEXACO DEVELOPMENT
CORPORATION
HOUSTON, TEXAS
NOTES:
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. TWO TRAINS AT 66% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.
2. THE GREY WATER TANK IS COMMON TO ALL TRAINS.
TEXACO GASIFICATION POWER SYSTEMS
BLACK WATER FILTRATION SECTION
DRAWN
DATE
DESIGNER
DATE
CHECKED
DATE
APPROVED
DATE
PROJECT
NO.
DRAWING
NO.
PFD-05
REV.

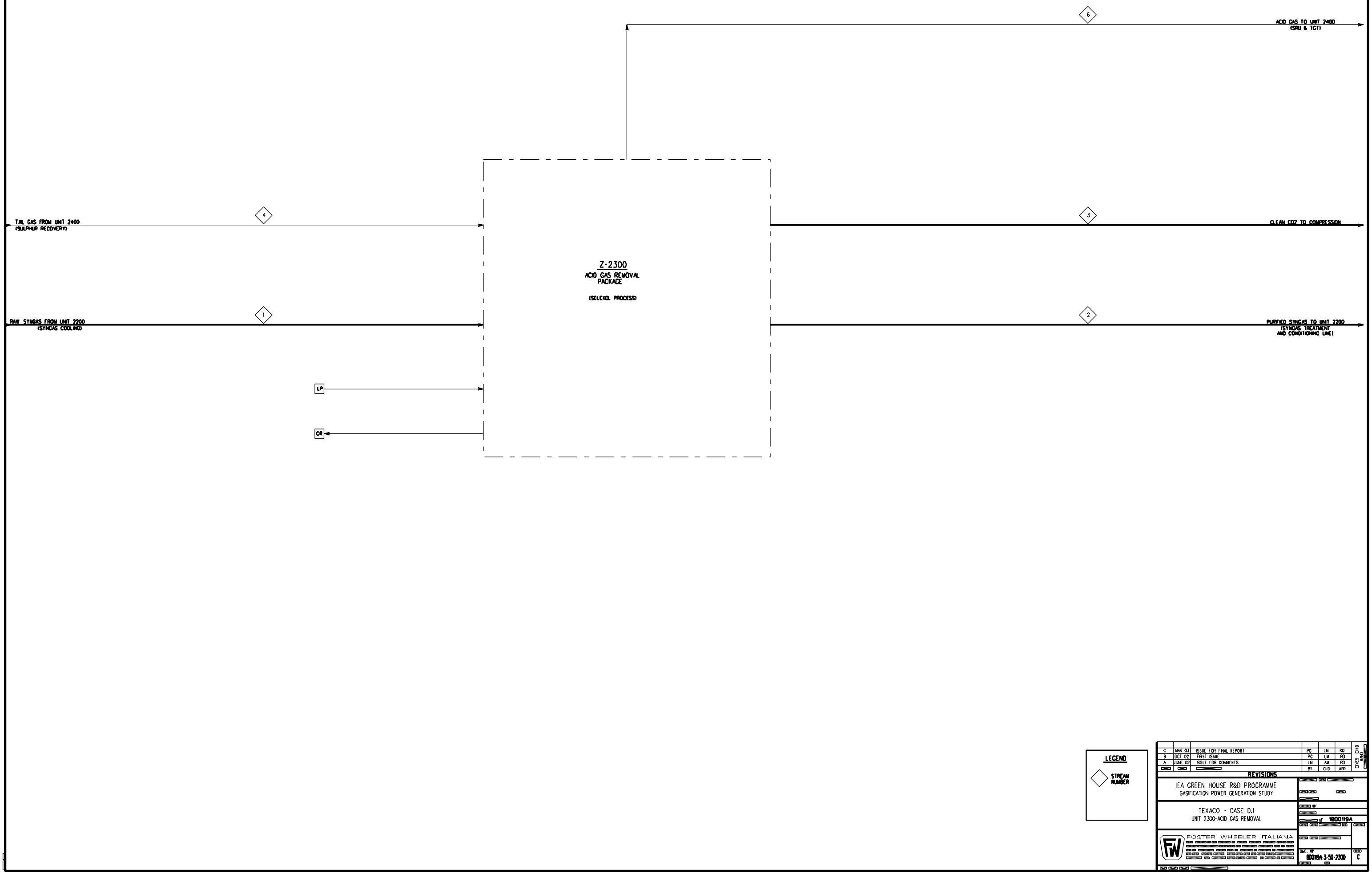
Case 2 - GEE IGCC with CCS

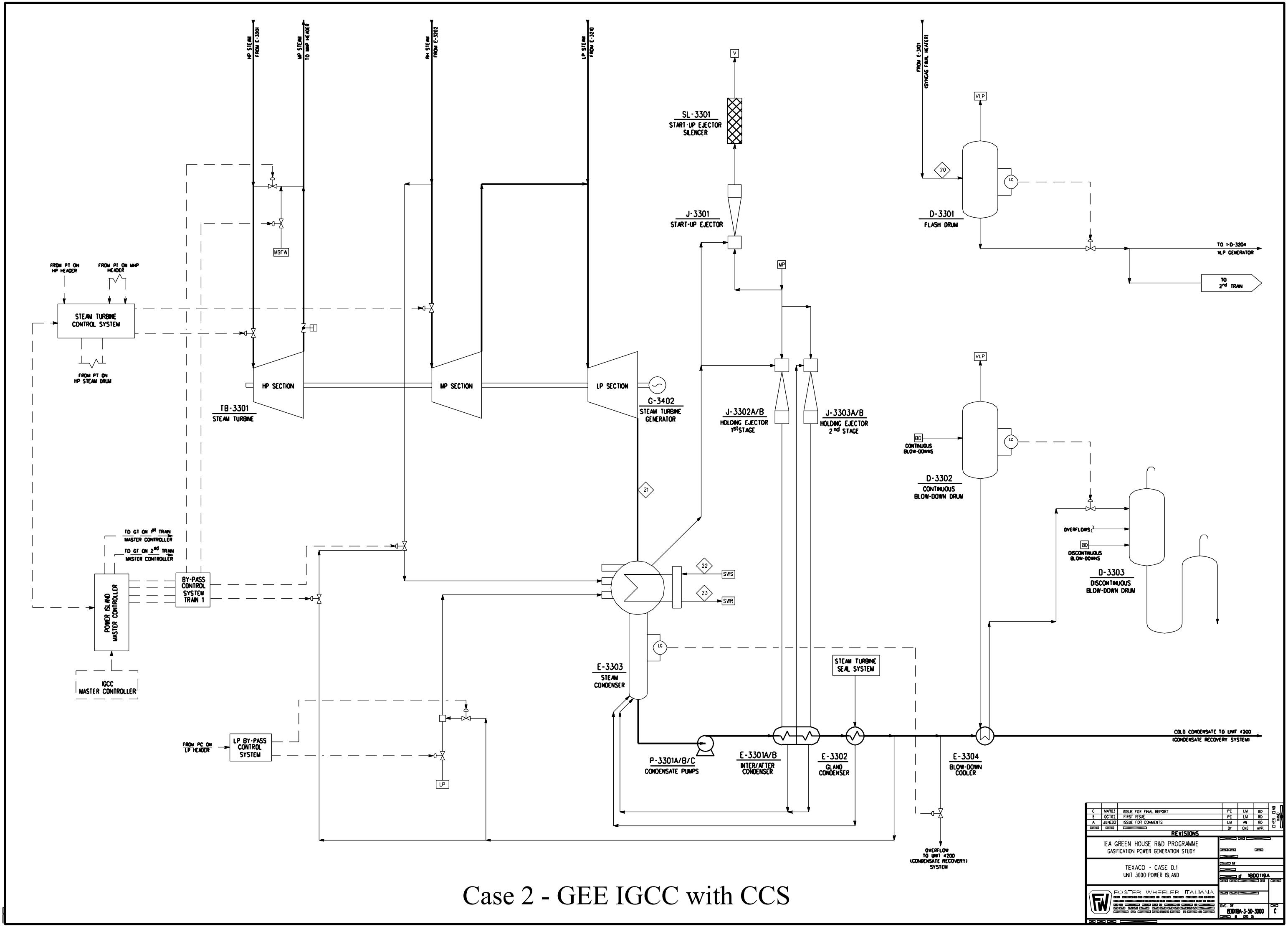


Case 2 - GEE IGCC with CCS



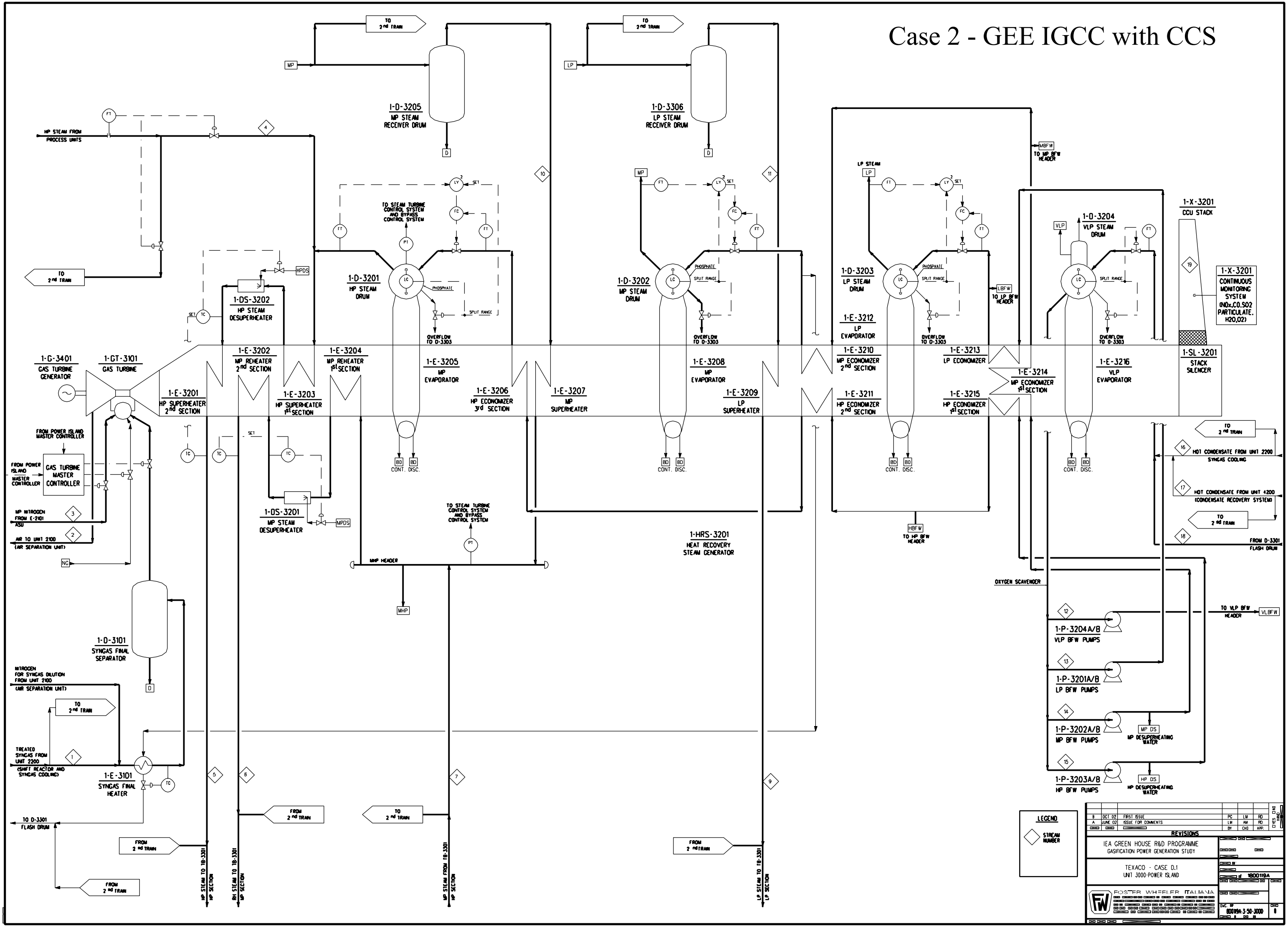
Case 2 - GEE IGCC with CCS





Case 2 - GEE IGCC with CCS

Case 2 - GEE IGCC with CCS



4 Heat and Material Balance

The Heat and Material Balance, referring to the Flow Diagrams attached in the previous paragraph 3, is attached hereafter.
The H&M balance makes reference to the schemes attached to paragraph 3.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
	CLIENT : IEA GHG R&D PROGRAMME						PREP.	NF		
	CASE : GEE IGCC CASE 2						APPROVED	LM		
	UNIT : 2100 AIR SEPARATION UNIT						DATE	February 2011		
STREAM	1	2	3	4	5	6	7	8		
	HP OXYGEN to Gasification	NOT USED	MP NITROGEN to each GT	Air Intake from Atmosphere	MP NITROGEN for Syngas Dilution	Air from each GT	TOTAL Air from GTs	TOTAL Air to ASU		
Temperature (°C)	148.9		212.7	AMB.	209	400	209			
Pressure (bar)	79.8		21.6	AMB.	28.0	14.4	13.9			
TOTAL FLOW										
Mass flow (kg/h)	278700		325206	613137	246834	306569	613137	1226274		
Molar flow (kgmole/h)	8650		11581	21236	8814	10618	21236	42471		
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	278700		325206	613137	246834	306568.5	613137	1226274		
Molar flow (kgmole/h)	8650		11581	21236	8814	10618	21236	42471		
Molecular Weight	32.22		28.00	28.87	28.00	28.87	28.87	28.87		
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	1.50		97.50	77.57	97.50	77.57	77.57	77.57		
O_2	95.00		2.15	20.86	2.15	20.86	20.86	20.86		
CH_4										
H_2S + COS										
Ar	3.50		0.26	0.89	0.26	0.89	0.89	0.89		
H2O			0.09	0.68	0.09	0.68	0.68	0.68		

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
	CLIENT : IEA GHG R&D PROGRAMME						PREP.	NF		
	CASE : GEE IGCC CASE 2						APPROVED	LM		
	UNIT : 2200 Syngas treatment and conditioning line						DATE	February 2011		
STREAM	1	2	3	4	5	6	7	8		
	SYNGAS at Scrubber Outlet to Shift Reactor (2 Trains)	SYNGAS at Shift Reactor Outlet (2 Trains)	RAW SYNGAS to Acid Gas Removal (2 Trains)	HP Purified SYNGAS from Acid Gas Removal (Total)	Treated SYNGAS to Power Island (Total)	Return Condensate to Gasification (2 Trains)	Contaminated Condensate to Stripping (2 Trains)	Cold Condensate from Unit 4200 (2 Trains)		
Temperature (°C)	243	434	38	30	135	160	38	21		
Pressure (bar)	63.3	60.8	57.2	56.2	26.5	57.2	57.2	11.0		
TOTAL FLOW										
Mass flow (kg/h)	694000	694000	388000	159700	159700	298850	6000	605155		
Molar flow (kgmole/h)	36130	36130	19185	24060	24060					
LIQUID PHASE										
Mass flow (kg/h)						298850	6000	605155		
GASEOUS PHASE										
Mass flow (kg/h)	694000	694000	388000	159700	159700					
Molar flow (kgmole/h)	36130	36130	19185	24060	24060					
Molecular Weight	19.21	19.2	20.2	6.6	6.6					
Composition (vol %)										
H_2	15.13	29.25	55.04	86.75	86.75					
CO	15.64	1.51	2.84	4.43	4.43					
CO_2	7.33	21.46	40.22	6.47	6.47					
N_2	0.36	0.36	0.68	1.07	1.07					
O_2	0.00	0.00	0.00	0.00	0.00					
CH_4	0.01	0.01	0.02	0.03	0.03					
H_2S + COS	0.12	0.12	0.22	0.00	0.00					
Ar	0.49	0.42	0.79	1.23	1.23					
H2O	60.99	46.87	0.19	0.02	0.02					

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
	CLIENT : IEA GHG R&D PROGRAMME						PREP.	NF		
	CASE : GEE IGCC CASE 2						APPROVED	LM		
	UNIT : 2300 Acid Gas Removal						DATE	February 2011		
STREAM	1	2	3	4	5	6				
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	Clean CO2 to Compression	Recycle Tail Gas from SRU	NOT USED	Acid Gas to SRU & TGT				
Temperature (°C)	38	30	-	38		49				
Pressure (bar)	57.2	56.2	(1)	28.3		1.8				
TOTAL FLOW										
Mass flow (kg/h)	776000	159700	626354	25294		19573				
Molar flow (kgmole/h)	38370	24060	14550	622		485				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	776000	159700	626354	25294		19573				
Molar flow (kgmole/h)	38370	24060	14550	622		485				
Molecular Weight	20.2	6.6	43.0	40.7		40.4				
Composition (vol %)										
H_2	55.04	86.75	1.80	2.88		0.37				
CO	2.84	4.43	0.17	0.03		0.04				
CO_2	40.22	6.47	97.12	83.71		75.15				
N_2	0.68	1.07	0.55	12.47		0.00				
O_2	0.00	0.00	0.00	0.00		0.00				
CH_4	0.02	0.03	0.00	0.00		0.00				
H_2S + COS	0.22	0.00	0.01	0.52		17.94				
Ar	0.79	1.23	0.05	0.13		0.01				
H2O	0.19	0.02	0.30	0.26		6.49				

Note: (1) - CO2 stream is the combination of three different streams at following pressue levels: 28 bar; 11 bar; 1.5 bar;

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GHG R&D PROGRAMME						PREP.	NF		
	CASE : GEE IGCC CASE 2						APPROVED	LM		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	February 2011		
STREAM	1	2	3	4						
	Acid Gas from AGR Unit	Product Sulphur	Off-Gas from Gasification	Claus Tail Gas to AGR Unit						
Temperature (°C)	49		82.2	38						
Pressure (bar)	1.8		1.0	28.3						
TOTAL FLOW										
Mass flow (kg/h)	19573	66.8 (t/d)	4235	25294						
Molar flow (kgmole/h)	485.0		200	622						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	19573		4235	25294						
Molar flow (kgmole/h)	485.0		200	622						
Molecular Weight	40.4		21.2	40.7						
Composition (vol %)										
H_2	0.37		21.15	2.88						
CO	0.04		28.45	0.03						
CO_2	75.15		13.49	83.71						
N_2	0.00		0.00	12.47						
O_2	0.00		0.00	0.00						
CH_4	0.00		0.00	0.00						
H_2S + COS	17.94		1.14	0.52						
Ar	0.01		0.00	0.13						
H2O	6.49		35.77	0.26						

FOSTER WHEELER

IGCC HEAT & MATERIAL BALANCE

CLIENT : IEA GHG R&D PROGRAMME
CASE : GEE IGCC CASE 2
UNIT : 3000 POWER ISLAND

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	Treated SYNGAS from Syngas Cooling (*) (1)	79.85	135	26.5	326.0
2	Extraction Air to Air Separation Unit (*)	306.57	400	14.4	-
3	MP Nitrogen from ASU (*)	325.2	212.70	21.60	-
4	HP Steam from Process Units (*)	26.30	348	161.0	2582
5	HP Steam to Steam Turbine (*)	231.49	552	156.5	3447
6	Hot RH Steam to Steam Turbine (*)	369.39	527	36.7	3510
7	MP Steam from Steam Turbine (*)	231.49	344	39.7	3080
8	- - NOT USED - -				
9	LP Steam to Steam Turbine (*)	235.76	237	6.1	2930
10	MP Steam to MP -Superheater (*)	137.90	251.8	41.0	2800
11	LP Steam to LP Superheater (*)	235.76	166.8	7.2	2765
12	BFW to VLP Pumps (*)	36.15	119	1.9	499
13	BFW to LP BFW Pumps (*)	299.57	119	1.9	499
14	BFW to MP BFW Pumps (*)	163.11	119	1.9	499
15	BFW to HP BFW Pumps (*)	235.06	119	1.9	499
16	Hot Condensate returned from Unit 2200 (*)	605.15	98	2.5	454
17	Hot Condensate returned from CR (*)	82.90	94	2.5	394
18	Water from Flash Drum (*)	20.93	119	1.9	499
19	FLUE GAS AT STACK (*) (2)	2556.00	129	AMB.	117
20	Condensate from Syngas Final Heater (*)	46.56	170	1.9	722
21	LP Steam Turbine exhaust	1210.31	21.7	0.026	2220
22	Sea Water Supply to Steam Condenser	88003	12	3.0	50.5
23	Sea Water Return from Steam Condenser	88003	19	2.1	79.8

(*) flowrate for one train
(1) Syngas composition as per stream 5 of Material Balance for Unit 2200 .
(2) Flues gas molar composition: N_2: 75.7%; H_2O: 11.7%; O_2: 10.2%; CO_2: 1.4%; Ar: 1%.

5 Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter, for both base load operation and partial load operation, considering or a single gas turbine in operation to produce around 50% of the plant power output or two gas turbine in operation at the plant minimum efficient load, i.e. 70% of the ASU and CO_2 compressor load.

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2 - Base load

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**21.5**						**21.5**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**423.6**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**165.8**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	REVISION / DATE	Draft / Jun-11	Rev.1 / Rev.2
PROJECT:	Operating Flexibility of Power Plants with CCS	ISSUED BY	NF	
LOCATION:	Netherlands	CHECKED BY	PC	
FWI Nº:	1- BD 0530 A	APPROVED BY	LM	

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2 - 50% NPO

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	2.5 (2)								2.5	
2100	**Air Separation Unit**			10.8						10.8	
2200	**Syngas Treating and Conditioning Line**	-26.3	-60.8	-264.2	-10.2	26.5	61.4	266.8	36.5	25.9	3.9
2300	**Acid Gas Removal**			36.2						36.2	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		-0.7	-0.6			2.2	0.6		1.5	0.0
3000	**POWER ISLANDS UNITS**	23.7	61.4	205.8	10.2	-26.5	-63.6	-267.4	-36.5		
4000 to 5300	**UTILITY and OFFSITE UNITS**			12.0						12.0	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.9	3.9

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2 - Minimum effcient load

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.5** (2)								**3.5**	
2100	**Air Separation Unit**			**14.9**						**14.9**	
2200	**Syngas Treating and Conditioning Line**	**-36.3**	**-84.0**	**-365.4**	**-14.2**	**36.7**	**84.9**	**369.0**	**50.5**	**35.9**	**5.4**
2300	**Acid Gas Removal**			**50.1**						**50.1**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.8**			**3.0**	**0.9**		**2.1**	**0.0**
3000	**POWER ISLANDS UNITS**	**32.8**	**85.0**	**289.3**	**14.2**	**-36.7**	**-87.9**	**-369.9**	**-50.5**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**118.4**	**5.4**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separated H_2S and CO_2 removal, Case 2 - Base load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	283.0		3122	
2100	**Air Separation Unit**				25682
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			3053	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			330	
2500	**CO2 Compression and drying**				(6780)
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1742	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		88003
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				14777
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE excluding CO2 compression	300.3	0	8611	128462
	BALANCE including CO2 compression	300.3	0	8611	135242

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	Jun-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separated H_2S and CO_2 removal, Case 2 - 50% NPO

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**141.5**		**1561**	
2100	**Air Separation Unit**				**12841**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**1527**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**165**	
2500	**CO2 Compression and drying**				**(3390)**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**				
				852	
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**38673**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**7661**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE excluding CO2 compression	**158.8**	**0**	**4469**	**59174**
	BALANCE including CO2 compression	**158.8**	**0**	**4469**	**62564**

Note: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2 - Minimum efficient load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	195.7		2159	
2100	**Air Separation Unit**				27366
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			2112	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			228	
2500	**CO2 Compression and drying**				4746
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			1156	
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		52802
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				10318
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	213.0	0	6019	95232

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - GEE IGCC - CASE 2 - Base load - HP with CO_2 capture, separated H_2S and CO_2 removal

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**128620**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**(38500)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4769**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2158**
3500	**Miscellanea**	**598**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**(500)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE excluding CO2 compression	**203511**
	BALANCE including CO2 compression	**242511**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	Jun-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - GEE IGCC - CASE 2 - 50% NPO

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**180**
1000	**Gasification Section**	**6962**
2100	**Air Separation Unit**	**65558**
2200	**Syngas treatment and conditioning line**	**126**
2300	**Acid Gas Removal**	**16522**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**1777**
2500	**CO2 Compression and drying**	**(19250)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2353**
3200	**Heat Recovery Steam Generator**	**2332**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1022**
3500	**Miscellanea**	**292**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**5813**
	Additional consumption including CO_2 compression and drying	**(250)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE excluding CO2 compression	**104026**
	BALANCE including CO2 compression	**123526**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2 - Minimum efficient load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**250**
1000	**Gasification Section**	**9630**
2100	**Air Separation Unit**	**133893**
2200	**Syngas treatment and conditioning line**	**175**
2300	**Acid Gas Removal**	**22855**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2459**
2500	**CO2 Compression and drying**	**26950**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**3026**
3200	**Heat Recovery Steam Generator**	**3164**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1432**
3500	**Miscellanea**	**397**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**8214**
	Additional consumption including CO_2 compression and drying	**346**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**213875**

Notes: (1) Minus prior to figure means figure is generated

6 Overall performance

The table summarizing the Overall Performance of the GEE IGCC power plant, case 2, is attached hereafter, for both base load operation and partial load operation, considering or a single gas turbine in operation to produce around 50% of the plant power output or two gas turbine in operation at the plant minimum efficient load, i.e. 70% of the ASU and CO_2 compressor load.

GEE IGCC				
High pressure with CO_2 capture, separated H_2S and CO_2 removal				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		base load 2x100% GT	**part load** 1x100% GT	**Min. efficient load**
Coal Flowrate (fresh, air dried basis)	t/h	323.1	161.6	223.5
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**1160.9**	**1605.9**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	819.0	1132.8
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	744.2	1029.4
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	281.6	362.1
Steam turbine power output	MWe	398.0	188.5	275.7
Expander power output	MWe	11.2	5.6	7.7
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**475.7**	**645.5**
IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	65.6	133.9
Process Units consumption	MWe	50.8	25.4	35.1
Utility Units consumption	MWe	1.7	1.4	1.3
Offsite Units consumption (including sea cooling water system)	MWe	10.2	5.7	8.2
Power Islands consumption	MWe	12.2	6.0	8.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**104.0**	**186.6**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**371.7**	**458.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.0**	**40.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**32.0**	**28.6**
IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	19.3	27.0
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.3	0.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**123.5**	**213.9**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**352.2**	**431.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.0**	**40.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**30.3**	**26.9**
Specific fuel (coal) consumption per MW net produced	**MWt/MWe**	**3.181**	**3.297**	**3.721**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.158**	**0.178**
Specific water consumption per MW net produced	**t/MWh**	**0.411**	**0.426**	**0.481**

The following Table shows the overall CO_2 removal efficiency of the IGCC Complex.

	Equivalent flow of CO_2, kmol/h
Coal (Carbon=82,5%wt)	17393
Slag (Carbon =~4% wt)	708
Net Carbon flowing to Process Units (A)	16685
Liquid Storage	
CO	24,3
CO_2	14131,4
CH_4	0,3
COS	0,02
Total to storage (B)	14156,0
Emission	
CO_2	2523,5
CO	6,5
Total Emission	2530,0
Overall CO_2 removal efficiency, % (B/A)	84,8

7 Environmental Impact

The GEE IGCC power plant, case 2, is designed to process coal, whose characteristic is shown at Section B of present report, and produce electric power.
The gaseous emissions, liquid effluents and solid wastes from the power plant are summarized in the present paragraph.

7.1 Gaseous Emissions

7.1.1 Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases of the two trains of the Power Island, proceeding from the combustion of the Syngas in the two gas turbines.

The following Table 7-1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 7-1. Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	710
Flow, $Nm^3/h^{(1)}$	2.881.500
Temperature, °C	129
Composition	(%vol)
Ar	0,98
N_2	75,74
O_2	10,21
CO_2	1,35
H_2O	11,72
Emissions	$mg/Nm^{3\,(1)}$
NOx	50
SOx	0,7
CO	31,4
Particulate	4,3

(1) Dry gas, O_2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The expected total gaseous emissions of the Power Island are given in Table 7-2.

Table 7-2. Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1420
Flow, $Nm^3/h^{(1)}$	5.763.000
Temperature, °C	129
Emissions	kg/h
NOx	291,8
SOx	4,0
CO	183,2
Particulate	24,9

(1) Dry gas, O_2 content 15%vol

7.1.2 Minor Emissions

The remainder gaseous emissions within the IGCC Complex are created by process vents and fugitive emissions.
Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable gaseous components are sent to a flare system. Venting via the flare will be minimal during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

7.2 Liquid Effluent

Most of the effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island (21.7 t/h water recovered from WWT vs 35.6 t/h total water effluent). The water effluent from WWT, which is not recycled to the gasification island (13.9 t/h), is to be disposed outside Power Plant battery limit.

Sea water in open circuit is used for cooling.
The return stream Water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 136.000 m^3/h
- Temperature : 19 °C
- Cl_2 : <0.05 ppm

7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2.5 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.
In addition, the Gasification Island is expected to produce the following solid byproducts:

<u>Fine Slag</u>

Flow rate	:	31,8	t/h
Water content	:	70	%wt

<u>Coarse Slag</u>

Flow rate	:	76,3	t/h
Water content	:	50	%wt

Both slag products can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

8 Equipment List

The list of main equipment and process packages is included in this paragraph.

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EQUIPMENT LIST

Unit 1000 - Gasification Unit - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		Syngas scrubber							
		Black water flash drum							
		Black water flash drum							
		Grey water tank							
		Grey water tank							
		Grey water tank							
		Drag conveyor and slag screen							
		Rotatory filter							
		Gasification section							

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EQUIPMENT LIST

Unit 2100 - Air Separation Unit - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		**S, m2**		shell / tube	shell / tube		
1	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14236 kW
2	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14236 kW
1	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3550 kW
2	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3550 kW
		PACKAGES							
	Z-2100	**Air Separation Unit Package** (two parallel trains, each sized for 50% of the capacity)		HP O_2 flow rate to Gasifier = 290 t/h		85			Oxygen purity = 95 %
				MP N_2 flow rate to GTs = 900 t/h		27			Nitrogen purity = 98 %
				LP N_2 flow rate to Proc Unit = 2.7 t/h		14			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 620 t/h					Nitrogen purity = 99,99 %
		ASU Compressors		126.9 MW					
		ASU Heat Exchangers	Shell & Tube	16 services; duty=12 MWth each; surface = 1000 m2 each				tubes: titanium shell: CS	sea water coolers
		ASU chiller		5.2 MW th @ 5°C					

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16670 kW H2 service H2/Wet H2S serv. on channel
2	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16670 kW H2 service H2/Wet H2S serv. on channel
1	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 14840 kW H2 service H2/Wet H2S serv. on channel
2	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 14840 kW H2 service H2/Wet H2S serv. on channel
1	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37055 kW H2 service H2/Wet H2S serv. on channel
2	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37055 kW H2 service H2/Wet H2S serv. on channel
1	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 155600 kW H2 service H2/Wet H2S serv. on channel
2	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 155600 kW H2 service H2/Wet H2S serv. on channel
1	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel
2	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube		
1	**E-2206 A/B**	**Condensate Preheater**	Shell & Tube	exchanger area = 3200 m2 (exchanger A+B)		20 / 68	130 / 185		DUTY = 50670 kW H2 service H2/Wet H2S serv. on channel
2	**E-2206 A/B**	**Condensate Preheater**	Shell & Tube	exchanger area = 3200 m2 (exchanger A+B)		20 / 68	130 / 185		DUTY = 50670 kW H2 service H2/Wet H2S serv. on channel
	E-2207	**Expander Feed Heater**	Shell & Tube			7 / 68	165 / 175		DUTY = 19690 kW H2 service H2/Wet H2S serv. on channel
	E-2208	**Syngas pre-heater**	Shell & Tube			7 / 68	165 / 175		DUTY = 11270 kW H2 service H2/Wet H2S serv. on channel

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS		D,mm x TT,mm					
1	D-2201	**Condensate Separator**	Vertical			68	205		Wet H2S service/H2 service
2	D-2201	**Condensate Separator**	Vertical			68	205		Wet H2S service/H2 service
1	D-2202	**Condensate Separator**	Vertical			68	185		Wet H2S service/H2 service
2	D-2202	**Condensate Separator**	Vertical			68	185		Wet H2S service/H2 service
1	D-2203 A/B	**Condensate Separator**	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
2	D-2203 A/B	**Condensate Separator**	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
	D-2204	**Process Condensate Accumulator**	Horizontal			68	190		
		PUMPS		$Q,m^3/h$ x H,m					
	P-2201 A/B	**Process condensate pump**	centrifugal						One operating, one spare
		REACTOR		D,mm x TT,mm					
1	R-2201	**Shift Catalyst Reactor**	vertical			68	464		H2 service Wet H2S service
2	R-2201	**Shift Catalyst Reactor**	vertical			68	464		H2 service Wet H2S service

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		EXPANDERS							
	EX- 2201	**Purified Syngas Expander**	centrifugal	Pout/Pin = 0,51 Flow = 590 kNm^3/h Pow = 10.5 MWe					
		GENERATORS		**P, MWe**					
	G-3201	**Expander Generator**							
		PACKAGE UNITS							
	Z-2201	**Catalyst Loading System**							
	Z-2202	**Shift Catalyst**							Catalyst volume: 150 m^3

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=66.8 t/d					Sulphur content = 99,9 wt min (dry basis)
				Acid Gas from AGR = 485 kmol/h		6	65		Sulphur content = 17.94 % (wet basis)
				Sour gas from Gasif. = 200 kmol/h		5	110		Sulphur content = 1,1 % (wet basis)
				Expected Treated Tail Gas=622 kmol/h		33	70		Major components (wet basis): CO_2 = 83.71%, H_2=2.88%, N_2 = 12.47%

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EQUIPMENT LIST

Unit 2500 - CO_2 compression - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		Compression package							
		Compressor	3 stage compressor	165000 Nm3/h x overall β = 73; β per stage = 4.5 approx	motor = 20 MW each machine			SS	2 x 50% machines (165000 Nm3/h each)
		Intercoolers	Shell & tube	19 MWth				tubes: Titanium shell: SS	6 shell and tube, 19 MWth each sea water heat exchangers
		Dryer							

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2050 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2050 kW Tubes: H2 service
		DRUMS		D,mm x TT,mm					
1	**D-3101**	**Syngas Final Separator**	vertical			68	200		H2 service
2	**D-3101**	**Syngas Final Separator**	vertical			68	200		H2 service
		PACKAGES							
1	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	282 MW					Included in 1-Z- 3101 Included in 1-Z- 3101
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	282 MW					Included in 2-Z- 3101 Included in 2-Z- 3101

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		$Q,m^3/h$ x H,m					
1	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	**D-3205**	**MP Steam Receiver Drum**	horizontal			44	260		
2	**D-3205**	**MP Steam Receiver Drum**	horizontal			44	260		
1	**D-3206**	**LP Steam Receiver Drum**	horizontal			12	250		
2	**D-3206**	**LP Steam Receiver Drum**	horizontal			12	250		
		MISCELLANEA		D,mm x H,mm					
1	**X-3201**	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
2	**X-3201**	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
1	**STK-3201**	**CCU Stack**							
2	**STK-3201**	**CCU Stack**							
1	**SL-3201**	**Stack Silencer**							
2	**SL-3201**	**Stack Silencer**							
1	**DS-3201**	**MP Steam Desuperheater**							Included in 1-HRSG-3201
2	**DS-3201**	**MP Steam Desuperheater**							Included in 2-HRSG-3201
1	**DS-3202**	**HP Steam Desuperheater**							Included in 1-HRSG-3201
2	**DS-3202**	**HP Steam Desuperheater**							Included in 2-HRSG-3201
		PACKAGES							
	Z-3201	**Fluid Sampling Package**							
	Z-3202	**Phosphate Injection Package**							Included in Z - 3202
	D-3204	Phosphate storage tank							Included in Z - 3202
	P-3204 a/b/c	Phosphate dosage pumps							One operating , one spare
	Z-3203	**Oxygen Scavanger Injection Package**							Included in Z - 3203
	D-3205	Oxygen scavanger storage tank							Included in Z - 3203
	P-3205 a/b/c	Oxygen scavanger dosage pumps							One operating , one spare
	Z-3204	**Amines Injection Package**							Included in Z - 3204
	D-3206	Amines Storage tank							Included in Z - 3204
	P-3206 a/b/c	Amines Dosage pumps							One operating , one spare

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Superheater**							Included in 1-HRS-3201
1	E-3208	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**LP Superheater**							Included in 1-HRS-3201
1	E-3210	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3212	**LP Evaporator**							Included in 1-HRS-3201
1	E-3213	**LP Economizer**							Included in 1-HRS-3201
1	E-3214	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3216	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	feb-11			
		ISSUED BY	NF			
		CHECKED BY	PC			
		APPROVED BY	LM			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
2	D-3201	**HP steam Drum**							Included in 2-HRS-3201
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3207	**MP Superheater**							Included in 2-HRS-3201
2	E-3208	**MP Evaporator**							Included in 2-HRS-3201
2	E-3209	**LP Superheater**							Included in 2-HRS-3201
2	E-3210	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3212	**LP Evaporator**							Included in 2-HRS-3201
2	E-3213	**LP Economizer**							Included in 2-HRS-3201
2	E-3214	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3216	**VLP Evaporator**							Included in 2-HRS-3201

FOSTER WHEELER		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
	CLIENT: IEA GHG R&D PROGRAMME	DATE	feb-11			
	LOCATION: Netherlands	ISSUED BY	NF			
	PROJ. NAME: Operating Flexibility of Power Plants with CCS	CHECKED BY	PC			
	CONTRACT N. 1- BD- 0530 A	APPROVED BY	LM			

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		**S, m2**		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	58 / 140		DUTY = 853 kW
		DRUMS		**D,mm x TT,mm**					
	D-3301	**Flash Drum**	vertical			3.5	230		
	D-3302	**Continuous Blow-down Drum**	vertical			3.5	140		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3.5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine		428 MWe gross					Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser	shell & tube	702 MW th				tubes: titanium; shell: CS	Included in Z - 3201 Sea water heat exchanger
	G-3402	Steam Turbine Generator							Included in Z - 3201
	J-3301	Start-up Ejector							Included in Z - 3201
	J-3302 A/B	Holding Ejector 1st Stage							Included in Z - 3201
	J-3303 A/B	Holding Ejector 2nd Stage							Included in Z - 3201
	P-3301A/B/C	Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
	SL-3301	Start-up Ejector Silencer							Included in Z - 3201

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION / DATE / ISSUED BY / CHECKED BY / APPROVED BY	Rev.: Draft: feb-11, NF, PC, LM; Rev.: 1; Rev.2; Rev.3

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - GEE IGCC - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2, Case 2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	**G-3401**	**Gas Turbine Generator**							Included in 1 -Z- 3101
2	**G-3401**	**Gas Turbine Generator**							Included in 2 -Z- 3101
	G-3402	**Steam Turbine Generator**							Included in Z- 3301
				MISCELLANEA EQUIPMENT					
		Closed loop water cooler	shell and tube	120 MW th				plates: titanium frame: SS	sea water
		Close loop CW pumps	centrifugal	8610 m3/h x 30m	1290 kWe			CS	1 pump in operation + 1 spare
		Waste water treatment plant							
		Sea water pumps	submerged	20000 m3/h x 20m	1640 kWe			casing, shaft: SS; impeller: duplex	7 pumps in operation + 1 spare
		Seawater chemical injection							
		Sea water inlet/outlet works							

9 Investment cost

The main cost estimating bases are shown in section B of this report. This section details the investment cost of the following units or blocks of units:

Unit 900	Coal Handling and Storage
Unit 1000	Gasification
Unit 2100	ASU
Unit 2200	Syngas Treatment and Conditioning Line
Unit 2300	AGR
Unit 2400	SRU & TGT
Unit 2500	CO_2 Compression and Drying
Unit 3000	Power Island
Unit 4000	Utility & Offsites

The overall investment cost of each unit is split into the following items:

- **Direct Materials:** including equipment and bulk materials;
- **Construction**: including mechanical erection, instrument and electrical installation, civil works, buildings and site preparation;
- **Other Costs:** including temporary construction facilities, solvent, chemicals, training, commissioning and start-up costs, spare parts;
- **EPC services:** including Contractor's home office services and construction supervision.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : May-11
Rev. : 0

CASE 2 - IGCC WITH CCS (reference case)

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	135,003,000	47,339,000	43,594,000	30,917,000	29,766,000	438,499,000	122,195,000	1,051,321,000	
2	CONSTRUCTION	1,853,000	77,366,000	35,971,000	20,857,000	18,091,000	12,357,000	6,610,000	97,365,000	59,691,000	330,161,000	
3	OTHER COSTS	996,000	27,699,000	5,151,000	12,376,000	19,528,000	4,129,000	1,421,000	41,831,000	11,656,000	124,787,000	
4	EPC SERVICES	1,338,000	57,945,000	17,320,000	12,456,000	8,810,000	3,966,000	1,782,000	30,003,000	20,902,000	154,522,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	193,445,000	93,028,000	90,023,000	51,369,000	39,579,000	607,698,000	214,444,000	1,660,791,000	
5	CONTINGENCY	1,000,000	25,000,000	9,700,000	6,500,000	6,300,000	3,600,000	2,000,000	42,500,000	10,700,000	107,300,000	
6	LICENSE FEES	300,000	7,100,000	3,900,000	1,900,000	1,800,000	1,000,000	800,000	12,200,000	4,300,000	33,300,000	
7	OWNER COSTS	700,000	17,800,000	9,700,000	4,700,000	4,500,000	2,600,000	2,000,000	30,400,000	10,700,000	83,100,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	216,745,000	106,128,000	102,623,000	58,569,000	44,379,000	692,798,000	240,144,000	1,884,491,000	

10 Operating and Maintenance Costs

The Operating and Maintenance Costs of this case are summarised in the following table. Fixed costs have been considered constant, independently from the plant operating mode, and are expressed as M€/y.
Variable costs, expressed as €/h, are evaluated for the two operating modes of the plant, i.e. peak and off-peak operation.

Case	**2**	
Description	IGCC with CCS	
Fixed costs		
Maintenance	60.6	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	33.2	
Total fixed cost, M€/y	103.8	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	13	7
Chemicals and solvents	349	175
Catalysts	134	134
Total variable cost, €/h	497	316

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME : CAPTURE PLANT DEFINITION – CASE 3: USC PC WITH CCS
FWI CONTRACT : 1-BD-0530 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION E.3

INDEX

1 Introduction

The present Case 3 refers to a USC PC plant, fed with bituminous coal, and with post-combustion capture of the produced CO_2

Foster Wheeler has included in the report the outcomes of studies, made by the other Companies, and made available by IEA GHG. However, FW should not be regarded as having endorsed the results of the above third-party studies.

The IEA GHG study 'Water usage and loss Analysis in Power plants without and with CO_2 capture' has been taken as a reference for the configuration and performances of the plant here below described. In particular, Plant description, process schemes and performance data have been taken directly from reference study report.

The main features of the Case 3 configuration of the USC PC plant are:

- Mitsui-Babcok boiler pulverized fuel ultra supercritical design.
- Flue Gas Desulphurization Plant
- DeNOx Plant
- CO_2 capture unit

The configuration of the plant is based on a once through steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the main process units is:

Unit		Trains
100	Coal and Ash Handling	1 x 100%
200	Boiler Island	1 x 100%
300	FGD and Gypsum Handling Plant	1 x 100%
400	DeNOx Plant	1 x 100%
500	Steam Turbine Unit	1 x 100%
600	CO_2 Amine Absorption	1 x 100%
700	CO_2 compression	1 x 100%

2 Process Description

2.1 Overview

This description should be read in conjunction with block flow diagrams attached in the following paragraph 3.

Case 3 is a pulverized coal fired ultra supercritical steam plant. The design is a market based design.

The boiler is staged for low NOx production and is fitted with SCR for NOx abatement and a forced oxidation limestone/gypsum wet FGD system to limit emissions of sulphur dioxide. The carbon dioxide capture plant is based on solvent scrubbing of flue gas with amine solvents followed by steam stripping and recycle of the solvent. Carbon dioxide is then dried and compressed.
A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

2.2 Unit 100 - Coal Handling

A coal handling system is provided to unload, convey, prepare and store the coal delivered to the plant.

Coal is delivered to the site by rail. Train cars are unloaded into hoppers from which the coal is conveyed to the reclaim area. Coal passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal is reclaimed and conveyed on belt conveyors which transfer it to a surge bin located in the crusher tower. The coal is reduced in size by means of a crusher and is then transferred by conveyor to silos from which it is conveyed and fed by weight feeders into mills for pulverization. Pulverised coal exits each mill via the coal piping and is distributed to the coal burners in the furnace front and rear walls.

2.3 Unit 200 – Boiler Island

2.3.1 Coal Combustion

Each coal burner is designed as a low NOx burner with staging of the coal combustion to minimize NOx formation. In addition, additional overfire air is introduced to cool rising combustion products to inhibit NOx formation.

Air from the FD fans is preheated by contact with exhaust gases through regenerative preheaters. This preheated air is distributed to the burner wind box as secondary air. A portion of the air supply (primary air) is routed around the air preheaters and is used as tempering air in the coal pulverisers. Preheated primary air and tempering air are mixed at each pulveriser to obtain the desired pulveriser fuel-air mixture and transport the pulverized fuel to the coal burners.

Hot combustion products exit the furnace and pass through to the radiative and convective heating surfaces and the downstream regenerative preheaters after providing steam generation and steam reheat and thence to the flue gas clean-up plant comprising of the ESP and FGD plant.

2.3.2 Steam Raising

Boiler feedwater enters the economizer, recovers heat from the combustion gases and then passes to the water wall circuits enclosing the furnace. The fluid then passes through heating surface banks to convective primary superheat, radiative secondary superheat and then to convective final superheat. The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and is returned to the IP turbine.

2.3.3 Soot and Ash Handling

A steam fed soot blowing system is provided with an array of retractable nozzles and lances which travel forward to the blowing position, rotate through the blowing cycle and are then withdrawn.
The furnace bottom comprises hoppers with a clinker grinding system situated below it. Ash passes through the clinker grinder to the ash handling system.
Fly ash is collected from the discharge hoppers on the economisers and on the ESPs.

2.4 Unit 400 - DeNOx

SCR is provided to reduce the NOx produced by the boiler form about 317 ppm @ 6% O_2 v/v (corresponding to approximately 650 mg/Nm^3), dry to a level which does not exceed the inlet requirement of the carbon dioxide absorption plant which corresponds to less than 20 ppmv @ 6%O_2 v/v, dry of NO_2. In fact this specification is exceeded and the SCR plant will reduce NO_2 to around 5 ppm @ 6%O_2 v/v, dry. The NO_2, in fact, are expected to be less than 10% (tipically 5%) of the total NOx.
The SCR reactor is designed to achieve a total amount of NOx of 100 ppm @ 6%O_2 v/v, dry and therefore, the amount of NO_2 is expected to be around 5 ppm. Therefore, for an USC PC, the SCR designed for the base case without CO_2 capture, is suitable for the case with CO_2 capture without significant differences.

The catalytic DENOX reactor is situated in the gas stream between the boiler outlet and the air heaters. The reactors consist of catalyst tiers arranged in a number of units with space allowed for future units. A system of rails and runway beams is incorporated for initial and future catalyst loading. Gaseous ammonia is added to air supplied from the FD fan in a mixer and is injected into the flue gas via a grid of headers and nozzles in a horizontal flue shortly after the boiler. Turning vanes are incorporated to ensure good distribution.
A schematic Process Flow Diagram is attached in the following paragraph 3.

2.5 Unit 300 - Flue Gas Desulphurization

Flue gas desulphurization is provided to reduce the sulphur dioxide level in the flue gas from the boiler to around 10 ppm @ 6%O_2 v/v, dry (a level which does not exceed the inlet requirement of the carbon dioxide absorption plant) from an expected inlet level of about 660 ppm @ 6%O_2 v/v, dry based on the specified coal quality.
This unit is designed by ALSTOM. The flue gas enters the spray tower at the bottom and is immediately quenched as it travels upward countercurrent to a continuous spray of process (recycle) slurry produced by multiple spray banks. The recycle slurry (a 15 percent concentration slurry of calcium sulphate, calcium sulphite, unreacted alkali, inert materials, fly-ash, etc.) extracts the sulphur dioxide from the flue gas. Once in the liquid phase, the sulphur dioxide reacts with the dissolved alkali (calcium carbonate) to form dissolved calcium.
The recycle slurry falls from the spray zone into the reaction tank that forms the base of the absorber. This tank is sized to provide sufficient residence time for all of the FGD chemical reactions to take place. Fresh reagent slurry is added to the reaction tank where it reaches equilibrium with the bulk of the recycle slurry prior to being returned to the spray banks via the recycle pumps.
Forced oxidation of the recycle slurry in a limestone wet FGD system produces a more manageable, easily handlable by-product. To produce the fully oxidized by-product, centrifugal blowers supply compressed air to a sparging system in the reaction tank. The oxygen in the air converts the dissolved calcium sulfite ($CaSO_3$) to calcium sulfate ($CaSO_4$), which then crystallizes as $CaSO_4 \cdot 2H_2O$, gypsum.
The produced gypsum is dewatered and delivered with a belt discharge conveyor to the storage system.
A schematic Process Flow Diagram is attached in the following paragraph 3.

2.6 Unit 500 - Steam Turbine Generator

The turbine consists of a HP, IP and LP sections all connected to the generator with a common shaft. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine. Exhaust steam from the IP turbines then flows into the double flow LP turbine system. Boiler and turbine interface data are as follows:

HP turbine inlet	290 bar a / 600°C
HP exhaust	64.5 bar a / 363°C
IP Turbine Inlet	60 bar a / 620°C
LP Turbine Inlet	3.6 Bara
Condenser Pressure	0.04 Bara

Recycled vacuum condensate from the condenser hot well is pumped to the CO_2 capture plant and preheated in the amine stripper overhead condenser and the CO_2 compressor intercoolers. About 96 MWe of heat are picked up and this obviates the need for LP steam extracts in the preheat train. The preheated feedwater stream is then deaerated in the deaerator which is fed with a bleed of IP steam from the IP turbine exit which also deaerates make up demineralised water and condensate returned from the amine stripper reboiler. Following the deaerator, a further bank of preheaters preheats the feed water 300°C prior to the boiler. These heaters are heated by IP turbine extract and finally by HP steam extracts from the turbines.
A schematic Process Flow Diagram is attached in the following paragraph 3.

2.7 Unit 600 - CO_2 Amine Absorption

Treated flue gas from the FGD plant flows into a direct contact quench coolers (two streams), where it is contacted with cooled, circulating water. This adiabatic saturation process cools the gas. The cooled gas is blown into two MEA absorbers arranged in a parallel configuration, where it is contacted in a first packed bed with a countercurrent flow of semi regenerated MEA. Further contact takes place in the second bed with lean, fully regenerated MEA. CO_2 is absorbed from the flue gas and the gas stream is then cooled in a direct contact quench bed at the top of the absorber. Some of the heat of reaction of amine with CO_2 is removed by pump around coolers which reject the heat to cooling water. Additional reaction heat is removed from a pump around at the base of the absorption columns.
Before leaving the column, the gas is scrubbed with make up water to remove any entrained MEA and the gas is then discharged to atmosphere from the top of the absorbers via a short stack section mounted on the absorber top. The gas is discharged to atmosphere at 55°C.

Rich amine is pumped from the bottom of the absorbers and is split into two streams. The first is heated in a cross exchanger with hot stripper bottoms and the preheated rich amine flows to the stripper. The other part of the stream is flashed to produce steam, which is used in the stripping column and this reduces the amount of steam needed in the reboiler. The rich amine prior to being flashed is heated in a pair of exchangers (semi-lean MEA cooler where it is cross exchanged with hot flashed semi-lean amine from the flash drum and Flash preheater which is heated by hot stripper bottoms on their way to the amine cross exchanger). This flash, as well as producing additional stripping steam, partially desorbs carbon dioxide and creates a semi-lean amine stream which is introduced back into the absorber first mass transfer bed.

The fully stripped amine stripper bottoms are re-introduced into the second absorber bed after they have been cooled, finally, in the lean solvent cooler.

Hot rich MEA is regenerated in the stripping column, which has a stripping and rectification section. Flash steam plus some CO_2 from the amine flash drum is used in the top rectifying section of the column. Column traffic in the lower section is created by vertical thermosyphon reboilers arranged around the base of the stripping column. These reboilers are heated by condensing the steam extract from the IP/LP cross over in the power island. Condensate at saturation conditions is returned to the power island deaeration system.

Overhead vapour from the column passes through a disentrainment section and into the column overhead condenser where it is cooled with recycled condensate from the boiler island in a special set of tube passes. The remaining cooling duty is achieved with sea water. The flowsheet shows a single condenser with one cooling water stream but in reality this would be designed with multiple tube passes for cold condensate and seawater cooling to effect the thermal integration scheme.

A two-phase mixture of water and carbon dioxide vapour is disengaged in the overhead accumulator and some of the water is returned to the column as reflux. The excess condensed water is pumped to storage. This water is very clean, so it can be partially used as make-up water in the CO_2 capture plant to reduce the overall water consumption. The excess has to be treated before discharging it to the sea.

Periodically some of the circulating amine is sent to the reclaimer, where it is distilled with sodium carbonate to break down some of the heat stable salts, which are formed from the reaction of trace impurities with the MEA. The heavy residues remaining after this batch regeneration are pumped away for disposal.

MEA is made up into the system from the amine storage tanks.

A schematic Process Flow Diagram is attached in the following paragraph 3.

2.8 Unit 700 - CO_2 compression

Carbon dioxide from the stripper is compressed to a pressure of 74 bara by means of a four stage compressor. The compression includes interstage cooling (with both

recycled condensate from the power island and trim cooling with sea water) and knockout drums to remove and collect condensed water. The carbon dioxide is dehydrated to remove water to a very low level. Beyond the critical point a booster pump is used for the final stage of compression to deliver a dense phase carbon dioxide stream at pipeline pressure assumed to be 110 bara.
A schematic Process Flow Diagram is attached in the following paragraph 3.

2.9 Unit 800 - Balance of Plant (Utility Units)

This comprises all the systems necessary to allow operation of the plant and export of the produced power, as shown on the equipment list attached in the following paragraph 8.

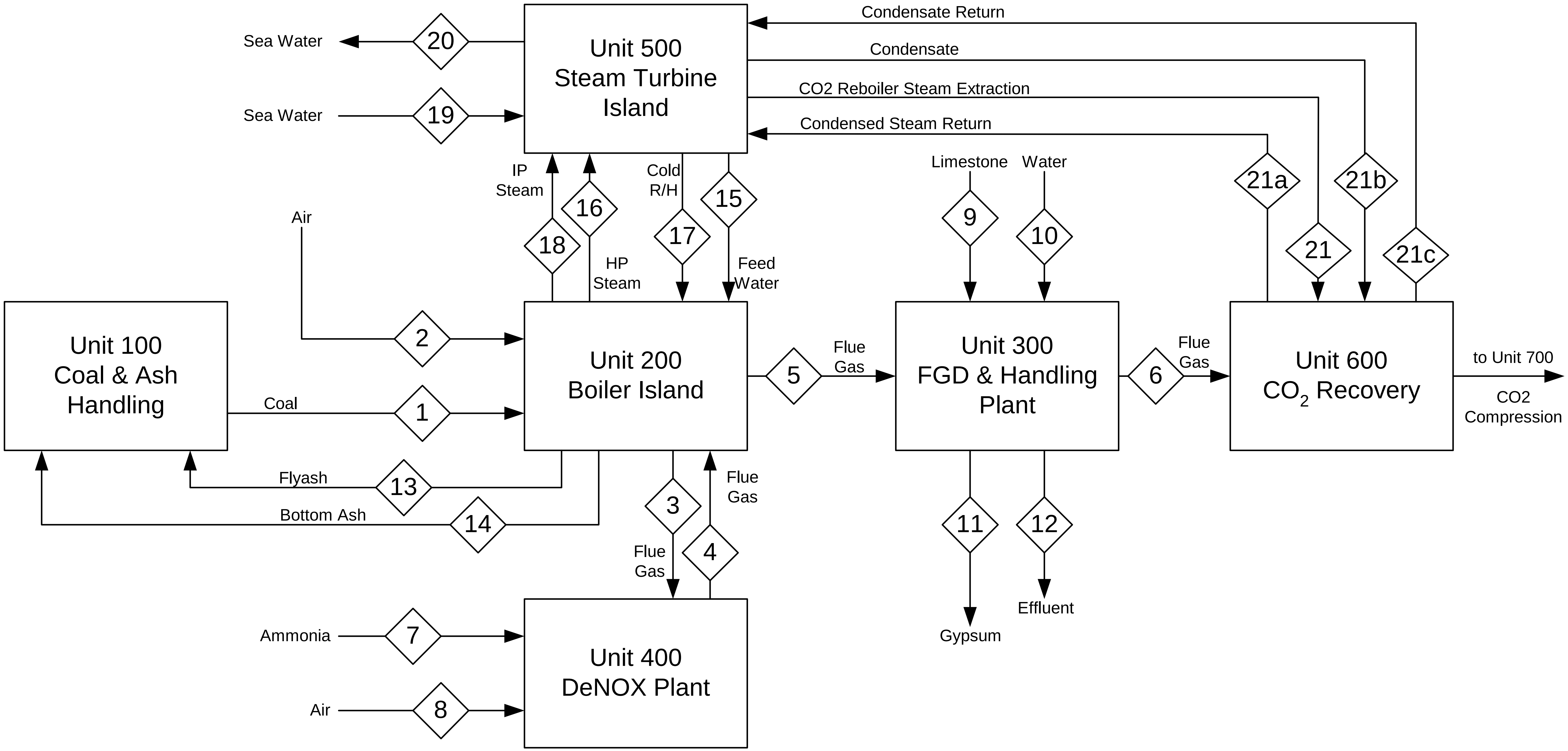
The main utility units are the following:
- Sea Cooling water
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

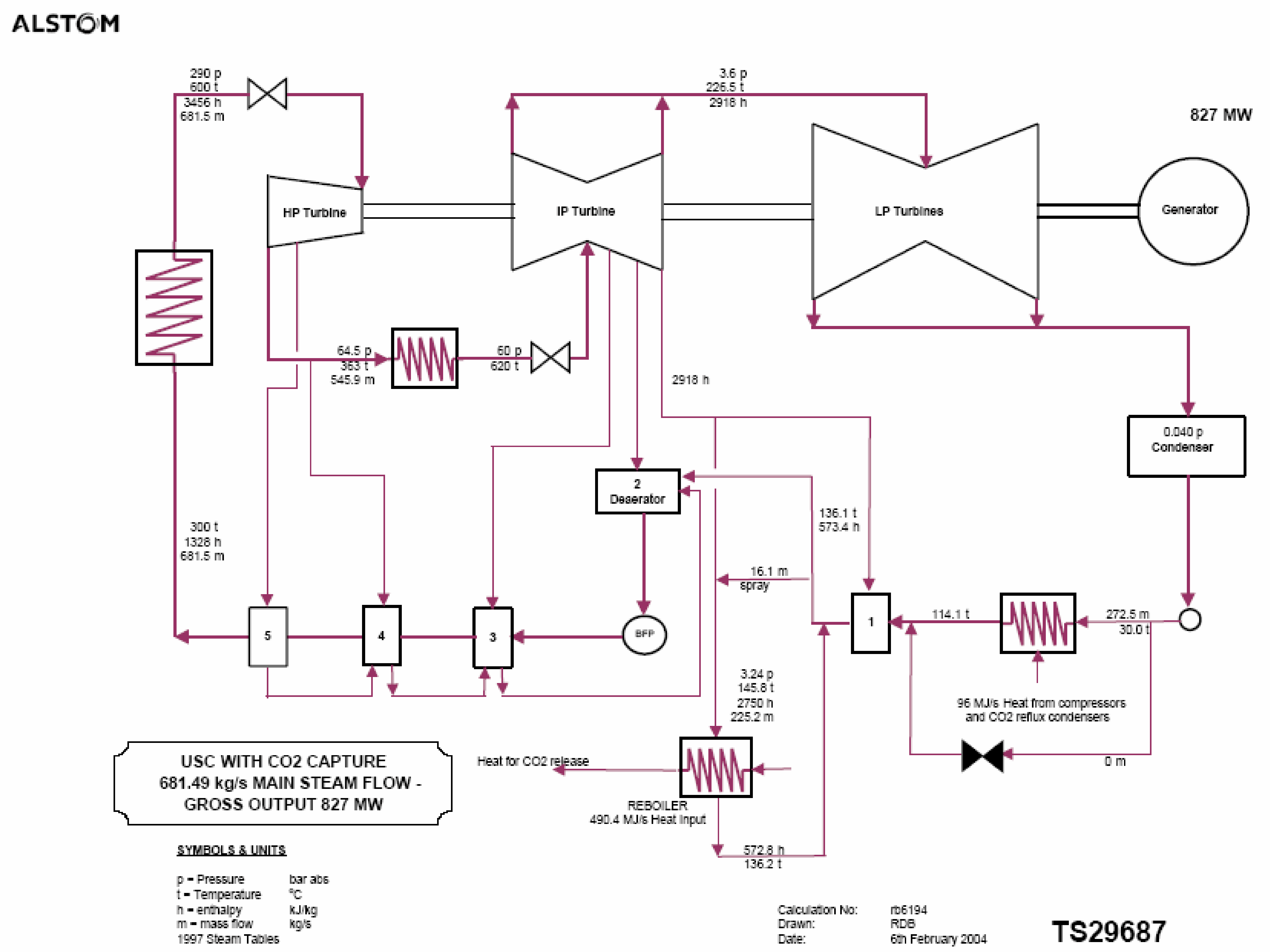
3 Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagrams of the USC PC Plant, Case 3, and the schematic Process Flow diagram of Units 300, 400, 500, 600 and 700 are attached hereafter.

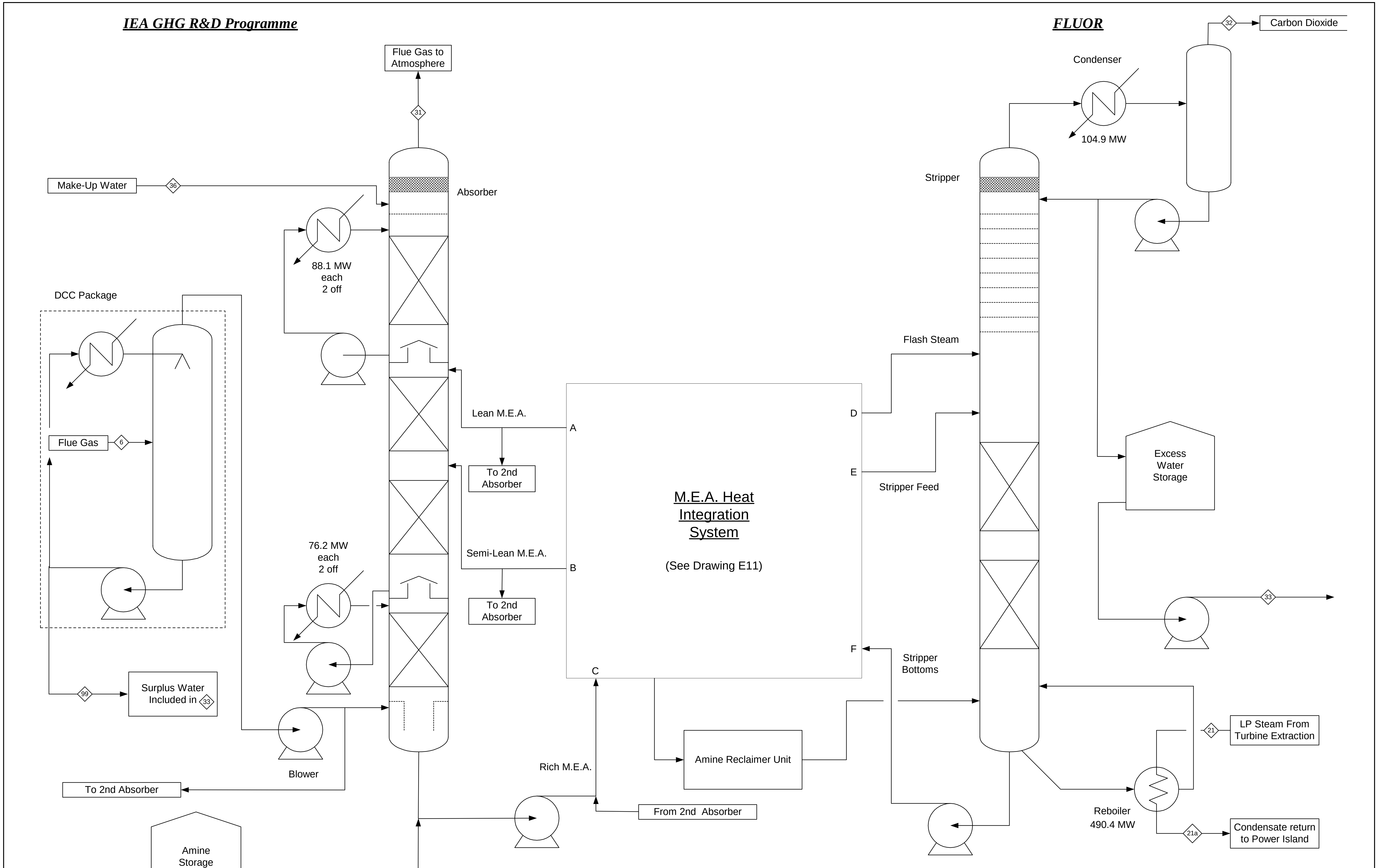
The H&M balances relevant to the scheme attached are shown in paragraph 4.

Case 3: USC PC boiler Power Plant with post-combustion capture: Block Flow Diagram





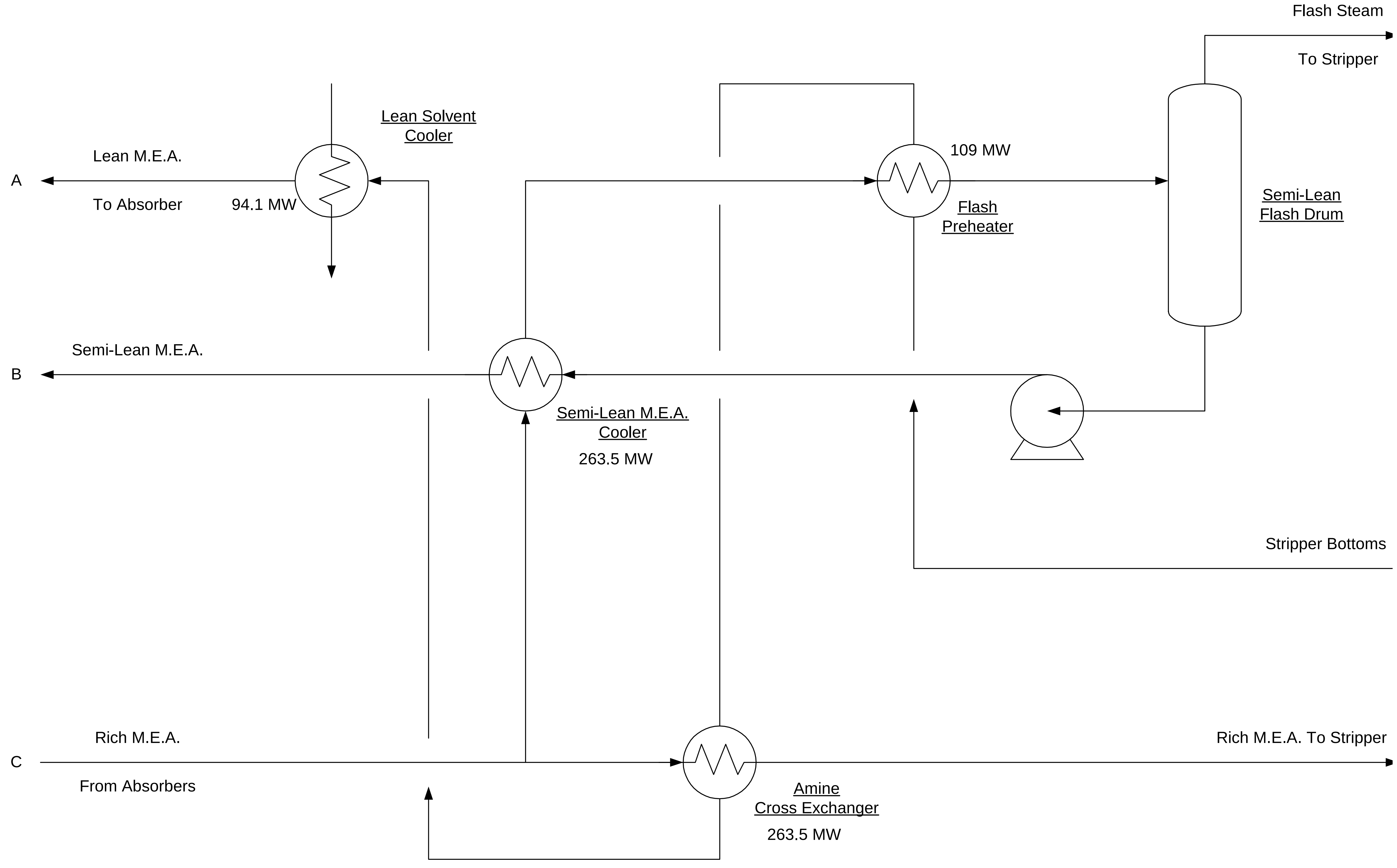
Drawing E9 ***USCPF WITH CAPTURE - TURBINE POWER ISLAND***



Case 3: USC PC boiler Power Plant with post-combustion capture: CO_2 absorption and amine scrubbing

Drawing E10

IEA GHG R&D Programme *FLUOR*

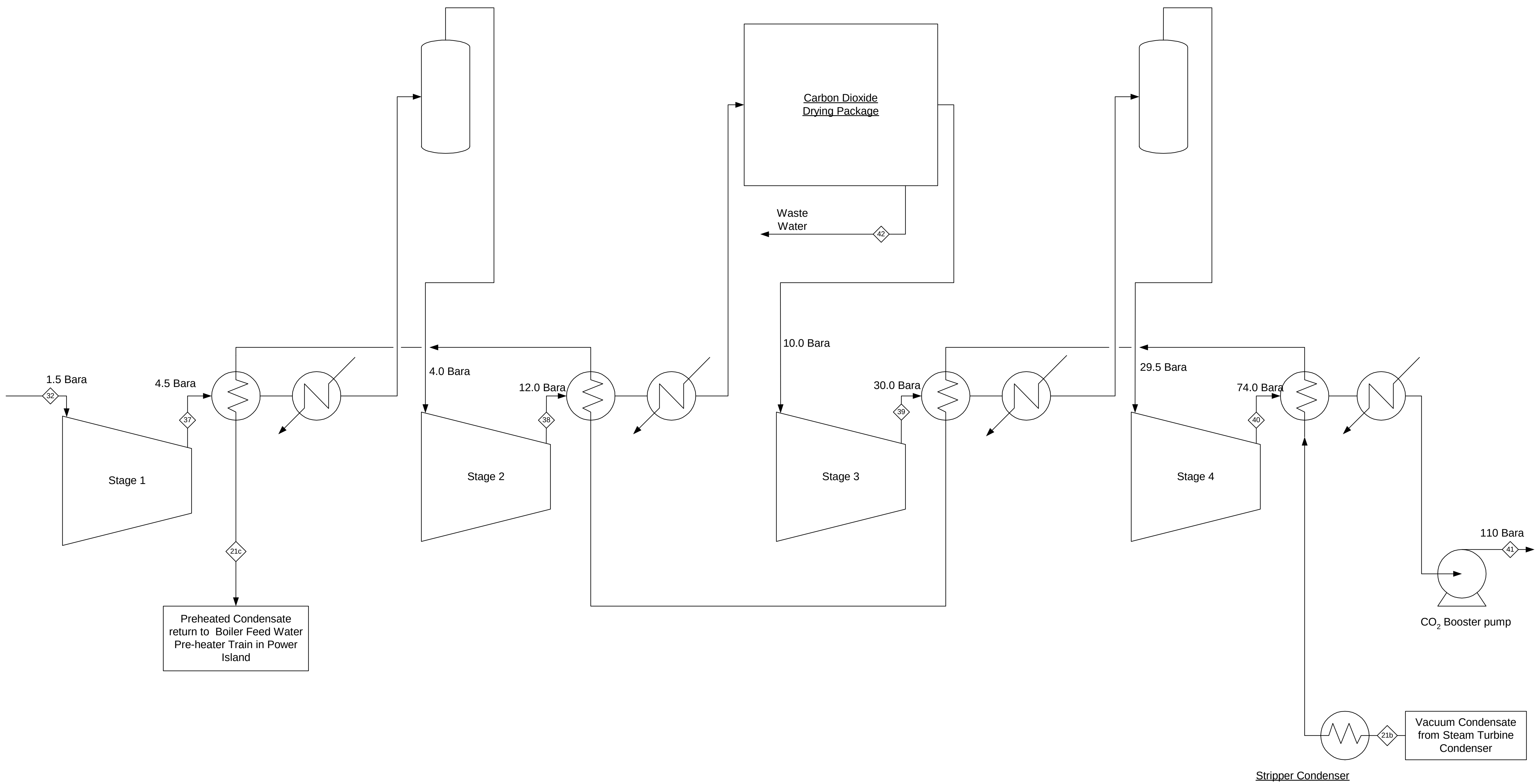


Drawing E11

Case 3: USC PC boiler Power Plant with post-combustion capture: MEA Heat integration system

IEA GHG R&D Programme

FLUOR

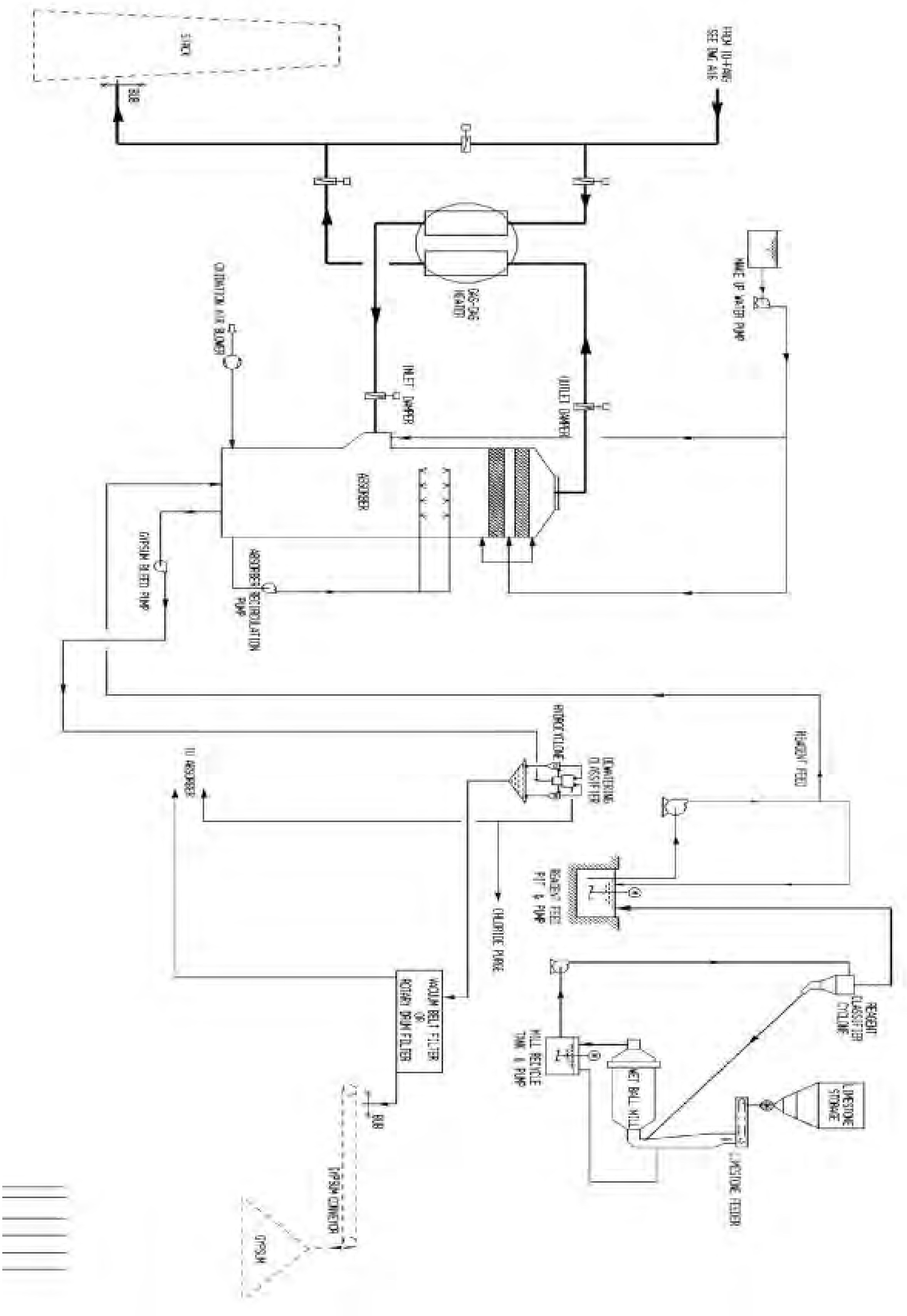


Case 3: USC PC boiler Power Plant with post-combustion capture:
CO_2 Compression and Recovery System

Drawing E12

ALSTOM

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



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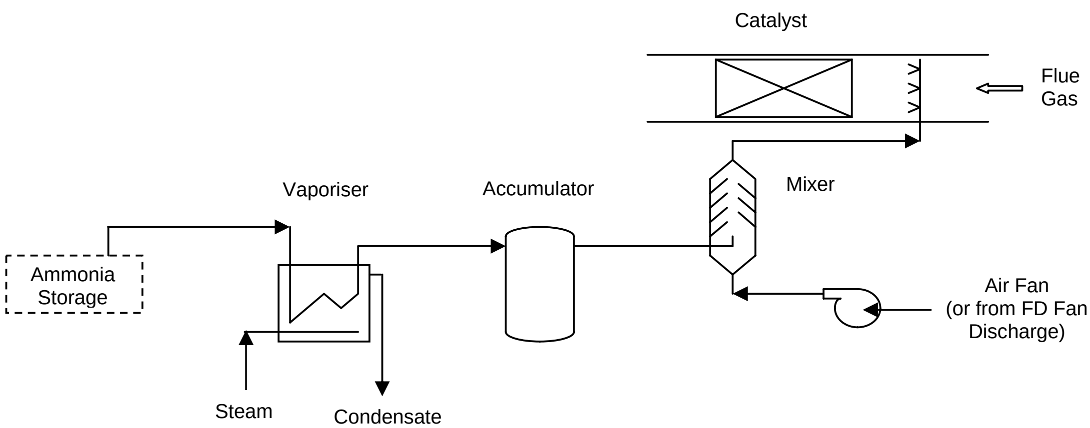
Issue

A1

Ammonia / Air System

Condition			Vaporiser (H_2O side)	Vaporiser (NH_3 side)	Accumulator	Mixer (after)	Air supply	Grid (gas side)
Operating	Flow	Nm^3/h		603	603	12,060	11,457	2,357,186
		kg/h		465	465	9,385	8,920	3,102,772
	Temperature	°C	~45	~35	~35	~35	~35	380
	Pressure	MPa (g)	see note 1	0.29	0.15			
	Concentration	%				5% NH3		
Design Limits	Pressure	MPa (g)						
	Pressure	MPa (g)						
	Temperature	°C						
	Concentration	%						

Notes
*1. Depends on Steam Supply



Issue	Date	Reason For Change	By	Chk'd	Rev'd / App'd
D					
C					
B					
A1	08/04/04	Draft Issue	RSP		

4 Heat and Material Balance

The Heat and Material Balance, referring to the Block Flow diagram attached in the previous paragraph, is attached hereafter.
The H&M balance makes reference to the schemes attached to paragraph 3.

Stream ID		1	2	3	4	5	6	7	8	9	10
Material		Coal	Air	Gas	Gas	Gas	Gas	Ammonia	Air	Limestone	Water
Mass Flow Rate											
- Coal	kg/s	73.96	0	0.32	0.32	0	0	0	0	0	0
- Air	kg/s	0	835.2	0	0	0	0	0	2.48	0	0
- Flue Ga	kg/s	0	0	864.6	867.3	908.1	938.0	0	0	0	0
- Ash	kg/s	0	0	5.9	5.9	0.02	0.009	0	0	0	0
- Water	kg/s	0	0	0	0	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	0	0	0	0	0
- Ammoni	kg/s	0	0	0	0	0	0	0.129	0	0	0
- Limesto	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	2.15	0
Volume Flo	Am^3/s	-	674.9	1568.4	1573.1	977.2	866.1	-	2.04	-	0.028
	Nm^3/s	-	653.1	658.0	660.0	692.8	729.9	0.168	1.93	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Tempera	°C	9	9	380	380	114	51	9	14	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.24	0.55	0.55	0.93	1.08	-	1.22	-	-
Composition											
O_2	%v/v,wet		20.90	3.27	3.27	4.50	4.28		20.40		
CO_2	%v/v,wet		0.03	13.80	13.80	12.79	12.22		0.03		
SO_2	%v/v,wet		0.00	0.07	0.07	0.06	0.00		0.00		
H_2O	%v/v,wet		0.70	9.77	9.79	9.33	13.31		0.70		
N_2	%v/v,wet		78.40	73.09	73.08	73.32	70.19		78.40		
Emissions @ 6%O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1877	1877	1732	29				
CO	mg/Nm^3			0	0	0	0				
Particula	mg/Nm^3			8444	8416	30	14				

Stream ID		11	12	13	14	15	16	17	18	19	20	21	21a	21b	21c
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Steam	Sat. Water	Condensate	Condensate
Mass Flow Rate															
- Coal	kg/s	0	0	0.37	0.12	0	0	0	0	0	0	0	0	0	0
- Air	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Flue Ga	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	0	6.75	2.26	0	0	0	0	0	0	0	0	0	0
- Water	kg/s	0.37	0.17	0	0	687.0	0	0	0	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	687.0	545.9	545.9	0	0	225.2	225.2	272.5	272.5
- Ammoni	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Limestor	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	3.54	0	0	0	0	0	0	0	0	0	0	0	0	0
Volume Flo	Am^3/s	-	-	-	-	-	-	-	-	20.6	20.6	-	-	-	-
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Props															
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas	Liquid	Liquid	Liquid
- Tempera	°C	-	-	114 / 380	1000	300	600	363	620	12	19	146	136	30	114
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	2.24	2.24	-	-
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Composition															
O_2	%v/v,wet														
CO_2	%v/v,wet														
SO_2	%v/v,wet														
H_2O	%v/v,wet														
N_2	%v/v,wet														
Emissions @ 6%O_2 Dry															
NOx	mg/Nm^3														
SOx	mg/Nm^3														
CO	mg/Nm^3														
Particula	mg/Nm^3														

Stream Description			Flue Gas to DCC	Flue Gas to Atmos	CO2 From Stripper	Surplus Water	LP Steam to Reboiler	Cond Return to Power Island	Make Up Water
Stream Number			6	31	32	33	21	21a	36
Temperature Deg C			52	46.8	37.8	37.8	136	136	37.8
Pressure,Bara			1.01	1.02	1.6	2.76	3.24	3.24	1.38
Component Flows		MW							
	H_2O	18.02	15608	10328	533	12435	44990	44990	7688
	CO_2	44.01	14330	2125	12181	24			
	MEA	61.08				9			
Note 3	N_2	28.02	82278	82277	1				
	O_2	32	5012	5012					
Note2	Nat Gas	19.35							
Note 4	AIR	28.89							
Total kgmol/hr			117228	99742	12715	12468	44990	44990	7688
Total Tonnes/hr			3376.8	2745.7	545.72	225.7	810.72	810.72	138.5
Molecular weight			28.80	27.53	42.92	18.10	18.02	18.02	18.02
Density,Kg/m3			1.083	1.05	2.71	990		929	990
			Note 4	**Note 2**	**Note 3**				**Note1**

NOTES

component flows in Kgmol/Hr

1 Flows for a total of two streams
2 Flows for two absorbers discharging to atmosphere
3 CO_2 recovered is 85% of inlet CO_2 in stream 6
4 This stream matches stream 6 on boiler island mass balance table

SEE DWG E10

Stream Description			Ist Stg Compressor Discharge	2nd Stg Compressor Discharge	3rd Stg Compressor Discharge	4th Stg Compressor Discharge	Turbine condensate from power plant	Turbine Condensate to power plant	Product CO2	Waste Water
Stream Number			37	38	39	40	21b	21c	41	42
Temperature Deg C			182	184	187	164	30	114	107	
Pressure,Bara			4.5	12	30	74	1 bar	hold	110	
Component Flows		MW	**Note 2**	**Note 2**	**Note 2**	**Note 2**	**Note 3**	**Note 3**		
	H2O	18.02	533						Trace	533
	CO2	44.01	12181						12181	
	MEA	61.08								
Note 3	N2	28.02	1							
	O2	32								
Note2	Nat Gas	19.35								
Note 4	AIR	28.89								
Total kgmol/hr			12715						12181	533
Total Tonnes/hr			545.72				989	989	536.0	9.59
Molecular weight			42.92						44.01	18.02
Density,Kg/m3							1000	1000		
									12865TPD	**Note 1**

NOTES

Component Flows in Kgmol/Hr

1 Interstage water knock out reported in total of stream 42
2 Compressor pressure profile is : In/Out stg 1:- 1.5/4.5 Bara;stg 2:-4/12 Bara;stg 3:-10/30 Bara; stg 4:-29.5/74 Bara
intermediate stream water contents not shown but correspond to saturation at 37.8 deg C for 1st two stages.
3 This stream is to and from prehaet train in power plant. See Alstom Dwg TS 29687 (DWG E9)

SEE DWG E12

5 Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter, for both base load operation, 50% load operation and minimum efficient plant load operation, i.e. 70% of CO_2 compressor load.

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3 - WATER CONSUMPTION SUMMARY - USC PC with CO2 capture - Base load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption and Amine Stripping**	138.5		30290	23170
700	**CO2 Compression and Recovery System**				5420
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2918	74160
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	57326
	BALANCE excluding CO_2 compression	134.2	0	3150	131486
	BALANCE including CO_2 compression	272.7	0	33440	160076

Note: (1) Minus prior to figure means figure is generated

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Jun-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3 - WATER CONSUMPTION SUMMARY - USC PC with CO2 capture - 50% NPO

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			38	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	54.2			
400	**DeNOx Plant**				
600	**CO2 Absorption and Amine Stripping**	76.2		16670	12750
700	**CO2 Compression and Recovery System**				2990
200	**BOILER ISLAND**			49	
500	**POWER ISLAND (Steam Turbine)**		17.8	2142	74160
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	19.6	-17.8	42	32470
	BALANCE excluding CO_2 compression	73.8	0	2271	106630
	BALANCE including CO_2 compression	150.0	0	18941	122370

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: Draft
Sep-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

CASE 3 - WATER CONSUMPTION SUMMARY - USC PC with CO2 capture - 70% load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			48	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	68.9			
400	**DeNOx Plant**				
600	**CO2 Absorption**	96.9		16480	9580
	Amine Stripping			4730	6650
700	**CO2 Compression and Recovery System**				3800
200	**BOILER ISLAND**			62	
500	**POWER ISLAND (Steam Turbine)**		22.7	2142	74160
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	25.0	-22.7	53	40311
	BALANCE	190.9	0	23515	134501

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3 - ELECTRICAL CONSUMPTION SUMMARY - USC PC with CO2 capture - Base load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**60000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**10000**
	Additional consumption including CO_2 Compression and Drying	**5000**
	BALANCE excluding CO_2 compression	**79400**
	BALANCE including CO_2 compression	**161400**

Notes: (1) Minus prior to figure means figure is generated

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Jun-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3 - ELECTRICAL CONSUMPTION SUMMARY - USC PC with CO2 capture - 50% NPO

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	Coal and Ash Handling	2700
300	FGD	3800
400	DeNOx	220
600	CO2 Absorption and Amine Stripping - DCC blower	7700
	CO2 Absorption and Amine Stripping - pumps	1600
700	CO2 Compression and Recovery System	42000
	POWER AND BOILER ISLAND UNITS	
200 - 500	Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)	24700
	Miscellanea utilities	5700
	UTILITY and OFFSITE	
800	Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems	8000
	Additional consumption including CO_2 Compression and Drying	3500
	BALANCE excluding CO_2 compression	45120
	BALANCE including CO_2 compression	99920

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CASE 3 - ELECTRICAL CONSUMPTION SUMMARY - USC PC with CO2 capture - 70% load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3500**
300	**FGD**	**4900**
400	**DeNOx**	**280**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**9800**
	CO2 Absorption and Amine Stripping - pumps	**2100**
700	**CO2 Compression and Recovery System**	**42000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**32300**
	Miscellanea utilities	**6800**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**8000**
	Additional consumption including CCS	**3600**
	BALANCE	**113280**

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6 Overall performance

The table summarizing the Overall Performance of the USC PC Plant, case 3, is attached hereafter, for both base load operation, 50% load operation and minimum efficient plant load operation, i.e. 70% of CO_2 compressor load.

USC PC				
bituminous coal, with CO_2 capture				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Base load	Min.Effcient load	50% NPO
Coal Flowrate (fresh, air dried basis)	t/h	266.3	186.4	146.4
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1339.3**	**1052.3**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**567.1**	**434.9**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
FW pumps	MWe	37.0	24.6	18.6
Draught Plant	MWe	9.0	6.3	4.9
Coal mills, handling, etc.	MWe	5.0	3.5	2.7
ESP	MWe	2.0	1.4	1.1
Miscellanea	MWe	9.0	6.8	5.7
Utility Units consumption	MWe	10.0	8.0	8.0
FGD	MWe	6.0	4.2	3.3
DeNOx	MWe	0.3	0.2	0.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**55.0**	**44.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**512.1**	**390.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**42.3**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**38.2**	**37.1**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY				
Additional consumption				
CO_2 Absorption - Blower	MWe	14.0	9.8	9.8
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	2.1	1.6
CO_2 Compression and Drying	MWe	60.0	42.0	42.0
Additional Process Units consumptions including CCS	MWe	1.1	0.8	0.6
Additional Utility Units consumptions including CCS	MWe	5.0	3.6	3.5
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**58.3**	**57.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**453.8**	**332.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**42.3**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**33.9**	**31.6**
Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.875**	**2.951**	**3.161**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.141**	**0.144**	**0.155**
Specific water consumption per MW net produced	**t /MWh**	**0.410**	**0.421**	**0.451**

7 Environmental Impact

The USC PC Plant, case 3, is designed to process coal, whose characteristic is shown at Section B of present report, and produce electric power.
The gaseous emissions, liquid effluents and solid wastes from the Power Plant are summarized in the present paragraph.

7.1 Gaseous Emissions

7.1.1 Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases, proceeding from the combustion of coal in the boiler.

Table 7-1 summarises expected flow rate and concentration of the combustion flue gas.

Table 7-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	762.7
Flow, Nm^3/h	2,235,617
Temperature, °C	90
Composition	**(%vol, wet)**
O_2	5.02
CO_2	2.13
H_2O	10.35
N_2+Ar	82.49
Emissions	**mg/Nm^3 (1)**
NOx	10
SOx	<20
MEA	1
Particulate	Nil

(1) Dry gas, O_2 Content 6% vol

7.1.2 Minor Emissions

Other minor gaseous emissions are the process vents and fugitive emissions.
Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable gaseous components are sent to a flare system. Venting via the flare will be minimal

during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation reduce these emissions to a very low level.

7.2 Liquid Effluent

Waste Water Treatment (included in Unit 800)

The expected flow rate of treated water to be discharged outside Plant battery limit is as follows:

- Flow rate : 249.8 m^3/h

Sea Cooling Water System

Sea water is returned to the sea basin after exchanging heat inside the Power Plant.
The cooling water maximum temperature rise considered in the study is 7°C.
The main characteristics of the discharged warm sea water are listed below:

- Flow rate : 160,076 m^3/h
- Temperature : 19 °C

Amine Unit Waste

The specific amine unit waste based on typical data reported in the reference study is equal to 0.0032 ton/ton CO_2. Amine reclaimer waste contains significant amount of MEA, products of MEA degradation, metals and water (about 30% wt).

Waste disposal has to be carried out by specialized companies, which charge about 250 $/$m^3$ to dispose of this waste. These companies process the waste by removing the metals and then incinerating the remainder. This waste can also be disposed of in a cement kiln where the waste metals become agglomerated in the clinker.

Reclaimer wastes are generated in a discontinuous mode and therefore they have not been taken into account in the overall water balance.

7.3 Solid Effluent

The plant is expected to produce the following solid by-products:

Furnace bottom ash			
Flow rate	:	8.1	t/h
Fly ash			
Flow rate	:	24.4	t/h
Mill rejects (pyritic)			
Flow rate	:	0.5	t/h
Gypsum			
Flow rate	:	14.1	t/h
Water content	:	9.5	%wt
Sludges from WWT			
Flow rate	:	0.8	t/h
Water content	:	74	%wt

Some of solids effluent could be theoretically dispatched to cement industries and therefore they could be treated as a revenue for the plant economics. There are fly and bottom ash, mill rejects and gypsum.
Vice versa, sludges from WWT have to be sent outside the Power Plant battery limit for disposal.

Therefore for the purposes of present study solids effluents are considered as neutral: neither as a revenue nor as a disposal cost.

8 Equipment List

The list of main equipment and process packages is included in this paragraph.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
FOSTER WHEELER		DATE	feb-11			
		ISSUED BY	NF			
		CHECKED BY	PC			
		APPROVED BY	LM			

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Coal delivery equipment							
	Stacker reclaimer							
	Yard equipment							
	Transfer towers							
	Crusher and screen house							
	Dust suppression equipment							
	Ventilation equipment							
	Belt feeders							
	Metal detection							
	Belt weighing equipment							
	Miscellaneous equipment							
	Bottom ash systems							
	Fly ash systems							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Operating Flexibility of Power Plants with CCS CONTRACT N. 1- BD- 0530 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	feb-11			
		ISSUED BY	NF			
		CHECKED BY	PC			
		APPROVED BY	LM			

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Furnace							
	Reheater							
	Superheater							
	Economiser							
	Piping							
	Air handling plant							
	Structures							
	Bunkers							
	Pumps							
	Coal feeders							
	Soot blowers							
	Blow down systems							
	Dosing equipment							
	Mills							
	Auxiliary boiler							
	Miscellaneous equipment							
	Burners							
	ESP							
	Flue gas blower	Axial fan	2.500.000Nm3/h x 700 mmH2O	11.0 MW			CS	1 blower in operation

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		APPROVED BY	LM			

EQUIPMENT LIST

Unit 300 - FGD and Handling Plant - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Ducts							
	GGH (gas to gas reheater)							
	Absorber island							
	Limestone storage							
	Limestone slurry preparation island							
	Gypsum dewatering and storage							
	Make up water pumps							
	Oxidation air blower							

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EQUIPMENT LIST

Unit 400 - DeNOx Plant - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Flue gas ducts							
	Reactor casing							
	Bypass system							
	Catalyst							
	Ammonia injection equipment							
	Handling equipment							
	Control system							

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EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Steam turbine island package							
	Steam turbine		827 MWe gross					
	Steam turbine condenser		592 MW th				tubes: titanium; shell: CS	Sea water heat exchanger

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EQUIPMENT LIST

Unit 600 - CO_2 Amine Absorption Unit - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	DCC circulation pumps	centrifugal	7750 m3/h x 50 m	1400 kW			casing: CS; internals: 12%Cr	two pumps in operation; one spare
	Wash water pumps							
	Rich amine pumps							
	Reflux pump							
	Stripper bottoms pump							
	Absorber column - upper pumparound pum	centrifugal	3200 m3/h x 60 m	750 kW			casing: CS; internals: 12%Cr	two pumps in operation; two spare
	Absorber column - lower pumparound pum	centrifugal	2700 m3/h x 50 m	530 kW			casing: CS; internals: 12%Cr	two pumps in operation; two spare
	Surplus water pump							
	Flue gas blowers							
	Amine filter package							
	Soda ash dosing							
	Reclaimer							
	DCC towers							
	Packing							
	Absorption towers							
	Stripper							
	Packing for stripper							
	Semi lean flash drum							
	Ohd accumulator							
	MEA storage							
	Surplus water tankage							
	DCC cooler	shell and tube	108 MW th; 6800 m2				tubes: titanium shell: CS	Sea water heat exchanger
	Water wash cooler							
	Absorber column - upper pumparound cool	shell and tube	88.1 MWth; 7000 m2				tubes: 316L shell: CS	2 exchangers with MCW (88.1 MW th each)
	Absorber column - lower pumparound cool	shell and tube	76.2 MWth; 6000 m2				tubes: 316L shell: CS	2 exchangers with MCW (76.2 MW th each)
	Cross exchangers							
	Flash preheater							
	Overhead stripper condenser	shell and tube	75 MW th; 1400 m2					Sea water heat exchanger
	Stripper reboiler	kettle	125 MW th; 2000 m2				shell/tubesheet: KCS; tubes: SS 304L	heat exchanger with steam, 4 exchangers in parallel, 2000 m2 each
	Lean solvent cooler	plate	94.1 MW th				plates: 316L frame: CS	heat exchanger with MCW

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EQUIPMENT LIST

Unit 600 - CO_2 Amine Absorption Unit - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks

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EQUIPMENT LIST

Unit 700 - CO_2 compression and inerts removal - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Compression package							
	Compressor	4 stage compressor	145000 Nm3/h x overall β = 49; β per stage = 2.7	motor = 30 MW each machine			SS	2 x 50% machines (145000 Nm3/h each)
	Intercoolers	Shell & tube						steam condensate heat exchanger
	Intercoolers	Shell & tube	6 MWth each; 215 m2 each				tubes: titanium shell: SS	8 sea water heat exchanger
	Dryer							
	CO2 pumps	centrifugal	750 m3/h x 500m	2.5 MW			SS	1 operating + 1 spare

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EQUIPMENT LIST

Unit 800 - Utility Units - USC PC with CO_2 capture, fed with bituminous coal, case 3

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Demin water storage tankage							
	Raw water and firewater storage							
	Plant air compression skid							
	Emergency diesel generator system							
	Closed loop water cooler	plate	466 MW th				plates: titanium frame: SS	sea water heat exchanger
	Blowdown water sump							
	Condensate return pump							
	Demin water pump							
	Sea water pumps	submerged	20000 m3/h x 20m	1600 kW			casing, shaft: SS; impeller: duplex	8 pumps in operation + 1 spare
	Close loop CW pumps	centrifugal	17000 m3/h x 30m	1800 kW			CS	2 pumps in operation + 1 spare
	Oily water sump pump							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	Waste water treatment plant							
	Seawater chemical injection							
	OWS							
	Sea water inlet/outlet works							
	Buildings							
	Electrical equipment							

9 Investment cost

The main cost estimating bases are shown in section B of this report. This section details the investment cost of the following units or blocks of units:

Unit 100	Coal and Ash Handling
Unit 200	Boiler Island
Unit 300	FGD and Gypsum Handling Plant
Unit 400	DeNOx Plant
Unit 500	Steam Turbine
Unit 600	CO_2 Amine Absorption
Unit 700	CO_2 compression
Unit 800	Utility and offsite

The overall investment cost of each unit is split into the following items:

- **Direct Materials:** including equipment and bulk materials;
- **Construction**: including mechanical erection, instrument and electrical installation, civil works, buildings and site preparation;
- **Indirect field Costs:** including construction management, commissioning, spare parts, temporary construction facilities, freight, taxes and insurance;
- **Engineering costs:** including Contractor's home office services and construction supervision.

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Client : IEA
Plant : USC PC with CO2 capture
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ESTIMATE SUMMARY

CASE 3 - USC PC WITH CCS (reference case)

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	122,884,000	44,824,000	31,377,000	189,912,000	767,424,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,408,000	66,477,000	21,729,000	53,330,000	330,052,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	166,292,000	111,301,000	53,106,000	243,242,000	1,097,476,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,226,000	1,062,000	4,865,000	21,949,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,226,000	1,062,000	4,865,000	21,949,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	831,000	557,000	266,000	1,216,000	5,488,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,315,000	5,565,000	2,655,000	12,162,000	54,874,000	
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,663,000	1,113,000	531,000	2,432,000	10,974,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	17,461,000	11,687,000	5,576,000	25,540,000	115,234,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	19,955,000	13,356,000	6,373,000	29,189,000	131,697,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	203,708,000	136,344,000	65,055,000	297,971,000	1,344,407,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,300,000	9,500,000	3,300,000	14,900,000	87,000,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,200,000	6,800,000	3,300,000	14,900,000	67,300,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	230,008,000	154,444,000	73,455,000	329,571,000	1,513,107,000	

10 Operating and Maintenance Costs

The Operating and Maintenance Costs of this case are summarised in the following table. Fixed costs have been considered constant, independently from the plant operating mode, and are expressed as M€/y.
Variable costs, expressed as €/h, are evaluated for the two operating modes of the plant, i.e. peak and off-peak operation.

Case	**3**	
Description	USC PC with CCS	
Fixed costs		
Maintenance	50.7	
Operating Labour	7.80	
Labour Overhead	2.34	
Insurance & local taxes	26.9	
Total fixed cost, M€/y	87.8	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	0	0
Chemicals and consumables	2340	1287
Total variable cost, €/h	2340	1287

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PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME: CAPTURE PLANT DEFINITION – CASE 4: OXY-COMB. PC PLANT
FWI CONTRACT : 1-BD-0530 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION E.4

INDEX

1 Introduction

The present Case 4 refers to a USC PC Oxyfuel plant, fed with bituminous coal, with cryogenic purification of the flue gases for CO_2 removal.

Foster Wheeler has included in the report the outcomes of studies, made by the other Companies, and made available by IEA GHG. However, FW should not be regarded as having endorsed the results of the above third-party studies.

The IEA GHG study 'Water usage and loss Analysis in Power plants without and with CO_2 capture' has been taken as a reference for the configuration and performances of the plant here below described. In particular, Plant description, process schemes and performance data have been taken directly from reference study report.

The main features of the present USC PC Oxyfuel plant configuration are:

- Mitsui-Babcok boiler pulverized fuel ultra supercritical market based design, converted to oxyfuel firing;
- Cryogenic Air Separation Unit;
- CO_2 compression, including Air Products CO_2 purification treatment.

The configuration of the plant is based on a once through steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.

The arrangement of the main process units is:

Unit		Trains
100	Coal and Ash Handling	1 x 100%
200	Boiler Island	1 x 100%
500	Steam Turbine Unit	1 x 100%
600	Air Separation Unit	2 x 50%
700	CO_2 compression and inerts removal	1 x 100%

2 Process Description

2.1 Overview

Case 4 is a pulverized coal, oxyfuel fired, ultra super critical steam plant. The design is based on a USC PC plant market based design, converted to oxyfuel fired operation.

A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

The following descriptions should be read in conjunction with block flow diagrams attached in the following paragraph 3.

2.2 Unit 100 - Coal Handling

A coal handling system is provided to unload, convey, prepare and store the coal delivered to the plant.

Coal is delivered to the site by rail. Train cars are unloaded into hoppers from which the coal is conveyed to the reclaim area. Coal passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal is reclaimed and conveyed on belt conveyors, which transfer it to a surge bin located in the crusher tower. The coal is reduced in size by means of a crusher and is then transferred by conveyor to silos from which it is conveyed and fed by weight feeders into mills for pulverization. Pulverised coal exits each mill via the coal piping and is distributed to the coal burners in the furnace front and rear walls.

2.3 Unit 200 – Boiler Island

The flue gas produced by the combustion of coal in air is mostly nitrogen. If the air is separated into its constituent components prior to combustion and only oxygen is supplied to the furnace then the resulting flue gas will contain only the products of combustion - the inert nitrogen “ballast” will have been eliminated and the quantity of flue gas to be treated will be significantly reduced.
This removal of the nitrogen ballast is at the heart of the proposed process. Oxygen at 95% vol purity, obtained from unit 600 (Air Separation Unit), is supplied to the burners.

For a description of a traditional boiler reference shall be made to Section E.3, paragraph 2.3.

If applied directly to conventional combustion plant, however, the reduced mass and volume flow through the plant this will result in a number of difficulties. In the furnace chamber the introduction of the same quantity of heat to a reduced mass of combustion products will result in greatly increased temperatures. As a result, increased radiant heat pick-up, greater slagging and higher NOx emissions are all anticipated. Furthermore, the reduced volumetric flow (and hence gas velocity) in the convective passes of the boiler leads to lower heat transfer coefficients and reduced heat absorption. Therefore, the overall balance of the heat absorbed throughout the unit is likely to be so disturbed as to make the plant inoperable without substantial modification to the heating surfaces.
The problem is resolved by recycling a proportion of the flue gas back to the furnace (around two third of the flow of flue gas originally leaving the boiler) so as to maintain the mass/volume flow at an acceptable level and to achieve a similar heat transfer in the radiant and convection sections as compared to conventional boilers. It is therefore possible to devise a conceptual process diagram whereby a standard designed pulverised coal fired utility boiler can be operated without nitrogen being present in the flue gas, resulting in a substantial reduction in the quantity of flue gas that must be treated in downstream processing equipment to capture the CO_2.

With reference to PFD 2 and 5A, two streams of recycle flue gas are required for the oxy-combustion system:

- Primary recycle, which passes through the coal mills and transports the PF to the burners. The volumetric flow rate of primary recycle gas is maintained at value required for air firing.
- Secondary recycle, which provides the additional gas ballast to the burners to maintain temperatures within the furnace at similar levels to air firing.

The combined primary and secondary gas recycle is approximately 67% of the original flue gas leaving the economiser.

The flue gas exiting the boiler at 340°C is used to heat the primary and secondary recycle flue streams via a regenerative gas / gas heater. The flue gas is de-dusted via the ESP. The clean flue gas is then split into two, with one stream forming the secondary recycle and returning back through the gas / gas heater (exit temp 330°C) to the burners. The remaining stream is cooled, dried and split again to form primary recycle and net flue gases (CO_2 product stream) respectively. The primary recycle passes through the gas / gas heater (exit temperature 250°C) and is delivered to the coal mills. The pulverized fuel is dried in the mill using this flow (mill exit temperature 105°C) and transported to the burners.

The net flue gas is then passed through a compression and CO_2 processing unit (inerts removal) that delivers a final CO_2 product of 95% mol purity, at 110 bara. The details of the compression and inerts removal are described in the following paragraph 2.6.

2.4 Unit 500 - Steam Turbine Generator

The condensate and the boiler feed water are heated utilising the available heat from the ASU, CO_2 compression and inerts removal and flue gas sources in order to maximise the overall efficiency of the plant.

For an air firing plant the condensate leaving the condenser would conventionally be heated utilising several feed water heaters fed with turbine bled steam, however, for the CO_2 capture plant, only a single feed heater is required for condensate preheating prior to the deaerator, as some 124.3MWt of heat is sourced from the other plant units (18.7MWt from the flue gas, 55.3MWt from the ASU and 50.3MWt from the CO_2 plant).
Following the condensate preheating the water is passed through the deaerator (operating at 6 bara) and then pumped to the required operating pressure (339 bara). The high pressure stream is then split to make use of heat from two different sources. The first stream is heated by the flue gas (28MWt) and then further heated by a feed water heater using turbine bleed. The second stream bypasses the feed heater and is heated exclusively by the CO_2 compression unit (16MWt) before being re-combined with the original stream. Two further feed heaters using turbine extracted stream, raise the temperature to the required economiser inlet temperature.

The supercritical boiler elevates the temperature of the feedwater and generates steam at 290 bara and 600°C which is then delivered to the HP steam turbine. Steam is extracted from the later stages of the HP turbine to feed the last feed water heater (HP FWH 5, reference is made to the steam turbine flow diagram attached in the paragraph 3). Upon exiting the HP turbine, a portion of steam is bled and utilised in the second to last feed water heater (HP FWH 4) with the remaining steam returned to the boiler to be reheated. Following reheat, the steam enters the IP turbine at 60 bara @ 620°C. where a bleed is taken in the later stages of the turbine to feed the first stage feed water heater (HP FWH 3).
Some of the steam exiting the IP turbine en route to the LP turbine is sent to the deaerator. Within the LP turbine, steam is bled to the remaining single condensate feed heater (LP FWH 1). Finally, the vapour exiting the LP turbine is sent to the condenser (40 mbara) where seawater at 12°C provides the source of cooling that returns the stream to a condensate ready to be recirculated.

2.5 Unit 600 - Air Separation Unit

The amount of oxygen required for the boiler of present case 4 is 10,400 tonne/day. Based on information contained in reference study, currently, the largest plants in construction are 3,750 tonnes/day. The proposal for the production of oxygen in this case is to use two cryogenic ASUs of 5,200 tonnes/day. This is within the range of plant output currently being offered for sale. The single train axial flow air compressors required for this duty are available commercially. The cycle chosen is one in which gaseous oxygen (GOX) is produced by boiling liquid oxygen (LOX) which is ideally suited to this application as the delivery pressure required is low. There is no requirement for either pumping the liquid O_2 or compressing the gaseous product.
A low purity cycle was chosen, which produces 95% oxygen purity. Other studies have been carried out to show that for oxyfuel combustion plants this is the optimum purity. Even new balanced-draught boiler plant are expected to have air in-leakage, and therefore there will always be some inerts that must be removed in the CO_2 processing plant.

To minimise the ASU power consumption because of its importance in this application, an innovative cycle was chosen that uses two high pressure columns. A process flow diagram of the process and the mass balance are given in the following paragraph 3.

The standard double column cycle has a low pressure column (C105) with its reboiler (E103) integrated with the condenser of a high pressure column (C104). The column pressures are set to give a temperature driving force in the reboiler/condenser E103.
In this cycle an extra column is added operating at an intermediate pressure (C103). The condenser (E104) for this column also integrates with a reboiler in the low pressure column but at a lower temperature, boiling a liquid stream higher up within the low pressure column.
This arrangement minimises the amount of feed air that must be compressed to the higher pressure of C104, leading to the low power requirement of this process cycle.

The plant consists of:
1) A compression system
2) An adsorption front end air purification system
3) A cold box containing the separation and the heat exchanger equipment
This process offers the benefits of high reliability, low maintenance cost and is simple to install and operate.

2.5.1 Air compression and cooling

Air is taken in through an inlet filter to remove dust and particulate matter prior to entering the main air compressor (MAC), where it is compressed to 3.5 bara. An axial compressor is used to compress the feed air without intercooling, so as to provide a higher temperature air stream to use as a source of heat for preheating condensate for the USC PC Oxyfuel boiler.

The air discharge is further cooled to a temperature of around 12°C in the Direct Contact Aftercooler (DCAC) with chilled water from the Chiller Tower which uses evaporation of water into the dry waste nitrogen stream leaving the ASU cold box to further cool part of the plant cooling water.

2.5.2 Air Cleanup

Before the air is cooled to cryogenic temperatures, water vapour and carbon dioxide and other trace impurities such as hydrocarbons and nitrous oxide are removed in a pair of dual bed adsorbers. Removal of carbon dioxide and water avoids blockage of cryogenic equipment. The adsorber operates on a staggered cycle, i.e. one vessel is adsorbing the contained impurities while the other is being reactivated by low pressure gaseous waste nitrogen using a temperature swing adsorber cycle. The nitrogen is heated to around 160°C against condensing steam. The adsorbents used are generally selected for optimum operation at the particular site. They consist of layers of alumina or silica gel plus layers of zeolite. The adsorber vessels are vertical cylindrical units having annular adsorbent beds. As an alternative, horizontal vessels with layers of adsorbents can be used.

2.5.3 Principle of Cryogenic Air Separation

The industry standard method of cryogenic air separation consists of a double column distillation cycle comprising a high pressure (HP) column (C104) and a low pressure (LP) column (C105) as shown in the relevant PFD.

2.5.4 Cooling and Refrigeration

Following the two front end adsorber systems (C101 and C102), both the intermediate and high pressure air streams are split in two. These four streams (4, 6, 14 and 18 as shown in relevant PFD3) are fed directly to the main heat exchanger (E101).
This consists of a number of parallel aluminium plate-fin heat exchanger blocks manifolded together.
The intermediate pressure stream 4 is cooled close to its dew point (-178°C) and fed to the bottom of the intermediate pressure column (C103). The second intermediate

pressure stream 6 is removed from the main heat exchanger at -171°C then expanded in a centrifugal single wheel expansion turbine K104 running on the same shaft as a single wheel centrifugal compressor K103 which adsorbs the expander power. The expanded air is fed to the middle of the low pressure column (C105) at a pressure of about 1.4 bara and –188°C to provide refrigeration for the operation of the ASU. The high pressure stream 18 is cooled close to its dew point (-173°C) and fed to the bottom of the high pressure column (C104). The second high pressure air stream is cooled and condensed in the main heat exchanger against boiling oxygen. The resulting liquid air from the main exchanger is fed to the middle of both the high pressure and intermediate pressure columns.

2.5.5 Distillation System

In the high (C104) and intermediate pressure (C103) columns, the gaseous air feed is separated in the distillation packing into an overhead nitrogen vapour and an oxygen-enriched bottom liquid. The nitrogen vapour from the high pressure column is condensed against boiling oxygen in the low pressure column sump and split into two parts. The first part is returned to the high pressure column as reflux, whilst the second part is subcooled, reduced in pressure and fed to the low pressure column (C105) as reflux. The nitrogen from the intermediate pressure column (C103) is condensed against a boiling liquid stream in the low pressure column. Part of this nitrogen is used as column reflux in the intermediate pressure column and part is subcooled and added to the reflux to the low pressure column.
Crude liquid oxygen is withdrawn from the sumps of the high and intermediate pressure columns, cooled in the subcooler (E102) against warming waste nitrogen and is flashed to the low pressure column as intermediate feeds. A portion of liquid air is also withdrawn from the middle of the high pressure column. This liquid is subcooled in the subcooler and fed to the middle of the low pressure column.

2.5.6 Low Pressure Column

The feeds to the low pressure column are separated into a waste nitrogen overhead vapour and a liquid oxygen bottom product, which reaches the required purity of 95% by volume. At present the nitrogen is vented to atmosphere, however, there is potential to utilise this warm dry nitrogen stream within the coal drying process.

The waste nitrogen is withdrawn from the top of the low pressure column and warmed in the subcooler and the main heat exchanger. A portion of the nitrogen stream from the main exchanger is used for adsorber reactivation. The remaining dry nitrogen is vented through a Chilled Water Tower to produce chilled water by evaporative cooling. The chilled water is used to provide additional feed air cooling in the top section of the DCACs.

Pure liquid oxygen is withdrawn from the reboiler sump of the low pressure column and is returned to the main heat exchanger where it is vaporised and warmed up to ambient conditions against boosted air feed to the columns. The gaseous O2 is then regulated and supplied to the power plant. The pressure in the low pressure column is typically 1.35 bara. The hydrostatic head between the sump of the LP Column and the LOX boil heat exchanger results in the O2 product being available at approximately 0.6 barg.

2.5.7 Oxygen Backup

The USC PC boilers will be designed in such a way as to allow air-firing as a fall-back position should there be an interruption in supply from the ASUs. Therefore, adequate backup for the ASUs should be provided in order to allow a controlled change-over to air-firing.

Backup will be in the form of liquid oxygen (LOX) enough of which will be stored on site to allow controlled changeover to air-firing. A PFD for this backup system is shown in paragraph 3.

The LOX will be held at a pressure of 2.5 bara in a 200 tonne capacity vacuum insulated storage tank which can be filled by gravity from the ASU. If backup oxygen is required from storage, detected by a pressure controller on the GOX header, the control valves will open to allow LOX to enter the vaporiser. Because of the short time lag in the system to initiate the GOX backup flow through the vaporiser, a temporary means of providing GOX is required. The GOX pressure is maintained in the system using a GOX buffer vessel kept at 30 bara pressure, which discharges into the GOX header under pressure control.

2.6 Unit 700 – CO_2 compression and inerts removal

The net flue gas from the 740 MWe gross USC PC oxyfuel boiler must be cooled, dried, compressed, and purified to the required level, before injection into the transfer pipeline.

The Unit 700 considered in the present power plant, case 4.11, has been modified, compared with the Unit 700 in the reference study. Indeed, the CO_2 compression and treatment process described in the Air Products patent N° US 7,416,716 B2 is introduced into unit 700.
The present Unit 700 consists of the following main equipment:

1) A venturi scrubber;V201
2) An indirect contact cooler; C204

3) The Air Products package, which includes: part of the compression system (K205, K204) with relevant aftercoolers (E208 and E209), contacting columns (C206, C207), contacting column circulation pumps (P202, P203), contacting column cooler (sea water) (E210, E211), BFW and Condensate preheating exchangers (E206 and E207)
4) A drier system
5) The remaining part of the compression system; K202, K201
6) A cold box containing CO_2 purification equipment

The CO_2-rich flue gas leaves the heat recovery system of the USC PC oxyfuel power plant at approximately 110°C.

A venturi scrubber V201 is used to quench the gas with water to a temperature where a conventional indirect seawater contact cooler can be used with standard plastic packing. The column C204 cools all of the flue gas to about 35°C by direct contact with condensate that has been cooled against seawater in titanium plate-frame heat exchangers E205. Around half of this flue gas is then recycled to the boiler system as primary recycle gas, stream 4. The temperature of 35°C at cooler outlet is high, especially if 12°C sea water is available and the absorption power of downstream compressor is increased. This approach has been used in the reference case and therefore has been maintained in this case 4.11.

The rest, stream 5, is sent to the Air Products patented process.

In the Air Products patented scheme SO_2 and NO_x are removed from gaseous CO_2: in fact, at elevated pressure, providing enough contact time and in the presence of molecular oxygen and water, the above-mentioned contaminants react to form respectively sulphuric acid and nitric acid. The latter acids are removed from the system as aqueous solutions to produce a SO_2-free, NO_x-lean carbon dioxide stream.
More in detail: the CO_2 stream entering Air Products package is compressed to about 15 bara to produce a stream of compressed impure carbon dioxide at about 310°C. Such stream is used to preheat boiler feed water and condensate and then is further cooled against a stream of sea water to produce a stream of CO_2 at about 30°C. The previously mentioned coolers provide sufficient contact time between the contaminants to convert a portion of SO_2 to sulphuric acid. Such CO_2 stream is fed to the bottom of the first contacting column, where it ascends and contact countercurrently a stream of descending acid water. The column is designed to provide sufficient contact time between the ascending gas and the descending liquid to completely convert the remaining SO_2 contaminant to produce sulphuric acid and also to convert part of NO_x to nitric acid. Thus, a stream of SO_2-free carbon dioxide is removed from the top of the column and a stream of aqueous sulphuric acid that also contains some nitric acid is removed from the column bottom. The liquid is then pumped and split into two: part of the liquid is cooled down and recycled to the same

contacting column as reflux, whereas the excess of liquid is sent to Waste Water Treatment section.

The stream of SO_2-free carbon dioxide from the top of the first contacting column is compressed to about 30 bara. Heat of compression generated in such compression stage is removed in the sea water cooler to produce a stream of cooled, compressed SO_2-free carbon dioxide, which is fed to the bottom of the second contacting column. The gas stream ascends the column and contacts countercurrently a stream of aqueous nitric acid solution. The column is designed to provide sufficient contact time between the ascending gas and the descending liquid to almost completely convert the remaining NO_x contaminant to produce nitric acid. Thus, a stream of SO_2-free and NO_x-lean carbon dioxide is removed from the top of the column and a stream of aqueous nitric acid is removed from the column bottom. The liquid is then pumped and divided into two: part of the liquid is cooled down and recycled to the same contacting column as reflux, whereas the excess of liquid is sent to Waste Water Treatment section. A stream of fresh water is injected into the top of the column to increase NO_x conversion and to ensure that no acid droplets are entrained in the gas stream leaving the column top.

The result obtained from the Air Products patent package is that all the SO_2 and about 90% the NO_x contained in flue gas and generated in the USC PC oxyfuel combustion process is removed and a stream of SO_2-free and NO_x-lean carbon dioxide is obtained.
Such stream is then sent to the following sections of CO_2 inerts removal and compression, whose arrangement is exactly the same as in the reference IEA study.

The raw CO_2 is dried and the inerts (N_2 and Ar) and oxygen are separated to give >96 mol% CO_2. The CO_2 is then compressed to 110 bara for pipeline transmission. Any excess O_2 or NOx present in the CO_2 need not be removed, as the final CO_2 product will be used either for enhanced oil recovery (EOR) or stored in aquifers.
The raw CO_2 gas passes through a temperature swing dual bed desiccant dryer (C201) to reach a dew point of below -55°C before entering the "cold box". This desiccant dryer system prevents ice formation which could cause a blockage in the cold box as well as causing corrosion in the pipeline. The cold equipment is contained in a steel jacketed container or "cold box" with pearlite granular insulation. The inerts removal process uses the principle of phase separation between condensed liquid CO_2 and insoluble inerts gas at a temperature of –55°C, which is very close to the triple point, or freezing temperature, of CO_2. The actual CO_2 pressure levels used for the separation are fixed by the specification of >95 mol% CO_2 product purity and the need to reduce the CO_2 vented with the inerts to an economic minimum.

The system proposed uses two flash separators C202 and C203 at temperatures of -25°C and -55°C. The CO_2 feed gas pressure is at 30 bara. The necessary refrigeration for plant operation is obtained by evaporating liquid CO_2 at pressure levels of 18.6 bara (stream 20 on the relevant PFD attached at following paragraph 3) and 9.3 bara (stream 16) and compressing these two low pressure gas streams in the main CO_2 product compressor to the final pipeline delivery pressure of 110 bara. The separated inert gas leaving the cold box at 29 bara (stream 7) can be heated and passed through a power recovery turbine. It is possible to reach a CO_2 purity in excess of 96% using this method at inlet CO_2 concentrations as low as 77% by volume with a CO_2 recovery of better than 90%.

The dry gas is fed to the cold box and is cooled by heat exchange to –25°C with the returning evaporating and superheating CO_2 streams and the waste streams in the main exchanger. The main heat exchangers, E201 and E202, are multi-stream plate-fin aluminium blocks. The cooled feed stream 3 is sent to a separator pot C202 at a temperature of –25°C where it is split into liquid and vapour; the liquid product, stream 18, contains part of the required CO_2 product at 29.7 bara.
The vapour from the separator, stream 4, still contains a large proportion of CO_2. In order to recover this CO_2 the vapour is cooled further to –54°C where it partially condenses and is passed to another separator pot C203. The pressure at this point is critical in controlling the process since cooling the vapour below –56.2°C would lead to the formation of solid carbon dioxide. The vapour, stream 6, from the second separator, containing the separated inerts together with some CO_2 at a partial pressure of about 7 bara, is sent back through the heat exchangers E202 and E201 where it is heated to 8°C. This stream of inerts, which is at a pressure of 29 bara, is then heated against hot compressed CO_2 product (E210) and hot flue gas in the boiler area (E203) and expanded in a power producing turbo-expander (K203) before being vented.

Liquid, stream 18, from the first separator C202 containing part of the CO_2 is expanded through a J-T valve to 18.8 bara (stream 19) and heated to 8°C (stream 20). The liquid, stream 12, from the second separator C203, is heated, expanded through a valve to 9.7 bara and a temperature of about –55°C (stream 13) to provide refrigeration in E202 by evaporation, while the vapour formed is heated to 8°C. The CO_2 vapour stream leaving E202 at 9.5 bara is then compressed in a single radial wheel (K202) to 18.7 bara, the same pressure as the CO_2 stream from the first separator C202. The two streams are combined and compressed to the required pressure of 110 bara. This machine (K201) is a four stage integrally geared unit (Figure 13) which could be operated from the 18.7 bara to 110 bara level as either an intercooled compressor or as an adiabatic compressor with an aftercooler used to heat flue gas before expansion and condensate for the boiler system. In the latter case no cooling water would be required for this section of the compressor. The reference project selected K201 to be run adiabatically, with condensate being preheated in the aftercooler along with some of the flue gas heating duty. This has the benefit of simplifying the final stages of K201, since it avoids supercritical dense fluid CO_2

forming in K201. The likelihood of dense fluid CO_2 forming in K201 has meant that the four stage isothermal option only had one intercooler, to prevent the dense phase forming within the machine. Therefore, the power penalty in removing this intercooler to give an adiabatic compressor is small, but gives the benefit of a simpler machine, reduced cooling water requirement and saves low pressure steam that would have otherwise been used to preheat the condensate.

2.7 Unit 800 - Balance of Plant (Utility Units)

This comprises all the systems necessary to allow operation of the plant and export of the produced power, as shown on the equipment list attached in the following paragraph 8.

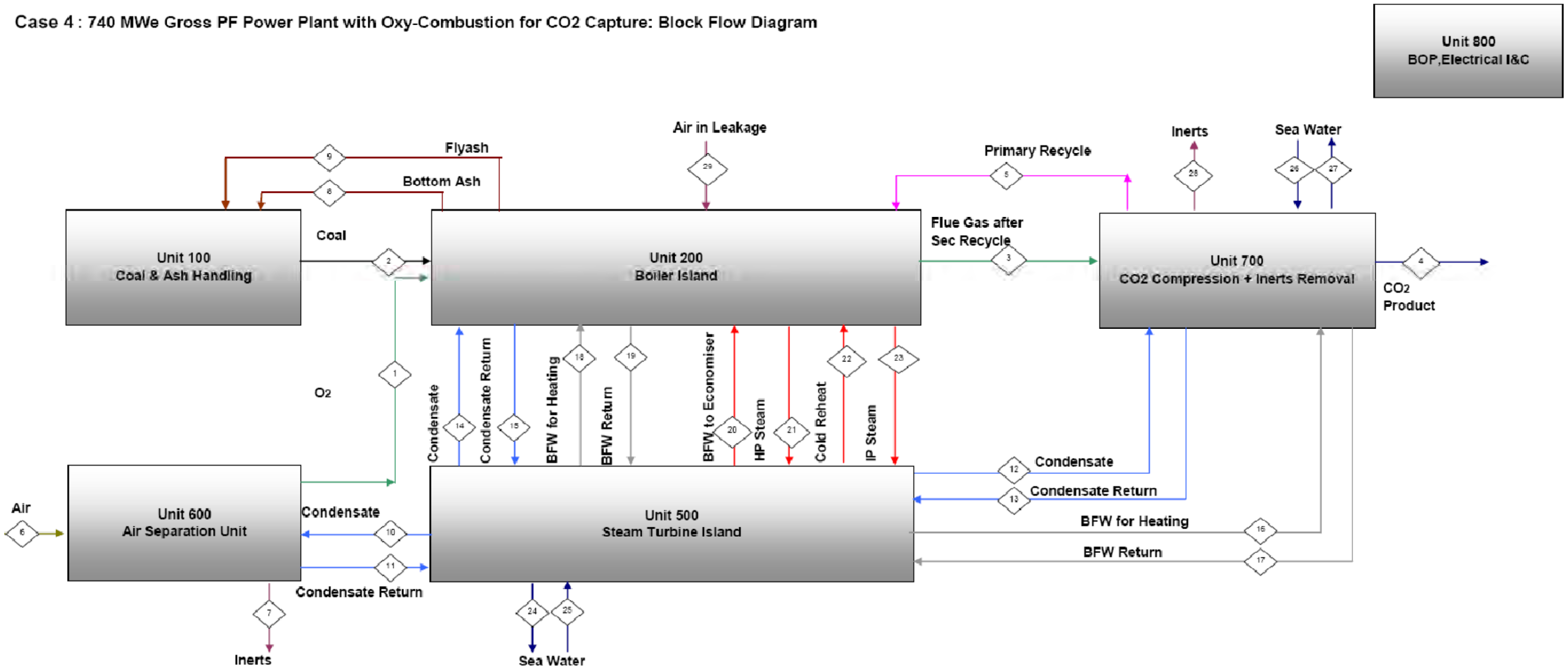
The main utility units are the following:
- Sea Cooling water
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

3 Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagrams of the USC PC Oxyfuel plant, Case 4, and the schematic Process Flow Diagram of Units 500, 600 and 700 are attached hereafter.

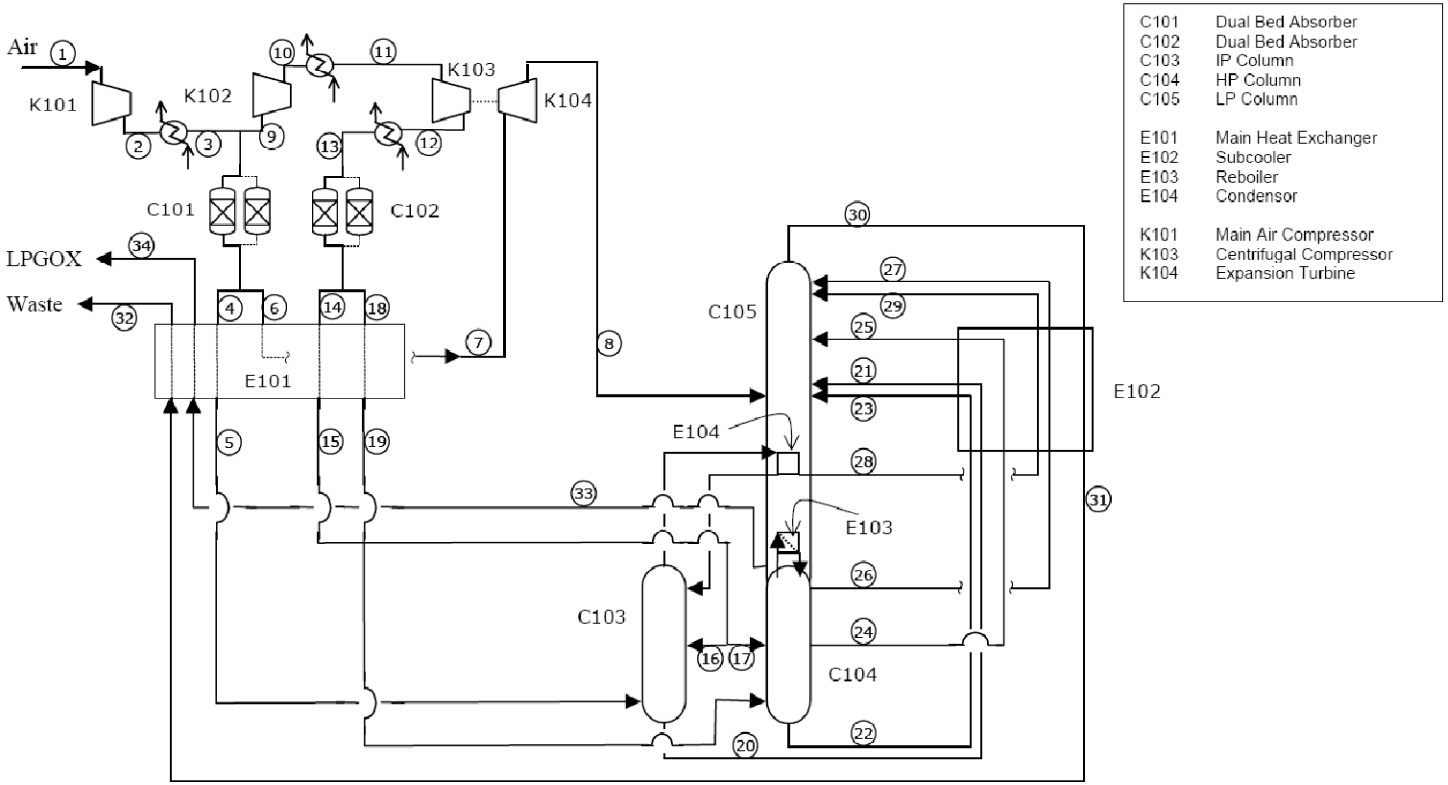
The H&M balances relevant to the scheme attached are shown in paragraph 4.

Case 4 : 740 MWe Gross PF Power Plant with Oxy-Combustion for CO2 Capture: Block Flow Diagram



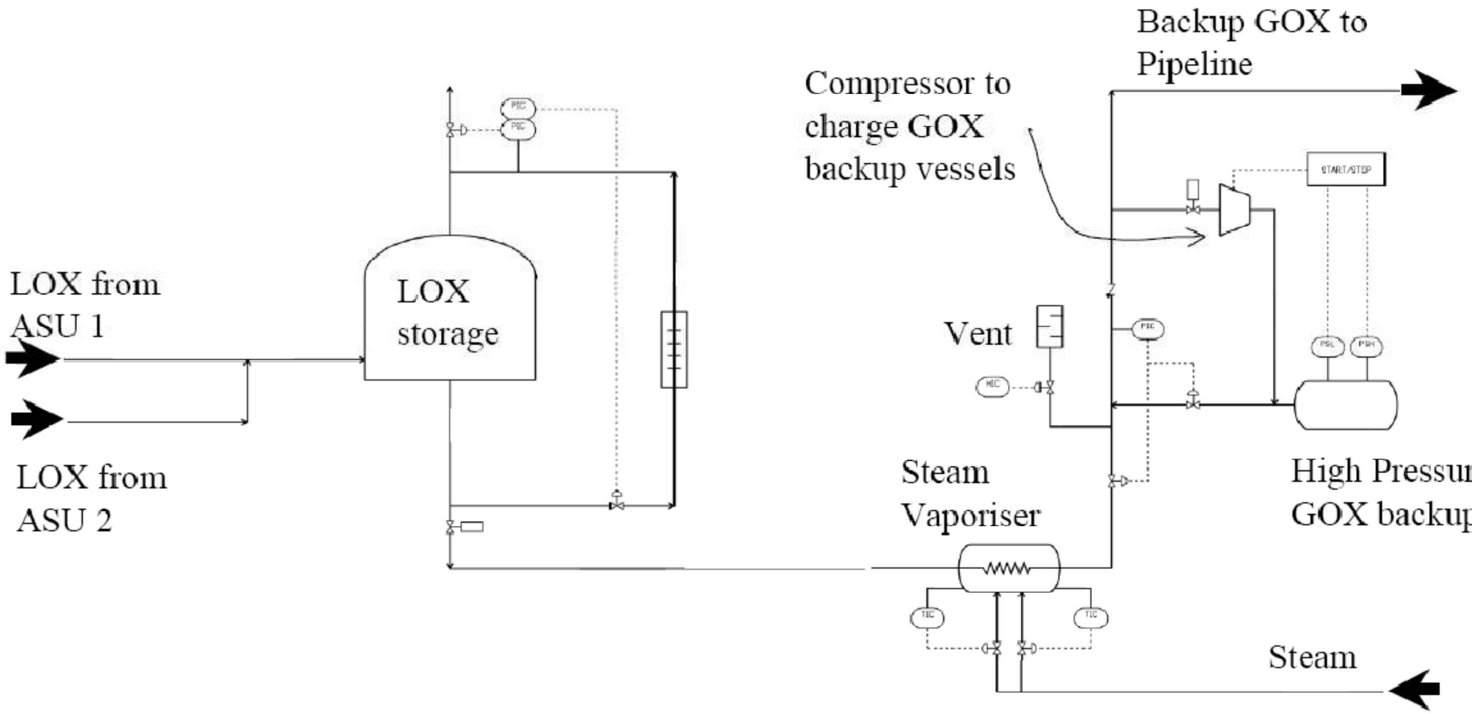
CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM

PFD 2



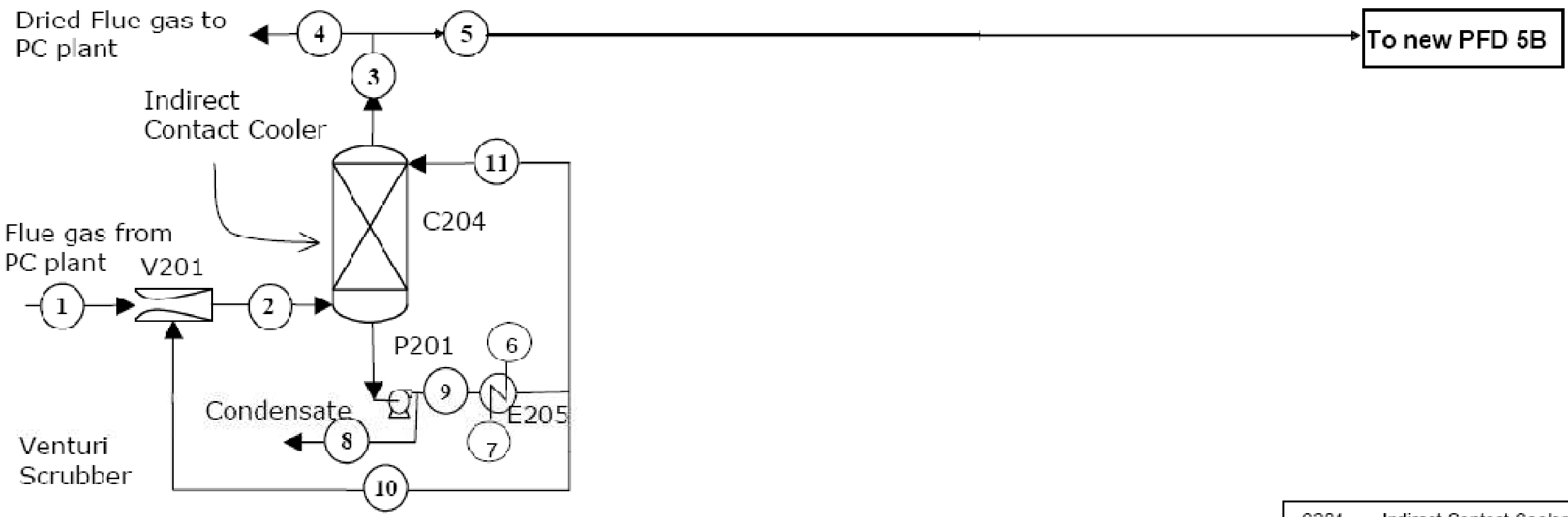
CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : ASU PROCESS FLOW DIAGRAM

PFD 3



CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : OXYGEN BACK UP SYSTEM

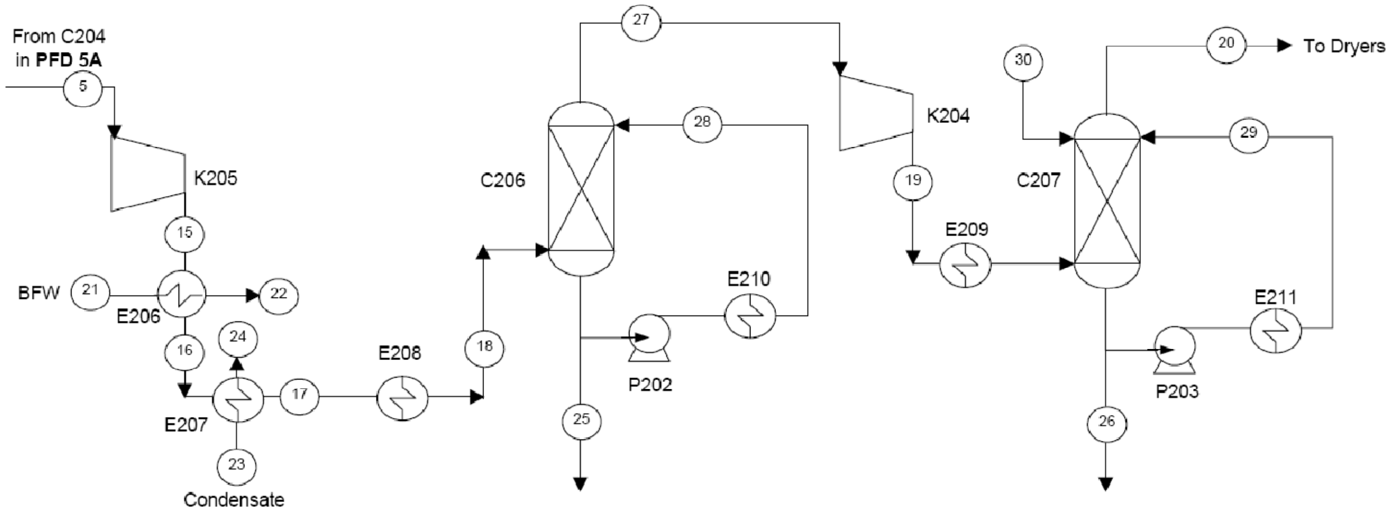
PFD 4



C204	Indirect Contact Cooler
E205	Plate Frame Heat Exchanger
P201	Contact water pump
V201	Venturi Scrubber

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 COOLING AND COMPRESSION TO 30 BAR (a)

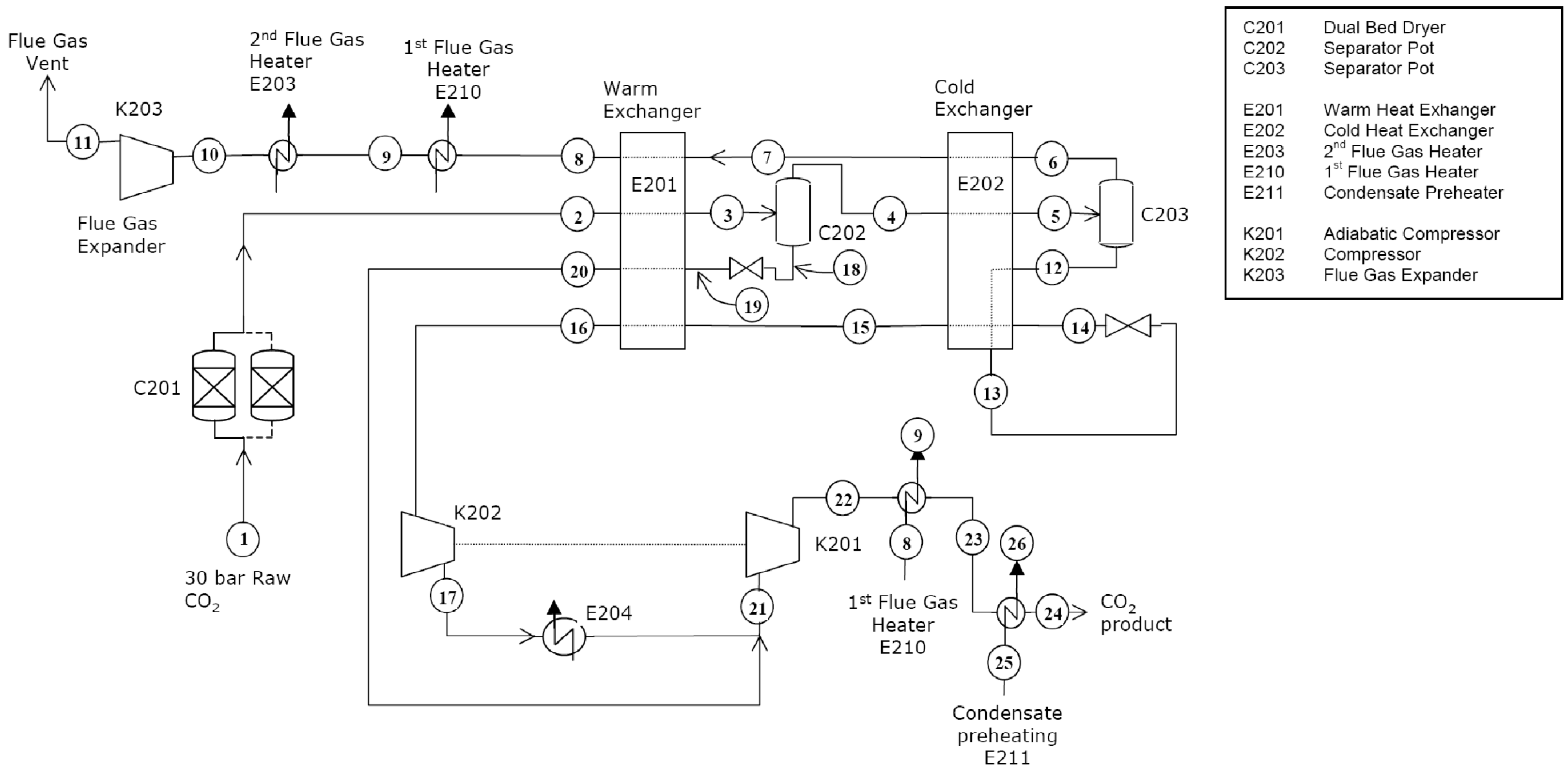
PFD 5A



CASE 4 : ASC PF POWER PLANT WITH CO2 CAPTURE: CO2 COOLING AND COMPRESSION TO 30 BAR (a) **PFD 5B**

The present scheme is in accordance with Air Products patent No. US 7,416,716 B2: "PURIFICATION OF CARBON DIOXIDE".

C206	First contacting column	E206	BFW preheater
C207	Second contacting column	E207	Condensate preheater
		E208	CO2 cooler (sea water)
K205	CO2 compression to 15 bara	E209	CO2 aftercooler (sea water)
K204	CO2 compression to 30 bara	E210	First contacting column cooler (sea water)
		E211	Second contacting column cooler (sea water)
P202	First contacting column circulation pumps		
P203	Second contacting column circulation pumps		



CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR (a)

PFD 6

4 Heat and Material Balance

The Heat and Material Balance, referring to the Block Flow diagram attached in the previous paragraph, is attached hereafter.
The H&M balance makes reference to the schemes attached to paragraph 3.

Stream ID		1	2	3	4	5	6	7	8	9	10
Material		Oxygen	Coal	Flue Gas -sec	prod	p rycl	air in	Asu inerts	btm ash	Fly ash	Condensate
model stream No.		Ap A 34	Ec N1b	Ap C 1	Ap C 24	Ap C 4	Ap A 1	Ap A 32	Ec S17	Ec N11	Ec AS1
Total mass flow	kg/s	127.1	58.09	351.85	126.6	154.87	534.68	403.91	1.446	5.767	243.7
- Coal	kg/s	0	45.484	0	0	0	0	0	0	0	0
- Air	kg/s	0	0.0	0	0	0	0	0	0	0	0
- Flue Gas	kg/s	0	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	7.087	0	0	0	0	0	1.446	5.767	0
- Water	kg/s	0	5.5186	34.61	0	3.964	3.334	0	0	0	243.7
- Steam	kg/s	0	0	0	0	0	0	0	0	0	0
- Argon	kg/s	4.7	0	7.59	0.72	3.615	6.807	2.022	0	0	0
- Nitrogen	kg/s	2.2	0	33.09	1.655	15.741	401.23	399.064	0	0	0
- Oxygen	kg/s	120.1	0	15.51	0.9779	7.373	122.9	2.798	0	0.00	0
- Carbon Dioxide	kg/s	0	0	259.09	123.2	123.24	0.326	0	0	0	0
- Sulphur Dioxide	kg/s	0	0	1.82	0.0	0.8786	0	0	0	0	0
- Hydrogen Chloride	kg/s	0	0	0.027	0	0.0125	0	0	0	0	0
- Nitric Oxide	kg/s	0	0	0.099	0.0	0.047	0	0	0	0	0
- Nitrogen dioxide	kg/s	0	0	0.0044	0	0.0018	0	0	0	0	0
- NOx	kg/s	0	0	0.10	0.0	0.05	0	0	0	0	0
Props											
- Phase		Gas	Solid	Gas	liquid	Gas	Gas	Gas	Solid	Solid	Liquid
- Temperature	°C	16	15	110	50	35	9	16	1102	264	29
- Pressure	bara	1.600	-	1.020	110.000	1.020	1.010	1.2	-	-	16.0
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-
Composition											
O_2	%v/v,wet	94.94	-	5.00	1.05	5.88	20.73	0.608	-	-	-
CO_2	%v/v,wet	0	-	60.71	96.29	71.46	0.04	0	-	-	-
SO_2	%v/v,wet	0	-	0.29	0.0	0.35	0.00	0	-	-	-
H_2O	%v/v,wet	0	-	19.81	0.00	5.62	1.00	0	-	-	-
N_2	%v/v,wet	1.98	-	12.18	2.04	14.34	77.30	99.04	-	-	-
Ar	%v/v,wet	3.03	-	1.96	0.62	2.31	0.92	0.352	-	-	-
NO	%v/v,wet	0	-	0.0034	0.0	0.04	0.00	0	-	-	-
NO_2	%v/v,wet	0	-	0.001	0	0.001	0.00	0	-	-	-
molecular weight	kg/kmol	32.1	-	36.29	43.53	39.52	28.86	28.08	-	-	-
Emissions											
NOx	mg/MJ	-	-	66	0	32	-	-	-	-	-
SOx	mg/MJ	-	-	1174	0	559	-	-	-	-	-
Particulates	mg/MJ	-	-	6	0	0	-	-	-	-	-

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM STREAMS 1 - 10

PFD 2

Stream ID		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Material		Cond Return	Condensate	Cond Return	Condensate	Cond Return	BFW	BFW return	BFW	BFW return	BFW to Econ
model stream No.		Ec AS2	Ec NN6A	Ec S47B	Ec FG1	Ec FG2	Ec NN9A	Ec S54A	Ec NN9B	Ec S52	Ec NN10
Total mass flow	kg/s	243.7	95	95	69.95	69.95	91.65	91.65	429.0	429.0	520.69
- Coal	kg/s	0	0	0	0	0	0	0	0	0	0
- Air	kg/s	0	0	0	0	0	0	0	0	0	0
- Flue Gas	kg/s	0	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	0	0	0	0	0	0	0	0	0
- Water	kg/s	243.7	95	95	69.95	69.95	91.65	91.65	429.0	429.0	520.69
- Steam	kg/s	0	0	0	0	0	0	0	0	0	0
- Argon	kg/s	0	0	0	0	0	0	0	0	0	0
- Nitrogen	kg/s	0	0	0	0	0	0	0	0	0	0
- Oxygen	kg/s	0	0	0	0	0	0	0	0		0
- Carbon Dioxide	kg/s	0	0	0	0	0	0	0	0	0	0
- Sulphur Dioxide	kg/s	0	0	0	0	0	0	0	0	0	0
- Hydrogen Chloride	kg/s	0	0	0	0	0	0	0	0	0	0
- Nitric Oxide	kg/s	0	0	0	0	0	0	0	0	0	0
- Nitrogen dioxide	kg/s	0	0	0	0	0	0	0	0	0	0
- NOx	kg/s	0	0	0	0	0.00	0	0	0	0	0
Props											
- Phase		Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
- Temperature	°C	83	29	155	29	93	165	206	165	180	270
- Pressure	bara	16	16	16	16	13	339	339	339	335	329
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	801.45
Composition											
O_2	%v/v,wet	-	-	-	-	-	-	-	-	-	-
CO_2	%v/v,wet	-	-	-	-	-	-	-	-	-	-
SO_2	%v/v,wet	-	-	-	-	-	-	-	-	-	-
H_2O	%v/v,wet	-	-	-	-	-	-	-	-	-	-
N_2	%v/v,wet	-	-	-	-	-	-	-	-	-	-
Ar	%v/v,wet	-	-	-	-	-	-	-	-	-	-
NO	%v/v,wet	-	-	-	-	-	-	-	-	-	-
NO_2	%v/v,wet	-	-	-	-	-	-	-	-	-	-
molecular weight	kg/kmol	-	-	-	-	-	-	-	-	-	-
Emissions @ 6%O_2 Dry											
NOx	mg/MJ	-	-	-	-	-	-	-	-	-	-
SOx	mg/MJ	-	-	-	-	-	-	-	-	-	-
Particulates	mg/MJ	-	-	-	-	-	-	-	-	-	-

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM STREAMS 11 - 20

PFD 2

Stream ID		21	22	23	24	25	26	27	28	29
Material		HP Steam	Cold RH	IP Steam	Cond Sea water in	Cond Seawater out	Comp Sea water in	Comp Sea water ou	CO2 Inerts	Air in leakage
model stream No.		Ec S24	Ec S26	Ec NN3	Ec Utility	Ec Utility	Ap CO 12&6	Ap CO 13&7	Ap CO 11	Ec S16C/S13C
Total mass flow	kg/s	520.69	410.807	410.807	20891	20891	2975.2	2978.9	38.6	18.8
- Coal	kg/s	0	0	0	0	0	0	0	0	0
- Air	kg/s	0	0	0	0	0	0	0	0	0
- Flue Gas	kg/s	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	0	0	0	0	0	0	0	0
- Water	kg/s	0	0	0	20891	20891	2975.2	2975.2	0	0.1167
- Steam	kg/s	520.69	410.807	410.807	0	0	0	0	0	0
- Argon	kg/s	0	0	0	0	0	0	0	3.2688	0.2388
- Nitrogen	kg/s	0	0	0	0	0	0	0	15.688	14.112
- Oxygen	kg/s	0	0	0	0	0	0	0	[illegible]	4.323
- Carbon Dioxide	kg/s	0	0	0	0	0	0	0.535	12.455	0.0079
- Sulphur Dioxide	kg/s	0	0	0	0	0	0	0.129	0	0
- Hydrogen Chloride	kg/s	0	0	0	0	0	0	0	-	-
- Nitric Oxide	kg/s	0	0	0	0	0	0	0	0.0005	0
- Nitrogen dioxide	kg/s	0	0	0	0	0	0	0	0	0
- NOx	kg/s	0	0	0	0	0	0	0	0.0005	0
Props										
- Phase		Gas	Gas	Gas	Liquid	Liquid	Liquid	Liquid	Gas	Gas
- Temperature	°C	597	360	620	12	-	12	19	20.17	15
- Pressure	bara	290.0	64.50	61.14	-	-	4.0	3.0	1.01	1.013
- Density	kg/m^3	84.61	25.10	15.23	-	-	-	-	-	-
Composition										
O_2	%v/v,wet	-	-	-	-	-	-	-	19.44	20.73
CO_2	%v/v,wet	-	-	-	-	-	-	-	24.65	0.028
SO_2	%v/v,wet	-	-	-	-	-	-	-	0	0
H_2O	%v/v,wet	-	-	-	-	-	-	-	0	0.995
N_2	%v/v,wet	-	-	-	-	-	-	-	48.78	77.328
Ar	%v/v,wet	-	-	-	-	-	-	-	7.13	0.92
NO	%v/v,wet	-	-	-	-	-	-	-	0.0014	0
NO_2	%v/v,wet	-	-	-	-	-	-	-	0	0
molecular weight	kg/kmol	-	-	-	18.02	18.02	18.02	18.02	33.58	28.96
Emissions										
NOx	mg/MJ	-	-	-	-	-	-	-	0.12	-
SOx	mg/MJ	-	-	-	-	-	-	82	0	-
Particulates	mg/MJ	-	-	-	-	-	-	-	0	-

CASE 4 : ASC PF POWER PLANT WITH CO2 CAPTURE: PROCESS FLOW BLOCK DIAGRAM STREAMS 21 - 29

PFD 2

STREAM No.		1	2	3	4	5	6	7	8	9	10	11	12	13
Composition - (mol%)														
Nitrogen		77.308	77.308	77.763	78.120	78.120	78.120	78.120	78.120	77.763	77.763	77.763	77.763	77.763
Argon		0.920	0.920	0.926	0.930	0.930	0.930	0.930	0.930	0.926	0.926	0.926	0.926	0.926
Oxygen		20.732	20.732	20.854	20.950	20.950	20.950	20.950	20.950	20.854	20.854	20.854	20.854	20.854
Water		1.000	1.000	0.417	0.000	0.000	0.000	0.000	0.000	0.417	0.417	0.417	0.417	0.417
Carbon Dioxide		0.040	0.040	0.040	0.000	0.000	0.000	0.000	0.000	0.040	0.040	0.040	0.040	0.040
Molecular Weight	kg/kmol	28.86	28.86	28.92	28.96	28.96	28.96	28.96	28.96	28.92	28.92	28.92	28.92	28.92
Flowrate	kg/hr	962,422	962,422	958,904	188,577	188,577	290,223	290,223	290,223	478,563	478,563	478,563	478,563	478,563
	Nm3/hr	747,095	747,095	742,721	145,862	145,862	224,485	224,485	224,485	370,672	370,672	370,672	370,672	370,672
Phase		Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour
Pressure	bar(a)	1.01	3.50	3.50	3.10	3.02	3.10	3.01	1.46	3.50	4.96	4.96	5.41	5.41
Temperature	°C	9.00	144.39	12.00	20.00	-178.54	20.00	-171.44	-188.16	12.00	46.19	20.00	28.92	20.00

STREAM No.		14	15	16	17	18	19	20	21	22	23	24	25	26
Composition - (mol%)														
Nitrogen		78.120	78.120	78.120	78.120	78.120	78.120	54.410	54.410	58.892	58.892	78.120	78.120	98.822
Argon		0.930	0.930	0.930	0.930	0.930	0.930	1.554	1.554	1.527	1.527	0.930	0.930	0.287
Oxygen		20.950	20.950	20.950	20.950	20.950	20.950	44.036	44.036	39.581	39.581	20.950	20.950	0.891
Molecular Weight	kg/kmol	28.96	28.96	28.96	28.96	28.960	28.96	29.954	29.954	29.773	29.773	28.960	28.960	28.084
Flowrate	kg/hr	240,378	240,378	44,788	195,590	236,650	236,650	110,843	110,843	152,635	152,635	145,882	145,882	133,723
	Nm3/hr	185,930	185,930	34,643	151,287	183,046	183,046	82,890	82,890	114,836	114,836	112,839	112,839	106,659
Phase		Vapour	Liquid	Liquid	Liquid	Vapour	Vapour	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Pressure	bar(a)	5.30	5.10	5.10	5.10	5.30	5.09	3.02	2.92	5.09	4.99	5.10	5.00	4.99
Temperature	°C	20.00	-176.75	-176.75	-176.75	20.00	-173.52	-180.78	-187.04	-174.64	-183.74	-176.75	-188.68	-179.06

STREAM No.		27	28	29	30	31	32	33	34
Composition - (mol%)									
Nitrogen		98.822	98.254	98.254	99.040	99.040	99.040	1.981	1.981
Argon		0.287	0.400	0.400	0.352	0.352	0.352	3.033	3.033
Oxygen		0.891	1.347	1.347	0.608	0.608	0.608	94.985	94.985
Molecular Weight	kg/kmol	28.08	28.12	28.12	28.08	28.08	28.08	32.16	32.16
Flowrate	kg/hr	133,723	122,522	122,522	727,040	727,040	727,040	228,788	228,788
	Nm3/hr	106,659	97,615	97,615	579,970	579,970	579,970	159,354	159,354
Phase		Liquid	Liquid	Liquid	Vapour	Vapour	Vapour	Liquid	Vapour
Pressure	bar(a)	4.89	2.92	2.82	1.36	1.31	1.20	1.72	1.60
Temperature	°C	-190.52	-185.39	-190.43	-193.00	-178.53	15.54	-180.05	15.54

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE PLANT : ASU PROCESS FLOW DIAGRAM STREAMS 1 - 34

PFD 3

STREAM No.		1	2	3	4	5	6	7	8	9	10	11	12 (DELETED)
Composition - (mol%)													
Carbon Dioxide		60.72	57.93	71.46	71.46	71.46	0.00	0.00	0.04	0.04	0.04	0.04	0.00
Oxygen		5.00	4.77	5.88	5.88	5.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argon		1.96	1.87	2.31	2.31	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrogen		12.18	11.62	14.34	14.34	14.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water		19.81	23.49	5.62	5.62	5.62	100.00	100.00	99.95	99.95	99.95	99.95	100.00
Sulphur Dioxide		0.29	0.28	0.35	0.35	0.35	0.00	0.00	0.01	0.01	0.01	0.01	0.00
NO		0.034	0.032	0.040	0.040	0.040	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NO2		0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.002	0.002	0.002	0.002	0.000
Molecular Weight	kg/kmol	36.29	35.45	39.52	39.52	39.52	18.02	18.02	18.03	18.03	18.03	18.03	18.02
Flow	kg/hr	1,266,660	1,296,950	1,171,841	557,562	614,279	10,195,000	10,195,000	94,570	3,965,000	30,321	3,934,679	1,303,688
	Nm3/hr	782,400	820,080	664,217	316,035	348,183	12,676,000	12,676,000	117,550	4,930,000	37,675	4,888,882	1,621,016
Phase		Vapour	2 Phase	Vapour	Vapour	Vapour	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Pressure	bar(a)	1.02	1.02	1.02	1.02	1.02	4.00	3.00	4.00	4.00	3.00	3.00	1.00
Temperature	°C	110.95	61.09	35.00	35.00	35.00	12.00	19.00	35.02	35.02	17.00	17.00	12.00

STREAM No.		13 (DELETED)	14 (DELETED)	15	16	17	18	19	20	21	22	23	24
Composition - (mol%)													
Carbon Dioxide		0.06	74.34	71.46	71.46	71.46	71.46	75.85	75.86	0.00	0.00	0.00	0.00
Oxygen		0.00	6.14	5.88	5.88	5.88	5.88	6.24	6.24	0.00	0.00	0.00	0.00
Argon		0.00	2.41	2.31	2.31	2.31	2.31	2.45	2.45	0.00	0.00	0.00	0.00
Nitrogen		0.00	14.98	14.34	14.34	14.34	14.34	15.22	15.23	0.00	0.00	0.00	0.00
Water		99.93	1.77	5.62	5.62	5.62	5.62	0.23	0.22	100.00	100.00	100.00	100.00
Sulphur Dioxide		0.01	0.32	0.35	0.35	0.35	0.35	0.00	0.00	0.00	0.00	0.00	0.00
NO		0.000	0.042	0.040	0.040	0.040	0.040	0.042	0.0004	0.000	0.000	0.000	0.000
NO2		0.000	0.000	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Molecular Weight	kg/kmol	18.04	40.38	39.52	39.52	39.52	39.52	40.63	40.67	18.02	18.02	18.02	18.02
Flow	kg/hr	1,317,061	600,906	614,279	614,279	614,279	614,279	595,900	595,100	150,956	150,956	330,635	330,635
	Nm3/hr	1,635,819	333,380	348,183	348,183	348,183	348,183	328,700	327,970	187,700	187,700	411,114	411,114
Phase		Liquid	Vapour	Vapour	Vapour	Vapour	2 Phase	Vapour	Vapour	Liquid	Liquid	Liquid	Liquid
Pressure	bar(a)	1.01	1.01	15.00	15.00	15.00	15.00	30.00	30.00	338.53	338.53	6.00	6.00
Temperature	°C	19.00	13.01	311.3	223.9	106.1	36.0	94.3	30.00	165.00	250.00	33.37	93.20

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 COOLING AND COMPRESSION TO 30 BAR (a) STREAMS 1 - 24

PFD 5A

STREAM No.		25	26	27	28	29	30						
Composition - (mol%)													
Carbon Dioxide		0.03	1.00	75.72	0.03	1.00	0.00						
Oxygen		0.00	0.00	6.23	0.00	0.00	0.00						
Argon		0.00	0.00	2.45	0.00	0.00	0.00						
Nitrogen		0.00	0.00	15.20	0.00	0.00	0.00						
Water		92.38	98.83	0.36	92.38	98.83	100.00						
Sulphur Dioxide		0.00	0.00	0.00	0.00	0.00	0.00						
NO		0.00	0.00	0.04	0.00	0.00	0.00						
NO2		0.00	0.00	0.00	0.00	0.00	0.00						
Sulphuric acid		6.89	0.00	0.00	6.89	0.00	0.00						
Nitric Acid		0.70	0.17	0.00	0.70	0.17	0.00						
Molecular Weight	kg/kmol	23.85	18.36	40.63	23.85	18.36	18.02						
Flow	kg/hr	19,497	6,800	595,900	540,000	460,000	6,200						
	Nm3/hr	18,323	8,302	328,735	507,490	561,638	7,712						
Phase		Liquid	Liquid	Vapour	Liquid	Liquid	Liquid						
Pressure	bar(a)	15	30	15	15	30	30						
Temperature	°C	46	36	30	30	30	30						

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE: CO_2 COOLING AND COMPRESSION TO 30 BAR (a). STREAMS 25-30

PFD 5B

STREAM No.		1	2	3	4	5	6	7	8	9	10	11	12	13
Composition - (mol%)														
Carbon Dioxide		75.86	76.03	76.03	63.79	63.79	24.65	24.65	24.65	24.65	24.65	24.65	95.19	95.19
Oxygen		6.24	6.25	6.25	9.42	9.42	19.44	19.44	19.44	19.44	19.44	19.44	1.38	1.38
Argon		2.45	2.46	2.46	3.62	3.62	7.13	7.13	7.13	7.13	7.13	7.13	0.80	0.80
Nitrogen		15.22	15.26	15.26	23.17	23.17	48.78	48.78	48.78	48.78	48.78	48.78	2.63	2.63
Water		0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulphur Dioxide		0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO		0.0004	0.0004	0.0004	0.0006	0.0006	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.00	0.00
NO2		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Molecular Weight	kg/kmol	40.67	40.71	40.71	39.02	39.02	33.58	33.58	33.58	33.58	33.58	33.58	43.39	43.39
Flow	kg/hr	595,100	594,520	594,520	361,925	361,925	138,628	138,628	138,628	138,628	138,628	138,628	223,297	223,297
	Nm3/hr	327,970	327,329	327,329	207,898	207,898	92,531	92,531	92,531	92,531	92,531	92,531	115,367	115,367
Phase		Vapour	Vapour	2 Phase	Vapour	2 Phase	Vapour	Vapour	Vapour	Vapour	Vapour	Vapour	Liquid	2 Phase
Pressure	bar(a)	30.00	30.00	29.72	29.72	29.45	29.45	29.17	28.90	28.90	28.90	1.10	29.45	29.24
Temperature	°C	30.00	30.00	-24.51	-24.51	-54.69	-54.69	-42.17	15.0	170.00	300.00	20.17	-54.69	-46.44
STREAM No.		**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Composition - (mol%)														
Carbon Dioxide		95.19	95.19	95.19	95.19	97.34	96.34	96.34	96.28	96.28	96.28	96.28	0.00	0.00
Oxygen		1.38	1.38	1.38	1.38	0.74	0.74	0.74	1.05	1.05	1.05	1.05	0.00	0.00
Argon		0.80	0.80	0.80	0.80	0.44	0.44	0.44	0.62	0.62	0.62	0.62	0.00	0.00
Nitrogen		2.63	2.63	2.63	2.63	1.48	1.48	1.48	2.05	2.05	2.05	2.05	0.00	0.00
Water		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	100.00
Sulphur Dioxide		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NO2		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Molecular Weight	kg/kmol	43.39	43.39	43.39	43.39	43.68	43.68	43.68	43.53	43.53	43.53	43.53	18.02	18.02
Flow	kg/hr	223,297	223,297	223,297	223,297	232,595	232,595	232,595	455,892	455,892	455,892	455,892	378,478	378,478
	Nm3/hr	115,367	115,367	115,367	115,367	119,354	119,354	119,354	234,721	234,721	234,721	234,721	470,602	470,602
Phase		2 Phase	2 Phase	Vapour	Vapour	Liquid	2 Phase	Vapour	Vapour	Vapour	Vapour	Liquid	Liquid	Liquid
Pressure	bar(a)	9.74	9.54	9.33	18.69	29.72	18.80	18.59	18.59	110.00	110.00	110.00	6.00	6.00
Temperature	°C	-55.69	-42.17	15.0	65.63	-24.51	-31.27	15.0	22.5	192	154	50	33.37	93.20

CASE 4 : ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR(a)
STREAMS 1 – 26

PFD 6

5 Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter, for both base load operation, 50% load operation and minimum efficient plant load operation, i.e. 70% of CO_2 compressor load.

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME PROJECT: OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS LOCATION: NETHERLANDS FWI Nº: 1- BD 0530 A				Rev: Draft mar-11 ISSUED BY: NF CHECKED BY: PC APPR. BY: LM

CASE 4 - WATER CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - Base load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	54.0	-
600	**Air Separation Unit**	-	-	834.0	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	6.1	-	1635.0	13110
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	24.7	2362.0	98538.9
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	8475.4
	BALANCE excluding CO_2 compression	33.3	0.0	3309.0	107014.3
	BALANCE including CO_2 compression	33.3	0.0	4944.0	120124.3

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Jun-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 4 - WATER CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - 50% load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	30.0	-
600	**Air Separation Unit**	-	-	583.8	-
700	**CO_2 Compression and Inerts Removal**	3.4	-	1144.5	9177
	(including Air Products package)				
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	13.8	1322.0	82121.2
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	15.2	-13.8	33.0	5337.1
	BALANCE excluding CO_2 compression	18.6	0.0	1968.8	87458.3
	BALANCE including CO_2 compression	18.6	0.0	3113.3	96635.3

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	NETHERLANDS
FWI Nº:	1- BD 0530 A

Rev: Draft
Sep-11
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APPR. BY: LM

CASE 4 - WATER CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - 70% load

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	37.8	-
600	**Air Separation Unit**	-	-	583.8	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	4.3	-	1144.5	9177.0
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	17.3	1653.4	98538.9
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	19.0	-17.3	41.3	5932.8
	BALANCE excluding CO_2 compression	23.3	0.0	2316.3	104471.7
	BALANCE including CO_2 compression	23.3	0.0	3460.8	113648.7

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	NETHERLANDS
FWI Nº:	1- BD 0530 A

Rev: Draft
mar-11
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CASE 4 - ELECTRICAL CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - Base load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit**	**86740**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**76100**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE excluding CO_2 compression	**142340**
	BALANCE including CO_2 compression	**218440**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Jun-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 4 - ELECTRICAL CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - 50% load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2238**
600	**Air Separation Unit**	**60690**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53172**
	Exhaust gas expander	(-6266)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**21860**
	Miscellanea utilities	**1120**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE excluding CO_2 compression	**92308**
	BALANCE including CO_2 compression	**145480**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 4 - ELECTRICAL CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture - 70% load

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2800**
600	**Air Separation Unit**	**60718**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53270**
	Exhaust gas expander	(-7840)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**28092**
	Miscellanea utilities	**1400**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE excluding CO_2 compression	**100610**
	BALANCE including CO_2 compression	**153880**

Notes: (1) Minus prior to figure means figure is generated

6 Overall performance

The table summarizing the Overall Performance of the USC PC Oxyfuel Plant, case 4, is attached hereafter, for both base load operation, 50% load operation and minimum efficient plant load operation, i.e. 70% of CO_2 compressor load.

USC PC, Oxyfuel bituminous coal, with CO_2 capture				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Base load	70% load	50% NPO
Coal Flowrate (fresh, air dried basis)	t/h	209.1	146.4	117.0
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0
Main steam flow	kg/s	528.2	350.0	270.8
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1051.5**	**840.5**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**512.5**	**405.6**
Expander power output	**MWe**	**11.2**	**7.8**	**6.3**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
ASU	MWe	86.7	60.7	60.7
FW pumps	MWe	35.0	23.2	17.9
Draught Plant	MWe	5.0	3.5	2.8
Coal mills, handling, etc.	MWe	4.0	2.8	2.2
ESP	MWe	2.0	1.4	1.1
Miscellanea	MWe	9.6	9.0	7.5
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	53.3	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**153.9**	**145.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**366.5**	**266.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**48.7**	**48.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**34.9**	**31.7**
Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.819**	**2.869**	**3.154**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.084**	**0.086**	**0.094**
Specific water consumption per MW net produced	**t /MWh**	**0.063**	**0.064**	**0.070**

7 Environmental Impact

The USC PC Oxyfuel plant, case 4, is designed to process coal, whose characteristic is shown at Section B of present report, burning it with Oxygen at 95%vol, and to produce electric power.
The gaseous emissions, liquid effluents and solid wastes from the power plant are summarized in the present paragraph.

7.1 Gaseous Emissions

7.1.1 Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases of the two trains of the Power Island, proceeding from the combustion of coal in the boiler.

Table 7-1 summarizes expected flow rate and concentration of the combustion flue gas.

Table 7-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	38.5
Flow, Nm^3/h	92,531
Temperature, °C	20.2
Composition	**(%vol, wet)**
O_2	19.44
CO_2	24.65
SO_x	0
H_2O	0
N_2+Ar	55.91
Emissions	**mg/Nm^3 (1)**
NOx	180
SOx	0
Particulate	0

(1) Dry gas, O_2 Content 6% vol

7.1.2 Minor Emissions

Other minor gaseous emissions are the process vents and fugitive emissions.
Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable

gaseous components are sent to a flare system. Venting via the flare will be minimal during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation reduce these emissions to a very low level.

7.2 Liquid Effluent

Waste Water Treatment

The expected flow rate of treated water to be discharged outside Plant battery limit is as follows:

- Flow rate : 140.8 m^3/h

Sea Cooling Water System

Sea water is returned to the sea basin after exchanging heat inside the Power Plant.
The cooling water maximum temperature rise considered in the study is 7°C.
The main characteristics of the discharged warm sea water are listed below:

- Maximum flow rate : 93,900 m^3/h
- Temperature : 19 °C

7.3 Solid Effluent

The plant is expected to produce the following solid by-products:

Bottom ash
Flow rate : 5.2 t/h

Fly ash
Flow rate : 20.8 t/h

Sludges from WWT
Flow rate : 13.7 t/h
Water content : 42 %wt

Some of solids effluent could be theoretically dispatched to cement industries and therefore they could be treated as revenue for the plant economics. There are fly and bottom ash.
Vice versa, sludges from WWT have to be sent outside the Power Plant battery limit for disposal.

Therefore, for the purposes of present study solids effluents are considered as neutral: neither as revenue nor as disposal cost.

8 Equipment List

The list of main equipment and process packages is included in this paragraph.

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EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Coal delivery equipment							
	Bunkers							
	Yard equipment							
	Transfer towers							
	Dust suppression equipment							
	Ventilation equipment							
	Belt feeders							
	Metal detection							
	Belt weighing equipment							
	Miscellaneous equipment							
	Bottom ash systems							
	Fly ash systems							

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EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Furnace							
	Reheater							
	Superheater							
	Economiser							
	Regenerative Gas / Gas heaters							
	Piping							
	Flue gas recycle system							
	Structures							
	Fans: ID, FD and PA							
	Pumps							
	Coal feeders							
	Soot blowers							
	Drains systems							
	Dosing equipment							
	Mills							
	Auxiliary boiler							
	Miscellaneous equipment							
	Burners							
	ESP							

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EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HP, IP & LP Turbines		740 MWe gross					
	Associated Pipework							
	Feedwater heaters							
	Deaerator							
	Condenser		802 MW th				tubes: titanium; shell: CS	sea water heat exchanger
	Condensate polishing							
	LP Pump							
	HP Pump							
	Sea water Circulation Pumps	submerged	20,000 m3/h x 20m	1250 kW			casing, shaft: SS; impeller: duplex	6 pump in operation + 1 spare
	Waste water treatment plant							
	Sea water inlet /outlet works							
	Demiwater plant							
	Machinery cooling water cooler	plate heat exchanger	70 MW th;				plates: titanium frame: SS	sea water heat exchanger
	Machinery cooling water pumps	centrifugal	5000 m3/h x 30 m	600 kW			CS	1 pump in operation + 1 spare

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EQUIPMENT LIST

Unit 600 - Air Separation Unit (2 x 50%) - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Equipment per train (2 x 50%)								
	Main air compressors	centrifugal	37.8 MW					each train
	Air purification system							
	Main heat exchanger							
	ASU compander							
	ASU Column System							
	Pumps	centrifugal	0.37 MW					each train
	ASU chiller		13 MW th					each train
Equipment common to both train (2x50%)								
	Backup storage vessel		200 t					

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EQUIPMENT LIST

Unit 700 - CO_2 compression and inerts removal - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Venturi scrubber							
	Indirect contact cooler							
P-201	**Indirect contact cooler circulation pump**	centrifugal	3800 m3/h x 40 m	560 kW			casing: CS; internals: 12%Cr	one pump in operation, one spare
	Compressors	centrifugal	75.4 MWe				SS	4 stage compressor
	Heat exchangers							heat exchanged with BFW and steam condensate
E-205	**Heat exchanger**	Shell and Tube	37 MW th; 5000 m2				tubes: titanium shell: SS	sea water heat exchanger; 2 shells in parallel
E-208	**Heat exchanger**	Shell and Tube	3.0 MW th; 110 m2				tubes: titanium shell: SS	sea water heat exchanger
E-209	**Heat exchanger**	Shell and Tube	10.8 MW th; 370m2				tubes: titanium shell: SS	sea water heat exchanger
E-204	**Heat exchanger**	Shell and Tube	2.0 MW th; 80m2				tubes: titanium shell: SS	sea water heat exchanger
	Flue gas expander		11.2 MWe					
	Dual bed dryers							
C-206	**First contacting column**		D=3.5 m; H=10.5 m				Shell: Alloy 20 CLAD	
C-207	**Second contacting column**		D=2.7 m; H=8.1 m				Shell: SS 304L CLAD	
E-210	**First contacting column cooler**	Shell and Tube	600 m2; 10.5 MW th				Shell: Alloy 20 clad Tubes: Hastelloy C-276	sea water heat exchanger
E-211	**Second contacting column cooler**	Shell and Tube	250 m2; 3.5 MW th				Shell: SS 304L CLAD Tubes: Titanium	sea water heat exchanger
P-202	**First contacting column circulation pumps**	centrifugal	600 m3/h x 50 m	110 kW			Alloy 20	one pump in operation, one spare
P-203	**Second contacting column circulation pumps**	centrifugal	500 m3/h x 45 m	90 kW			SS 304L	one pump in operation, one spare

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EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel with CO_2 capture, fed with bituminous coal, case 4

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	Balance of Power Plant							
	Controls							
	Instruments							
	Electrics							

9 Investment cost

The main cost estimating bases are shown in section B of this report. This section details the investment cost of the following units or blocks of units:

Unit 100	Coal and Ash Handling
Unit 200	Boiler Island
Unit 500	Steam Turbine
Unit 600	Air Separation Unit
Unit 700	CO_2 compression and inerts removal
Unit 800	Utility and offsite

The overall investment cost of each unit is split into the following items:

- **Direct Materials:** including equipment and bulk materials;
- **Construction**: including mechanical erection, instrument and electrical installation, civil works, buildings and site preparation;
- **Other Costs:** including temporary construction facilities, solvent, chemicals, training, commissioning and start-up costs, spare parts;
- **EPC services:** including Contractor's home office services and construction supervision.

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ESTIMATE SUMMARY

CASE 4 - Oxyfuel USC PC (reference case)

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 ASU	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,246,000	199,242,000			135,690,000	153,416,000	66,986,000	166,435,000	775,015,000	
2	CONSTRUCTION	19,832,000	122,040,000			47,291,000	51,684,000	35,087,000	47,977,000	323,911,000	
3	OTHER COSTS	3,277,000	13,108,000			9,831,000	15,140,000	4,916,000	11,142,000	57,414,000	
4	EPC SERVICES	4,407,000	16,159,000			11,752,000	13,574,000	10,283,000	14,984,000	71,159,000	
	TOTAL INSTALLED COST	80,762,000	350,549,000			204,564,000	233,814,000	117,272,000	240,538,000	1,227,499,000	
5	CONTINGENCY	5,700,000	24,500,000			14,300,000	11,700,000	5,900,000	12,000,000	74,100,000	
6	LICENSE FEES	1,600,000	7,000,000			4,100,000	4,700,000	2,300,000	4,800,000	24,500,000	
7	OWNER COSTS	4,000,000	17,500,000			10,200,000	11,700,000	5,900,000	12,000,000	61,300,000	
	TOTAL INVESTMENT COST	92,062,000	399,549,000			233,164,000	261,914,000	131,372,000	269,338,000	1,387,399,000	

10 Operating and Maintenance Costs

The Operating and Maintenance Costs of this case are summarised in the following table. Fixed costs has been considered constant, independently from the plant operating mode, and are expressed as M€/y.
Variable costs, expressed as €/h, are evaluated for the two operating modes of the plant, i.e. peak and off-peak operation.

Case	**4**	
Description	Oxyfuel	
Fixed costs		
Maintenance	49.1	
Operating Labour	8.16	
Labour Overhead	2.45	
Insurance & local taxes	24.5	
Total fixed cost, M€/y	84.3	
Variable costs		
	peak	**offpeak**
Make up water	0	0
Chemicals and consumables	37	21
Total variable cost, €/h	37	21

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DOCUMENT NAME : FLEXIBLE OPERATION OF NGCC PLANTS WITH CCS
FWI CONTRACT : 1-BD-0530 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

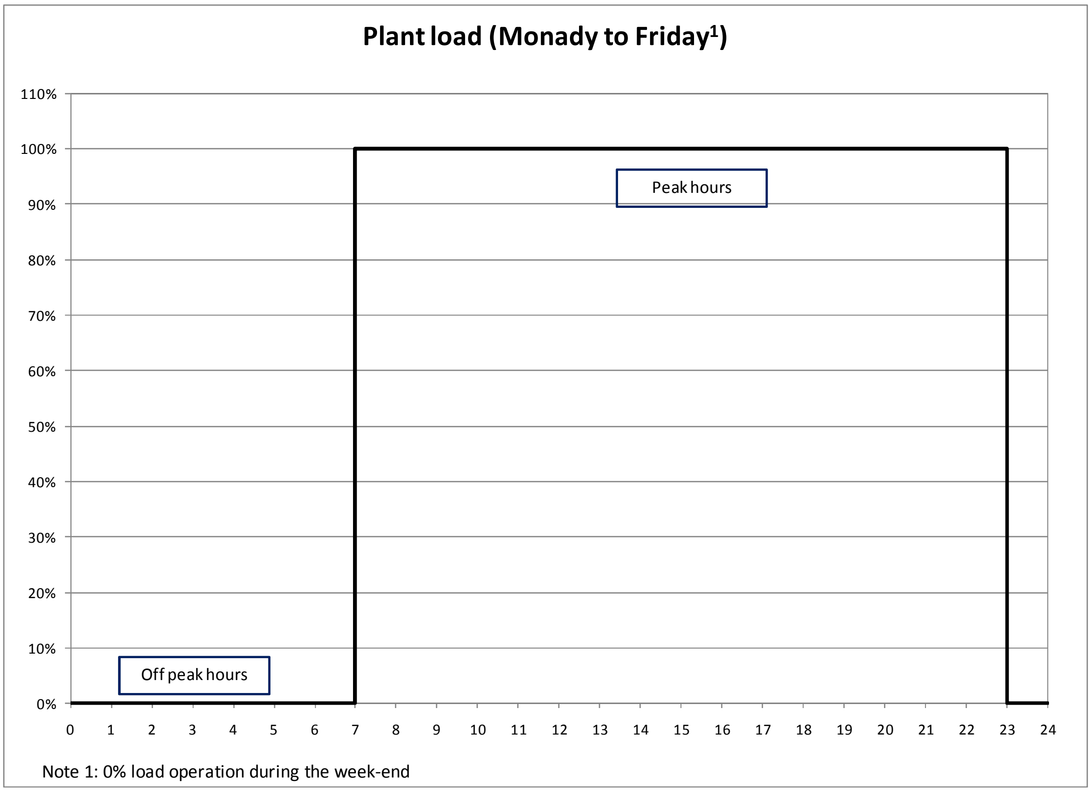
INDEX

1 Introduction

The main objective of this Section F is to assess the operating flexibility of NGCC power plants, with post-combustion capture of the CO_2 from the HRSG flue gases.

The considerations shown in this section are based on the assumption that these plant types will be requested to operate in the mid and peak merit market in order to meet recent power market requirements and generally following a weekly demand curve as shown in Figure 1-1.

Figure 1-1: NGCC plant load operation



From the above graph, it can be drawn that the NGCC plants will be maintained at base load for 80 hours per week, while being shutdown during the remaining 88 hours.

The capability of these plant types for a flexible operation is mainly affected by the constraints related to CO_2 capture and compression units, as well as the transportation pipeline. To investigate these main features, the following cases are presented in this section:

- **Case 1a**: This case assesses the constraints given by the CO_2 capture unit in a conventional NGCC plant, mainly in relation to their frequent start-ups/shut-downs and rapid load change requirements.
- **Case 1b**: This case considers the rich solvent storage, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
- **Case 1c**: This case makes an assessment of capturing the CO_2 from the flue gases of an aero-derivative gas turbine, coupled with a once through steam generator, generally used to cover peak grid demand.
- **Case 1d**: This case assesses the introduction in the power plant of a CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, despite the cycling operation of the plant, thus avoiding a two-phase flow or a significant change of the physical properties.
- **Case 1e**: This case evaluates the possibility of tuning ON/OFF the CO_2 capture in the plant, depending on the possible CO_2 allowance cost fluctuations.

In addition, the following case has been investigated using an alternative weekly demand curve, based on the assumption that the plant will need to provide two hours of peak operation per each working day, while it is shutdown during night and weekend (off-peak):

- **Case 1f**: This case considers the rich solvent storage during peak demand mode, in order to minimize the plant power consumption and increase the overall power production. In fact, regeneration is shut down for the two hours of peak demand during the day and the stored rich solvent is regenerated during the rest of the daytime, thus leading to an oversize of the regenerator.

2 Case 1a – Thermal cycling

2.1 Introduction

As highlighted in section C of this report, in the recent years, NGCC Power Plants have been used to cover the variable electricity demand, during day and night (or during the different seasons), because of their short start-up time and fast ramp rate.

As a consequence, the NGCC plant is generally shutdown during off-peak electricity demand period, while following a cycling demand trend similar to the one shown in section 1.

By introducing the post-combustion capture in NGCC plants, some additional constraints of certain equipment, like the stripper and the reboiler, may limit the operating flexibility of the modern combined cycles, in particular during the frequent start-ups/shut-downs and the rapid load change requirements.

If the release of flue gas, and hence CO_2, were accepted during transient operating modes, then the operating flexibility of the plant would not be affected. However, in electricity markets where there is a hypothetical high cost related to the CO_2 emissions, this release could represent an important additional cost that should be as much as possible reduced. To overcome this problem, it is possible to consider the storage of CO_2-laden or rich solvent (Case 1a), which allows decoupling the Gas Turbine from the CO_2 capture unit during start-up or when fast overall plant load changes are required.

In alternative, a small fired heater could be installed to provide the heat required for preheating of the regenerator column before the combined cycle start-up (approx. 15-20 t/h of LP steam), thus avoiding the need for solvent storage during start-up. However, in this case a certain amount of CO_2 in the flue gas from the fired heater is released to the atmosphere.

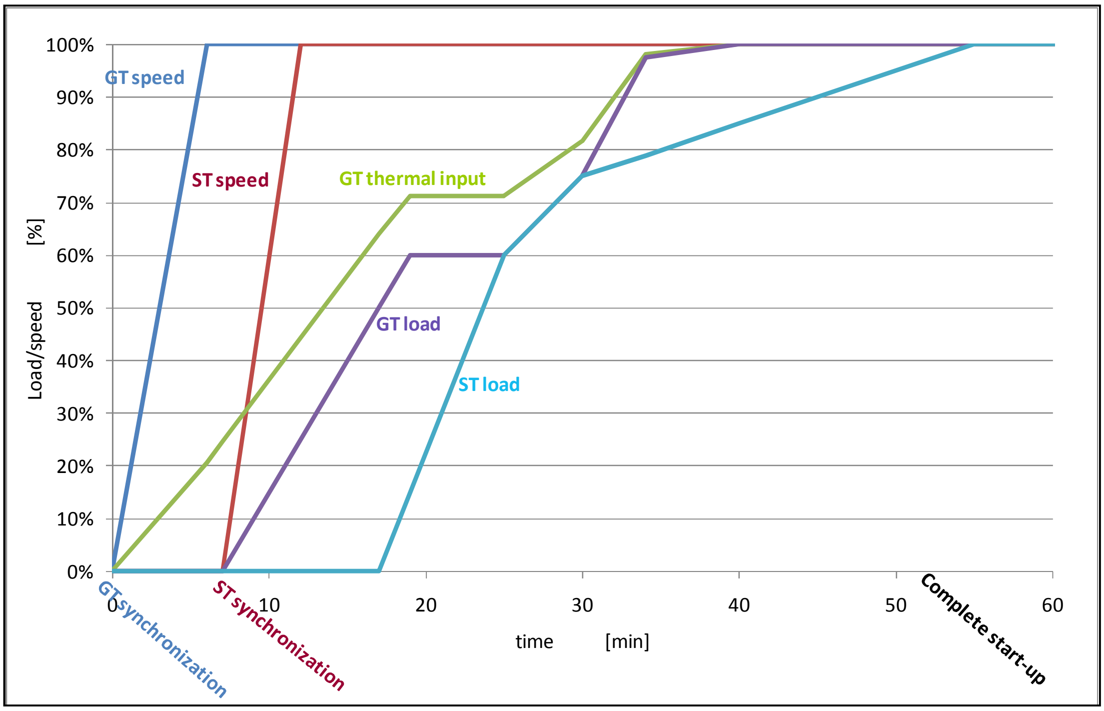
2.2 Case description

The main factor related to the CO_2 Capture Plant that potentially limits the NGCC start-up capability is the time required to pre-heat the regeneration column and the related reboilers.

In fact, recent designed combined cycle plants can be started-up in 45-55 minutes, after night shutdown (hot start-up), or 2 hours after weekend shutdown (warm start-up), while heating up a regenerator column could require a few hours, once the steam is available from the power island.

The hot start-up sequence that can be followed by a conventional combined cycle, without CCS, is shown in Figure 2.2-1. The objective of the considerations made for Case 1a is to assess the design features of a CO_2 capture plant that does not introduce limitations in both the hot and warm start-up sequences of the combined cycle.

Figure 2.2-1: Case 1a – NGCC Hot start-up



Based on the above trend, the gas turbine is ignited in order to have the combined cycle timely on load, in accordance to the variable electricity demand.

The solvent circulation in the CO_2 absorber shall be started before the gas turbine ignition so that, when the gas turbine is started-up with its own ramp-up rate, the exhaust gases can be fed to the absorption column and the CO_2 can be captured by the lean solvent.

During this phase, the column is not working at its optimal design conditions, as the ratio between liquid and gas is higher than nominal, leading to possible weeping on the plate or the column packed bed, with a possible capture rate lower than required. However, modern columns are designed for working efficiently in a wide range of gas flowrate: lower limit for efficient operation is around 30% of the gas design flowrate for packed column and around 50% for trays column.
As soon as the steam from the HRSG is available at the required pressure, the regeneration section can be heated up. For the purpose of the assessment, it is

estimated that the regeneration section is ready for operation at full load in 120 minutes after gas turbine ignition during hot start-up, while 240 minutes are required in case of warm start-up. It is also noted that during HRSG hot and warm start-up, the high pressure steam generation starts from a pressure level that is already adequate for the heating of the regenerator.
A LP steam turbine is installed to expand the excess steam during the start-up sequence, as the steam required for preheating the regenerator is less than the normal steam consumption of the reboiler during base load operation.

In order not to limit the operating flexibility of the combined cycle with CCS, the strategy considered in this Case 1a is that until the regenerator is not able to purify the CO_2-rich amine from the bottom of the absorber, the rich solvent is stored in a storage tank, while the lean amine and the semi-lean amine are taken from other dedicated tanks, as shown in Figure 2.2-4.

The solid lines in the following figures show the solvent flowrate from and to the storage tanks during hot (Figure 2.2-2) and warm start-up (Figure 2.2-3) sequence, while the dashed lines represent the consequent storage volume required.

Figure 2.2-2: Case 1a – Stored solvent volume during hot start-up

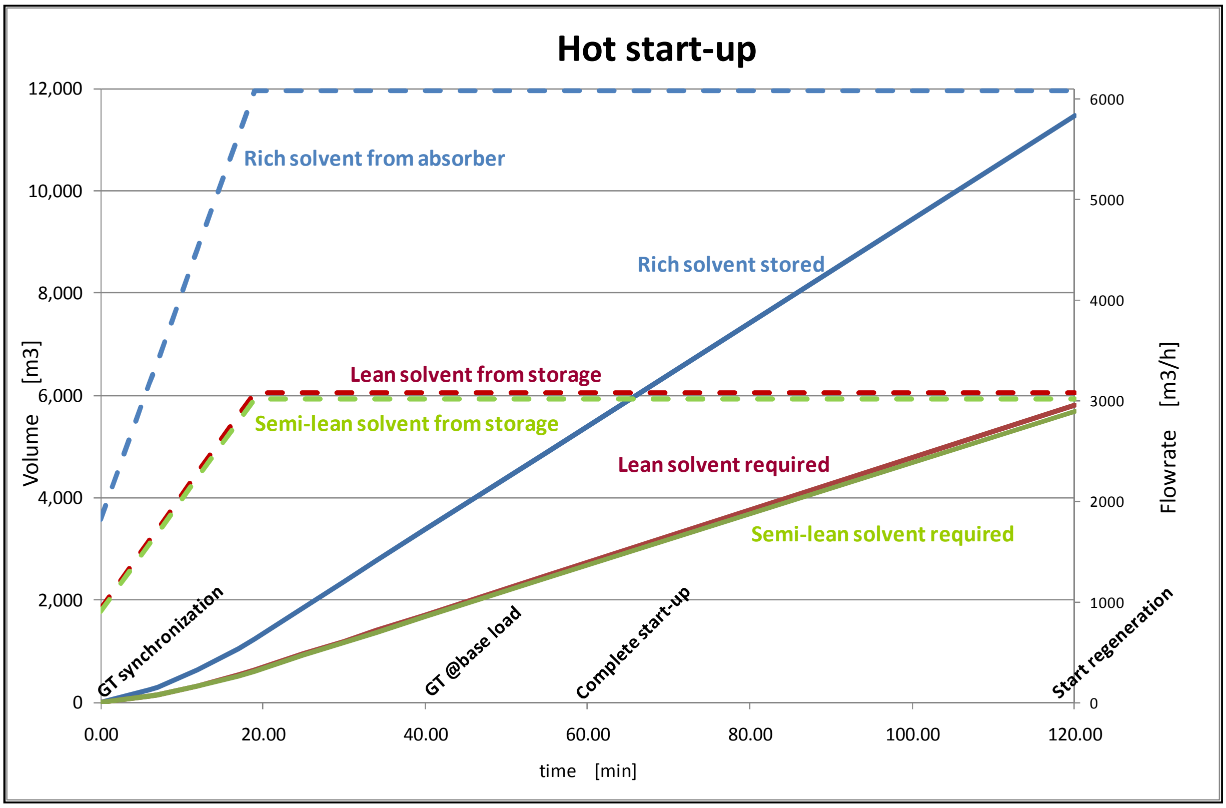
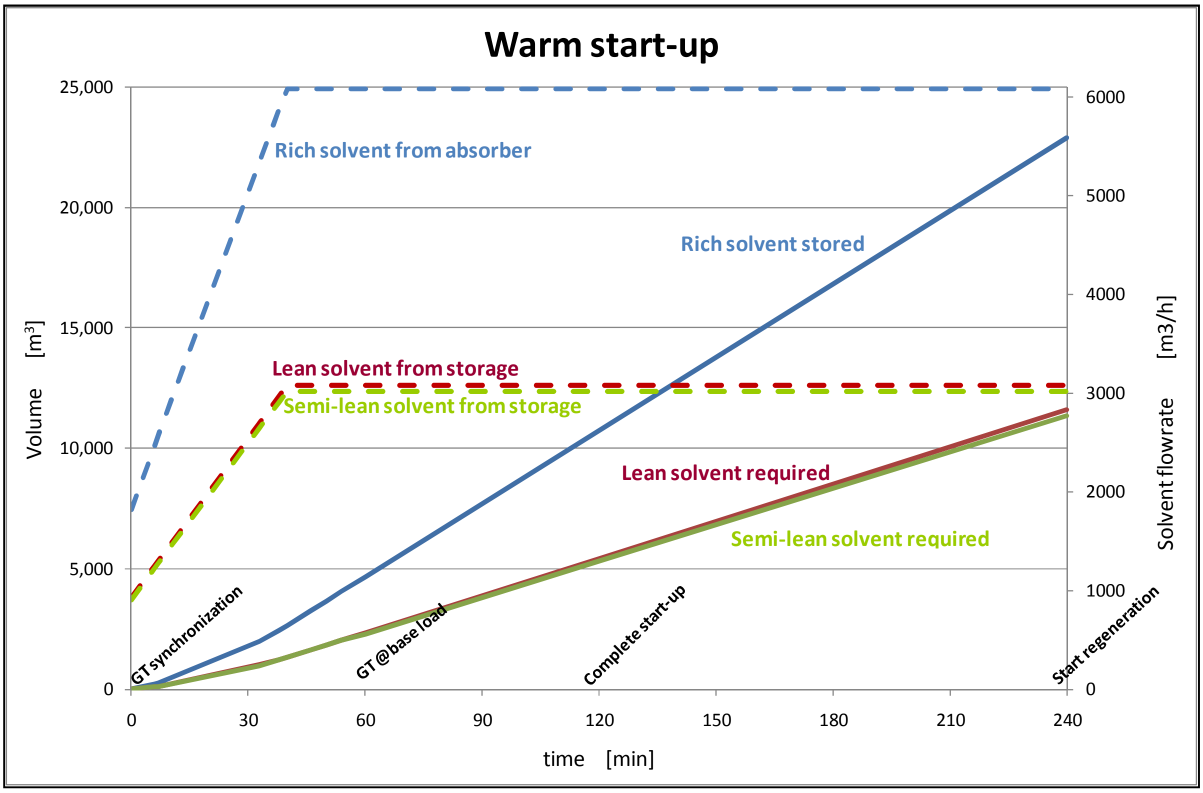


Figure 2.2-3: Case 1a – Stored solvent volume during warm start-up



Two possibilities have been considered for the regeneration of the stored rich solvent and the refilling of the lean and semi-lean amine storage tanks:

1. The regeneration of the stored solvent is carried out during off-peak hours, maintaining the plant in operation at the minimum environmental load, i.e. one gas turbine operated at about 40%, for about 3-4 hours per night is order to provide the steam for the reboiler. In this case, the plant in required to operate during low electricity demand period, when cost of electricity is low.

2. The regeneration of the stored solvent is carried out during peak hours, when the plant is operated at full load, thus requiring an oversize of 15% of the regeneration and compression section. In this case, the plant power output is reduced during peak hours, when electricity price is higher, due to the greater amount of steam required in the regenerator reboiler and to the higher consumption of the CO_2 compressor. An additional investment cost related to the oversize of the regenerator and compression section has also to be considered in this case.

Figure 2.2-4: Post combustion unit with solvent storage

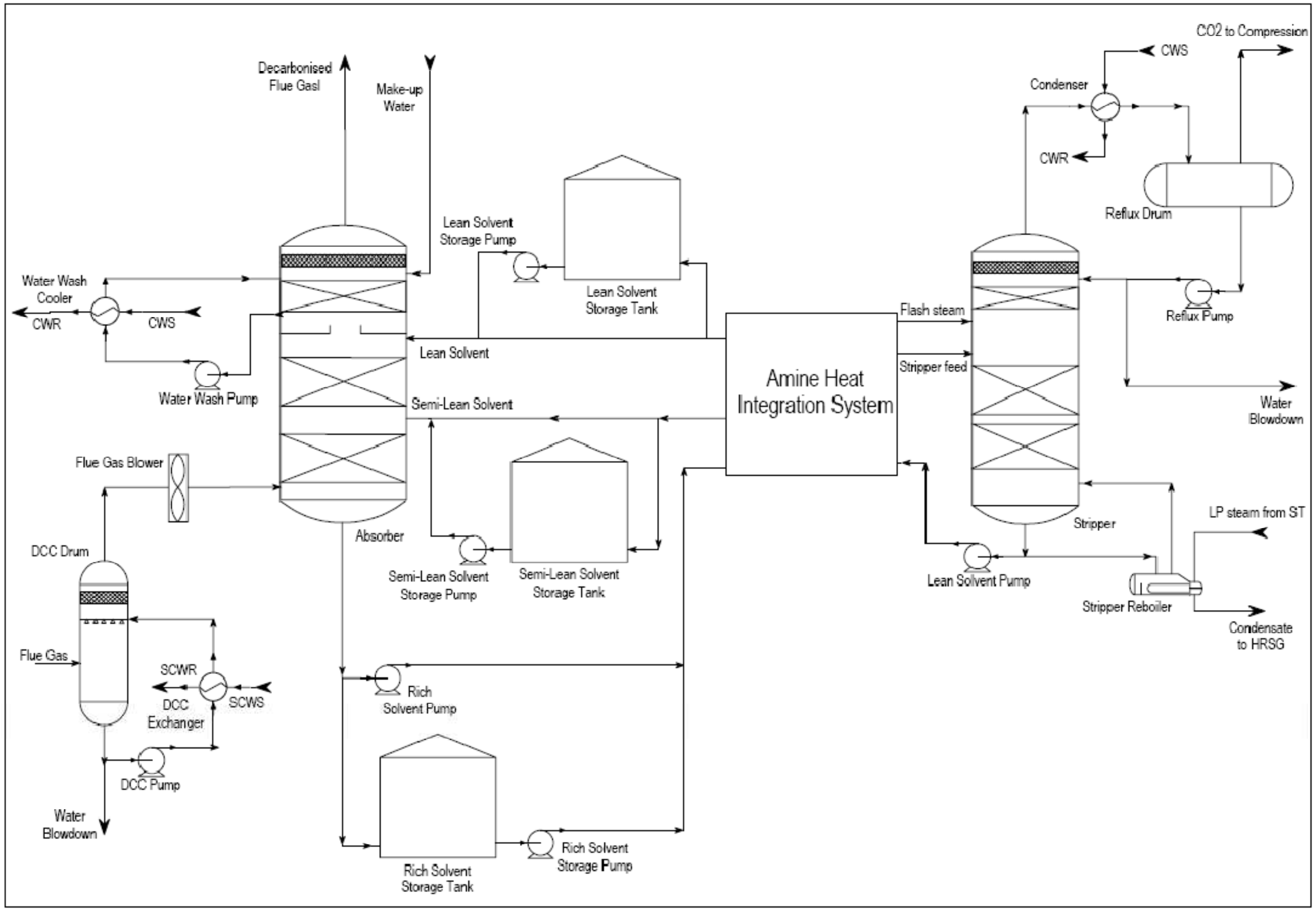


Figure 2.2-5 (off-peak time regeneration) and Figure 2.2-6 (pick time regeneration) show the dynamic trend of the stored solvent volume during the week. The design of the storage tanks is in both cases based on the amount of stored solvent required during warm start-up.

From the considerations made in this section, the regeneration during low peak demand period is considered the most reasonable alternative, because it has the lowest investment cost and the highest power production during peak demand period. However, higher variable and fixed operating cost have to be considered during off-peak demand period, because the power plant has to be operated at minimum environmental load for the time required for rich solvent regeneration and refilling of the lean solvent tanks.

The performance and the economic data shown in the following sections are referred to this scenario. It is noted that during peak electricity demand period the plant is operated as in the reference case.
To allow the rich solvent regeneration, one gas turbine is operated at minimum environmental load, i.e. 40% of the power output for about 20% of the off-peak hours. The steam turbine and the condenser are bypassed, because the overall steam production is below the minimum load of the steam turbine. The whole LP steam flowrate is exported from the combined cycle to the regenerator reboiler for rich solvent regeneration, which operates at approximately 90% of its design duty.

Figure 2.2-5: Case 1a – Stored solvent volume during the week (regeneration during off-peak time)

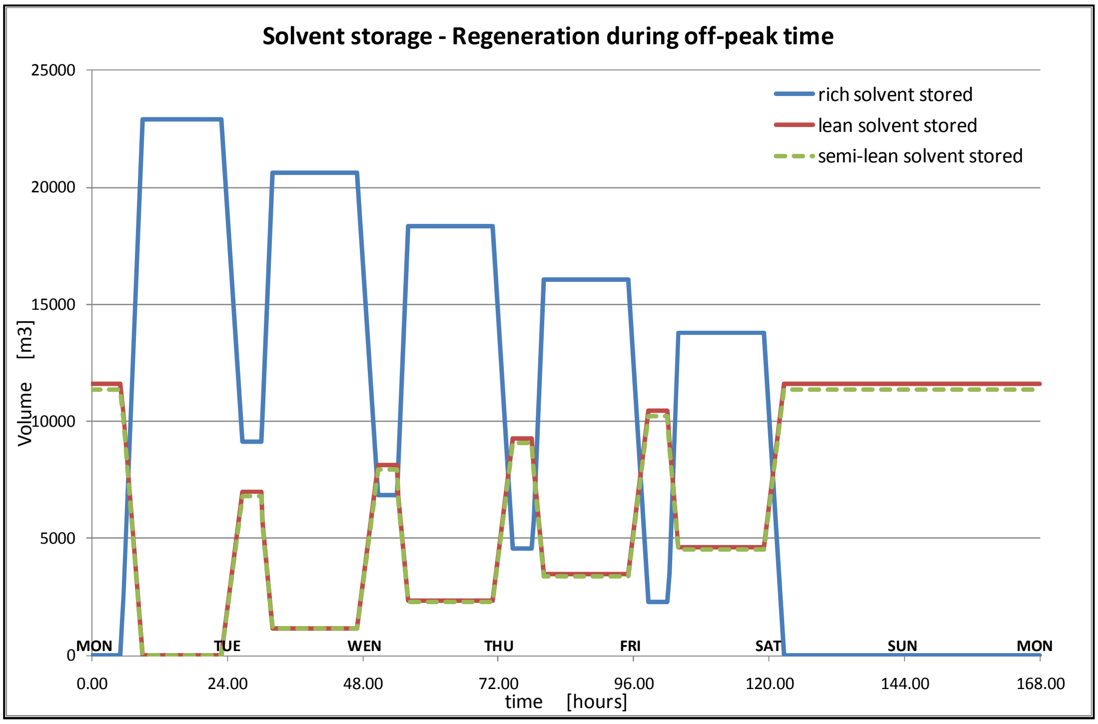
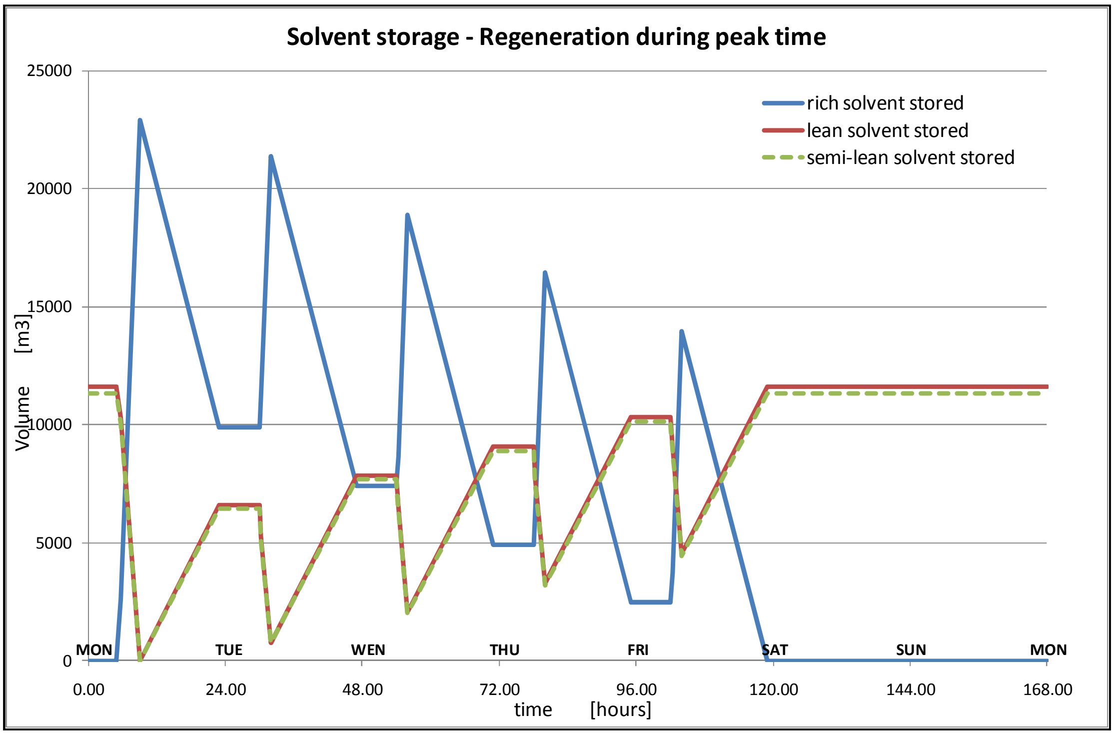


Figure 2.2-6: Case 1a – Stored solvent volume during the week (regeneration during peak time)



2.3 Utility consumption

During peak electricity demand period, the utility consumption is same as the reference case because the operating modes of the plant are identical.

On the other hand, the water and steam consumptions during the time required for regeneration, when the plant is operated at the minimum load, are summarised in the following tables.

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CASE 1a - WATER CONSUMPTION SUMMARY - Regeneration during off-peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			200	
3200	**Heat Recovery Steam Generator Package**		1.5	3	
3300	**Steam Turbine and Generator Package**			-	
	Water-cooled Steam Condenser				-
4000	**CO_2 Absorption and Amine Stripping**	39.5		1000	10644
5000	**CO_2 Compression and Recovery System**				5349
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	1.7	-1.5	75	2191
	BALANCE	41.1	0	1278	18183

Note: (1) Minus prior to figure means figure is generated

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1a - ELECTRICAL CONSUMPTION SUMMARY - Regeneration during off-peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**240**
3200	**Heat Recovery Steam Generator Package**	**1472**
3300	**Steam Turbine and Generator Package**	**0**
4000	**CO2 Absorption and Amine Stripping**	**6900**
5000	**CO2 Compression and Recovery System**	**23618**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**3034**
	BALANCE	**35265**

Notes: (1) Minus prior to figure means figure is generated

2.4 Performance

The plant performance during peak demand period (same as the reference case) and during the time required for regeneration are summarised in the following table. During remaining hours of off-peak demand period the plant is shut down.

Case 1a - Impact of CCS on plant start-up			
OVERALL PLANT PERFORMANCES			
		Reference case Peak hours	1 GT 40% Regeneration
PLANT THERMAL INPUT			
Natural Gas Flowrate	t/h	112.6	31.9
Natural Gas LHV	MJ/kg	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	416.1
PLANT ELECTRICAL OUTPUT			
Electric Power Output at Generator			
Gas Turbine	MWe	561.0	112.2
Steam Turbine	MWe	238.5	-
Total	**MWe**	**799.5**	**112.2**
Gross Electrical Efficiency (LHV basis)	%	54.5	27.0
Auxilliary Electrical Consumption			
Power Plant	MWe	5.7	1.7
Balance of Plant	MWe	5.3	3.0
CO_2 Capture - Blower	MWe	15.2	4.3
CO_2 Capture - Pump	MWe	3.1	2.6
CO_2 Compression	MWe	26.2	23.6
Electric Power Consumption of the Plant	MWe	55.5	35.3
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**76.8**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	18.4
CO_2 EMISSION			
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	1969.4
Captured CO_2	kmol/h	5903.2	1673.9
Removal efficiency	%	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**3.6**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.169**

The following table shows the expected performance of the plant at discrete time intervals, during the ramp-up phase hot start-up to base load (peak-hours).

		CASE 1a - PLANT HOT START UP										
		GT ignition	GT ramp up	ST roll off	ST ramp up	GT 60% plateau			GT 97.5%	GT 100%	CC 100%	start regeneration
TIME	min	0.00	7.00	12.00	17.00	19.00	25.00	30.00	34.00	40.00	55.00	120.00
PLANT THERMAL INPUT												
Natural Gas Flowrate	t/h	0.0	27.8	49.9	72.1	80.3	80.3	92.0	110.5	112.6	112.6	112.6
	%		25%	44%	64%	71%	71%	82%	98%	100%	100%	100%
Thermal Energy of Natural Gas (LHV basis)	MWth	0.0	361.8	650.5	939.3	1046.3	1046.3	1198.1	1440.2	1467.5	1467.5	1467.5
PLANT ELECTRICAL OUTPUT												
Electric Power Output at Generator												
Gas Turbine	MWe	0.0	0.0	140.2	280.5	336.6	336.6	420.7	547.0	561.0	561.0	561.0
	%			25%	50%	60%	60%	75%	98%	100%	100%	100%
Steam Turbine	MWe	0.0	0.0	0.0	0.0	25.4	101.4	164.8	176.6	194.3	238.5	238.5
	%					11%	43%	69%	74%	81%	100%	100%
New Steam Turbine	MWe	0.0	0.0	0.0	0.0	0.0	26.3	48.2	50.7	51.9	64.0	67.5
Total	**MWe**	0.0	0.0	140.2	280.5	361.9	464.3	633.7	774.3	807.2	863.5	867.0
Gross Electrical Efficiency (LHV basis)	%		0.0	21.6	29.9	34.6	44.4	52.9	53.8	55.0	58.8	59.1
Auxilliary Electrical Consumption												
Power Plant	MWe	1.0	1.0	2.1	3.3	3.7	3.8	4.6	5.6	5.8	6.0	6.0
Balance of Plant	MWe	2.0	1.6	2.9	4.1	4.1	4.1	5.3	5.3	5.3	5.3	5.3
CO_2 Capture - Blower	MWe	-	3.8	6.7	9.7	10.8	10.8	12.5	15.0	15.2	15.2	15.2
CO_2 Capture - Pump	MWe	-	0.8	1.4	2.1	2.2	2.2	2.5	3.0	3.1	3.1	3.1
CO_2 Compression	MWe	-	-	-	-	-	-	-	-	-	-	-
Electric Power Consumption of the Plant	MWe	3.0	7.2	13.1	19.2	20.8	20.9	24.9	28.9	29.4	29.6	29.6
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	-3.0	-7.2	127.1	261.3	341.1	443.4	608.8	745.3	777.8	833.9	837.4
Net Electrical Efficiency (LHV basis) [A]	%			19.5	27.8	32.6	42.4	50.8	51.8	53.0	56.8	57.1

2.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order not to limit the operating flexibility of a standard combined cycle without CCS.

Case 1a - Impact of CCS on plant start-up			
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Rich solvent storage tank (for start-up)	not foreseen	2 x 12'500 m3 (Diameter: 31.1 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank (for start-up)	not foreseen	1 x 13'000 m3 (Diameter: 31.1 m H: 17.1 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank (for start-up)	not foreseen	1 x 12'500 m3 (Diameter: 31.1 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 1120 kW 3760 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 1000 kW 3100 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 600 kW 3200 m3 x 46 m each	One pump in operation, one spare
Unit 3300 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
New steam turbine	-	65 MWe gross	
Steam turbine condenser	230 MWth	430 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	3 x 280 kW	Two operating, one spare

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.
An overall area of 10,500 m^2 is required for the storage tanks of this case 1a, i.e. around 20% of typical area requirements for a NGCC power plant.

2.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 7.8%.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 06-ott-11
Rev. : 1

CASE 1a- Impact of CCS on start-up

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	
1	DIRECT MATERIAL	199,850,000	60,030,000	19,610,000	15,720,000	295,210,000	
2	CONSTRUCTION	87,470,000	69,850,000	13,650,000	87,120,000	258,090,000	
3	OTHER COSTS	20,530,000	9,350,000	2,180,000	7,110,000	39,170,000	
	solvent inventory for flexible operation (*)		10,500,000			10,500,000	(*) Assumed solvent inventory cost: 1000 €/t
4	EPC SERVICES	44,140,000	20,430,000	5,980,000	15,870,000	86,420,000	
	TOTAL INSTALLED COST - EURO	351,990,000	170,160,000	41,420,000	125,820,000	689,390,000	
5	CONTINGENCY	24,640,000	11,910,000	2,070,000	6,290,000	44,910,000	
6	LICENSE FEES	7,040,000	3,400,000	830,000	2,520,000	13,790,000	
7	OWNER COSTS	17,600,000	8,510,000	2,070,000	6,290,000	34,470,000	
	TOTAL INVESTMENT COST - EURO	**401,270,000**	**193,980,000**	**46,390,000**	**140,920,000**	**782,560,000**	

2.7 Operating and Maintenance Costs

Not applicable.

3 Case 1b – Solvent storage

3.1 Introduction

This Case 1b assesses how the operating flexibility of NGCC's with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing the solvent storage from/to the absorber and the stripper.

In fact, solvent storage can allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases.

In addition, the solvent regeneration and CO_2 compression, with their associated energy penalties, can be operated during low electricity demand periods, while maximizing the electricity production when the market requires a higher electricity generation.

3.2 Case description

This alternative is assessed considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 1.

To maximize the energy production, the rich solvent can be partially or even totally stored during the 80 hours per week of peak load operation, when the plant is at base-load, while the regeneration of stored solvent can be made during the remaining 88 hours per week of off-peak load operation. With this strategy, the solvent flowrates from and to the storage are balanced in one week of plant operation.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are at low or even no load, thus reducing the energy penalties in the plant.

Depending on the regeneration load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the storage tanks, as shown in Figure 3.2-1.

During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the NGCC plant shall be operated in order to regenerate the rich solvent stored in the tanks and refill the lean amine storage tanks. The minimum load the combined cycle is fixed by the minimum environmental load of the gas turbine, i.e. 40% as assumed in the study.

During night and week-end the combined cycle is in operation with one gas turbine only at its minimum load. The steam generated in the HRSG is entirely used in the regenerator reboiler, i.e. the steam turbine and the condenser are by-passed.
The power plant at minimum load is capable to provide approximately 90% of the steam required from the regenerator reboiler of the reference case, thus limiting the solvent regeneration capacity.

It has to be noted that in this condition, the gas turbine power output exceeds the internal consumption of the plant, while, for the NGCC plants, no power production is required during low electricity demand period.

The scenarios shown in the following sections, each characterised by a different regeneration load during high electricity demand period, have been investigated, in order to evaluate the most convenient operating conditions. The main operating parameters for each possible scenario are also summarised in Table 3.2-1.

3.2.1 Regeneration halted during peak time

In this scenario, the energy production during peak demand periods is maximized by shutting down both the regeneration and the CO_2 compression units. Therefore, this alternative shows the highest increase of the daily net power production with respect to the reference case.

However, an oversize of the regeneration and compression section is required for regenerating all the solvent stored during the peak time period. Considering one gas turbine operating at minimum load during off-peak time, the regeneration capacity required is about 120% of the reference case, while the steam available from the power island is about 90%. To generate the amount of steam required for the regeneration, the gas turbine load during off-peak time should be increased, thus increasing the net power output and the operating costs during non-profitable period, as well as the extra capacity required for the regenerator. In addition, the volume and the area required for the storage tanks are very large, thus making this alternative not economically attractive.

3.2.2 Minimum regeneration load during peak time

The minimum regeneration load during peak time is such that all the solvent stored during this period can be regenerated during off-peak hours, with the regenerator operated at the maximum load allowed by the steam generation in the power island at minimum load, i.e. 90% of the reboiler design capacity as previously described.

This condition leads to a regenerator load during peak time slightly above the unit minimum turndown of 30%, corresponding to a consequent increase of the net power output of about 65 MWe. Though the net power output is significantly increased when the market requires greater amount of electricity, this alternative is not attractive as it requires a very large area for the solvents storage.

3.2.3 <u>50% regeneration load during peak time</u>

Operating the regeneration section at 50% of the reference case load, it is possible to limit the area and the volume required for the solvent storage tanks. In this case, during peak time half of the rich solvent from the absorber is fed to the regenerator, while the remainder is stored in a dedicated tank. In the same way half of the lean solvent required for the absorption is taken from the storage tanks.

The following possible scenarios are considered in this case.

1) *Scenario 1: Reduced regenerator size*
The maximum regeneration load at which the plant is required to operate during low electricity demand period for regeneration of the stored solvent is about 74% of the reference plant capacity.
In this case, as the regeneration and compression sections are never operated at the design capacity of the reference case, it would be possible to reduce their size, leading to an investment cost saving.
In this configuration the CO_2 flowrate, sent to the external pipeline, is lower than the flowrate when the plant is operated at base load; therefore, it is possible to select a lower pipeline size, leading to a possible cost saving.

2) *Scenario 2: 100% regenerator size*
In this second scenario, no reduction in the regenerator design capacity is considered with respect to the reference case is considered, even if the regenerator is always operated at lower loads. This does not limit the plant flexibility in response to possible changes in the electricity market demand trends.
In order to reduce the storage size, the regeneration load from the turndown of Friday night to the ramp-up of Monday morning has to be minimised. For this purpose, during the remainder of the off-peak hours the regeneration section is operated at the maximum load allowed by the steam generation in the power plant at minimum load.

The performance and the economic data in the following sections are referred to these two scenarios.

Figure 3.2-1: Post combustion unit with solvent storage

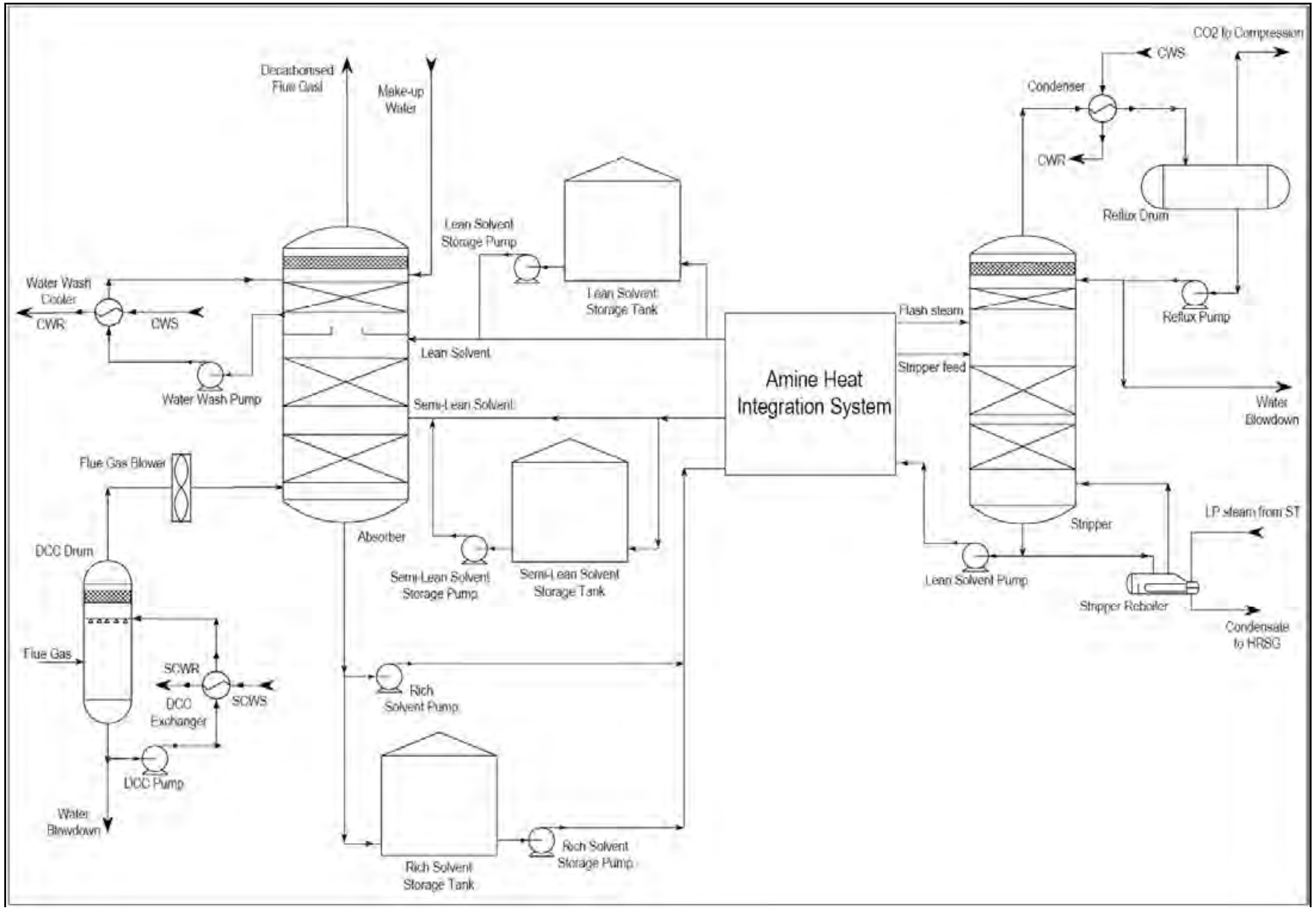


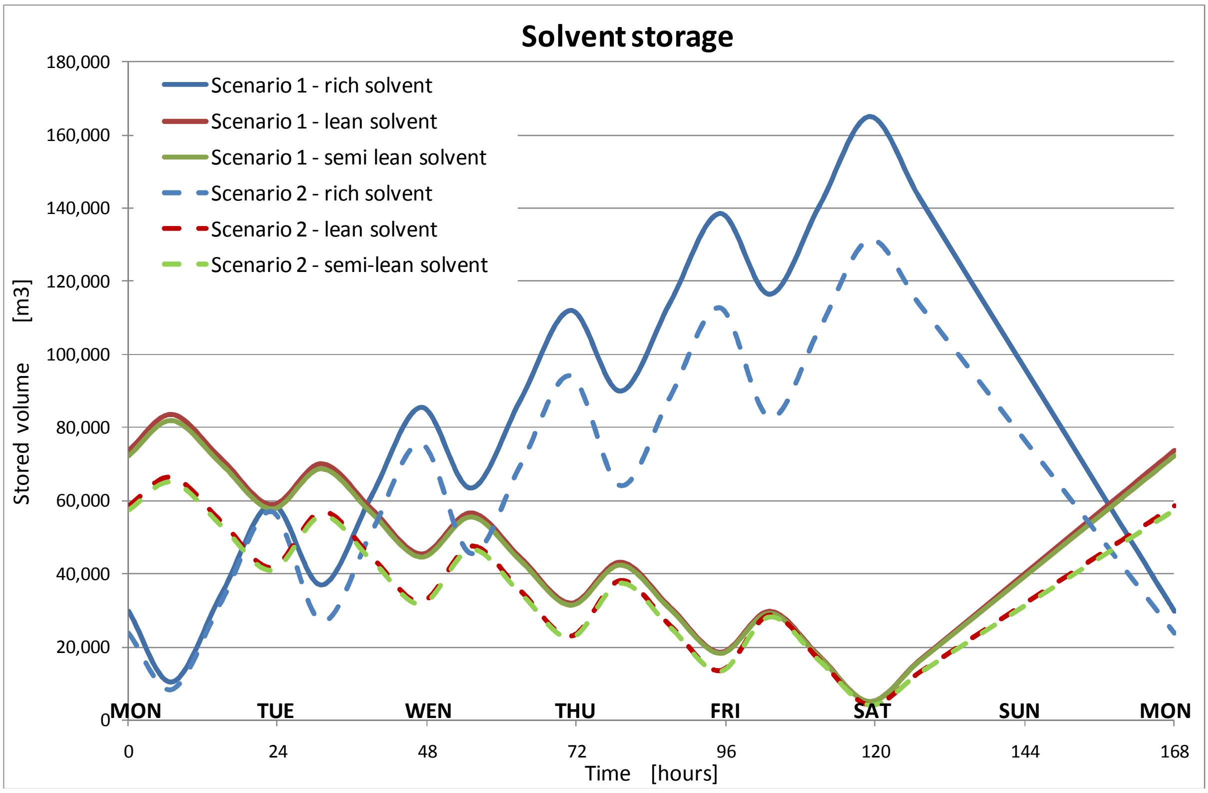
Table 3.2-1: Case 1b – Operating scenarios summary

Scenario: peak hours regenerator operating condition		Minimum regeneration load	50% solvent storage Sub-scenario 1	50% solvent storage Sub-scenario 2
Daily full load operation (80 hours/week)				
Power island operating condition		**2GT x 100%**	**2GT x 100%**	**2GT x 100%**
GT Power output	MWe	561.0	561.0	561.0
ST power output	MWe	286.5	271.8	271.8
CO2 Capture Unit operating condition		**absorber 100%** **regenerator 32%**	**absorber 100%** **regenerator 50%**	**absorber 100%** **regenerator 50%**
Nightly part load operation (32 hours/week)				
Power island operating condition		**1GT x 40%**	**1GT x 40%**	**1GT x 40%**
GT Power output	MWe	112.2	112.2	112.2
ST power output	MWe	-	-	-
CO2 Capture Unit operating condition		**absorber 28%** **regenerator 90%**	**absorber 28%** **regenerator 74%**	**absorber 28%** **regenerator 90%**
Weekend part load operation (56 hours/week)				
Power island operating condition		**1GT x 40%**	**1GT x 40%**	**1GT x 40%**
GT Power output	MWe	112.2	112.2	112.2
ST power output	MWe	-	-	-
CO2 Capture Unit operating condition		**absorber 28%** **regenerator 90%**	**absorber 28%** **regenerator 74%**	**absorber 28%** **1. Regenerator 64%** **2. Regenerator 90% (except for 23 hours of plant shutdown)**
Regenerator design				
Regenerator size respect to reference case		100%	74%	100%
Storage tanks				
Rich solvent		2 x 120'000 m3 D = 95 m x H = 17 m	2 x 87'500 m3 D = 81 m x H = 17 m	2 x 71'600 m3 D = 73 m x H = 17 m
Lean solvent		1 x 120'000 m3 D = 95 m x H = 17 m	1 x 87'500 m3 D = 81 m x H = 17 m	1 x 71'600 m3 D = 73 m x H = 17 m
Semi-lean solvent		1 x 110'000 m3 D = 91 m x H = 17 m	1 x 87'500 m3 D = 81 m x H = 17 m	1 x 71'600 m3 D = 73 m x H = 17 m
Consideration				
		NOT ATTRACTIVE Area for solvent storage excessive	**ATTRACTIVE** Lower flexibility	**ATTRACTIVE** Higher flexibility

Figure 3.2-2 shows the stored volumes of rich, lean and semi-lean solvents during the week, for the scenarios considered in this Case1b. The net volume of the storage tank is the difference between the maximum and the minimum volume of solvent stored during the week. It corresponds to the solvent stored during the weekend, from the turndown of Friday night to the-ramp up of Monday morning.

The solid line corresponds to the stored volume for scenario 1, while the dashed line corresponds to the stored volume for the scenario 2.
Although both scenarios are designed for the same regeneration load during peak time, the storage tanks required for the second alternative are smaller.
In fact, as the regenerator size is not reduced, it is possible to maintain this section at the maximum allowed load during the off-peak hours of the working days, while maintaining a lower load during the week-end, enough to avoid accumulations in the storage tanks. As an alternative operating mode, the regenerator section could be operated at its maximum load also during the weekend for the time required for complete solvent regeneration; then the plant is shutdown for the rest of the time. It has been evaluated that with this strategy the power plant could be shutdown for approximately 23 hours each week.

Figure 3.2-2: Case 1b –Stored solvent volume during the week



3.3 Utility consumption

The utility consumptions of the process/utility & offsite units during peak and off-peak demand periods are attached hereafter, for the two assessed scenarios.

Scenario 1

	CLIENT:	IEA GHG R&D PROGRAMME			Rev: 0
					mar-11
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS			ISSUED BY: NF
	LOCATION:	Netherlands			CHECKED BY: PC
	FWI Nº:	1- BD 0530 A			APPR. BY: LM

CASE 1b - Scenario 1 - WATER CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**1020**	
3200	**Heat Recovery Steam Generator Package**			**20**	
3300	**Steam Turbine and Generator Package**			**630**	
	Water-cooled Steam Condenser		**5.0**		**38813**
4000	**CO_2 Absorption and Amine Stripping**	**131.5**		**2370**	**14890**
5000	**CO_2 Compression and Recovery System**				**3066**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**7054**
	BALANCE	**137.0**	**0**	**4115**	**63823**

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	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

CASE 1b - Scenario 1 - WATER CONSUMPTION SUMMARY - Off-peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			200	
3200	**Heat Recovery Steam Generator Package**			3	
3300	**Steam Turbine and Generator Package**			-	
	Water-cooled Steam Condenser		0.0		16480
4000	**CO_2 Absorption and Amine Stripping**	39.5		930	9263
5000	**CO_2 Compression and Recovery System**				4379
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	0.0	0.0	75	2071
	BALANCE	39.5	0	1208	32193

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1b - Scenario 1 - ELECTRICAL CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**3996**
3300	**Steam Turbine and Generator Package**	**640**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**13537**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5775**
	BALANCE	**43428**

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CASE 1b - Scenario 1 - ELECTRICAL CONSUMPTION SUMMARY - Off-peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**240**
3200	**Heat Recovery Steam Generator Package**	**1472**
3300	**Steam Turbine and Generator Package**	**0**
4000	**CO2 Absorption and Amine Stripping**	**6500**
5000	**CO2 Compression and Recovery System**	**19338**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**3029**
	BALANCE	**30580**

Notes: (1) Minus prior to figure means figure is generated

Scenario 2

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME			Rev: 0
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS			mar-11
	LOCATION:	Netherlands			ISSUED BY: NF
	FWI Nº:	1- BD 0530 A			CHECKED BY: PC
					APPR. BY: LM

CASE 1b - Scenario 2 - WATER CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**1020**	
3200	**Heat Recovery Steam Generator Package**			**20**	
3300	**Steam Turbine and Generator Package**			**630**	
	Water-cooled Steam Condenser		**5.0**		**38813**
4000	**CO_2 Absorption and Amine Stripping**	**131.5**		**2370**	**14890**
5000	**CO_2 Compression and Recovery System**				**2967**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**7054**
	BALANCE	**137.0**	**0**	**4115**	**63724**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
mar-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

CASE 1b - Scenario 2 - WATER CONSUMPTION SUMMARY - Off-peak nightly hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**200**	
3200	**Heat Recovery Steam Generator Package**			**3**	
3300	**Steam Turbine and Generator Package**			**-**	
	Water-cooled Steam Condenser		**1.5**		**-**
4000	**CO_2 Absorption and Amine Stripping**	**39.5**		**1000**	**10644**
5000	**CO_2 Compression and Recovery System**				**5349**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**1.7**	**-1.5**	**75**	**2191**
	BALANCE	**41.1**	**0**	**1278**	**18183**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
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CASE 1b - Scenario 2 - WATER CONSUMPTION SUMMARY - off-peak weekend hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			200	
3200	**Heat Recovery Steam Generator Package**			3	
3300	**Steam Turbine and Generator Package**			-	
	Water-cooled Steam Condenser		1.5		16480
4000	**CO_2 Absorption and Amine Stripping**	39.5		890	8474
5000	**CO_2 Compression and Recovery System**				3826
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	1.7	-1.5	75	2002
	BALANCE	41.1	0	1168	30782

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
		mar-11
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
LOCATION:	Netherlands	CHECKED BY: PC
FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 1b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**3996**
3300	**Steam Turbine and Generator Package**	**640**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**13100**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5775**
	BALANCE	**42991**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - off-peak nightly hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**240**
3200	**Heat Recovery Steam Generator Package**	**1472**
3300	**Steam Turbine and Generator Package**	**0**
4000	**CO2 Absorption and Amine Stripping**	**6900**
5000	**CO2 Compression and Recovery System**	**23618**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**3034**
	BALANCE	**35265**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - off-peak weekend hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**240**
3200	**Heat Recovery Steam Generator Package**	**1472**
3300	**Steam Turbine and Generator Package**	**0**
4000	**CO2 Absorption and Amine Stripping**	**6200**
5000	**CO2 Compression and Recovery System**	**18340**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**3026**
	BALANCE	**29278**

Notes: (1) Minus prior to figure means figure is generated

3.4 Performance

The overall plant performance during peak and off-peak demand periods are shown in the following table, for the two assessed scenarios.

During high electricity demand period, the net plant power output is about 45 MWe higher than the reference plant. During low electricity demand period, the plant is operated to generate the steam required for solvent regeneration. As the gas turbine power output at minimum load exceeds the internal consumption of the plant, in this scenario the NGCC plant is not able to comply with the assumed electricity demand trend.

Case 1b - Scenario 1 - Solvent storage				
OVERALL PLANT PERFORMANCES				
		Reference case	2 GT 100% (50% regen)	1 GT 40% (74% regen)
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	112.6	112.6	31.9
Natural Gas LHV	MJ/kg	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1467.5	416.1
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	561.0	561.0	112.2
Steam Turbine	MWe	238.5	271.8	-
Total	**MWe**	**799.5**	**832.8**	**112.2**
Gross Electrical Efficiency (LHV basis)	%	54.5	56.7	27.0
Auxilliary Electrical Consumption				
Power Plant	MWe	5.7	5.8	1.7
Balance of Plant	MWe	5.3	5.8	3.0
CO_2 Capture - Blower	MWe	15.2	15.2	4.3
CO_2 Capture - Pump	MWe	3.1	3.1	2.2
CO_2 Compression	MWe	26.2	13.5	19.3
Electric Power Consumption of the Plant	MWe	55.5	43.4	30.6
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**787.8**	**81.5**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	53.7	19.6
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	6945.2	1969.4
Captured CO_2	kmol/h	5903.2	5903.2	1673.9
Removal efficiency	%	85.0	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**12.7**	**3.6**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.058**	**0.160**

Case 1b - Scenario 2 - Solvent storage					
OVERALL PLANT PERFORMANCES					
		Reference case	2 GT 100% (50% regen)	1 GT 40% (90% regen)	1 GT 40% (64% regen)
PLANT THERMAL INPUT					
Natural Gas Flowrate	t/h	112.6	112.6	31.9	31.9
Natural Gas LHV	MJ/kg	46.90	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1467.5	416.1	416.1
PLANT ELECTRICAL OUTPUT					
Electric Power Output at Generator					
Gas Turbine	MWe	561.0	561.0	112.2	112.2
Steam Turbine	MWe	238.5	271.8	-	-
Total	**MWe**	**799.5**	**832.8**	**112.2**	**112.2**
Gross Electrical Efficiency (LHV basis)	%	54.5	56.7	27.0	27.0
Auxilliary Electrical Consumption					
Power Plant	MWe	5.7	5.8	1.7	1.7
Balance of Plant	MWe	5.3	5.8	3.0	3.0
CO_2 Capture - Blower	MWe	15.2	15.2	4.3	4.3
CO_2 Capture - Pump	MWe	3.1	3.1	2.6	1.9
CO_2 Compression	MWe	26.2	13.1	23.6	18.3
Electric Power Consumption of the Plant	MWe	55.5	43.0	35.3	29.3
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**788.2**	**76.8**	**82.8**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	53.7	18.4	19.9
CO_2 EMISSION					
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	6945.2	1969.4	1969.4
Captured CO_2	kmol/h	5903.2	5903.2	1673.9	1673.9
Removal efficiency	%	85.0	85.0	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**12.7**	**3.6**	**3.6**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.058**	**0.169**	**0.157**

3.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to improve the operating flexibility of NGCC plant with post-combustion capture.

Case 1b - Solvent storage - Scenario 1: Regenerator size 74%

Unit 3300 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	240 MWe gross	275 MWe gross	
Steam turbine condenser	230 MWth	355 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	2 x 400 kW	

Unit 4000 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regenerator section	CO_2 outlet flow = 6,185 kmol/h Rich solvent feed = 3,220 m^3/h Reboiler duty = 250 MW th	CO_2 outlet flow = 4,640 kmol/h Rich solvent feed = 2,415 m^3/h Reboiler duty = 185 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 87'500 m3 (Diameter: 81 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 87'500 m3 (Diameter: 81 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 87'500 m3 (Diameter: 81 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 800 kW 2760 m3/h x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 500 kW 1540 m3/h x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 300 kW 1580 m3/h x 45 m each	One pump in operation, one spare

Unit 5000 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 69'300 Nm3/h each train	CO2 flow = 51'300 Nm3/h each train	Inluding: - four stage compressor - intercoolers - dryers - CO2 pumps

Unit 6000 - Utility Units

Sea water pumps	5 x 15'000 m3/h	5 x 16'000 m3/h	4 pumps in operation + 1 spare

Case 1b - Solvent storage - Scenario 2: Regenerator size 100%			
Unit 3300 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam turbine	240 MWe gross	275 MWe gross	
Steam turbine condenser	230 MWth	355 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	2 x 400 kW	
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 71'600 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 71'600 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 71'600 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 1120 kW 3760 m3/h x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 500 kW 1540 m3/h x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 300 kW 1580 m3/h x 45 m each	One pump in operation, one spare
Unit 6000 - Utility Units			
Sea water pumps	5 x 15'000 m3/h	5 x 16'000 m3/h	4 pumps in operation + 1 spare

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.
An overall area of 40,600 m^2 and 34,600 m^2 is required for the storage tanks respectively for Scenario 1 and Scenario 2 of this case 1a, i.e. around 75% and 64% of typical area requirements for a NGCC power plant.

3.5.1 Scenario 1: CO_2 transport pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 1b – Scenario 1. Reducing the regenerator capacity, the pipeline diameter is 50 mm lower than the reference case.

Case 1b - Scenario 1 - Regenerator size 74%

CO_2 pipeline characteristics

		Reference plant	Flexible plant Scenario 1
CO_2 flowrate	kg/h	259,844	191,793
Inlet pressure	barg	110	110
Inlet temperature	°C	20	20
Outlet pressure	bar	90.4	92.7
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	350	300

3.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, Scenario 1 and Scenario 2 show a total investment cost increase respectively of 22% and 19.6%.

In addition, it has been estimated that the reduction of the pipeline diameter in Scenario 1 leads to a saving on the cost per unit length of the pipeline of around 170,000 €/km, i.e. about 10% lower than the reference case. Therefore, a cost saving of 17 M€ is expected for the pipeline by considering an overall length of 100 km.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 13-Jun-11
Rev. : 0

CASE 1b - Scenario 1 - Solvent storage: Regenerator size 74%

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	
1	DIRECT MATERIAL	195,840,000	91,140,000	16,660,000	18,120,000	321,760,000	
2	CONSTRUCTION	87,065,000	69,300,000	13,350,000	87,720,000	257,435,000	
3	OTHER COSTS	20,530,000	10,050,000	1,960,000	7,830,000	40,370,000	
	solvent inventory for flexible operation (*)		70,700,000			70,700,000	(*) Assumed solvent inventory cost: 1000 €/t
4	EPC SERVICES	44,140,000	22,210,000	5,260,000	17,780,000	89,390,000	
	TOTAL INSTALLED COST - EURO	347,575,000	263,400,000	37,230,000	131,450,000	779,655,000	
5	CONTINGENCY	24,330,000	18,440,000	1,860,000	6,570,000	51,200,000	
6	LICENSE FEES	6,950,000	5,270,000	740,000	2,630,000	15,590,000	
7	OWNER COSTS	17,380,000	13,170,000	1,860,000	6,570,000	38,980,000	
	TOTAL INVESTMENT COST - EURO	**396,235,000**	**300,280,000**	**41,690,000**	**147,220,000**	**885,425,000**	

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 13-Jun-11
Rev. : 0

CASE 1b - Scenario 2 - Solvent storage: Regenerator size 100%

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	
1	DIRECT MATERIAL	195,840,000	86,070,000	19,610,000	18,240,000	319,760,000	
2	CONSTRUCTION	87,065,000	69,540,000	13,650,000	87,750,000	258,005,000	
3	OTHER COSTS	20,530,000	10,050,000	2,180,000	7,830,000	40,590,000	
	solvent inventory for flexible operation (*)		56,200,000			56,200,000	(*) Assumed solvent inventory cost: 1000 €/t
4	EPC SERVICES	44,140,000	22,210,000	5,980,000	17,780,000	90,110,000	
	TOTAL INSTALLED COST - EURO	347,575,000	244,070,000	41,420,000	131,600,000	764,665,000	
5	CONTINGENCY	24,330,000	17,080,000	2,070,000	6,580,000	50,060,000	
6	LICENSE FEES	6,950,000	4,880,000	830,000	2,630,000	15,290,000	
7	OWNER COSTS	17,380,000	12,200,000	2,070,000	6,580,000	38,230,000	
	TOTAL INVESTMENT COST - EURO	**396,235,000**	**278,230,000**	**46,390,000**	**147,390,000**	**868,245,000**	

3.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	1b - Scenario 1		1b - Scenario 2	
Description	Solvent storage Reduced regenerator size		Solvent storage Regenerator size 100%	
Fixed costs				
Maintenance	28.4		27.9	
Operating Labour	3.72		3.72	
Labour Overhead	1.12		1.12	
Insurance & local taxes	15.6		15.3	
Total fixed cost, M€/y	48.9		48.0	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak**
Make up water	0	0	0	0
Chemicals and consumables	740	207	740	207
Total variable cost, €/h	740	207	740	207

4 Case 1c – Aeroderivative gas turbine

4.1 Introduction

As described in section C of this report, the aeroderivative gas turbine is suited for peaking applications, mainly due to its fast start-up capability and high ramp rates. Typically this machine is required to operate a few hours and usually twice a day, during peak electricity demand.

Case 1c shows how an aeroderivative gas turbine can be used to cover peak generation demand, while complying with the requirement of capturing CO_2 from the flue gases. However, by introducing the CO_2 capture from the aeroderivative gas turbine flue gases, some additional constraints have to be considered, mainly related to the regeneration section of the capture plant, which may limit the plant capability of a fast start-up.

4.2 Case description

If no CO_2 capture is required, the power plants based on a aeroderivative gas turbine is usually simple cycle power plants, as they are capable to respond faster to the electricity demand changes with respect to a combined cycle power plants.

Introducing the post combustion CO_2 capture, the high-grade heat of the flue gases can be used for generating the steam required by the solvent regenerator reboiler, in a steam generator downstream the gas turbine.
In addition, if no steam generator downstream the aeroderivative gas turbine is provided, the flue gases have to be quenched to a temperature adequate for the CO_2 absorption in a Direct Contact Cooler, however resulting in a significant waste of high-grade heat. In addition, a large amount of water is circulating in the DCC system to cool down the flue gases to about 50°C, thus implying a large consumption of cooling water and large heat transfer area requirement for the coolers.

For these reasons, in Case 1c a combined cycle power plant based on a 100 MW-class aeroderivative gas turbine has been considered, either designed as a stand-alone combined cycle or coupled to a conventional NGCC power plant with post-combustion capture of the CO_2.

4.2.1 Stand-alone combined cycle

The combined cycle power plant considered for this case mainly consists of the following main units:

- One natural gas fired, 100 MWe-class, aeroderivative gas turbine.
- Once-Through Steam Generator (OTSG), generating steam at two pressure levels, i.e. high pressure steam at 50 bar and low pressure steam at 4-5 bar as required by the capture plant.
- CO_2 capture from the gas turbine exhaust gases, using a generic MEA-based chemical solvent process.
- CO_2 compression and drying.

When CCS is not required, a simple cycle power plant is generally the preferred option, to avoid additional constraints due to the presence of the steam cycle, which limit the cycling capability of the aeroderivative gas turbine.

Introducing the CO_2 capture, the thermal heat of the flue gases is initially recovered in a OTSG, generating steam for power production and solvent regeneration. Then, the flue gases from the steam generator are cooled to an acceptable temperature before feeding the AGR unit.

It is noted that due to the inertia of the steam generator, the start-up time of the combined cycle is typically 5-10 minutes longer than the time required for the start-up of the machine in an open-cycle plant. However, the key feature that limits the plant capability to operate in a cycling mode, while capturing the CO_2, is represented by the time required to pre-heat the regeneration column and related reboilers, after a plant shutdown. In fact, as the peak electricity demand period and the time required for putting the regenerator section in operation are similar, when the aeroderivative gas turbine is in operation no regeneration of the CO_2 rich solvent from the absorber can be carried out.

As a consequence, solvent regeneration has to be delayed during off-peak demand period, thus requiring solvent storage tanks for both rich and lean solutions and an oversize of the regenerator and compression sections.
In addition, the gas turbine shall be kept in operation also during off-peak period, generating the steam required for solvent regeneration.

As for these considerations, adding the CO_2 capture to a combined cycle power plant based on an aeroderivative gas turbine prevents these plants from operating efficiently in the peak load market, as the capture plants are not suited for intermittent applications.

4.2.2 Aeroderivative gas turbine coupled to a conventional combined cycle

Introducing the aeroderivative gas turbine in a conventional natural gas fired combined cycle allows the plant to participate effectively in the peak load market while complying with the requirement of capturing CO_2 from the flue gases.

During normal operation the power plant is operated as in the reference case, while the CO_2 capture and compression sections are operated at part load. In fact, the CO_2 capture and compression sections are designed for the peak-hours operation, when the aeroderivative gas turbine is in operation.
An oversize of about 15% is estimated, with respect to the reference case, to process the flue gases from all the gas turbines.

During peak electricity demand, the aeroderivative gas turbine is started-up. The flue gases at 410°C from the gas turbine are conveyed to a Once-Through Steam Generator, generating steam at two pressure levels.
The Once-Through Steam Generator is integrated with the existing power island.
The high pressure steam is mixed with the with the exhaust steam of the HP section of the Steam Turbine. The resulting stream is mixed with MP steam from the super-heater coils of the HRSG and fed to the re-heater coils, before entering the MP section of the Steam Turbine.
The superheated low pressure steam is sent to the LP steam header to feed the regenerator reboiler. The LP steam extraction from the crossover of the MP/LP modules of the Steam Turbine is required to meet the reboiler demand.
After steam generation, the flue gases are sent to the CO_2 capture unit, in operation at base load capacity.

The performance and the economic data shown in the following sections are referred to this scenario.

4.3 Utility consumption

During normal operation, the utility consumption is same as the reference case because the operating modes of the plant are identical.

On the other hand, the water and steam consumptions during peak generation, when the aeroderivative gas turbine is in operation, are summarised in the following tables.

FOSTER WHEELER

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
May-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

CASE 1c - WATER CONSUMPTION SUMMARY - NGCC with CO_2 capture + aeroderivative gas turbine

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	Gas Turbine and Generator Package			1020	
	LMS100 - Compressor intercooler			1924	
3200	Heat Recovery Steam Generator Package			18	
3300	Steam Turbine and Generator Package			550	
	Water-cooled Steam Condenser		5.0		29158
4000	CO_2 Absorption and Amine Stripping	152.3		2980	22057
5000	CO_2 Compression and Recovery System				6815
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	11258
	BALANCE including CCS	157.8	0	6567	69287

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	May-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1c - ELECTRICAL CONSUMPTION SUMMARY - NGCC with CO2 capture + aeroderivative gas turbine

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**4161**
3300	**Steam Turbine and Generator Package**	**485**
4000	**CO2 Absorption and Amine Stripping**	**21200**
5000	**CO2 Compression and Recovery System**	**30100**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor…)**	**6425**
	BALANCE including CCS	**63551**

Notes: (1) Minus prior to figure means figure is generated

4.4 Performance

The overall plant performances during normal operation and during peak electricity demand are shown in the following table.

By adding the aeroderivative gas turbine, an additional power production around 100 MWe is expected, allowing the NGCC plant to participate to the peak load market.

Case 1c - NGCC with CCS + Aeroderivative gas turbine				
OVERALL PLANT PERFORMANCES				
		ref case	peak demand + LMS100	normal operation
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	112.6	129.4	112.6
Natural Gas LHV	MJ/kg	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1685.6	1467.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	561.0	659.9	561.0
Steam Turbine	MWe	238.5	250.6	238.5
Total	**MWe**	**799.5**	**910.4**	**799.5**
Gross Electrical Efficiency (LHV basis)	%	54.5	54.0	54.5
Auxilliary Electrical Consumption				
Power Plant	MWe	5.7	5.8	5.7
Balance of Plant	MWe	5.3	6.4	5.3
CO_2 Capture - Blower	MWe	15.2	17.6	15.2
CO_2 Capture - Pump	MWe	3.1	3.6	3.1
CO_2 Compression	MWe	26.2	30.1	26.2
Electric Power Consumption of the Plant	MWe	55.5	63.6	55.5
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**845.2**	**742.5**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	50.1	50.6
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	7977.0	6945.2
Captured CO_2	kmol/h	5903.2	6780.5	5903.2
Removal efficiency	%	85.0	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**14.6**	**12.7**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.062**	**0.062**

4.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to increase the peak generating capability of NGCC plant with post-combustion capture, adding an aeroderivative gas turbine.

Case 1c - Aeroderivative gas turbine

Unit 2000 - Aeroderivative gas turbine package

Equipment	Reference plant	Flexible plant	Remarks
100 MW-class Aeroderivative gas turbine package	not foreseen	100 MWe	

Unit 2500 - Once-Through Steam Generator package

Equipment	Reference plant	Flexible plant	Remarks
Once-Through Steam Generator package	not foreseen	Dual pressure steam generator: - HP steam: 55.8 t/h @ 42 bara - LP steam: 25 t/h @ 5.5 bar a	
LP BFW pumps	not foreseen	2 x 9 kW 30 m3/h x 55 m each	one operating, one spare
HP BFW pumps	not foreseen	2 x 160 kW 60 m3/h x 500 m each	one operating, one spare

Unit 3300 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	240 MWe gross	250 MWe gross	
Steam turbine condenser	230 MWth	237 MWth	Sea water heat exchanger tubes: titanium; shell: CS

Unit 4000 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regenerator section	CO_2 outlet flow = 6,185 kmol/h Rich solvent feed = 3,220 m^3/h Reboiler duty = 250 MW th	CO_2 outlet flow = 7,110 kmol/h Rich solvent feed = 3,700 m^3/h Reboiler duty = 290 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler

Unit 5000 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package (2x50% train)	CO2 flow = 69'300 Nm3/h each train	CO2 flow = 79'700 Nm3/h each train	Inluding: - four stage compressor - intercoolers - dryers - CO2 pumps

Unit 6000 - Utility Units

Sea water pumps	5 x 15'000 m3/h	6 x 14'000 m3/h	5 pumps in operation + 1 spare

4.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 15%.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 16 May 2011
Rev. : 0

CASE 1c - Aeroderivative gas turbine

COST CODE	DESCRIPTION	UNIT 2000 GAS	UNIT 2500 STEAM	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO
1	DIRECT MATERIAL	37,190,000	4,890,000	186,040,000	49,485,000	21,400,000	16,920,000	315,925,000
2	CONSTRUCTION	7,440,000	1,060,000	86,190,000	70,220,000	14,850,000	87,420,000	267,180,000
3	OTHER COSTS	5,580,000	740,000	20,530,000	10,050,000	2,400,000	7,830,000	47,130,000
4	EPC SERVICES	9,300,000	1,230,000	44,140,000	22,210,000	6,700,000	17,780,000	101,360,000
	TOTAL INSTALLED COST - EURO	59,510,000	7,920,000	336,900,000	151,965,000	45,350,000	129,950,000	731,595,000
5	CONTINGENCY	4,170,000	550,000	23,580,000	10,640,000	2,270,000	6,500,000	47,710,000
6	LICENSE FEES	1,190,000	160,000	6,740,000	3,040,000	910,000	2,600,000	14,640,000
7	OWNER COSTS	2,980,000	400,000	16,850,000	7,600,000	2,270,000	6,500,000	36,600,000
	TOTAL INVESTMENT COST - EURO	**67,850,000**	**9,030,000**	**384,070,000**	**173,245,000**	**50,800,000**	**145,550,000**	**830,545,000**

4.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**1c**	
Description	Aeroderivative gas turbine	
Fixed costs		
Maintenance	26.7	
Operating Labour	3.72	
Labour Overhead	1.12	
Insurance & local taxes	14.6	
Total fixed cost, M€/y	46.2	
Variable costs (without fuel)		
	peak	**normal operation**
Make up water	0	0
Chemicals and consumables	851	740
Total variable cost, €/h	851	740

5 Case 1d – Constant CO_2 flowrate in transport pipeline

5.1 Introduction

The cycling operation of the power plant, required to meet the variable grid demand, leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating conditions in the pipeline.

As a consequence, a two-phase flow or a significant change of the physical properties could occur in the pipeline, if pressure and temperature were not maintained close to the conditions of the capture plant. Furthermore, for some applications like the Enhanced Oil Recovery (EOR) it would be preferred to have a constant flowrate rather than a fluctuating stream.

Two different approaches have been considered in this Case 1d, in order to produce a constant CO_2 stream flowrate, sent to the external pipeline for storage, thus avoiding pressure fluctuations and consequent possible changes of the CO_2 physical state.

- *Scenario 1* (CO_2 buffer storage)
  The introduction in the power plant of a properly designed CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, is considered.

- *Scenario 2* (Reduced regenerator capacity)
  The regeneration and compression sections are operated at a constant reduced load. Therefore, these sections are designed for the new required capacity, while solvent storage tanks are provided to compensate the difference between the absorber and the regenerator load.

In this configuration a constant CO_2 flowrate, lower than peak production when the plant is operated at base load, is sent to the external pipeline; therefore, it is possible to select a lower pipeline size, leading to a possible significant cost saving. For this reason, a comparison between the additional costs of the two above scenarios versus the saved cost of a larger pipeline is also made in this Case 1d.

5.2 Case description

The considerations made in this section refer to the whole week of plant operation, on the basis of the grid demand cycling trend summarised in section 1.

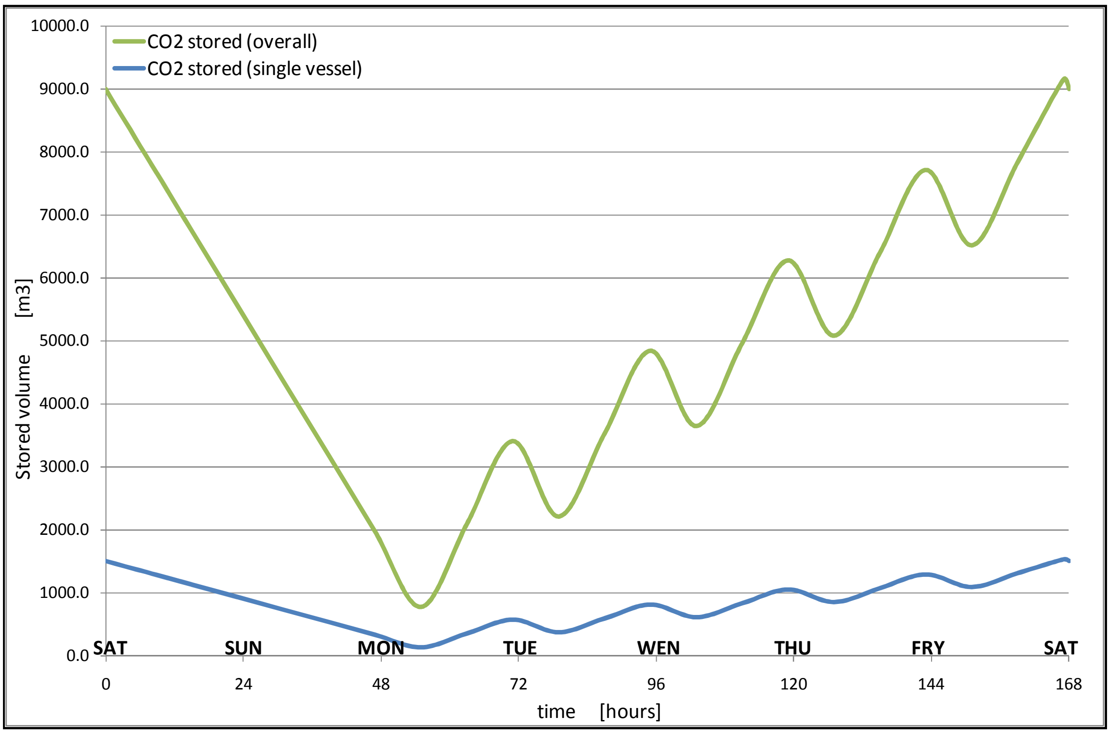
5.2.1 Scenario 1: CO_2 buffer storage

The required CO_2 buffer storage volume is evaluated considering that the power plant is operated at base load for 80 hours per week, while it is generally shutdown during the off-peak electricity demand period.

The constant CO_2 flow in the pipeline is a consequence of the balance of the CO_2 flowrate from and to the storage system during the whole week of operation, made to avoid any accumulation in the buffer vessels and resulting in about 48% of the CO_2 captured when the plant is operated at its maximum capacity.

Figure 5.2-1 shows the whole volume of stored CO_2 during the week and the single vessel volume trend (six vessels in total are considered). The required net volume of the storage vessels is the difference between the maximum and the minimum volume of stored CO_2 during the week. From the graph, it can be drawn that it corresponds to the CO_2 accumulated during the weekdays, and mainly discharged during the partial load operation from Friday night to Monday morning.

Figure 5.2-1: Case 1d – Scenario 1 – Stored CO_2 volume during the week



The CO_2 from the cooling water exchanger, downstream the last compression stage, is stored, in liquid phase, at 85 bar and 20°C, i.e. above its critical pressure and below its critical temperature. Storing and maintaining the CO_2 in liquid form below its critical pressure, even if it is easily practicable at the ambient condition selected for the study, i.e. ambient temperature around 9°C, could be a more critical aspect in hotter countries.

A constant flow is pumped from the vessels to the pipeline by means of properly designed pumps, smaller than those required in the reference case.

5.2.2 Scenario 2: Reduced regenerator capacity

In this scenario the constant CO_2 flowrate results from operating the regeneration and compression system at constant load. Hence, solvent storage is required to decouple the boiler and absorber operation from the regeneration and CO_2 compression, allowing the power plant to operate flexibly in response to the electricity demand.

In this case, the regeneration and compression sections are required to operate at a constant reduced load, allowing to design these units for a lower capacity with respect to the reference case.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are operated at their base load, properly designed for this scenario, thus reducing the energy penalties in the plant.

As the regenerator is smaller than the size required to treat the whole solvent from the absorber operated at base load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from dedicated storage tanks.

During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the NGCC plant shall be operated in order to regenerate the rich solvent stored in the tanks and refill the lean amine storage tanks. The minimum load of the combined cycle is fixed by the minimum environmental load of the gas turbine, i.e. 40% as assumed in the study.

The regeneration section is designed properly to avoid stored product accumulation within the week of plant operation and results in about 62.5% of the reference case design capacity.

This means that, by operating the regenerator at the new selected design capacity, the rich solvent stored during the 80 hours per week of peak load operation, when the plant is at base-load, is balanced by the rich solvent from the storage regenerated during the 88 hours per week of off-peak load operation, when the NGCC is at its minimum load.

As a consequence, also the lean and semi-lean solvent flowrates from and to the storage are balanced in one week of plant operation.

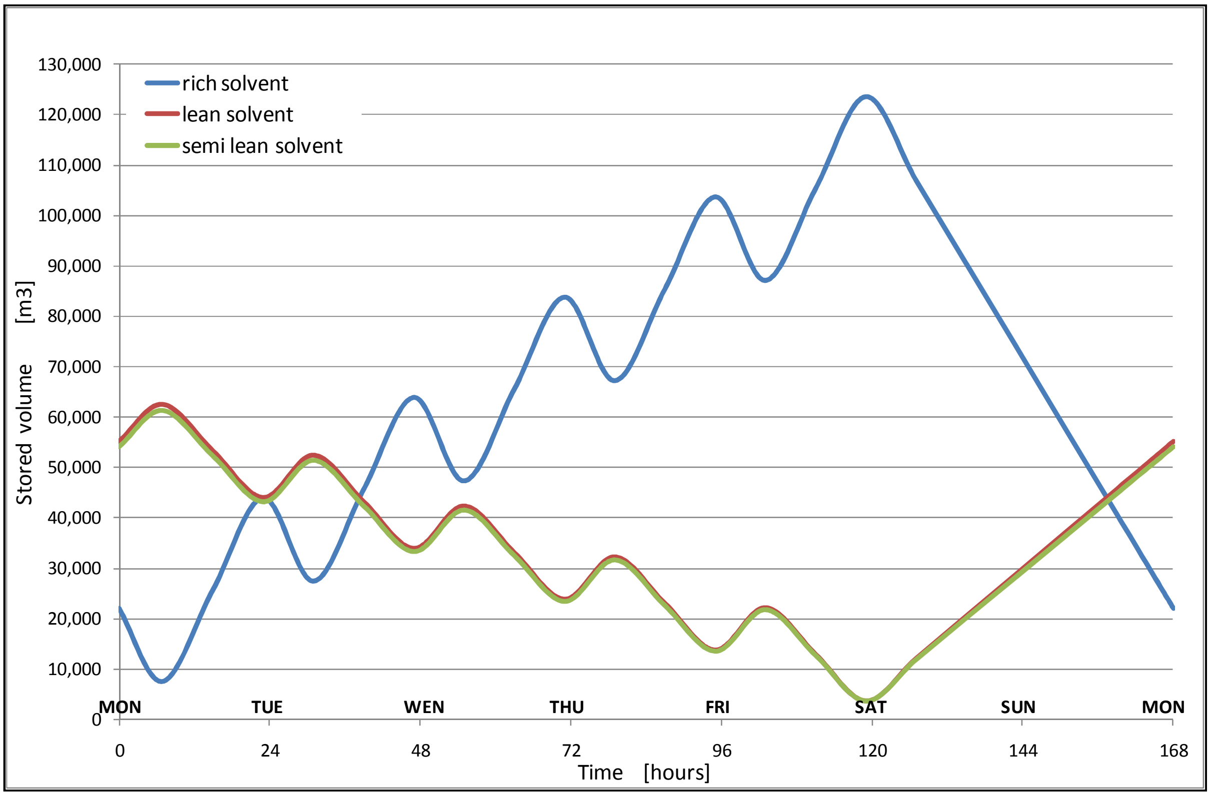
During night and week-end, when the combined cycle is in operation with one gas turbine only at its minimum load, the steam turbine is by-passed because the overall steam production is below the minimum load of the steam turbine.

Most of the steam generated in the HRSG is used in the regenerator reboiler, while the remainder flows directly in the condenser.

It has to be noted that in this condition, the gas turbine power output exceeds the internal consumption of the plant, while, for the NGCC plants, no power production is required during low electricity demand period.

Figure 5.2-2 shows the stored volumes of rich, lean and semi-lean solvents during the week, for the Scenario 2 considered in this Case1d. The net volume of the storage tank corresponds to the difference between the maximum and the minimum volume of solvent stored during the week. That corresponds to the solvent stored during the weekend, from the turndown of Friday night to the-ramp up of Monday morning.

Figure 5.2-2: Case 1d –Stored solvent volume during the week



5.3 Utility consumption

Considering the plant operation as described in Scenario 1, during peak electricity demand period the utility consumption is same as the reference case because the operating modes of the plant are identical, while during off-peak demand period the plant is shut down.

For Scenario 2, the utility consumption of the process/utility & offsite units during peak and off-peak demand periods are attached hereafter.

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
mar-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

CASE 1d - Scenario 2 - WATER CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**1020**	
3200	**Heat Recovery Steam Generator Package**			**20**	
3300	**Steam Turbine and Generator Package**			**600**	
	Water-cooled Steam Condenser		**5.0**		**35438**
4000	**CO_2 Absorption and Amine Stripping**	**131.5**		**2420**	**15947**
5000	**CO_2 Compression and Recovery System**				**3708**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**7089**
	BALANCE	**137.0**	**0**	**4135**	**62182**

Note: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG R&D PROGRAMME			Rev: 0
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS			mar-11
	LOCATION:	Netherlands			ISSUED BY: NF
	FWI Nº:	1- BD 0530 A			CHECKED BY: PC
					APPR. BY: LM

CASE 1d - Scenario 2 - WATER CONSUMPTION SUMMARY - off-peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**200**	
3200	**Heat Recovery Steam Generator Package**			**3**	
3300	**Steam Turbine and Generator Package**			**-**	
	Water-cooled Steam Condenser		**0.0**		**15450**
4000	**CO_2 Absorption and Amine Stripping**	**39.5**		**910**	**8482**
5000	**CO_2 Compression and Recovery System**				**3708**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**0.0**	**0.0**	**75**	**2037**
	BALANCE	**39.5**	**0**	**1188**	**29677**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1d - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**4008**
3300	**Steam Turbine and Generator Package**	**600**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**16368**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor…)**	**5337**
	BALANCE	**45792**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1d - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - off-peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**240**
3200	**Heat Recovery Steam Generator Package**	**1472**
3300	**Steam Turbine and Generator Package**	**0**
4000	**CO2 Absorption and Amine Stripping**	**6200**
5000	**CO2 Compression and Recovery System**	**16368**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**2807**
	BALANCE	**27087**

Notes: (1) Minus prior to figure means figure is generated

5.4 Performance

Considering the plant operation as described in Scenario 1, the plant performance during peak demand period is same as the reference case, while during off-peak demand period the plant is shut down.

For Scenario 2, the overall plant performance during peak and off-peak demand periods are shown in the following table. It is noted that, during high electricity demand period the net plant power output is about 33 MWe higher than the reference plant. During low electricity demand period, the plant is operated to generate the steam required for solvent regeneration, still delivering about 85 MWe to the electrical grid.

Case 1d - Scenario 2 - Constant CO_2 flowrate				
OVERALL PLANT PERFORMANCES				
		Reference case	2 GT 100% (rigen size 62.5%)	1 GT 40% (rigen size 62.5%)
			Peak hours	Off-peak hours
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	112.6	112.6	31.9
Natural Gas LHV	MJ/kg	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1467.5	416.1
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	561.0	561.0	112.2
Steam Turbine	MWe	238.5	262.0	-
Total	**MWe**	**799.5**	**823.0**	**112.2**
Gross Electrical Efficiency (LHV basis)	%	54.5	56.1	27.0
Auxilliary Electrical Consumption				
Power Plant	MWe	5.7	5.8	1.7
Balance of Plant	MWe	5.3	5.3	2.8
CO_2 Capture - Blower	MWe	15.2	15.2	4.3
CO_2 Capture - Pump	MWe	3.1	3.1	1.9
CO_2 Compression	MWe	26.2	16.4	16.4
Electric Power Consumption of the Plant	MWe	55.5	45.8	27.1
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**775.6**	**84.9**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	52.9	20.4
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	6945.2	1969.4
Captured CO_2	kmol/h	5903.2	5903.2	1673.9
Removal efficiency	%	85.0	85.0	85.0
CO_2 emission	**kg/s**	**12.7**	**12.7**	**3.6**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.059**	**0.153**

5.5 Equipment list

For the two scenarios assessed in this case, the following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to avoid the flowrate fluctuations in the CO_2 pipeline in relation to the flexible operation of the plant.

Case 1d - Constant CO2 to storage - Scenario 1: CO_2 buffer storage

UNIT 5000 - CO2 compression - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
CO2 buffer storage vessel	not foreseen	6 x 1'535 m3 (Diameter: 8.7 m, H: 26.1 m)	Nitrogen blanketed vessel Material: SS
CO_2 pump	(2 + 2) x 180 kW 160 m3 x 350 m each	(2 + 2) x 110 kW 75 m3/h x 350 m each	Two operating, two spare

Note: The number of equipment is referred to both trains

Case 1d - Constant CO2 to storage - Scenario 2: Reduced regenerator size

Unit 3300 - Steam turbine package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	240 MWe gross	265 MWe gross	
Steam turbine condenser	230 MWth	330 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	2 x 400 kW	

Unit 4000 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regenerator section	CO_2 outlet flow = 6,185 kmol/h Rich solvent feed = 3,220 m^3/h Reboiler duty = 250 MW th	CO_2 outlet flow = 3,870 kmol/h Rich solvent feed = 2,015 m^3/h Reboiler duty = 156 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 63'560 m3 (Diameter: 69 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 63'560 m3 (Diameter: 69 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 63'560 m3 (Diameter: 69 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 600 kW 2100 m3/h x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 375 kW 1155 m3/h x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 220 kW 1185 m3/h x 45 m each	One pump in operation, one spare

Unit 5000 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 69'300 Nm3/h each train	CO2 flow = 43'300 Nm3/h each train	Inluding: - four stage compressor - intercoolers - dryers - CO2 pumps

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.
An overall area of 31,600 m^2 is required for the storage tanks of Scenario 2 of this case 1d, i.e. around 68% of typical area requirements for a NGCC power plant.

5.5.1 CO_2 transport pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 1d. It can be drawn that with a plant designed to provide a constant CO_2 flowrate to the pipeline, despite the cyclic operation of the plant, the pipeline diameter is 100 mm and 50 mm lower than the reference case, respectively for scenario 1 and scenario 2.

Case 1d - Constant CO_2 flow

CO_2 pipeline characteristics

		Reference plant	**Flexible plant Scenario 1**	**Flexible plant Scenario 2**
CO_2 flowrate	kg/h	259,844	123,735	162,331
Inlet pressure	barg	110	110	110
Inlet temperature	°C	20	20	20
Outlet pressure	bar	90.4	92.1	97.9
CO_2 phase condition	-	liquid	liquid	liquid
Pipeline diameter	mm	350	250	300

5.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, Scenario 1 and Scenario 2 show a total investment cost variation respectively of +3% and +15.4%.

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 325,000 €/km and 170,000 €/km, respectively for Scenario 1 and 2, i.e. about 20% and 10% lower than the reference case. Therefore, depending on the overall length, the investment increase of the plant may be offset by the lower cost of the pipeline. For example, in Scenario 1, the plant investment cost is expected to be 22 M€ higher than the reference case, while a cost saving of 32 M€ is expected for the pipeline by considering an overall length of 100 km.

FOSTER WHEELER

ESTIMATE SUMMARY

CASE 1d - Scenario 1 - CO2 buffer storage

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 16 May 2011
Rev. : 0

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	
1	DIRECT MATERIAL	182,440,000	48,380,000	34,490,000	15,720,000	281,030,000	
2	CONSTRUCTION	85,840,000	68,720,000	17,370,000	87,120,000	259,050,000	
3	OTHER COSTS	18,660,000	9,130,000	2,400,000	7,110,000	37,300,000	
4	EPC SERVICES	39,410,000	19,830,000	6,700,000	15,870,000	81,810,000	
	TOTAL INSTALLED COST - EURO	326,350,000	146,060,000	60,960,000	125,820,000	659,190,000	
5	CONTINGENCY	22,840,000	10,220,000	3,050,000	6,290,000	42,400,000	
6	LICENSE FEES	6,530,000	2,920,000	1,220,000	2,520,000	13,190,000	
7	OWNER COSTS	16,320,000	7,300,000	3,050,000	6,290,000	32,960,000	
	TOTAL INVESTMENT COST - EURO	**372,040,000**	**166,500,000**	**68,280,000**	**140,920,000**	**747,740,000**	

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 13-Jun-11
Rev. : 0

CASE 1d - Scenario 2 - Constant CO2 to storage - Reduced regeneretor size

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	
1	DIRECT MATERIAL	192,340,000	78,040,000	15,260,000	15,720,000	301,360,000	
2	CONSTRUCTION	86,715,000	69,000,000	13,210,000	87,120,000	256,045,000	
3	OTHER COSTS	20,530,000	10,050,000	1,960,000	7,110,000	39,650,000	
	solvent inventory for flexible operation (*)		53,000,000			53,000,000	(*) Assumed solvent inventory cost: 1000 €/t
4	EPC SERVICES	44,140,000	22,210,000	5,260,000	15,870,000	87,480,000	
	TOTAL INSTALLED COST - EURO	343,725,000	232,300,000	35,690,000	125,820,000	737,535,000	
5	CONTINGENCY	24,060,000	16,260,000	1,780,000	6,290,000	48,390,000	
6	LICENSE FEES	6,870,000	4,650,000	710,000	2,520,000	14,750,000	
7	OWNER COSTS	17,190,000	11,620,000	1,780,000	6,290,000	36,880,000	
	TOTAL INVESTMENT COST - EURO	**391,845,000**	**264,830,000**	**39,960,000**	**140,920,000**	**837,555,000**	

5.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	1d - Scenario 1		1d - Scenario 2	
Description	CO_2 buffer storage		CO_2 constant flow Reduced regenerator size	
Fixed costs				
Maintenance	24.0		26.9	
Operating Labour	3.72		3.72	
Labour Overhead	1.12		1.12	
Insurance & local taxes	13.2		14.8	
Total fixed cost, M€/y	42.1		46.5	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak**
Make up water	0	0	0	0
Chemicals and consumables	740	0	740	207
Total variable cost, €/h	740	0	740	207

6 Case 1e – Turning CO_2 capture ON/OFF

6.1 Introduction

This Case 1e shows how NGCC plants with post-combustion capture of the CO_2 can be also maintained in continuous operation without making the capture and compression of the carbon dioxide for transportation outside plant battery limits.

Depending on possible CO_2 emission allowances cost, this operating flexibility may improve the economics of the plant, because of its resulting higher power production, as shown in the following sections.

6.2 Case description

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems, as it is possible to totally by-pass the CO_2 capture unit, directly venting to atmosphere the flue gas from the HRSG, similarly to a conventional NGCC plant without CO_2 capture. When the CO_2 capture unit is bypassed, around 260 t/h of CO_2 are released to atmosphere instead, of being captured and compressed.

In this operating mode, the energy penalties related to the CO_2 capture and compression units, as well as the steam requirement for solvent regeneration, are avoided, leading to an overall higher plant net power production.

As no heat is required by the regenerator reboiler, the low pressure steam from the steam generators and the exhaust steam from the MP module of the Steam Turbine are used to generate additional power in the LP module of the Steam Turbine.

The resulting LP steam entering this section of the machine is about twice the flowrate of the reference case. Therefore, the low pressure steam turbine module, the condenser and condensate system shall be properly designed for the increased steam flow during the CO_2 venting operating mode. The power plant shall be designed to operate efficiently in this condition, while allowing partial load operation when CO_2 is captured and compressed.

6.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

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CASE 1e - WATER CONSUMPTION SUMMARY - NO CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**1020**	
3200	**Heat Recovery Steam Generator Package**			**23**	
3300	**Steam Turbine and Generator Package**			**720**	
	Water-cooled Steam Condenser		**5.0**		**56250**
4000	**CO_2 Absorption and Amine Stripping**	**-**		**-**	**-**
5000	**CO_2 Compression and Recovery System**				**-**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**3151**
	BALANCE	**5.5**	**0**	**1838**	**59401**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
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CASE 1e - WATER CONSUMPTION SUMMARY - with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			**1020**	
3200	**Heat Recovery Steam Generator Package**			**17**	
3300	**Steam Turbine and Generator Package**			**530**	
	Water-cooled Steam Condenser		**5.0**		**25313**
4000	**CO_2 Absorption and Amine Stripping**	**131.5**		**2580**	**19117**
5000	**CO_2 Compression and Recovery System**				**5933**
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**5.5**	**-5.0**	**75**	**7238**
	BALANCE	**137.0**	**0**	**4222**	**57601**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	apr-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1e - ELECTRICAL CONSUMPTION SUMMARY - NO CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**3950**
3300	**Steam Turbine and Generator Package**	**780**
4000	**CO2 Absorption and Amine Stripping**	**-**
5000	**CO2 Compression and Recovery System**	**-**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5158**
	BALANCE	**11068**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: 0
apr-11
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CASE 1e - ELECTRICAL CONSUMPTION SUMMARY - with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**4042**
3300	**Steam Turbine and Generator Package**	**465**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**26200**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5343**
	BALANCE	**55530**

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6.4 Performance

The overall plant performances, with and without CO_2 capture are shown in the following table.

In case of venting the CO_2, the plant net power output is expected to be around 120 MWe higher than the base case with full capture and compression of the CO_2, due to the reduction of the internal power demand, leading to an expected net electrical efficiency of 58.6%.

As the power plant is designed also for operation without CCS, the plant net power production is around 6 MWe lower than the reference case, when the capture and compression units are operated.

Case 1e - Turning ON/OFF CO_2 Capture				
OVERALL PLANT PERFORMANCES				
		Reference case	Design case NO CCS	2 GT 100% (with CCS)
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	112.6	112.6	112.6
Natural Gas LHV	MJ/kg	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1467.5	1467.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	561.0	561.0	561.0
Steam Turbine	MWe	238.5	312.4	232.4
Total	**MWe**	**799.5**	**873.3**	**793.4**
Gross Electrical Efficiency (LHV basis)	%	54.5	59.5	54.1
Auxilliary Electrical Consumption				
Power Plant	MWe	5.7	5.9	5.7
Balance of Plant	MWe	5.3	5.2	5.3
CO_2 Capture - Blower	MWe	15.2	-	15.2
CO_2 Capture - Pump	MWe	3.1	-	3.1
CO_2 Compression	MWe	26.2	-	26.2
Electric Power Consumption of the Plant	MWe	55.5	11.1	55.5
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**860.5**	**736.4**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	58.6	50.2
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	6945.2	6945.2	6945.2
Captured CO_2	kmol/h	5903.2	5903.2	-
Removal efficiency	%	85.0	85.0	-
CO_2 emission	**kg/s**	**12.7**	**12.7**	**84.9**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.062**	**0.053**	**0.415**

6.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to allow the plant to operate either capturing or venting the CO_2.

Case 1e - Tuning ON/OFF CCS			
Unit 3300 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam turbine	240 MWe gross	315 MWe gross	
Steam turbine condenser	230 MWth	460 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	2 x 560 kW	

6.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 6%.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 16 May 2011
Rev. : 0

CASE 1e - ON/ OFF CCS

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO
1	DIRECT MATERIAL	209,840,000	48,380,000	19,610,000	15,720,000	293,550,000
2	CONSTRUCTION	88,465,000	68,720,000	13,650,000	87,120,000	257,955,000
3	OTHER COSTS	20,530,000	9,130,000	2,180,000	7,110,000	38,950,000
4	EPC SERVICES	44,140,000	19,830,000	5,980,000	15,870,000	85,820,000
	TOTAL INSTALLED COST - EURO	362,975,000	146,060,000	41,420,000	125,820,000	676,275,000
5	CONTINGENCY	25,410,000	10,220,000	2,070,000	6,290,000	43,990,000
6	LICENSE FEES	7,260,000	2,920,000	830,000	2,520,000	13,530,000
7	OWNER COSTS	18,150,000	7,300,000	2,070,000	6,290,000	33,810,000
	TOTAL INVESTMENT COST - EURO	**413,795,000**	**166,500,000**	**46,390,000**	**140,920,000**	**767,605,000**

6.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	1e	
Description	On-Off CO_2 capture	
Fixed costs		
Maintenance	25.0	
Operating Labour	3.72	
Labour Overhead	1.12	
Insurance & local taxes	13.7	
Total fixed cost, M€/y	43.5	
Variable costs (without fuel)		
	with CCS	**without CCS**
Make up water	0	0
Chemicals and consumables	740	44
Total variable cost, €/h	740	44

7 Case 1f – Daily solvent storage with an alternate demand curve

7.1 Introduction

This case is based on the assumption that the weekly demand curve is different from the one shown in Figure 1-1 and characterised by the following three different electricity demand periods:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (plant shutdown): night and weekend.

As discussed in Case 1b, the operating flexibility of NGCC's with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing the solvent storage from/to the absorber and the stripper.

In fact, solvent storage can allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases.

7.2 Case description

To maximize the energy production, the rich solvent is entirely stored during the 2 hours per day of peak load operation, when the plant is at base-load, while the regeneration of stored solvent is made during the 14 hours per day of normal operation, thus leading to an oversize of the regenerator. On the other hand, the plant is shut down overnight and at the weekend. With this strategy, the solvent flowrates from and to the storage are balanced within each day of plant operation.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gases in the absorber column, while the solvent regeneration and CO_2 compression sections are halted, thus reducing the energy penalties in the plant. A certain amount of steam is sent to the regenerator reboiler to keep the column warm during the two hours of shutdown.

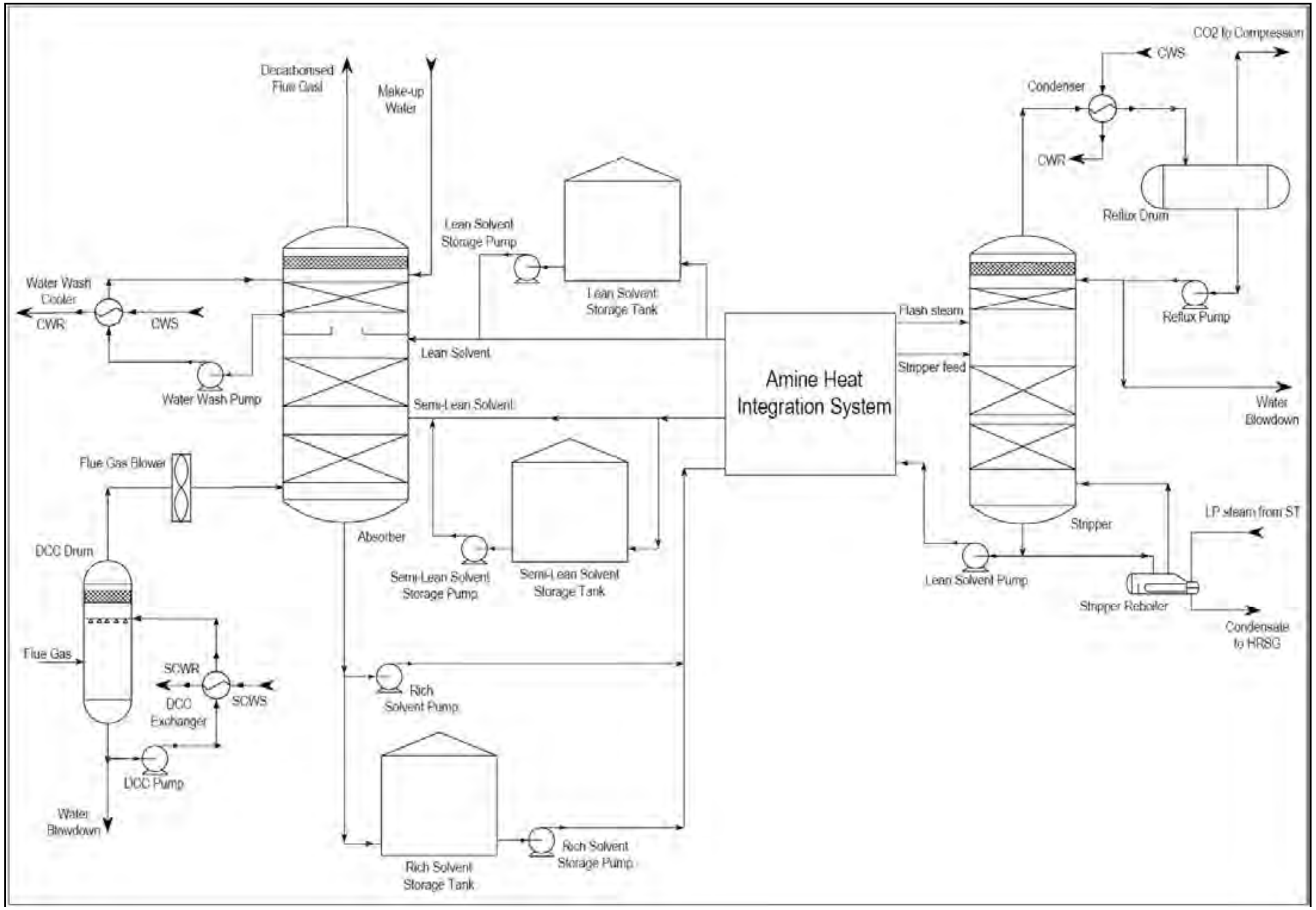
A supplementary LP pressure steam turbine has been considered to expand the additional steam available when the regeneration is halted; this avoided to over sizing the steam turbine for the total amount of steam, as well as the inefficient operation of the machine during normal operation. In this case, the time required for shutting down the capture unit is limited by the steam turbine start-up time, which determines the steam flowrate that can be diverted from the regenerator reboiler to the steam turbine. A time around 20-30 minutes is expected after steam turbine synchronization. In case the main steam turbine is designed for the operation without solvent regeneration, the plant could have a faster ramp up of power output, achieving the maximum power output in 10 minutes.

The CO_2-rich solvent from the absorber column is stored in dedicated storage tanks. The lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the storage tanks, as shown in Figure 7.2-1.

During the rest of the day time, during normal electricity demand period, the NGCC plant shall be operated in order to regenerate the rich solvent stored in the tanks and refill the lean amine storage tanks. An oversize of 14% of the regenerator and compression section is required to regenerate all the solvent stored during the two hours of peak load operation, avoiding any accumulation of the stored solvent.

During night and week-end the combined cycle is shutdown, in line with the relevant electricity demand curve.

Figure 7.2-1: Post combustion unit with solvent storage



7.3 Utility consumption

The utility consumptions of the process/utility & offsite units during peak and normal electricity demand periods are attached hereafter.

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CASE 1f - WATER CONSUMPTION SUMMARY - Peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			1020	
3200	**Heat Recovery Steam Generator Package**			23	
3300	**Steam Turbine and Generator Package**			700	
	Water-cooled Steam Condenser		5.0		54803
4000	**CO_2 Absorption and Amine Stripping**	131.5		2150	10664
5000	**CO_2 Compression and Recovery System**				0
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	6802
	BALANCE	137.0	0	3968	72269

Note: (1) Minus prior to figure means figure is generated

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1f - WATER CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
3100	**Gas Turbine and Generator Package**			1020	
3200	**Heat Recovery Steam Generator Package**			17	
3300	**Steam Turbine and Generator Package**			530	
	Water-cooled Steam Condenser		5.0		24248
4000	**CO_2 Absorption and Amine Stripping**	131.5		2640	20324
5000	**CO_2 Compression and Recovery System**				6781
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	5.5	-5.0	75	7341
	BALANCE	137.0	0	4282	58694

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		Sep-11
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
LOCATION:	Netherlands	CHECKED BY: PC
FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 1f - ELECTRICAL CONSUMPTION SUMMARY - Peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**3950**
3300	**Steam Turbine and Generator Package**	**750**
4000	**CO2 Absorption and Amine Stripping**	**18300**
5000	**CO2 Compression and Recovery System**	**0**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**6574**
	BALANCE	**30754**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 1f - ELECTRICAL CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
3100	**Gas Turbine and Generator Package**	**1180**
3200	**Heat Recovery Steam Generator Package**	**4050**
3300	**Steam Turbine and Generator Package**	**430**
4000	**CO2 Absorption and Amine Stripping**	**18800**
5000	**CO2 Compression and Recovery System**	**29950**
	UTILITY and OFFSITE	
6000	**UTILITY and OFFSITE (Cooling Water, Air compression, gas compressor...)**	**5430**
	BALANCE	**59840**

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7.4 Performance

The overall plant performance during peak and normal electricity demand periods are shown in the following table.

During peak electricity demand period, the net plant power output is about 93 MWe higher than the reference plant. During the rest of the day time the net power output of the plant is around 14 MWe lower than the reference case, due to the additional steam and power requirement of the regeneration and compression sections.

CASE 1f - OVERALL PLANT PERFORMANCE				
		Reference case	Peak load operation	Normal operation
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	112.6	112.6	112.6
Natural Gas LHV	MJ/kg	46.90	46.90	46.90
Thermal Energy of Natural Gas (LHV basis)	MWth	1467.5	1467.5	1467.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	561.0	561.0	561.0
Steam Turbine	MWe	238.5	303.8	228.8
Total	**MWe**	**799.5**	**864.8**	**789.8**
Gross Electrical Efficiency (LHV basis)	%	54.5	58.9	53.8
Auxilliary Electrical Consumption				
Power Plant	MWe	5.7	5.9	5.7
Balance of Plant	MWe	5.3	6.6	5.4
CO_2 Capture - Blower	MWe	15.2	15.2	15.2
CO_2 Capture - Pump	MWe	3.1	3.1	3.6
CO_2 Compression	MWe	26.2	0.0	30.0
Electric Power Consumption of the Plant	MWe	55.5	30.8	59.8
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**742.5**	**832.4**	**728.5**
Net Electrical Efficiency (LHV basis) [A]	%	50.6	56.7	49.6

7.5 Equipment list

The following table shows the equipment and process packages that have to be added or modified with respect to the design of the reference case, in order to improve the operating flexibility of NGCC plant with post-combustion capture.

Case 1f - Solvent storage - Daily cycle			
Unit 3300 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam turbine	240 MWe gross	230 MWe gross	
New steam turbine		77 MWe gross	
Steam turbine condenser	230 MWth	445 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	2 x 280 kW	3 x 280 kW	Two operating, one spare
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Compression package (2x50% train)	CO2 flow = 69'300 Nm3/h each train	CO2 flow = 79'210 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps
Unit 6000 - Utility Units			
Sea water pumps	5 x 15'000 m3/h	6 x 15'000 m3/h	5 pumps in operation + 1 spare

Case 1f - Solvent storage - Daily cycle			
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Regenerator section	CO_2 outlet flow = 6,185 kmol/h Rich solvent feed = 3,220 m^3/h Reboiler duty = 250 MW th	CO_2 outlet flow = 7,070 kmol/h Rich solvent feed = 3,680 m^3/h Reboiler duty = 286 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 7'600 m3 (Diameter: 27.4 m H: 12.8 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 7'600 m3 (Diameter: 27.4 m H: 12.8 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 7'600 m3 (Diameter: 27.4 m H: 12.8 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 280 kW 870 m3/h x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 1000 kW 3080 m3/h x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 600 kW 3160 m3/h x 45 m each	One pump in operation, one spare

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.

An overall area of 8,100 m^2 is required for the storage tanks of this case 1f, i.e. around 15% of typical area requirements for a NGCC power plant.

7.5.1 CO_2 transport pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 1f. As the regenerator capacity is increased, the pipeline diameter is 50 mm higher than the reference case.

Case 1f - Solvent storage - Daily cycle			
CO_2 pipeline characteristics			
		Reference plant	**Flexible plant**
CO_2 flowrate	kg/h	259,844	297,000
Inlet pressure	barg	110	110
Inlet temperature	°C	20	20
Outlet pressure	bar	90.4	97.7
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	350	400

7.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for this case.

With respect to the figures included in Section E for the reference plant, this alternative shows a total investment cost increase around 9%.

In addition, it has been estimated that the increase of the pipeline diameter leads to an additional cost per unit length of the pipeline around 170,000 €/km, i.e. about 10% higher than the reference case. Therefore, an additional cost 17 M€ is expected for the pipeline by considering an overall length of 100 km.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : NGCC WITH CARBON DIOXIDE CAPTURE
Date : 06-ott-11
Rev. : 0

CASE 1f - Daily Solvent storage

COST CODE	DESCRIPTION	UNIT 3000 POWER	UNIT 4000 CO2	UNIT 5000 CO2 COMP	UNIT 6000 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	199,670,000	57,325,000	21,300,000	19,500,000	297,795,000	
2	CONSTRUCTION	87,770,000	71,060,000	14,790,000	88,070,000	261,690,000	
3	OTHER COSTS	20,900,000	10,780,000	2,400,000	7,830,000	41,910,000	
	solvent inventory for flexible operation (*)		5,600,000			5,600,000	(*) Assumed solvent inventory cost: 1000 €/t
4	EPC SERVICES	44,140,000	23,500,000	6,700,000	17,780,000	92,120,000	
	TOTAL INSTALLED COST - EURO	352,480,000	168,265,000	45,190,000	133,180,000	699,115,000	
5	CONTINGENCY	24,670,000	11,780,000	2,260,000	6,660,000	45,370,000	
6	LICENSE FEES	7,050,000	3,370,000	900,000	2,660,000	13,980,000	
7	OWNER COSTS	17,620,000	8,410,000	2,260,000	6,660,000	34,950,000	
	TOTAL INVESTMENT COST - EURO	**401,820,000**	**191,825,000**	**50,610,000**	**149,160,000**	**793,415,000**	

7.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**1f**	
Description	Daily solvent storage	
Fixed costs		
Maintenance	25.5	
Operating Labour	3.72	
Labour Overhead	1.12	
Insurance & local taxes	14.0	
Total fixed cost, M€/y	44.3	
Variable costs (without fuel)		
	peak/normal oper.	**offpeak**
Make up water	0	0
Chemicals and consumables	740	0
Total variable cost, €/h	740	0

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME	:	FLEXIBLE OPERATION OF IGCC WITH CCS
FWI CONTRACT	:	1-BD-0530A

ISSUED BY	:	N. FERRARI
CHECKED BY	:	P. COTONE
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

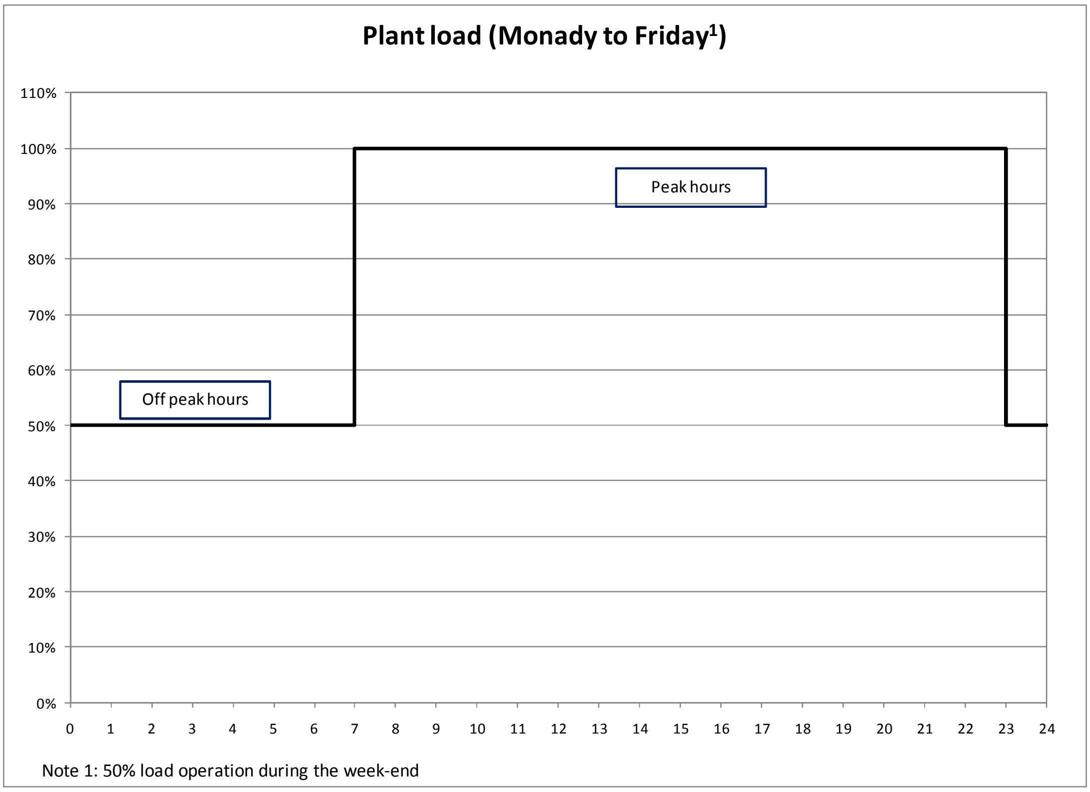
INDEX

1 Introduction

The main objective of this Section G is to assess the operating flexibility of IGCC power plants, with pre-combustion capture of the CO_2 from the shifted syngas.

The considerations shown in this section are based on the assumption that these plant types will be requested to operate in the mid merit market, thus participating to the first step of the variable electricity and generally following a weekly demand curve as shown in Figure 1-1.

Figure 1-1: IGCC plant load operation



From the above graph, it can be drawn that the IGCC plants are supposed to operate at base load for 80 hours per week, while 50% of their overall net power production capacity shall be generated during the remaining 88 hours.

The capability of these plant types for a flexible operation is affected by a serious of constraints, mainly related to the inertia of the process units (Gasification, syngas cooling and conditioning line, etc.) and the Air Separation Unit (ASU) to generate and prepare the fuel at the conditions required by the gas turbine. Furthermore,

IGCCs require significantly longer time to start up the plant, because of pre-heating requirements related to the gasifier, downstream unit pressurization and because of the deep cool-down sequence of the Air Separation Unit.
However, it is noted that for these plant types there are no specific constraints given by the introduction of the CO_2 capture equipment in the AGR, because their normal or transient operation is always in shadow of the other process units.

To investigate these main features, the following cases are presented in this section:

- **Case 2a**: This case considers liquid oxygen (LOX) storage, in conjunction with either ASU partial load operation or reduced ASU design capacity, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
- **Case 2b:** This case shows how the operating flexibility of the IGCC improves when the plant is designed for the co-production of electricity and hydrogen. As the hydrogen production line can operate independently from the power line, then the gasification, CO_2 capture, transport and storage equipment can run continuously at full load, while the power plant follows the variable electricity demand. However, large hydrogen storage is required in this case.
- **Case 2c:** This case shows how the operating flexibility of the IGCC improves when an intermediate storage of de-carbonised fuel gas is considered in the plant design. In this case, the syngas production line can operate constantly at base load, while the power plant follows the variable electricity demand.
- **Case 2d**: This case evaluates the possibility of tuning ON/OFF the CO_2 capture in the plant, depending on the possible CO_2 allowances cost fluctuations.
- **Case 2e**: This case assesses the introduction in the power plant of a CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, despite the cycling operation of the plant, thus avoiding a two-phase flow or a significant change of the physical properties.

In addition to the above, the following cases have been investigated based on a weekly electricity demand curve different from that shown in Figure 1-1:

- **Case 2f:** In this case, the syngas production line is kept constantly at base load (lower than reference case), while the power plant operates similarly to a combined cycle, i.e. at full load during weekday day time and at the lowest load (ideally without exporting power to the grid, i.e. in island mode) during weekend and weekday night time. This case shows how the operating flexibility of the IGCC improves when an intermediate storage of de-carbonised fuel gas is considered in the plant design.
- **Case 2g**: In this case, two hours of peak demand are considered during the day time, while overnight and during the weekend the plant is turned down to 50% output. This case considers liquid oxygen (LOX) storage, in conjunction with ASU partial load operation, in order to minimize the plant power consumption and increase the overall power production during peak load demand period. Stored oxygen is supplied to the gasification during the two hours of peak demand, while it is stored overnight when the plant is turned down to 50% output.

It has to be noted that, analogously to the liquid oxygen storage option, in the IGCC plants the storage of CO_2-laden solvent from the AGR is technically feasible and, in principle, it improves also the plant operating flexibility as the net power output increases during peak electricity demand period. However, the expected investment cost of this case is higher and the expected power output gain is lower than the oxygen storage solution, so it has been decided of not further investigating this alternative.

2 Case 2a – LOX/LIN storage

2.1 Introduction

The ASU significantly reduces the overall net electricity production of the plant, mainly due to its high auxiliary power demand. By reducing the energy requirement of this unit, at least during peak-demand hours, it would be possible to increase the overall net power export during remunerative hours and improve the overall economics of the plant.

Two different approaches have been considered in this Case 2a, in order to reduce the ASU internal consumption when the market requires a higher electricity generation. In both cases, oxygen and nitrogen storages are required in the plant, sized to cover their production fluctuations. The two scenarios assessed in this Case 2a are listed in the following:

- *Scenario 1* (partial load)
  The ASU is operated at partial load during peak hours, while the rest of the plant is running at full load, thus reducing the auxiliary consumption and increasing the overall net electricity production.

- *Scenario 2* (reduced capacity)
  The ASU is design at reduced capacity, with a consequent lower investment cost, while the plant load is changing in response to the variable electricity market requirements.

2.2 Case description

The considerations are made for the whole week of plant operation on the basis of the grid demand cycling trend summarised in section 1. From this trend, during peak electricity demand the IGCC is operated at base load to maximise the electricity production, while during off-peak electricity demand, the plant is required to produce 50% of the overall net electricity production capacity. This shall be considered compatibly with the plant technical constraints, identified in section C and D of this report, like the gasification minimum turndown, the gas turbine minimum environmental load, etc.

For the two scenarios listed above, oxygen and nitrogen from and to the storage systems have to be balanced during the cyclic weekly operation, in order to avoid any accumulation of the products.

The need of balancing the oxygen and nitrogen flows to and from the storage determine a relation between the air separation unit, running at low load during high electricity demand hours, and the other units, running at partial load during low electricity demand period. In fact, during off-peak operation the IGCC load strongly depends on the difference between the oxygen production from the ASU running at base load and the oxygen that has to be sent to storage to balance the oxygen demand during peak hours. In addition, the IGCC shall meet the network requirements during peak hours, i.e. 50% of the peak-hour production.

It has to be noted that the integration between the Air Separation Unit and the gas turbine may potentially limit the flexible operation of the IGCC, in the operating modes where the ASU and the other units are maintained at different loads. In this case, an additional main air compressor shall be considered for the off-peak hours, as the air extracted from the gas turbine, operated at part load, is lower the amount required by the air separation unit, operated at base load.

2.2.1 Scenario 1: partial load

The main technical constraint to be considered in this scenario is the minimum efficient turndown of the main air compressors, because the minimum turndown of the cold box represents a less stringent limitation for the minimum load of the ASU. In fact, as written in section C and D of this report, the minimum technical load for the cold box operation is around 50% of the design capacity, while the minimum efficient load of the compressors is around 70%. At lower loads, the main air compressors generally operate by introducing the air recycle system, with a significant impact on the power requirement. In fact, when the recycle is in operation, the cold box of the ASU is operating at partial load, while the compressor is still running at high load, without a significant reduction of the electric power consumption.

As a consequence, by reducing the Air Separation Unit load below 70% of design capacity, the net power production is not significantly increased, unless multiple train configuration were selected for the ASU compressors, leading to a higher investment cost.

During *peak demand period*, i.e. when the ASU is required to operate at partial load to decrease the power consumption, it has been initially considered to maintain the two air compressors (one for each ASU train) at their minimum efficient load (70%). In this case, because the air extraction flowrate from the gas turbines is same as the reference case (gas turbines are in operation at 100% load), the correspondent ASU load would be approximately 85% of design capacity.

This marginal reduction does not lead to a significant reduction of the power requirement, therefore to increase the flexibility of the plant it has been considered to have a dual train air compressors configuration for each of the two ASU trains. In this case, two out of the four compressors are shutdown during peak demand period, while the other two compressors are maintained at their minimum efficient load (70%), thus providing 35% of the overall ASU air requirement. As previously described, by considering the full air extraction flow from the gas turbines, then the relevant ASU load is approximately 67.5% of the design capacity.

On the other hand, during *off-peak demand period* the Air Separation Unit is operated at base load. About 30% of the produced oxygen is sent to storage to cover the peak load operation requirements, while the remainder flowrate is fed to the gasification.
Therefore, the process units and the gas turbines operate at about 70% of base load, which also corresponds to a net power output of approximately 50% of the peak-hours production, as required by the grid during off-peak hours.

However, it is noted that an additional air compressor, one per each of the two ASU trains, is required because the air extraction from the gas turbine compressor decreases when the GT is operated at part load.

2.2.2 Scenario 2: reduced capacity

This scenario is characterised by the ASU operating steadily at base load, whilst the unit is designed for a lower capacity with respect to the reference case.

The main constraint to the reduction of the Air Separation Unit design capacity is related to the limit imposed by the minimum environmental load of the gas turbine, which is 60% of the power production, corresponding to approximately 66% of fuel requirement.

During off-peak load operation, the ASU shall produce the oxygen required by the gasification island to produce enough fuel for the gas turbines (66%), plus the oxygen for the storage system, to meet the demand of the peak hours. The resulting minimum Air Separation Unit design capacity is 82.5% of the reference case.

It is noted that for this scenario, there are no constraints imposed by the efficient turndown of the compressors.

2.2.3 LOX/LIN storage

For the two scenarios considered in this Case 2a, during peak demand period, oxygen and nitrogen from the ASU are integrated with the oxygen and nitrogen coming from the liquid storages, after vaporisation.

These flowrates are balanced by the production during off-peak hours, considering a whole week of plant operation. Therefore, the product required from storage during the 80 hours per week of peak load operation, when the plant is operated at base load, is balanced by the product stored during the 88 hours per week of off-peak load operation, when the plant is operated at partial load.

Figure 2.2-1 shows the volume of stored oxygen during the week, for the two scenarios of Case 2a. The required net volume of the storage tank is the difference between the maximum and the minimum volume of stored oxygen during the week. From the graph, it can be drawn that it corresponds to the oxygen stored during the weekend, from the turndown of Friday night to the ramp up of Monday morning.
A minimum oxygen storage volume corresponding to 12 hours at the design oxygen flow of one ASU train has been also considered while defining the tank size.

Figure 2.2-1: Case 2a –Stored Oxygen volume during the week

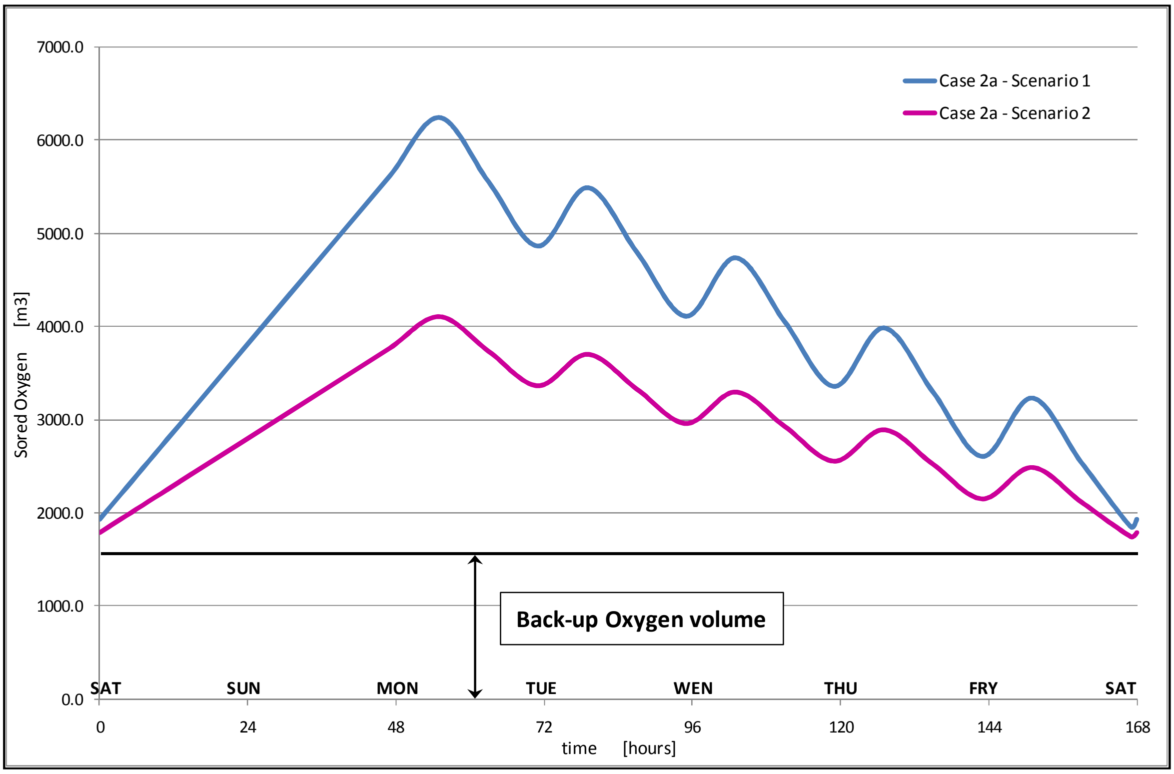
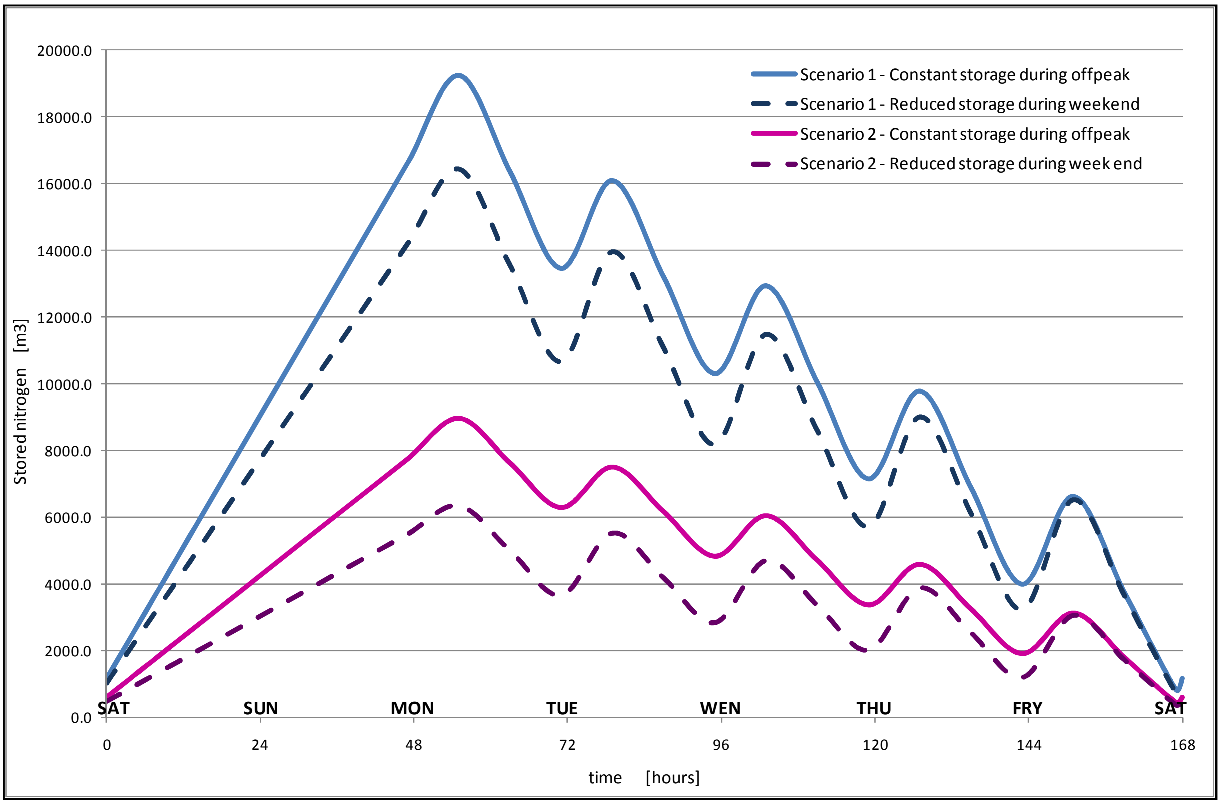


Figure 2.2-2 shows two different trends of the stored nitrogen during the week, for the two scenarios of Case 2a. The solid line corresponds to the stored volume if the nitrogen flowrate to storage were maintained constant during the hours of off-peak operation. The flowrate depends on the quantity required during peak load operation, while the excess is vented. As for the oxygen storage, the size depends on the product stored during the week end.

However, it is possible to reduce the storage size of the nitrogen by maximizing the nitrogen stored during the nights of the working days (i.e. without venting nitrogen), while storing a constant flow during the week-end (refer to the dashed line in the graph).

A minimum nitrogen storage volume corresponding to 12 hours for blanketing and purging and 4 minutes for turbine injection or fuel dilution have been also considered while defining the tank size.

Figure 2.2-2: Case 2a –Stored Nitrogen volume during the week



2.3 Utility consumption

The most relevant utility requirements for the two Scenarios of this case are shown in the following tables.

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PROJECT:	Operating Flexibility of Power Plants with CCS		
LOCATION:	Netherlands		
FWI Nº:	1- BD 0530 A		

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC
Case 2a (scenario 1)- peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**41.9**						**41.9**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**403.3**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**186.1**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

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PROJECT:	Operating Flexibility of Power Plants with CCS	DATE	feb-11		
LOCATION:	Netherlands	ISSUED BY	NF		
FWI Nº:	1- BD 0530 A	CHECKED BY	PC		
		APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC
Case 2a (scenario 1)- off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.6** (2)								**3.6**	
2100	**Air Separation Unit**			**15.1**						**15.1**	
2200	**Syngas Treating and Conditioning Line**	**-37.0**	**-85.6**	**-372.2**	**-14.4**	**37.4**	**86.5**	**375.9**	**51.5**	**36.5**	**5.5**
2300	**Acid Gas Removal**			**51.0**						**51.0**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.9**			**3.1**	**0.9**		**2.1**	**0.0**
3000	**POWER ISLANDS UNITS**	**33.5**	**86.5**	**294.9**	**14.4**	**-37.4**	**-89.6**	**-376.8**	**-51.5**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**120.4**	**5.5**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

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			APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2a (Scenario 1) - peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	283.0		3122	
2100	**Air Separation Unit**				17335
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			3053	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			330	
2500	**CO2 Compression and drying**				6780
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1742	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		88003
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				14777
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	300.3	0	8611	126895

Note: (1) Minus prior to figure means figure is generated

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		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2a (Scenario 1) - off peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	199.4		2200	
2100	**Air Separation Unit**				35527
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			2151	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			233	
2500	**CO2 Compression and drying**				4777
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1197	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		61964
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				10534
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	216.7	0	6145	112802

Note: (1) Minus prior to figure means figure is generated

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ELECTRICAL CONSUMPTION SUMMARY - Case 2a (Scenario 1) - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**69100**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**38500**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4753**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2140**
3500	**Miscellanea**	**596**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**182955**

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		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2a (Scenario 1) - off peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**254**
1000	**Gasification Section**	**9810**
2100	**Air Separation Unit**	**177900**
2200	**Syngas treatment and conditioning line**	**178**
2300	**Acid Gas Removal**	**23281**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2505**
2500	**CO2 Compression and drying**	**27125**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**3096**
3200	**Heat Recovery Steam Generator**	**3278**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1573**
3500	**Miscellanea**	**411**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9396**
	Additional consumption including CO_2 compression and drying	**352**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**260246**

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FWI Nº:	1- BD 0530 A	APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2a (Scenario 2) - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**30.9**						**30.9**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**414.2**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**175.2**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

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LOCATION:	Netherlands	ISSUED BY	NF		
FWI Nº:	1- BD 0530 A	CHECKED BY	PC		
		APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2a (Scenario 2) - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.4** (2)								**3.4**	
2100	**Air Separation Unit**			**14.3**						**14.3**	
2200	**Syngas Treating and Conditioning Line**	**-35.0**	**-80.9**	**-351.8**	**-13.6**	**35.3**	**81.7**	**355.3**	**48.6**	**34.5**	**5.2**
2300	**Acid Gas Removal**			**48.2**						**48.2**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.8**			**2.9**	**0.8**		**2.0**	**0.0**
3000	**POWER ISLANDS UNITS**	**31.6**	**81.8**	**278.1**	**13.6**	**-35.3**	**-84.6**	**-356.1**	**-48.6**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**114.4**	**5.2**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2a (Scenario 2) - peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Gasification Section	283.0		3122	
2100	Air Separation Unit				21188
2200	Syngas treatment and conditioning line			0	
2300	Acid Gas Removal			3053	
2400	Sulphur Recovery (SRU)- Tail gas treatment (TGT)			330	
2500	CO2 Compression and drying				6780
	POWER ISLANDS UNITS				
3100/3400	Gas Turbines and Generator auxiliaries			1742	
3200	Heat Recovery Steam Generator				
3300/3400	Steam Turbine and Generator auxiliaries		11.7		88003
3500	Miscellanea				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	Cooling Water (Sea Water / Machinery Water)				14777
4200	Demineralized/Condensate Recovery/Plant and Potable Water Systems	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	300.3	0	8611	130748

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	Operating Flexibility of Power Plants with CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: Draft
mar-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2a (Scenario 2) - off peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	188.5		2079	
2100	**Air Separation Unit**				32821
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			2033	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			220	
2500	**CO2 Compression and drying**				4746
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			1116	
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		58449
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				9964
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	205.7	0	5812	105980

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2a (Scenario 2) - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**97800**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**38500**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4753**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2140**
3500	**Miscellanea**	**596**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**211655**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2a - off peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**240**
1000	**Gasification Section**	**9272**
2100	**Air Separation Unit**	**151500**
2200	**Syngas treatment and conditioning line**	**168**
2300	**Acid Gas Removal**	**22004**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2367**
2500	**CO2 Compression and drying**	**26950**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2886**
3200	**Heat Recovery Steam Generator**	**3056**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1467**
3500	**Miscellanea**	**383**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9416**
	Additional consumption including CO_2 compression and drying	**333**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**231129**

Notes: (1) Minus prior to figure means figure is generated

2.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following tables, for the two assessed scenarios.

It is noted that during high electricity demand period, the net power production gain with respect to the reference plant is about 56 MWe and 29 MWe, respectively for Scenario 1 and Scenario 2.

Case 2a - Scenario 1 - ASU @ partial load during peak hours				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	227.6
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**1635.8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	1153.975
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	1048.6
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	370.5
Steam turbine power output	MWe	398.0	394.7	290.2
Expander power output	MWe	11.2	11.2	7.9
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**969.1**	**668.5**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	69.1	177.9
Process Units consumption	MWe	50.8	50.8	35.8
Utility Units consumption	MWe	1.7	1.7	1.6
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	9.2
Power Islands consumption	MWe	12.2	12.2	8.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**144.0**	**232.8**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**825.1**	**435.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.7**	**40.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**35.5**	**26.6**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5	27.1
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**183.0**	**260.3**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**786.1**	**408.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.7**	**40.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**33.9**	**25.0**

CO_2 emission	**kg/s**	**30.93**	**30.93**	**21.79**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.142**	**0.192**

Case 2a - Scenario 2 - Reduced ASU design capacity				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	215.2
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**1546.1**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	1090.6925
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	991.1
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	345.3
Steam turbine power output	MWe	398.0	396.5	270.6
Expander power output	MWe	11.2	11.2	7.5
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**970.9**	**623.4**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	97.8	151.5
Process Units consumption	MWe	50.8	50.8	33.8
Utility Units consumption	MWe	1.7	1.7	1.6
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	9.2
Power Islands consumption	MWe	12.2	12.2	7.8
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**172.7**	**203.8**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**798.2**	**419.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.8**	**40.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**34.4**	**27.1**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5	27.0
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**211.7**	**231.1**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**759.2**	**392.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.8**	**40.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**32.7**	**25.4**

CO_2 emission	**kg/s**	**30.93**	**30.93**	**20.60**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.147**	**0.189**

2.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for the two scenarios of this case with respect to the design of the reference plant.

Case 2a - Scenario 1 - ASU @ partial load during peak hours

UNIT 2100 - Air Separation Unit - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
Main air compressor	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	4 x 16.3 MWe β = 15.8 Flow = 119'000 Nm3/h each Vol. flow = 123'200 m3 each	
Additional main air compressor	not foreseen	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	
Oxygen storage tank	1 x 1'800 m3 (Diameter: 13.7 m, H: 12.2 m)	1 x 6'500 m3 (Diameter: 27.4 m, H: 11 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -165°C
Nitrogen storage tank	1 x 140 m3 (Diameter: 3.0 m, H: 3.0 m)	1 x 17'400 m3 (Diameter: 43 m, H: 12.2 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -180°C

Note: The number of equipment is referred to both trains

Case 2a - Scenario 2 - ASU design: 82.5%			
UNIT 2100 - Air Separation Unit - 2x50% train			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Air Separation Unit Package (two parallel trains, each sized for 50% of the capacity)	HP O2 flow rate to Gasifier = 290 t/h MP N2 flow rate to GTs = 900 t/h LP N2 flow rate to Proc Unit = 2.7 t/h Air flow rate from GTs = 620 t/h	HP O2 flow rate to Gasifier = 240 t/h MP N2 flow rate to GTs = 780 t/h LP N2 flow rate to Proc Unit = 2.7 t/h Air flow rate from GTs = 620 t/h	
Main air compressor	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	2 x 21 MWe β = 15.8 Flow = 155'000 Nm3/h each Vol. flow = 160'200 m3 each	
Booster Air Compressor	2 x 2.4 MWe β = 1.5 Flow = 136'600 Nm3/h each Vol. flow = 9'000 m3 each	2 x 2.0 MWe β = 1.5 Flow = 112'000 Nm3/h each Vol. flow = 7'400 m3 each	
GAN	2 x 28 MWe β = 5.4 Flow = 360'000 Nm3/h each Vol. flow = 75'900 m3 each	2 x 24 MWe β = 5.4 Flow = 310'000 Nm3/h each Vol. flow = 65'500 m3 each	
Dilution Booster	2 x 0.7 MWe β = 1.2 Flow = 99'000 Nm3/h each Vol. flow = 3'860 m3 each	2 x 0.45 MWe β = 1.2 Flow = 66'000 Nm3/h each Vol. flow = 2'570 m3 each	
Additional main air compressor	not foreseen	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	
ASU Heat Exchangers	16 services; duty = 12 MWth each; surface = 1000 m2 each	16 services; duty = 10 MWth each; surface = 825 m2 each	sea water coolers (tubes: titanium; shell: CS)
ASU chiller	5.2 MW th @ 5°C	4.3 MW th @ 5°C	
Oxygen storage tank	1 x 1'800 m3 (Diameter: 13.7 m, H: 12.2 m)	1 x 4'200 m3 (Diameter: 20.4 m, H: 12.8 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -165°C
Nitrogen storage tank	1 x 140 m3 (Diameter: 3.0 m, H: 3.0 m)	1 x 6'500 m3 (Diameter: 27.5 m, H: 11 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -179°C

Note: The number of equipment is referred to both trains

2.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, Scenario 1 and Scenario 2 show a total investment cost increase respectively of 3% and 1%.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 17 May 2011
Rev. : 0

CASE 2a - Scenario 1 - ASU @ partial load during peak hours

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	171,673,000	47,339,000	43,594,000	30,917,000	29,766,000	438,499,000	122,195,000	1,087,991,000	
2	CONSTRUCTION	1,853,000	77,366,000	43,381,000	20,857,000	18,091,000	12,357,000	6,610,000	97,365,000	59,691,000	337,571,000	
3	OTHER COSTS	996,000	27,699,000	5,671,000	12,376,000	19,528,000	4,129,000	1,421,000	41,831,000	11,656,000	125,307,000	
4	EPC SERVICES	1,338,000	57,945,000	19,400,000	12,456,000	8,810,000	3,966,000	1,782,000	30,003,000	20,902,000	156,602,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	240,125,000	93,028,000	90,023,000	51,369,000	39,579,000	607,698,000	214,444,000	1,707,471,000	
5	CONTINGENCY	1,000,000	25,000,000	12,000,000	6,500,000	6,300,000	3,600,000	2,000,000	42,500,000	10,700,000	109,600,000	
6	LICENSE FEES	300,000	7,100,000	4,800,000	1,900,000	1,800,000	1,000,000	800,000	12,200,000	4,300,000	34,200,000	
7	OWNER COSTS	700,000	17,800,000	12,000,000	4,700,000	4,500,000	2,600,000	2,000,000	30,400,000	10,700,000	85,400,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	268,925,000	106,128,000	102,623,000	58,569,000	44,379,000	692,798,000	240,144,000	1,936,671,000	

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 17 May 2011
Rev. : 0

CASE 2a - Scenario 2 - Reduced ASU design size

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	144,684,000	47,339,000	43,594,000	30,917,000	29,766,000	438,499,000	122,195,000	1,061,002,000	
2	CONSTRUCTION	1,853,000	77,366,000	37,395,000	20,857,000	18,091,000	12,357,000	6,610,000	97,365,000	59,691,000	331,585,000	
3	OTHER COSTS	996,000	27,699,000	5,671,000	12,376,000	19,528,000	4,129,000	1,421,000	41,831,000	11,656,000	125,307,000	
4	EPC SERVICES	1,338,000	57,945,000	19,400,000	12,456,000	8,810,000	3,966,000	1,782,000	30,003,000	20,902,000	156,602,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	207,150,000	93,028,000	90,023,000	51,369,000	39,579,000	607,698,000	214,444,000	1,674,496,000	
5	CONTINGENCY	1,000,000	25,000,000	10,400,000	6,500,000	6,300,000	3,600,000	2,000,000	42,500,000	10,700,000	108,000,000	
6	LICENSE FEES	300,000	7,100,000	4,100,000	1,900,000	1,800,000	1,000,000	800,000	12,200,000	4,300,000	33,500,000	
7	OWNER COSTS	700,000	17,800,000	10,400,000	4,700,000	4,500,000	2,600,000	2,000,000	30,400,000	10,700,000	83,800,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	232,050,000	106,128,000	102,623,000	58,569,000	44,379,000	692,798,000	240,144,000	1,899,796,000	

2.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	2a - Scenario 1		2a - Scenario 2	
Description	LOX Storage, ASU @ part load		LOX Storage, reduced ASU size	
Fixed costs				
Maintenance	62.3		61.1	
Operating Labour	7.68		7.68	
Labour Overhead	2.30		2.30	
Insurance & local taxes	34.1		33.5	
Total fixed cost, M€/y	106.4		104.6	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak**
Make up water	13	9	13	9
Chemicals and solvents	349	246	349	233
Catalysts	134	134	134	134
Total variable cost, €/h	362	255	362	241

3 Case 2b – H_2 and power co-production

3.1 Introduction

This Case 2b shows how the operating flexibility of IGCC's with pre-combustion capture of the CO_2 improves when the plant is designed for the co-production of electricity and hydrogen. In fact, the hydrogen production line can operate independently from the power line, allowing the gasification, CO_2 capture, transport and storage equipment to run continuously at full load, while the power plant follows the variable electricity demand.

However, to make the above operation feasible, large underground buffer storage of either high purity hydrogen or de-carbonized hydrogen-rich gas is required.

3.2 Case description

This alternative is assessed on a whole week of plant operation, based on the grid demand cycling trend summarised in section 1. From this trend, during peak electricity demand the power island shall be operated at base load to maximise the electricity production, while during off-peak electricity demand, the IGCC plant is required to produce 50% of the overall net electricity production capacity, compatibly with the gas turbine minimum environmental load.

During *low electricity demand period*, the excess syngas production, obtained from the process units running at base load, is used to produce hydrogen, while power plant is operated with two gas turbines at their minimum environmental load, which is 60% of base production, corresponding to approximately 66% of fuel requirement.

With this strategy, large underground hydrogen storage is required to maintain a constant hydrogen stream production, available for sale at plant Battery Limits (B.L.). However, the major advantage is that the gasification island and the downstream process units, up to the AGR section, are operated continuously at base load, generating de-carbonized fuel with a hydrogen molar content of approximately 85%.

The amount of fuel required by the gas turbines is expanded and sent to the power island for electricity generation in a combined cycle, while the remainder part from the AGR, corresponding to approximately 34% of the overall production, is split into two different streams: one is fed to a pressure swing adsorption (PSA) unit for high purity hydrogen production, while the other stream is sent to underground storage, at a pressure higher than 50 bar, and used as feeding stream for the PSA during peak-hours operation, i.e. when all the syngas generated from the gasification island is dedicated to the power production.

The tail gas stream from the PSA, consisting of hydrogen and other impurities present in the de-carbonised fuel, is constantly sent to the post-firing system of the heat recovery steam generators, while the high pressure hydrogen from the PSA, after preheating and expansion, is sent to plant battery limits.

The PSA design capacity is selected to generate a constant hydrogen flowrate at plant B.L., available for sale, during the whole week of plant operation. It has been estimated that by storing approximately 48% of the de-carbonised fuel used for hydrogen production during off-peak demand period, then the PSA can be maintained at constant load.

It is noted that, as the ASU and the power trains are maintained at different loads during the cyclic operation, the air integration between the ASU and the gas turbines may potentially represent a constraint for the flexible operation of the IGCC. In this case, an additional main air compressor has been considered for operation during off-peak hours, as the air extracted from the gas turbines, operated at part load, is significantly lower than the amount required by the air separation unit, operated at base load.

During *high electricity demand period*, the power island is operated with the two gas turbines at base load, similarly to the gasification island and the downstream process units. In this case, hydrogen rich gas from the storage is fed to the PSA, generating a constant hydrogen flow, while the off-gas stream is sent to the post-combustion system of the heat recovery steam generators, thus increasing the peak-hours power production with respect to the reference case.

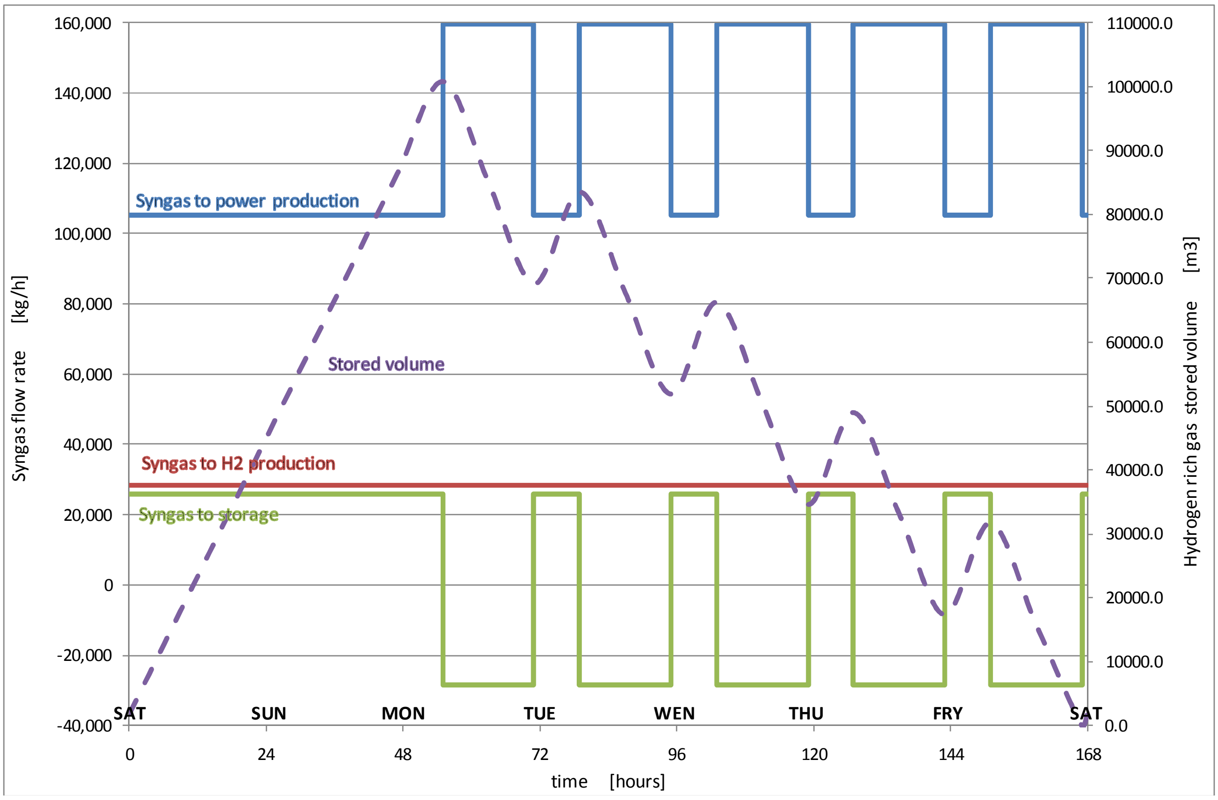
Following the operating strategy described above, the resulting hydrogen production is around 75,400 Nm^3/h, meeting the demand of a large refinery, while during low electricity demand period, the plant is producing a net power output slightly above the 50% required by the grid.

To increase the hydrogen production capacity, the plant could be operated with only one gas turbine at base load, during off-peak demand hours. However, this would result in a net power output lower than required, i.e. approximately 43% rather than the required 50%.

3.2.1 Hydrogen storage

Figure 3.2-1 shows the main hydrogen rich fuel flowrate on the whole week of plant operation and the related volumes of stored gas. From the graph, it can be drawn that a storage working volume of about 100,000 m^3 is required for this alternative, leading to the selection of an underground storage, rather than storage in vessels.

Figure 3.2-1: Case 2b – Balance of syngas within the week



3.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2b - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	5.1 (2)								5.1	
2100	**Air Separation Unit**			21.5						21.5	
2200	**Syngas Treating and Conditioning Line**	-52.6	-121.5	-528.3	-20.5	53.1	122.7	533.6	73.1	51.8	7.7
2300	**Acid Gas Removal**			72.4						72.4	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		-1.3	-1.2			4.4	1.2		3.0	0.1
3000	**POWER ISLANDS UNITS**	47.5	122.8	423.6	20.5	-53.1	-127.1	-534.8	-73.1		
4000 to 5300	**UTILITY and OFFSITE UNITS**			12.0						12.0	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.8	7.8

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	Operating Flexibility of Power Plants with CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2b - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**21.5**						**21.5**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**423.6**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**165.8**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2b - Peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**283.0**		**3122**	
2100	**Air Separation Unit**				**25682**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**3053**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**330**	
2500	**CO2 Compression and drying**				**6780**
2600	**H2 production - PSA**			**0**	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**1742**	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**88003**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**14777**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE	**300.3**	**0**	**8611**	**135242**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft	
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11	
LOCATION:	Netherlands	ISSUED BY: NF	
FWI Nº:	1- BD 0530 A	CHECKED BY: PC	
		APPR. BY: LM	

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2b - Off-peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	283.0		3122	
2100	**Air Separation Unit**				35088
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			3053	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			330	
2500	**CO2 Compression and drying**				6780
	H2 production - PSA			0	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1199	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		11.7		76467
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				13831
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE including CO2 compression	300.3	0	8068	132166

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2b - Peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**128620**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**38500**
2600	**H2 production - PSA**	**0**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4769**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2158**
3500	**Miscellanea**	**598**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**242511**

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2b - Off-peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**175700**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**38500**
2600	**H2 production - PSA**	**0**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2853**
3200	**Heat Recovery Steam Generator**	**3282**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1723**
3500	**Miscellanea**	**411**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**285629**

3.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following table.

Case 2b - Hydrogen production				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	323.1
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**2321.8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	1637.9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	982.3
Thermal Power of Clean Syngas to PSA (based on LHV) (G)	MWt		265.1	265.1
Thermal Power of Clean Syngas to storage (based on LHV) (H)	MWt		-265.1	240.9
Syngas treatment efficiency ((F+G+H)/E*100)	%	90.9	90.9	90.9
Hydrogen production	Nm3/h		75,343	75,343
	MWth		225	225
Gas turbines total power output	MWe	563.2	563.2	341.5
Steam turbine power output	MWe	398.0	418.1	333.9
Expander power output	MWe	11.2	11.2	7.4
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**992.5**	**682.7**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	128.6	175.7
Process Units consumption	MWe	50.8	50.8	50.8
Utility Units consumption	MWe	1.7	1.7	1.7
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	10.2
Power Islands consumption	MWe	12.2	12.2	8.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**203.5**	**246.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**789.0**	**436.0**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5	38.5
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**242.5**	**285.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**750.0**	**397.0**

CO_2 emission	**kg/s**	**30.93**	**36.65**	**20.36**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.176**	**0.185**

3.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant.

Case 2b - H2 production

UNIT 2100 - Air Separation Unit - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
Additional main air compressor	not foreseen	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	

UNIT 2600 - PSA

Equipment	Reference plant	Flexible plant	Remarks
PSA	not foreseen	H2 production = 75,400 Nm3/h	
Hydrogen heater	not foreseen	Duty = 1470 MWth Surface 25 m2	H2 service H2 service on tube side
Hydrogen expander	not foreseen	1 x 1.4 MWe Pin = 54 bar a; P out = 25 bar a Flow = 75,400 Nm3/h Vol. Flow = 1620 m3/h	

Offsite

Unit	Reference plant	Flexible plant	Remarks
Hydrogen rich gas underground storage	not foreseen	- Working volume = 100'000 m3 - Underground storage system - Pressure = 50-55 bar	

3.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 2.5%.

These cost figures do not include cost for hydrogen storage, which depends both on the storage type (natural reservoir or mined cavern) and whether it is constant-pressure or variable-pressure storage (refer to Section D – Attachment 1 for further information). From literature data, it can be derived that the expected cost for the hydrogen storage of these IGCCs plant may vary from 10 M€ to 50 M€, corresponding to about 2.6% of the overall plant cost.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 16 May 2011
Rev. : 0

CASE 2b - Hydrogen production

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 2600 PSA	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	155,933,000	47,339,000	43,594,000	30,917,000	29,766,000	9,489,000	438,499,000	122,195,000	1,081,740,000	
2	CONSTRUCTION	1,853,000	77,366,000	41,211,000	20,857,000	18,091,000	12,357,000	6,610,000	2,320,000	97,365,000	59,691,000	337,721,000	
3	OTHER COSTS	996,000	27,699,000	5,671,000	12,376,000	19,528,000	4,129,000	1,421,000	480,000	41,831,000	11,656,000	125,787,000	
4	EPC SERVICES	1,338,000	57,945,000	19,400,000	12,456,000	8,810,000	3,966,000	1,782,000	710,000	30,003,000	20,902,000	157,312,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	222,215,000	93,028,000	90,023,000	51,369,000	39,579,000	12,999,000	607,698,000	214,444,000	1,702,560,000	
5	CONTINGENCY	1,000,000	25,000,000	11,100,000	6,500,000	6,300,000	3,600,000	2,000,000	900,000	42,500,000	10,700,000	109,600,000	
6	LICENSE FEES	300,000	7,100,000	4,400,000	1,900,000	1,800,000	1,000,000	800,000	300,000	12,200,000	4,300,000	34,100,000	
7	OWNER COSTS	700,000	17,800,000	11,100,000	4,700,000	4,500,000	2,600,000	2,000,000	600,000	30,400,000	10,700,000	85,100,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	248,815,000	106,128,000	102,623,000	58,569,000	44,379,000	14,799,000	692,798,000	240,144,000	1,931,360,000	

3.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**2b**	
Description	H_2 production	
Fixed costs		
Maintenance	62.1	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	34.1	
Total fixed cost, M€/y	106.1	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	13	13
Chemicals and solvents	349	349
Catalysts	134	134
Total variable cost, €/h	362	362

4 Case 2c – Fuel storage

4.1 Introduction

This Case 2c shows how the operating flexibility of IGCC's with pre-combustion capture of the CO_2 improves when an intermediate storage of de-carbonised fuel gas is considered in the plant design. In fact, with a fuel gas buffer storage the syngas production line can operate constantly at base load, while the power plant follows the variable electricity demand.

In this case, part of the hydrogen rich gas from the CO_2 removal is fed to the storage during low electricity demand periods, while it is used during electricity peak demand. As a consequence, the gasification and other main process unit capacity can be reduced, because syngas from the process unit is integrated with the de-carbonised fuel from the storage, to meet the appetite of the two gas turbines operated at base load.

4.2 Case description

This alternative is assessed on a whole week of plant operation, based on the grid demand cycling trend summarised in section 1. From this trend, during peak electricity demand the power island shall be operated at base load to maximise the electricity production, while during off-peak electricity demand, the IGCC plant is required to produce 50% of the overall net electricity production capacity, compatibly with the gas turbine minimum environmental load.

With the strategy described above, during *high electricity demand period* the power island is operated with the two gas turbines at base load, while the hydrogen rich gas from the AGR unit is integrated with the stored gas, to meet the thermal requirement of the two machines.

During *low electricity demand period*, the power island is operated with the two gas turbines at their minimum environmental load, which is 60% of their base load, corresponding to approximately 66% of fuel requirement. The amount of de-carbonised fuel required by the gas turbines is expanded and sent to the power island for electricity generation in a combined cycle, while the remainder flowrate is sent to an underground storage system, at a pressure higher than 50 bar.

Fuel gas from and to the storage system has to be balanced during the cyclic weekly operation, in order to avoid any accumulation of fuel. The need of balancing the fuel gas fixes the design capacity of the whole syngas generation line, which results in 82% of the reference case.

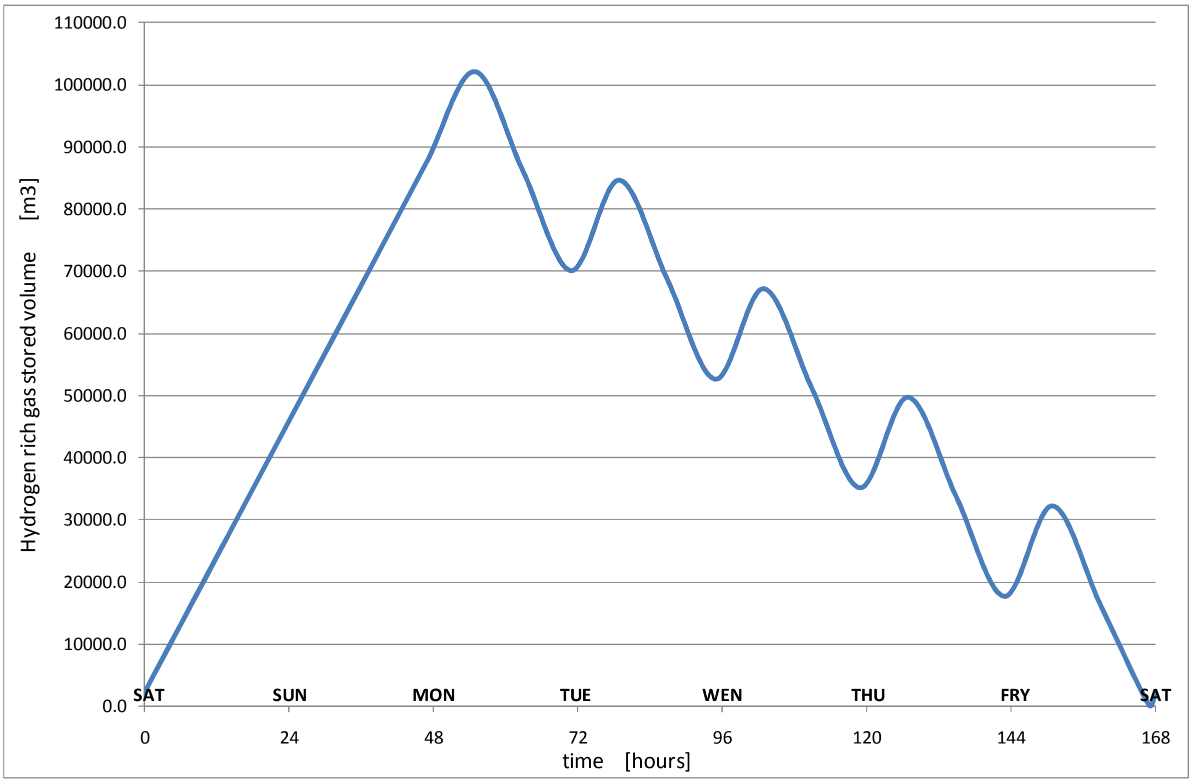
It is noted that, as the ASU and the power trains are maintained at different loads during the cyclic operation, the air integration between the ASU and the gas turbines may potentially represent a constraint for the flexible operation of the IGCC. In this case, an additional main air compressor has been considered for operation during off-peak hours, as the air extracted from the gas turbines, operated at part load, is significantly lower than the amount required by the air separation unit, operated at base load.

4.2.1 Hydrogen rich gas storage

Stored hydrogen rich gas, required during peak demand period, is balanced by the excess of production during off-peak hours, considering a whole week of plant operation. Therefore, the hydrogen rich gas required from storage during the 80 hours per week of peak load operation, when the power island is operated at base load, is balanced by the product stored during the 88 hours per week of off-peak load operation, when the gas turbines are operated at their minimum environmental load.

Figure 4.2-1 shows the volume of stored hydrogen rich gas during the week. From the graph, it can be drawn that a storage volume of about 100,000 m^3 is required for this alternative, leading to the selection of an underground storage, rather than the storage in vessels.

Figure 4.2-1: Case 2c – Stored fuel volume during the week



4.2.2 Nitrogen storage

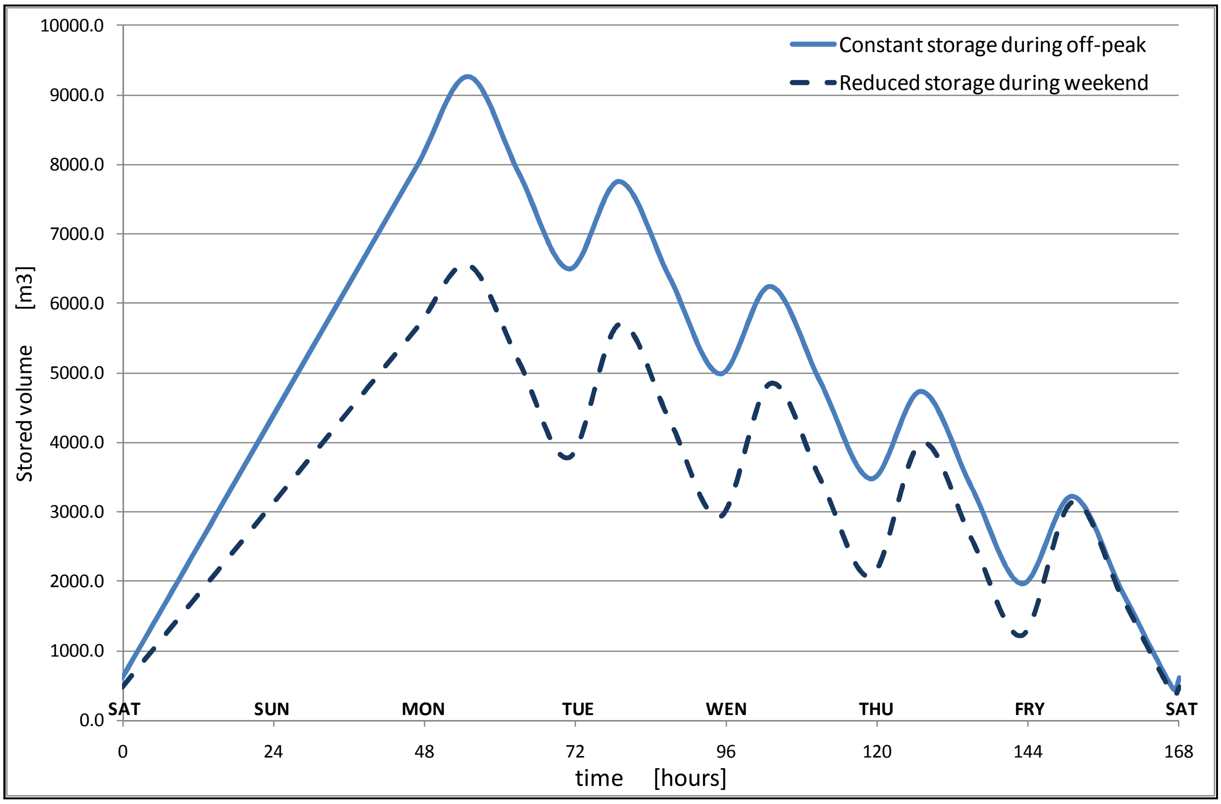
As the ASU capacity is reduced in accordance to smaller gasification island, during peak demand period the nitrogen from the ASU shall be integrated with the nitrogen from storage.

This stream is balanced by the higher production during off-peak hours, considering a whole week of plant operation. Therefore, the nitrogen required from storage during the 80 hours per week of peak load operation, when the power island is operated at base load, is balanced by the product stored during the 88 hours per week of off-peak load operation, when the gas turbines are operated at minimum load.

Figure 4.2-2 shows two different trends of the stored nitrogen during the week, for this case. The solid line corresponds to the stored volume if the nitrogen flowrate to storage is maintained constant during the hours of off-peak operation. The flowrate depends on the quantity required during peak load operation, while the excess is vented.

However, it is possible to reduce the storage size of the nitrogen by maximizing the nitrogen stored during the nights of the working days (i.e. without venting nitrogen), while storing a constant flow during the week-end (refer to the dashed line in the graph).
A minimum nitrogen storage volume corresponding to 12 hours for blanketing and purging and 4 minutes for turbine injection or fuel dilution have been also considered while defining the tank size.

Figure 4.2-2: Case 2c – Stored nitrogen volume during the week



4.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

		REVISION	Draft	Rev.1	Rev.2
CLIENT:	IEA GHG R&D PROGRAMME	DATE	mar-11		
PROJECT:	Operating Flexibility of Power Plants with CCS	ISSUED BY	NF		
LOCATION:	Netherlands	CHECKED BY	PC		
FWI Nº:	1- BD 0530 A	APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2c - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**4.1** (2)								**4.1**	
2100	**Air Separation Unit**			**27.4**						**27.4**	
2200	**Syngas Treating and Conditioning Line**	**-43.1**	**-99.6**	**-433.2**	**-16.8**	**43.5**	**100.6**	**437.5**	**59.9**	**42.5**	**6.4**
2300	**Acid Gas Removal**			**59.4**						**59.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.1**	**-1.0**			**3.6**	**1.0**		**2.5**	**0.0**
3000	**POWER ISLANDS UNITS**	**38.9**	**100.7**	**335.5**	**16.8**	**-43.5**	**-104.2**	**-438.5**	**-59.9**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**147.9**	**6.4**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	REVISION	Draft	Rev.1	Rev.2
PROJECT:	Operating Flexibility of Power Plants with CCS	DATE	mar-11		
LOCATION:	Netherlands	ISSUED BY	NF		
FWI Nº:	1- BD 0530 A	CHECKED BY	PC		
		APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2c - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	4.1 (2)								4.1	
2100	**Air Separation Unit**			17.6						17.6	
2200	**Syngas Treating and Conditioning Line**	-43.1	-99.6	-433.2	-16.8	43.5	100.6	437.5	59.9	42.5	6.4
2300	**Acid Gas Removal**			59.4						59.4	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		-1.1	-1.0			3.6	1.0		2.5	0.0
3000	**POWER ISLANDS UNITS**	38.9	100.7	345.2	16.8	-43.5	-104.2	-438.5	-59.9		
4000 to 5300	**UTILITY and OFFSITE UNITS**			12.0						12.0	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	138.1	6.4

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2c - Peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	232.1		2560	
2100	**Air Separation Unit**				21059
2200	**Syngas treatment and conditioning line**			0	
2300	**Acid Gas Removal**			2503	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			271	
2500	**CO2 Compression and drying**				5560
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			1697	
3300/3400	**Steam Turbine and Generator auxiliaries**		12		80135
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				12566
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	17.3	-15.7		
	Other Units		4.0	299	
	BALANCE	249.3	0	7330	119319

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2c - Off-peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**232.1**		**2560**	
2100	**Air Separation Unit**				**21059**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**2503**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**271**	
2500	**CO2 Compression and drying**				**5560**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**1139**	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**66512**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**11609**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**299**	
	BALANCE	**249.3**	**0**	**6772**	**104740**

Note: (1) Minus prior to figure means figure is generated

	CLIENT: IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT: Operating Flexibility of Power Plants with CCS	mar-11
	LOCATION: Netherlands	ISSUED BY: NF
	FWI Nº: 1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2c - Peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**296**
1000	**Gasification Section**	**11417**
2100	**Air Separation Unit**	**97600**
2200	**Syngas treatment and conditioning line**	**207**
2300	**Acid Gas Removal**	**27096**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2915**
2500	**CO2 Compression and drying**	**31570**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4646**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2024**
3500	**Miscellanea**	**582**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9303**
	Additional consumption including CO_2 compression and drying	**410**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**302**
	Other Units	**589**
	BALANCE	**193665**

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
FOSTER WHEELER	PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2b - Off-peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**296**
1000	**Gasification Section**	**11417**
2100	**Air Separation Unit**	**151200**
2200	**Syngas treatment and conditioning line**	**207**
2300	**Acid Gas Removal**	**27096**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2915**
2500	**CO2 Compression and drying**	**31570**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2834**
3200	**Heat Recovery Steam Generator**	**3119**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1570**
3500	**Miscellanea**	**391**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**8114**
	Additional consumption including CO_2 compression and drying	**410**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**302**
	Other Units	**589**
	BALANCE	**242031**

4.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following table.

Case 2c - Hydrogen storage				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	264.9	264.9
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**1903.9**	**1903.9**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1343.1	1343.1
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	976.9
Thermal Power of Clean Syngas from syngas cooling (based on LHV) (G)	MWt	1488.4	1220.5	1220.5
Thermal Power of Clean Syngas from storage (based on LHV) (H)	MWt		267.9	-243.6
Syngas treatment efficiency (G/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	339.1
Steam turbine power output	MWe	398.0	373.3	289.6
Expander power output	MWe	11.2	11.2	7.4
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**947.7**	**636.0**
IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	97.6	151.2
Process Units consumption	MWe	50.8	41.6	41.6
Utility Units consumption	MWe	1.7	1.4	1.4
Offsite Units consumption (including sea cooling water system)	MWe	10.2	9.1	7.9
Power Islands consumption	MWe	12.2	12.0	7.9
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**161.7**	**210.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**786.0**	**426.0**
IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	31.6	31.6
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.4	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**193.7**	**242.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**754.0**	**394.1**
CO_2 emission	**kg/s**	**30.93**	**30.93**	**20.30**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.148**	**0.185**

4.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant.

Case 2c - Hydrogen rich gas storage			
Process unit			
Unit	**Reference plant**	**Flexible plant**	**Remarks**
Unit 1000 - Gasification island	Coal inlet flow = 323 t/h	Coal inlet flow = 265 t/h	
Unit 2200 - Syngas treatment	Syngas inlet flow = 694 t/h	Syngas inlet flow = 570 t/h	
Unit 2300 - AGR	Syngas inlet flow = 776 t/h	Syngas inlet flow = 637 t/h	
Unit 2400 - SRU	Acid gas inlet flow = 485 kmol/h	Acid gas inlet flow = 398 kmol/h	
Unit 2500 - CO2 compressor (2x50%)	CO2 flow = 165'000 Nm3/h each	CO2 flow = 135000 Nm3/h each	
UNIT 2100 - Air Separation Unit - 2x50% train			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Air Separation Unit Package (two parallel trains, each sized for 50% of the capacity)	HP O2 flow rate to Gasifier = 290 t/h MP N2 flow rate to GTs = 900 t/h LP N2 flow rate to Proc Unit = 2.7 t/h Air flow rate from GTs = 620 t/h	HP O2 flow rate to Gasifier = 240 t/h MP N2 flow rate to GTs = 780 t/h LP N2 flow rate to Proc Unit = 2.2 t/h Air flow rate from GTs = 620 t/h	
Main air compressor	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	2 x 21 MWe β = 15.8 Flow = 155'000 Nm3/h each Vol. flow = 160'200 m3 each	
Booster Air Compressor	2 x 2.4 MWe β = 1.5 Flow = 136'600 Nm3/h each Vol. flow = 9'000 m3 each	2 x 2.0 MWe β = 1.5 Flow = 112'000 Nm3/h each Vol. flow = 7'400 m3 each	
GAN	2 x 28 MWe β = 5.4 Flow = 360'000 Nm3/h each Vol. flow = 75'900 m3 each	2 x 24 MWe β = 5.4 Flow = 310'000 Nm3/h each Vol. flow = 65'500 m3 each	
Dilution Booster	2 x 0.7 MWe β = 1.2 Flow = 99'000 Nm3/h each Vol. flow = 3'860 m3 each	2 x 0.45 MWe β = 1.2 Flow = 66'000 Nm3/h each Vol. flow = 2'570 m3 each	
Additional main air compressor	not foreseen	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	
ASU Heat Exchangers	16 services; duty = 12 MWth each; surface = 1000 m2 each	16 services; duty = 10 MWth each; surface = 825 m2 each	sea water coolers (tubes: titanium; shell: CS)
ASU chiller	5.2 MW th @ 5°C	4.3 MW th @ 5°C	
Nitrogen storage tank (for flexible operation)	1 x 140 m3 (Diameter: 3.0 m, H: 3.0 m)	1 x 7'200 m3 (Diameter: 27.4 m, H: 12.2 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -179°C

Note: The number of equipment is referred to both trains

Case 2c - Hydrogen rich gas storage			
Power Plant			
Unit	**Reference plant**	**Flexible plant**	**Remarks**
Unit 3300 - Steam turbine and condenser package	Steam turbine gross power output = 428 Mwe Condenser duty = 702 MWth	Steam turbine gross power output = 400 Mwe Condenser duty = 640 MWth	
Condensate pumps	2 x 475 kW 1220 m3/h x 100 m	2 x 425 kW 1110 m3/h x 100 m	One in operation, one spare
LP BFW pumps	4 x 132 kW 320 m3/h x 107 m	4 x 110 kW 271 m3/h x 107 m	Two in operation, two spare
MP BFW pumps	4 x 425 kW 175 m3/h x 540 m	4 x 400 kW 160 m3/h x 540 m	Two in operation, two spare

Offsite			
Unit	**Reference plant**	**Flexible plant**	**Remarks**
Hydrogen rich gas underground storage	not foreseen	- Working volume = 100'000 m3 - Underground storage system - Pressure = 50-55 bar	

4.5.1 CO_2 pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the “Upgraded calculator for CO_2 pipeline system” (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 2c. As the process unit, including the Acid Gas Removal Unit and consequently the CO_2 compression section are design for a lower capacity, the pipeline diameter is 50 mm lower than the one of the reference case.

Case 2c - Hydrogen rich gas storage			
CO_2 pipeline characteristics			
		Reference plant	**Flexible plant**
CO_2 flowrate	kg/h	626,354	513,610
Inlet pressure	barg	110	110
Inlet temperature	°C	20	20
Outlet pressure	bar	92.8	89.7
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	500	450

4.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost decrease of 5.5%.

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 105,000 €/km, i.e. about 5% lower than the reference case. Therefore, an additional cost 10 M€ is expected for the pipeline by considering an overall length of 100 km.

These cost figures do not include cost for hydrogen storage, which depends both on the storage type (natural reservoir or mined cavern) and whether it is constant-pressure or variable-pressure storage (refer to Section D – Attachment 1 for further information). From literature data, it can be derived that the expected cost for the hydrogen storage of these IGCCs plant may vary from 10 M€ to 50 M€, corresponding to about 2.8% of the overall plant cost.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 17 May 2011
Rev. : 0

CASE 2c - Hydrogen storage

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	9,270,000	171,900,000	143,190,000	42,070,000	38,730,000	27,460,000	26,390,000	428,579,000	113,650,000	1,001,239,000	
2	CONSTRUCTION	1,650,000	68,710,000	37,180,000	18,540,000	16,080,000	10,980,000	5,870,000	96,345,000	55,520,000	310,875,000	
3	OTHER COSTS	890,000	24,600,000	6,930,000	11,000,000	17,350,000	3,670,000	1,260,000	37,641,000	10,850,000	114,191,000	
4	EPC SERVICES	1,190,000	51,460,000	20,060,000	11,070,000	7,830,000	3,530,000	1,580,000	26,993,000	19,440,000	143,153,000	
	TOTAL INSTALLED COST	13,000,000	316,670,000	207,360,000	82,680,000	79,990,000	45,640,000	35,100,000	589,558,000	199,460,000	1,569,458,000	
5	CONTINGENCY	900,000	22,200,000	10,400,000	5,800,000	5,600,000	3,200,000	1,800,000	41,300,000	10,000,000	101,200,000	
6	LICENSE FEES	300,000	6,300,000	4,100,000	1,700,000	1,600,000	900,000	700,000	11,800,000	4,000,000	31,400,000	
7	OWNER COSTS	700,000	15,800,000	10,400,000	4,100,000	4,000,000	2,300,000	1,800,000	29,500,000	10,000,000	78,600,000	
	TOTAL INVESTMENT COST	14,900,000	360,970,000	232,260,000	94,280,000	91,190,000	52,040,000	39,400,000	672,158,000	223,460,000	1,780,658,000	

4.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	2c	
Description	H_2 storage	
Fixed costs		
Maintenance	57.3	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	31.4	
Total fixed cost, M€/y	98.6	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	11	11
Chemicals and solvents	286	286
Catalysts	134	134
Total variable cost, €/h	297	297

5 Case 2d – Venting CO_2

5.1 Introduction

This Case 2d shows how IGCC's with pre-combustion capture of the CO_2 can be also maintained in continuous operation without making the capture and compression of the carbon dioxide for transportation outside plant battery limits.

Depending on possible CO_2 emission allowances cost, this operating flexibility may improve the economics of the plant, because of its resulting higher power production, as shown in the following sections.

5.2 Case description

Unlike the post combustion CO_2 capture processes, the Acid Gas Removal Unit cannot be shut down because in IGCC plants it is necessary to remove at least the H_2S from the syngas, before combustion in the Gas Turbine, to meet the design environmental emission limits.
However, it is possible to tune to a certain extent the CO_2 capture rate, and consequently the plant net power output, varying the solvent circulation flowrate in the AGR unit, in order to absorb completely the H_2S while only part of the CO_2. With this strategy, the capture rate range to which is possible to operate is limited by the both the AGR design and the gas turbine flexibility to accept a variable fuel composition.

In the plant configuration assessed for this case, it has been considered an AGR unit that continues making the capture of the CO_2 from the syngas: part of it acts as diluent in the gas turbine for the reduction of NOx emissions and power augmentation, while the remainder part is vented, thus saving the CO_2 compressor power demand.

Considering the Acid Gas Removal unit of the reference case, based on a Selexol physical solvent washing, there are three streams of the captured CO_2 at different pressure and composition. The stream at the highest pressure can be fed to the gas turbine, without any further compression. The CO_2 stream from the low pressure flash drum (11 bar) can also be injected in the gas turbine's combustor, after adequate compression. The CO_2 stream from the last flash drum, slightly above the atmospheric pressure, shall be vented.

It is noted that not all the CO_2 from the AGR can be re-used as diluent for the gas turbines to respect the maximum range variation of fuel properties (e.g. LHV, Wobbe index) as tolerated by the machine. Furthermore, some CO_2 is at lower pressure than the nitrogen available from the ASU, thus making the carbon dioxide compression not economically advantageous.

This solution also allows reducing the power demand of the compression unit. However, it is noted that the content of toxic components, in particular H_2S and CO, does not allow the direct vent of the low pressure stream to the atmosphere. To overcome this problem, the following two alternatives have been considered:

- Scenario 1: Different AGR unit design, to meet minimum H_2S and CO specification for direct venting of the stream.
- Scenario 2: Treatment and purification of the CO_2 in a system downstream the AGR unit, without changing the design of the reference case.

In both the scenarios, the nitrogen compressors in the ASU trains are operated at part load, leading to a reduction of the power demand.

5.2.1 Scenario 1: modified AGR unit design

With respect to the AGR design selected for the reference plant, the Selexol unit to be installed in this case shall be capable to operate either capturing or venting part of the CO_2 contained in the entering fuel. The major design changes of this configuration are the following:

- Increased H_2S absorber height and additional solvent chiller to meet the H_2S specification in the CO_2 vent stream.
- Additional CO_2 flash drum and recycle compressor to remove enough CO and meet CO_2 vent stream specification.

As a consequence, these modifications lead to a higher investment cost and a higher steam and power consumptions of the unit, also when the plant is making the full capture of the CO_2 for delivery to plant battery limits.

5.2.2 Scenario 2: additional purification system

The main drawback for venting the CO_2 stream from the AGR is that the content of H_2S in the stream is higher than 100 ppmv, while the benchmark limit value is assumed to be 5 ppmv.

Several purification methods, based on sulphur absorption on catalyst bed, are proposed by specialised vendors, to meet the H_2S specification in the venting stream. Depending on the catalyst proposed by different vendors, the absorption could be at high or low temperature. The preheating of the feed stream required in case of

catalyst operating at 300-400°C leads to an additional steam or fuel consumption, thus affecting the overall plant performance.
The use of activated carbon catalyst bed requires the injection of small amount of water and oxygen in the feed stream. No impact is expected on the ASU capacity, as the oxygen content required in the feed stream is around 100-200 ppm.

The main disadvantage of all these alternatives based on the H_2S absorption on catalyst bed is the compression of the CO_2 vent stream up to at least 20 bar, as required by the upstream purification treatment.
In fact, lower pressure of the feed stream leads to excessive volumes of the reactors, and, consequently, of the catalyst required for the purification treatment.
Hence, the CO_2 streams from flash drums are compressed up to the second stage compressor outlet pressure, i.e. 26-27 barg.

In addition, other impurities in the CO_2 stream, as hydrogen and reducing compound like carbon monoxide, may poison the catalyst, affecting the adsorption performance and lowering the bed life.

To reduce also the CO and H_2 content in the CO_2 vent stream, an additional treatment is required, based on the catalytic oxidation of these components. As for the H_2S removal, the required amount of oxygen does not have an impact on the ASU capacity. However, the catalyst required for this purification treatment, typically based on platinum, can be poisoned by sulphur contaminants in the feeding stream.

5.3 Utility consumption

The most relevant utility requirements for the two Scenarios of this case are shown in the following sections.

5.3.1 Scenario 1: modified AGR unit design

The following variation range of the AGR utility consumption is expected with respect to the reference case configuration, if the Selexol is modified to produce a CO_2 stream that can be directly vented to the atmosphere:

- Steam consumption: +10 - 20%
- Cooling water consumption: +10%
- Power consumption: +10 - 20%.

These changes affect the performance of the plant during normal operation, when full CO_2 capture is made for delivery to plant battery limits, as well as when CO_2 is vented to atmosphere.

When CO_2 is vented, water and power consumptions of the compression unit are avoided, except for the power demand of the compressor of the low pressure CO_2 stream injected in the gas turbine for NOx control and power augmentation. ASU power demand is reduced of about 12-14%, as the nitrogen compressor is operated at partial load.

5.3.2 Scenario 2: additional purification system

No changes in the utility consumption during normal operation are expected with respect to the reference case.

When CO_2 is vented, the water and power consumptions of the compression unit are reduced of about 40-50% with respect to the normal operation, as the CO_2 vent stream has to be compressed before the purification treatment. ASU power demand is reduced of about 12-14% as the nitrogen compressor is operated at partial load.
Depending on the purification system selected, an additional consumption of steam or fuel gas could be expected.

5.4 Performance

The overall plant performances for the two assessed scenarios of this case are shown in the following sections.

5.4.1 Scenario 1: modified AGR unit design

As for the increased utility consumptions of the AGR unit, it is estimated a reduction of the net power output between 10-15 MWe with respect to the reference case, while capturing the CO_2, leading to an expected net electrical efficiency of 31.1% vs. 31.4% of the reference case.

In case of venting the CO_2, the plant net power output is expected to be around 55 MWe higher than the base case with full capture and compression the CO_2, due to the reduction of the internal power demand, leading to an expected net electrical efficiency of 33.5%

5.4.2 Scenario 2: additional purification system

No changes in the plant performances during normal operation are expected with respect to the reference case.

In case of venting the CO_2, the plant net power output is expected to be around 30-35 MWe higher than the reference case, due to the reduction of the internal power demand, leading to an expected net electrical efficiency of 32.2%

Case 2d - Scenario 1 - CO_2 venting				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	with CCS	without CCS
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	323.1
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**2321.8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	1637.9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	1488.4
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	563.2
Steam turbine power output	MWe	398.0	396.4	396.4
Expander power output	MWe	11.2	11.2	11.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**970.8**	**970.8**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	128.6	111.9
Process Units consumption	MWe	50.8	56.7	56.7
Utility Units consumption	MWe	1.7	1.7	1.7
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	10.2
Power Islands consumption	MWe	12.2	12.2	12.2
CO2 compression for syngas dilution	MWe	-	-	1.2
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**209.4**	**193.9**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**761.4**	**776.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.8**	**41.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**32.8**	**33.5**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5	0.0
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**248.4**	**193.9**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**722.4**	**776.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.8**	**41.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**31.1**	**33.5**

CO_2 emission	**kg/s**	**30.93**	**30.93**	**167.26**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.154**	**0.775**

Case 2d - Scenario 2 - CO_2 venting			
OVERALL PERFORMANCES OF THE IGCC COMPLEX			
		Reference case with CCS	without CCS
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4
Syngas treatment efficiency (F/E*100)	%	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2
Steam turbine power output	MWe	398.0	398.0
Expander power output	MWe	11.2	11.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**972.4**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION			
ASU power consumption	MWe	128.6	111.9
Process Units consumption	MWe	50.8	50.8
Utility Units consumption	MWe	1.7	1.7
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2
Power Islands consumption	MWe	12.2	12.2
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**186.8**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**785.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**33.8**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION			
Additional consumption			
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**225.8**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**746.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**32.2**

CO_2 emission	**kg/s**	**30.93**	**167.26**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.775**

5.5 Equipment list

For Scenario 1, the Selexol unit has to be modified as described in previous section, in order to produce a CO_2 stream that can be directly vented to atmosphere. No other relevant changes in the plant configuration are expected.

For Scenario 2, the main impact on plant design is the additional purification systems of the low pressure CO_2 stream.

5.6 Investment cost

For Scenario 1, the changes in the AGR design lead to an increase of the investment cost of 10% with respect to the AGR unit of the reference case. With respect to the figures included in Section E for the reference plant, this case shows a total investment cost variation of 10 M€, corresponding to the 0.5% of the reference case.

For Scenario 2, the additional facilities for the treatment of the CO_2 stream vented to atmosphere lead to an increase of the plant investment cost in the range of 17-30 M€ in the with respect to the reference case.

6 Case 2e – Constant CO_2 flowrate in transport pipeline

6.1 Introduction

The cycling operation of the power plant, required to meet the variable grid demand, leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating conditions in the pipeline. As a consequence, a two-phase flow or a significant change of the physical properties could occur in the pipeline, if pressure and temperature were not maintained close to the conditions of the capture plant. Furthermore, for some applications like the Enhanced Oil Recovery (EOR) it would be preferred to have a constant flowrate rather than a fluctuating stream.

This Case 2e assesses the introduction in the power plant of a properly designed CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, thus avoiding pressure fluctuations and consequent possible changes of the CO_2 physical state.

In this configuration a constant CO_2 flowrate lower than peak production, when the plant is operated at base load, is sent to the external pipeline; therefore, it is possible to select a lower pipeline size, leading to a possible significant cost saving. For this reason, a comparison between the additional costs of a buffer storage versus the saved cost of a larger pipeline is also made in this Case 2e.

6.2 Case description

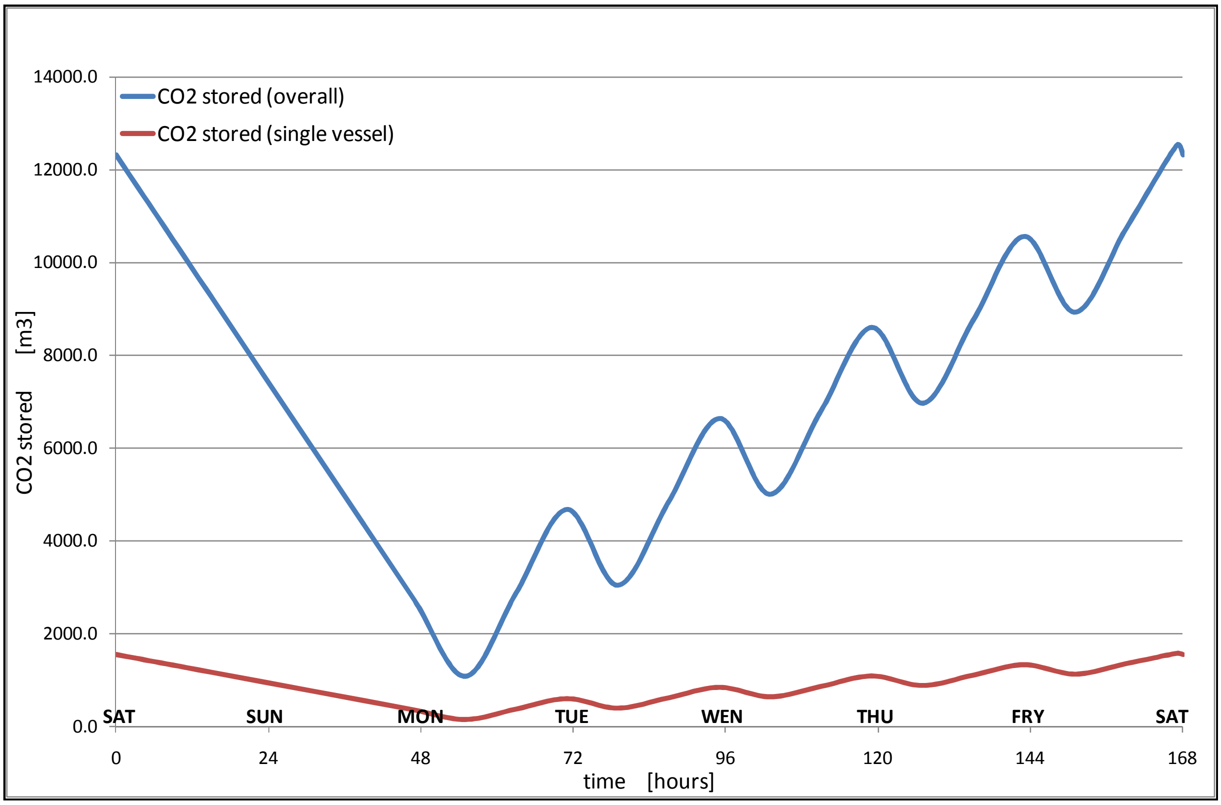
The required CO_2 buffer storage volume is evaluated considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 1. This means that the IGCC is operated at base load for 80 hours per week, while during the remaining 88 hours the plant is called to generate 50% of its overall net power production capacity.

Despite the other alternatives assessed in this section, there are no additional power consumptions due to the hydrogen production or the different loads of the ASU, so the 50% power generation can be ensured by keeping one gas turbine only in operation, whilst being fed by upstream process units that are generally running at their minimum turndown (50%).

The constant CO_2 flow in the pipeline is a consequence of the balance of the CO_2 flowrate from and to the storage system during the whole week of operation, made to avoid any accumulation in the buffer vessels and resulting in about 74% of the CO_2 captured when the plant is operated at its maximum capacity.

Figure 6.2-1 shows the whole volume of stored CO_2 during the week and the single vessel volume trend (eight vessels in total are considered). The required net volume of the storage vessels is the difference between the maximum and the minimum volume of stored CO_2 during the week. From the graph, it can be drawn that it corresponds to the CO_2 accumulated during the weekdays and mainly discharged during the partial load operation from Friday night to Monday morning.

Figure 6.2-1: Case 2e – Stored CO_2 volume during the week



The CO_2 is stored, in liquid phase, at 85 bar and 20°C, i.e. above its critical pressure and below its critical temperature. Storing and maintaining the CO_2 in liquid form below its critical pressure is not a concern for the reference design ambient conditions of the study (i.e. Tamb.=9°C, T sea cooling water =12°C); however, it is noted that this could be more critical in countries characterized by average warmer climates.

Therefore, the size and configuration of the CO_2 compression unit are also modified, to allow storing the CO_2 at these conditions. The CO_2 stream leaves the last stage compressor at 85 bar, instead of 110 barg, and it is cooled down in the existing cooling water cooler to drop down the temperature below its critical value. The cold CO_2 stream is sent to the dedicated buffer storage vessels, while a constant flow is pumped from the vessels to the pipeline by means of properly designed pumps.

6.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2e - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**21.5**						**21.5**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**423.6**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**165.8**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME	
PROJECT:	Operating Flexibility of Power Plants with CCS	
LOCATION:	Netherlands	
FWI Nº:	1- BD 0530 A	

REVISION	Draft	Rev.1	Rev.2
DATE	feb-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2e - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	2.5 (2)								2.5	
2100	**Air Separation Unit**			10.8						10.8	
2200	**Syngas Treating and Conditioning Line**	-26.3	-60.8	-264.2	-10.2	26.5	61.4	266.8	36.5	25.9	3.9
2300	**Acid Gas Removal**			36.2						36.2	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		-0.7	-0.6			2.2	0.6		1.5	0.0
3000	**POWER ISLANDS UNITS**	23.7	61.4	205.8	10.2	-26.5	-63.6	-267.4	-36.5		
4000 to 5300	**UTILITY and OFFSITE UNITS**			12.0						12.0	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.9	3.9

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2e - Peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**283.0**		**3122**	
2100	**Air Separation Unit**				**25682**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**3053**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**330**	
2500	**CO2 Compression and drying**				**6780**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			**1742**	
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**88003**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**14777**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE	**300.3**	**0**	**8611**	**135242**

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2e - Off-peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Gasification Section	141.5		1561	
2100	Air Separation Unit				12841
2200	Syngas treatment and conditioning line			0	
2300	Acid Gas Removal			1527	
2400	Sulphur Recovery (SRU)- Tail gas treatment (TGT)			165	
2500	CO2 Compression and drying				3390
	POWER ISLANDS UNITS				
3100/3400	Gas Turbines and Generator auxiliaries			852	
3200	Heat Recovery Steam Generator				
3300/3400	Steam Turbine and Generator auxiliaries		11.7		38673
3500	Miscellanea				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	Cooling Water (Sea Water / Machinery Water)				7661
4200	Demineralized/Condensate Recovery/Plant and Potable Water Systems	17.3	-15.7		
	Other Units		4.0	364	
	BALANCE	158.8	0	4469	62564

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2e - Peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**128637**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**36170**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4769**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2158**
3500	**Miscellanea**	**598**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**240198**

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	mar-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2e - Off-peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**180**
1000	**Gasification Section**	**6962**
2100	**Air Separation Unit**	**65558**
2200	**Syngas treatment and conditioning line**	**126**
2300	**Acid Gas Removal**	**16522**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**1777**
2500	**CO2 Compression and drying**	**18420**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2353**
3200	**Heat Recovery Steam Generator**	**2332**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1022**
3500	**Miscellanea**	**292**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**5813**
	Additional consumption including CO_2 compression and drying	**250**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**122696**

6.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following table.

Case 2e - CO_2 buffer storage				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	161.6
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**1160.9**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	818.95
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	744.2
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	281.6
Steam turbine power output	MWe	398.0	398.0	188.5
Expander power output	MWe	11.2	11.2	5.6
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**972.4**	**475.7**
IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	128.6	65.6
Process Units consumption	MWe	50.8	50.8	25.4
Utility Units consumption	MWe	1.7	1.7	1.4
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	5.7
Power Islands consumption	MWe	12.2	12.2	6.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**203.5**	**104.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**768.9**	**371.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**	**41.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**33.1**	**32.0**
IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	36.2	18.4
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**240.2**	**122.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**732.2**	**353.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**	**41.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**31.5**	**30.4**
CO_2 emission	**kg/s**	**30.93**	**30.93**	**15.46**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.152**	**0.158**

6.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant, in order to avoid the flowrate fluctuations in the CO_2 pipeline in relation to the flexible operation of the plant.

Case 2e - CO_2 buffer storage

UNIT 2500 - CO2 compression - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
CO2 buffer storage vessel	not foreseen	8 x 1'600 m3 (Diameter: 8.8 m, H: 26.4 m)	Nitrogen blanketed vessel Material: SS
CO2 compressor - 3rd stage	2 x 8 MWe β = 3.93 Flow = 165'000 Nm3/h each Vol. flow = 5'400 m3 each	2 x 6.5 MWe β = 3.0 Flow = 165'000 Nm3/h each Vol. flow = 5'400 m3 each	
CO_2 pump	not foreseen	4 x 355 kW 320 m3 x 400 m each	Two operating, two spare

Note: The number of equipment is referred to both trains

6.5.1 CO_2 pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 2e. It can be drawn that with a plant designed to provide a constant CO_2 flowrate to the pipeline, despite the cyclic operation of the plant, the pipeline diameter is 50 mm lower than the one of the reference case.

Case 2e - CO_2 buffer storage

CO_2 pipeline characteristics

		Reference plant	Flexible plant
CO_2 flowrate	kg/h	626,354	462,309
Inlet pressure	barg	110	110
Inlet temperature	°C	20	20
Outlet pressure	bar	92.8	93.8
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	500	450

6.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of nearly 2%.

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 105,000 €/km, i.e. about 5% lower than the reference case. Therefore, depending on the overall length, the investment increase of the plant may be offset by the lower cost of the pipeline. For this alternative, the plant investment cost is expected to be 30 M€ higher than the reference case, while a cost saving of 10 M€ is expected for the pipeline by considering an overall length of 100 km.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 16 May 2011
Rev. : 0

CASE 2e - CO2 buffer storage

cost code	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	135,003,000	47,339,000	43,594,000	30,917,000	51,006,000	438,499,000	122,195,000	1,072,561,000	
2	CONSTRUCTION	1,853,000	77,366,000	35,971,000	20,857,000	18,091,000	12,357,000	12,000,000	97,365,000	59,691,000	335,551,000	
3	OTHER COSTS	996,000	27,699,000	5,151,000	12,376,000	19,528,000	4,129,000	1,571,000	41,831,000	11,656,000	124,937,000	
4	EPC SERVICES	1,338,000	57,945,000	17,320,000	12,456,000	8,810,000	3,966,000	2,002,000	30,003,000	20,902,000	154,742,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	193,445,000	93,028,000	90,023,000	51,369,000	66,579,000	607,698,000	214,444,000	1,687,791,000	
5	CONTINGENCY	1,000,000	25,000,000	9,700,000	6,500,000	6,300,000	3,600,000	3,300,000	42,500,000	10,700,000	108,600,000	
6	LICENSE FEES	300,000	7,100,000	3,900,000	1,900,000	1,800,000	1,000,000	1,300,000	12,200,000	4,300,000	33,800,000	
7	OWNER COSTS	700,000	17,800,000	9,700,000	4,700,000	4,500,000	2,600,000	3,300,000	30,400,000	10,700,000	84,400,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	216,745,000	106,128,000	102,623,000	58,569,000	74,479,000	692,798,000	240,144,000	1,914,591,000	

6.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**2e**	
Description	CO_2 buffer storage	
Fixed costs		
Maintenance	61.6	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	33.8	
Total fixed cost, M€/y	105.3	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	13	7
Chemicals and solvents	349	175
Catalysts	134	134
Total variable cost, €/h	362	181

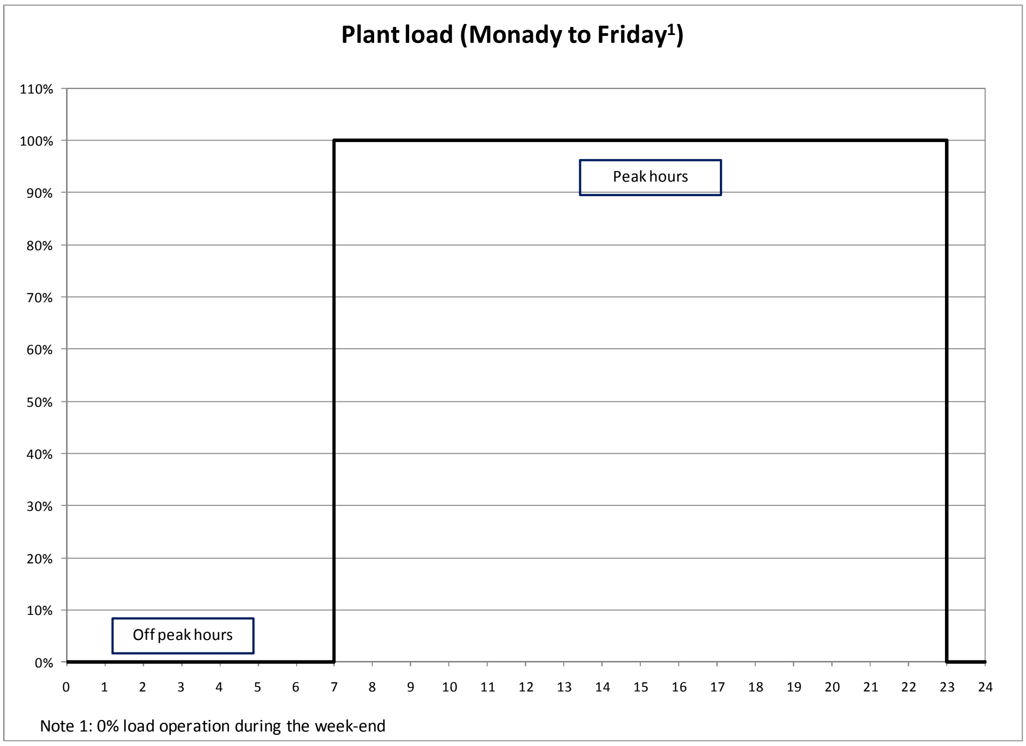
7 Case 2f – Fuel storage with an alternate demand curve

7.1 Introduction

This Case 2f is based on the assumption that the IGCC will be requested to operate at base load during weekday day time, corresponding to 80 hours per week, while no power should be exported to the grid in the remaining 88 hours, i.e. during weekday night time and weekend (refer to Figure 7.1-1). Moreover, during the non-power production time the syngas line has to be operated constantly at base load, so a significant amount of power and steam/water are still required by the process units from the power island.

Based on the above, the ideal operating mode of the combined cycle during the non-power production hours is the islanding mode, i.e. at the minimum load required to satisfy the internal demands of the IGCC only. However, it has been estimated that this operation is constrained by the minimum environmental load of the gas turbine, which is higher than the load required for islanding operation, so a certain amount of power is still exported to the grid during off-peak hours.

Figure 7.1-1: IGCC plant load operation



It is also noted that, to maintain the syngas production line at base load during the non-power production hours, an intermediate storage of de-carbonised fuel gas has to be considered in the plant design. In fact, part of the hydrogen rich gas from the CO_2 removal is fed to the storage during no electricity demand periods, while it is used during electricity peak demand. As a consequence, the gasification and the other main process unit capacity can be reduced, because syngas from the process units is integrated with the de-carbonised fuel from the storage, in order to meet the thermal requirement of the two gas turbines in the power island.

7.2 Case description

This case is assessed on a whole week of plant operation, based on the grid demand cycling trend described in the previous section. From this trend, during *high electricity demand period* the power island is operated with the two gas turbines at base load, while the hydrogen rich gas from the AGR unit is integrated with the fuel coming from the intermediate storage.

During *low electricity demand period*, the power island is operated with one gas turbine at its minimum environmental load, which is 60% of the base load, corresponding to approximately 66% of the fuel requirement. As the syngas production units are maintained constantly at base load, part of the de-carbonised fuel is used for electricity generation by the gas turbines, while the remainder flowrate is sent to an underground storage system, at a pressure higher than 50 bar.
With this operating configuration, the combined cycle power output exceeds the internal consumption of the plant, so the IGCC is not operated in islanding mode as required by the electricity market. However, it is noted that the island mode operation is technically feasible in principle, because to have no power export to the electrical grid the gas turbine load could be increased and the steam turbine fully bypassed, but this would lead to a significant loss of power production.

Fuel gas from and to the storage system has to be balanced during the cyclic weekly operation, in order to avoid any accumulation of fuel. The need of balancing the fuel gas fixes the design capacity of the whole syngas generation line, which results in 65% of the reference case.

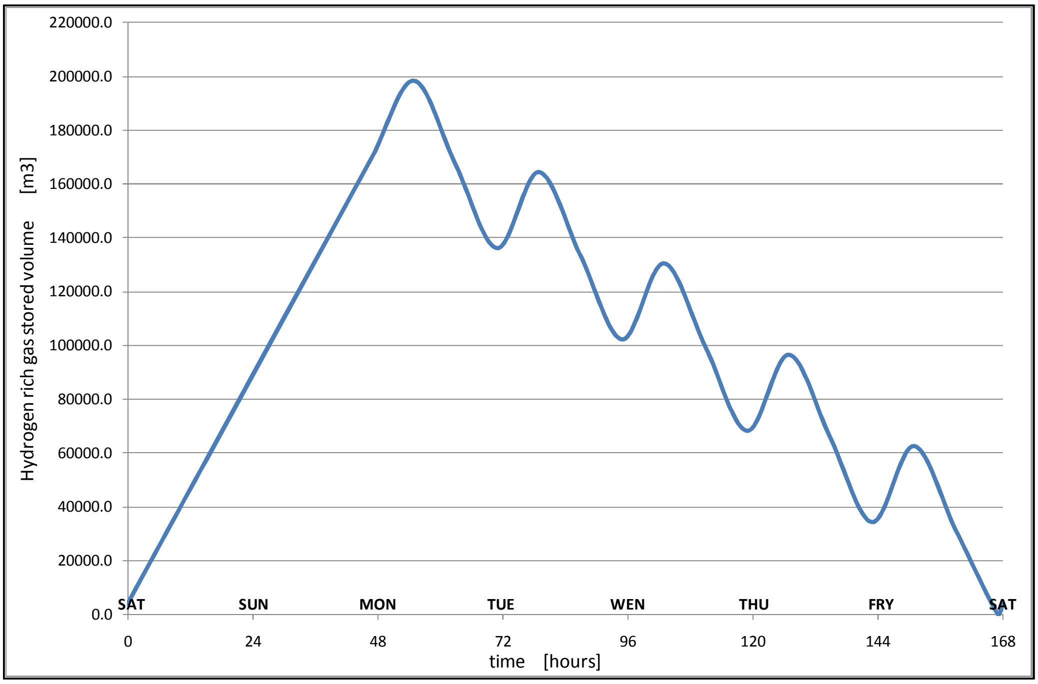
It is noted that, as the ASU and the power trains are maintained at different loads during the cyclic operation, the air integration between the ASU and the gas turbines may potentially represent a constraint for the flexible operation of the IGCC. In this case, an additional main air compressor has been considered for operation during off-peak hours, as the air extracted from the gas turbines, operated at part load, is significantly lower than the amount required by the air separation unit, operated at base load.

7.2.1 Hydrogen rich gas storage

Stored hydrogen rich gas, required during peak demand period, is balanced by the excess of production during off-peak hours, considering a whole week of plant operation. Therefore, the hydrogen rich gas required from storage during the 80 hours per week of peak load operation, when the power island is operated at base load, is balanced by the product stored during the 88 hours per week of off-peak load operation, when one gas turbine is operated at its minimum environmental load.

Figure 7.2-1 shows the volume of stored hydrogen rich gas during the week. From the graph, it can be drawn that a storage volume of about 100,000 m^3 is required for this alternative, leading to the selection of an underground storage, rather than the storage in vessels.

Figure 7.2-1: Case 2f – Stored fuel volume during the week



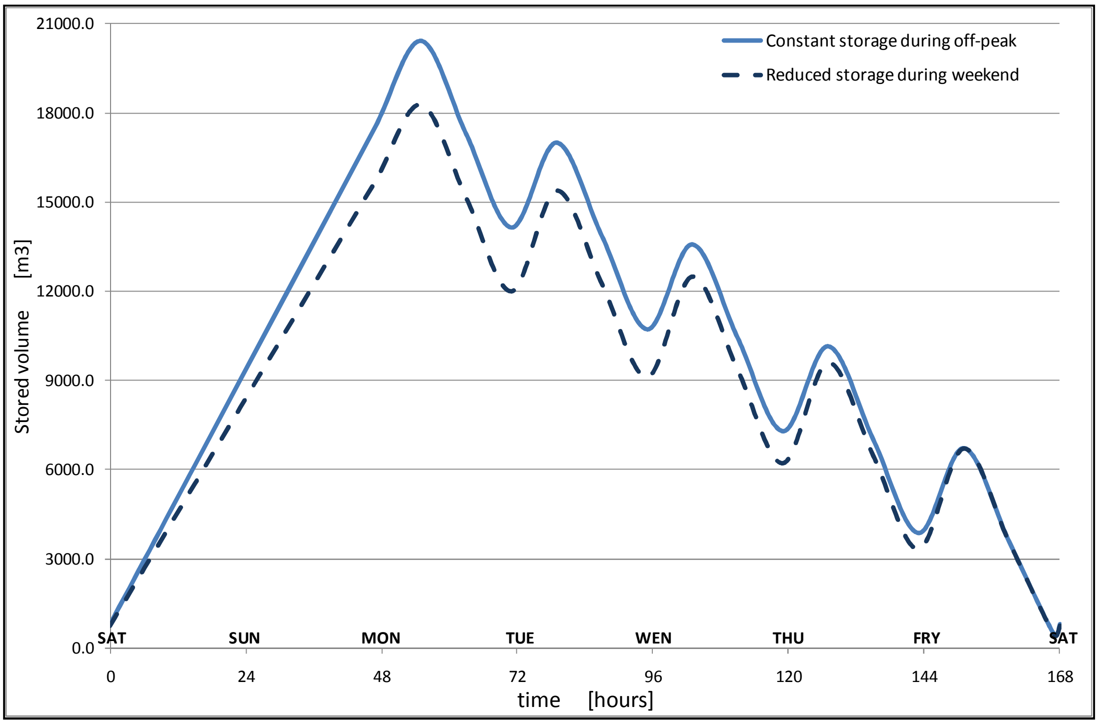
7.2.2 Nitrogen storage

As the ASU capacity is reduced in accordance to the lower size of the gasification island, during peak demand period the nitrogen from the ASU shall be integrated with the nitrogen from the storage.

This stream is balanced by the higher production during off-peak hours, considering a whole week of plant operation. Therefore, the nitrogen required from storage during the 80 hours per week of peak load operation, when the power island is operated at base load, is balanced by the product stored during the 88 hours per week of off-peak load operation, when one gas turbine is operated at its minimum environmental load.

Figure 7.2-2 shows two different trends of the stored nitrogen during the week, for this case. The solid line corresponds to the stored volume if the nitrogen flowrate to storage is maintained constant during the hours of off-peak operation. The flowrate depends on the quantity required during peak load operation, while the excess is vented.
However, it is possible to reduce the storage size of the nitrogen by maximizing the nitrogen stored during the nights of the working days (i.e. without venting nitrogen), while storing a constant flow during the week-end (refer to the dashed line in the graph).
A minimum nitrogen storage volume corresponding to 12 hours for blanketing and purging and 4 minutes for turbine injection or fuel dilution have been also considered while defining the tank size.

Figure 7.2-2: Case 2f – Stored nitrogen volume during the week



7.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

CLIENT:	IEA GHG R&D PROGRAMME	REVISION	Draft	Rev.1	Rev.2
PROJECT:	Operating Flexibility of Power Plants with CCS	DATE	Sep-11		
LOCATION:	Netherlands	ISSUED BY	NF		
FWI Nº:	1- BD 0530 A	CHECKED BY	PC		
		APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2f - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.3** (2)								**3.3**	
2100	**Air Separation Unit**			**36.1**						**36.1**	
2200	**Syngas Treating and Conditioning Line**	**-34.2**	**-79.0**	**-343.4**	**-13.3**	**34.5**	**79.8**	**346.8**	**47.5**	**33.7**	**5.0**
2300	**Acid Gas Removal**			**47.0**						**47.0**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.8**			**2.9**	**0.8**		**2.0**	**0.0**
3000	**POWER ISLANDS UNITS**	**30.9**	**79.8**	**249.1**	**13.3**	**-34.5**	**-82.6**	**-347.6**	**-47.5**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**134.1**	**5.1**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	Sep-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2f - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.3** (2)								**3.3**	
2100	**Air Separation Unit**			**14.0**						**14.0**	
2200	**Syngas Treating and Conditioning Line**	**-34.2**	**-79.0**	**-343.4**	**-13.3**	**34.5**	**79.8**	**346.8**	**47.5**	**33.7**	**5.0**
2300	**Acid Gas Removal**			**47.0**						**47.0**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.8**			**2.9**	**0.8**		**2.0**	**0.0**
3000	**POWER ISLANDS UNITS**	**30.9**	**79.8**	**271.2**	**13.3**	**-34.5**	**-82.6**	**-347.6**	**-47.5**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**112.0**	**5.1**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	Operating Flexibility of Power Plants with CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: Draft
Sep-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2f - Peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**184.0**		**2029**	
2100	**Air Separation Unit**				**16693**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**1984**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**215**	
2500	**CO2 Compression and drying**				**4407**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			**1645**	
3300/3400	**Steam Turbine and Generator auxiliaries**		**12**		**70815**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**10474**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**237**	
	BALANCE	**201.2**	**0**	**6110**	**102389**

Note: (1) Minus prior to figure means figure is generated

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	PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

WATER CONSUMPTION SUMMARY - GEE IGCC - Case 2f - Off-peak time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**184.0**		**2029**	
2100	**Air Separation Unit**				**16693**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**1984**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**215**	
2500	**CO2 Compression and drying**				**4407**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			**574**	
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**28326**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**8639**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**237**	
	BALANCE	**201.2**	**0**	**5039**	**58065**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2f - Peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**235**
1000	**Gasification Section**	**9050**
2100	**Air Separation Unit**	**65600**
2200	**Syngas treatment and conditioning line**	**164**
2300	**Acid Gas Removal**	**21479**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2311**
2500	**CO2 Compression and drying**	**25025**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4503**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1867**
3500	**Miscellanea**	**564**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**8166**
	Additional consumption including CO_2 compression and drying	**325**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**239**
	Other Units	**467**
	BALANCE	**144702**

Notes: (1) Minus prior to figure means figure is generated

	CLIENT: IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT: Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION: Netherlands	ISSUED BY: NF
	FWI Nº: 1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2f - Off-peak time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**235**
1000	**Gasification Section**	**9050**
2100	**Air Separation Unit**	**123600**
2200	**Syngas treatment and conditioning line**	**164**
2300	**Acid Gas Removal**	**21479**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2311**
2500	**CO2 Compression and drying**	**25025**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**1437**
3200	**Heat Recovery Steam Generator**	**1572**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**786**
3500	**Miscellanea**	**197**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**4599**
	Additional consumption including CO_2 compression and drying	**325**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**239**
	Other Units	**467**
	BALANCE	**191486**

Notes: (1) Minus prior to figure means figure is generated

7.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following table. During high electricity demand period, the net plant power output is about 45 MWe higher than the reference plant, while during low electricity demand period the IGCC plant still exports approximately 130 MWe to the electrical grid.

Case 2f - Hydrogen storage - CC in island mode during off-peak				
OVERALL PERFORMANCES OF THE IGCC COMPLEX				
		Reference case	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	210.0	210.0
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**1509.2**	**1509.2**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1064.6	1064.6
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	493.9
Thermal Power of Clean Syngas from syngas cooling (based on LHV) (G)	MWt	1488.4	967.5	967.5
Thermal Power of Clean Syngas from storage (based on LHV) (H)	MWt		520.9	-473.6
Syngas treatment efficiency (G/E*100)	%	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	171.9
Steam turbine power output	MWe	398.0	344.4	145.0
Expander power output	MWe	11.2	11.2	3.7
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**918.8**	**320.6**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION				
ASU power consumption	MWe	128.6	65.6	123.6
Process Units consumption	MWe	50.8	33.0	33.0
Utility Units consumption	MWe	1.7	1.1	1.1
Offsite Units consumption (including sea cooling water system)	MWe	10.2	8.0	4.4
Power Islands consumption	MWe	12.2	11.6	4.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**119.3**	**166.1**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**799.5**	**154.5**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION				
Additional consumption				
Unit 2500: CO_2 Compression and Drying	MWe	38.5	25.0	25.0
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.3	0.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**144.7**	**191.5**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**774.1**	**129.1**

CO_2 emission	**kg/s**	**30.93**	**30.93**	**10.26**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.144**	**0.286**

7.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant.

Case 2f - Hydrogen storage - CC in island mode during off-peak

Process unit

Unit	Reference plant	Flexible plant	Remarks
Unit 1000 - Gasification island	Coal inlet flow = 323 t/h	Coal inlet flow = 210 t/h	
Unit 2200 - Syngas treatment	Syngas inlet flow = 694 t/h	Syngas inlet flow = 450 t/h	
Unit 2300 - AGR	Syngas inlet flow = 776 t/h	Syngas inlet flow = 505 t/h	
Unit 2400 - SRU	Acid gas inlet flow = 485 kmol/h	Acid gas inlet flow = 315 kmol/h	
Unit 2500 - CO2 compressor (2x50%)	CO2 flow = 165,000 Nm3/h each	CO2 flow = 110,000 Nm3/h each	

UNIT 2100 - Air Separation Unit - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
Air Separation Unit Package (two parallel trains, each sized for 50% of the capacity)	HP O2 flow rate to Gasifier = 290 t/h MP N2 flow rate to GTs = 900 t/h LP N2 flow rate to Proc Unit = 2.7 t/h Air flow rate from GTs = 620 t/h	HP O2 flow rate to Gasifier = 288.5 t/h MP N2 flow rate to GTs = 710 t/h LP N2 flow rate to Proc Unit = 1.6 t/h Air flow rate from GTs = 620 t/h	
Main air compressor	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	2 x 10 MWe β = 15.8 Flow = 71'500 Nm3/h each Vol. flow = 74'000 m3 each	
Booster Air Compressor	2 x 2.4 MWe β = 1.5 Flow = 136'600 Nm3/h each Vol. flow = 9'000 m3 each	2 x 1.6 MWe β = 1.5 Flow = 89'000 Nm3/h each Vol. flow = 5'850 m3 each	
GAN	2 x 28 MWe β = 5.4 Flow = 360'000 Nm3/h each Vol. flow = 75'900 m3 each	2 x 24 MWe β = 5.4 Flow = 245'000 Nm3/h each Vol. flow = 51'700 m3 each	
Dilution Booster	2 x 0.7 MWe β = 1.2 Flow = 99'000 Nm3/h each Vol. flow = 3'860 m3 each	2 x 0.7 MWe β = 1.2 Flow = 99'000 Nm3/h each Vol. flow = 3'860 m3 each	
Additional main air compressor	not foreseen	2 x 32.1 MWe β = 15.8 Flow = 238'000 Nm3/h each Vol. flow = 246'400 m3 each	
ASU Heat Exchangers	16 services; duty = 12 MWth each; surface = 1000 m2 each	16 services; duty = 8 MWth each; surface = 650 m2 each	sea water coolers (tubes: titanium; shell: CS)
ASU chiller	5.2 MW th @ 5°C	3.5 MW th @ 5°C	
Nitrogen storage tank *(for flexible operation)*	1 x 140 m3 (Diameter: 3.0 m, H: 3.0 m)	2 x 9'700 m3 (Diameter: 31.1 m, H: 12.8 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -179°C

Note: The number of equipment is referred to both trains

Case 2f - Hydrogen storage - CC in island mode during off-peak			
Power Plant			
Unit	**Reference plant**	**Flexible plant**	**Remarks**
Unit 3300 - Steam turbine and condenser package	Steam turbine gross power output = 428 Mwe Condenser duty = 702 MWth	Steam turbine gross power output = 375 Mwe Condenser duty = 576 MWth	
Condensate pumps	2 x 475 kW 1220 m3/h x 100 m	2 x 425 kW 1110 m3/h x 100 m	One in operation, one spare
LP BFW pumps	4 x 132 kW 320 m3/h x 107 m	6 x 110 kW 275 m3/h x 107 m	Four in operation, two spare
MP BFW pumps	4 x 425 kW 175 m3/h x 540 m	4 x 450 kW 200 m3/h x 540 m	Two in operation, two spare

Offsite			
Unit	**Reference plant**	**Flexible plant**	**Remarks**
Hydrogen rich gas underground storage	not foreseen	- Working volume = 200'000 m3 - Underground storage system - Pressure = 50-55 bar	

7.5.1 CO_2 pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the “Upgraded calculator for CO_2 pipeline system” (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 2c. As the process unit, including the Acid Gas Removal Unit and consequently the CO_2 compression section are design for a lower capacity, the pipeline diameter is 50 mm lower than the one of the reference case.

Case 2f - Hydrogen storage - CC in island mode during off-peak

CO_2 pipeline characteristics

		Reference plant	Flexible plant
CO_2 flowrate	kg/h	626,354	407,130
Inlet pressure	barg	110	110
Inlet temperature	°C	20	20
Outlet pressure	bar	92.8	97.6
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	500	450

7.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost decrease of 12.5%

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 105,000 €/km, i.e. about 5% lower than the reference case. Therefore, an additional cost 10 M€ is expected for the pipeline by considering an overall length of 100 km.

These cost figures do not include cost for hydrogen storage, which depends both on the storage type (natural reservoir or mined cavern) and whether it is constant-pressure or variable-pressure storage (refer to Section D – Attachment 1 for further information). From literature data, it can be derived that the expected cost for the hydrogen storage of these IGCCs plant may vary from 20 M€ to 100 M€, corresponding to about 6% of the overall plant cost.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 07-ott-11
Rev. : 0

Case 2f - Hydrogen storage - CC in island mode during off-peak

COST CODE	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	8,060,000	149,510,000	131,760,000	36,510,000	33,690,000	23,870,000	23,340,000	420,979,000	105,090,000	932,809,000	
2	CONSTRUCTION	1,440,000	59,760,000	33,020,000	16,090,000	13,990,000	9,540,000	5,190,000	95,830,000	51,340,000	286,200,000	
3	OTHER COSTS	770,000	21,400,000	6,740,000	9,550,000	15,100,000	3,190,000	1,120,000	37,641,000	10,030,000	105,541,000	
4	EPC SERVICES	1,040,000	44,760,000	18,890,000	9,610,000	6,810,000	3,070,000	1,400,000	26,993,000	17,980,000	130,553,000	
	TOTAL INSTALLED COST	11,310,000	275,430,000	190,410,000	71,760,000	69,590,000	39,670,000	31,050,000	581,443,000	184,440,000	1,455,103,000	
5	CONTINGENCY	800,000	19,300,000	9,500,000	5,000,000	4,900,000	2,800,000	1,600,000	40,700,000	9,200,000	93,800,000	
6	LICENSE FEES	200,000	5,500,000	3,800,000	1,400,000	1,400,000	800,000	600,000	11,600,000	3,700,000	29,000,000	
7	OWNER COSTS	600,000	13,800,000	9,500,000	3,600,000	3,500,000	2,000,000	1,600,000	29,100,000	9,200,000	72,900,000	
	TOTAL INVESTMENT COST	12,910,000	314,030,000	213,210,000	81,760,000	79,390,000	45,270,000	34,850,000	662,843,000	206,540,000	1,650,803,000	

7.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	2f	
Description	H_2 storage	
Fixed costs		
Maintenance	53.1	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	29.1	
Total fixed cost, M€/y	92.2	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	9	9
Chemicals and solvents	227	227
Catalysts	134	134
Total variable cost, €/h	236	236

8 Case 2g – Daily LOX/LIN storage with an alternate demand curve

8.1 Introduction

This case is based on the assumption that the weekly demand curve is different from the one shown in Figure 1-1 and characterised by the following three different electricity demand periods:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (50% of net power output): night and weekend.

As discussed in Case 2a, the ASU significantly reduces the overall net electricity production of the plant, mainly due to its high auxiliary power demand. Therefore, by reducing the energy requirement of this unit, at least during peak-demand hours, it is possible to increase the overall net power and improve the overall economics of the plant.

In order to reduce the ASU internal consumption when the market requires a higher electricity generation, the ASU is operated at partial load, while the rest of the plant is running at full load and both the oxygen and the nitrogen required by the process units is taken from a purposely designed storage, sized to cover production fluctuations.

8.2 Case description

As described in the previous section, during normal and peak electricity demand the IGCC is operated at base load to maximise the electricity production, while during off-peak electricity demand the plant is required to produce 50% of the overall net electricity production capacity. However, it is noted that these operating modes have to be considered compatibly with the plant technical constraints, identified in section C and D of this report, like the minimum gasification turndown and the gas turbine minimum environmental load.

During peak demand period, both the oxygen and the nitrogen from the ASU are integrated with the oxygen and nitrogen coming from the liquid storages, after vaporisation. These flowrates are balanced by the production during night time, following a daily cycle operation and avoiding any accumulation of the stored product. Therefore, to define the tank size, the oxygen and nitrogen required for a flexible operation, i.e. the flow requirements for two hours of part load operation should be added to the minimum storage volume considered in the reference plant.

A minimum oxygen storage volume corresponding to 12 hours at the design oxygen flow of one ASU train has been considered to estimate the oxygen tank size, while the minimum storage volume considered for defining the nitrogen tank size corresponds to 12 hours for blanketing and purging and 4 minutes for turbine injection or fuel dilution.

It has to be noted that the integration between the Air Separation Unit and the gas turbine may potentially limit the flexible operation of the IGCC, in the operating modes where the ASU and the other units are maintained at different loads. In this case, an additional main air compressor shall be considered for the off-peak hours, as the air extracted from the gas turbine, operated at part load, is lower the amount required by the air separation unit, operated at higher load.

During *normal operation* the whole plant is operated at base load.

For the two hours of *peak electricity demand* the ASU is operated at its minimum load. Oxygen and nitrogen from the ASU are integrated with the oxygen and nitrogen coming from the liquid storages, after vaporisation. The minimum load is represented by the minimum technical load of the ASU cold box, i.e. around 50% of the design capacity, as written in section C of this report.

In this specific case, the integration between the gas turbines operation and the ASU is achieved at a level where 50% of the atmospheric air is compressed with self-standing units and the difference comes already pressurized from the compressors of both the gas turbines in the combined cycle. As a consequence, during peak demand period, the ASU main air compressors are shutdown and the whole amount of air required by the ASU to obtain the 50% oxygen production is derived from gas turbine compressors.

It has to be noted that, if the Air Separation Unit and the gas are not integrated, a dual train air compressors configuration for each of the two ASU trains has to be considered for increasing the flexibility of the plant. In fact, as the minimum efficient load of the compressors is around 70%, when the cold box is operated at 50% load, the main air compressors generally operate by introducing the air recycle system, with a significant impact on the power requirement, as the compressor is still running at high load.

During *off peak demand period* the process units operate at about 66% of the base load, corresponding to the operation of the two gas turbines at their minimum environmental load, and also to a net power output of approximately 50% of the normal production, as required by the grid during off-peak hours.

During weekday night time the ASU is required to operate at around 78% in order to store all the oxygen and nitrogen required during peak load operation, following a daily cycle operation. The product required from storage during the 2 hours per day of peak load operation, when the plant is operated at base load, is balanced by the product stored during the 8 night hours per day of off-peak load operation, when the plant is operated at partial load.

During weekend, both the process units and the ASU could be operated in order to feed two gas turbines at minimum load or a single gas turbine at base load, generating around 50% of the net power output.

It is noted that an additional air compressor, one per each of the two ASU trains, is required because the air extraction from the gas turbine compressor decreases when the GT is operated at part load.

8.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

CLIENT:	IEA GHG R&D PROGRAMME	REVISION	Draft	Rev.1	Rev.2
PROJECT:	Operating Flexibility of Power Plants with CCS	DATE	Sep-11		
LOCATION:	Netherlands	ISSUED BY	NF		
FWI Nº:	1- BD 0530 A	CHECKED BY	PC		
		APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2g - normal operation

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**5.1** (2)								**5.1**	
2100	**Air Separation Unit**			**21.5**						**21.5**	
2200	**Syngas Treating and Conditioning Line**	**-52.6**	**-121.5**	**-528.3**	**-20.5**	**53.1**	**122.7**	**533.6**	**73.1**	**51.8**	**7.7**
2300	**Acid Gas Removal**			**72.4**						**72.4**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1.3**	**-1.2**			**4.4**	**1.2**		**3.0**	**0.1**
3000	**POWER ISLANDS UNITS**	**47.5**	**122.8**	**423.6**	**20.5**	**-53.1**	**-127.1**	**-534.8**	**-73.1**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**165.8**	**7.8**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Operating Flexibility of Power Plants with CCS
LOCATION: Netherlands
FWI Nº: 1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	Sep-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2g - peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	5.1 (2)								5.1	
2100	**Air Separation Unit**			54.6						54.6	
2200	**Syngas Treating and Conditioning Line**	-52.6	-121.5	-528.3	-20.5	53.1	122.7	533.6	73.1	51.8	7.7
2300	**Acid Gas Removal**			72.4						72.4	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		-1.3	-1.2			4.4	1.2		3.0	0.1
3000	**POWER ISLANDS UNITS**	47.5	122.8	390.6	20.5	-53.1	-127.1	-534.8	-73.1		
4000 to 5300	**UTILITY and OFFSITE UNITS**			12.0						12.0	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.9	7.8

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	Operating Flexibility of Power Plants with CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

REVISION	Draft	Rev.1	Rev.2
DATE	Sep-11		
ISSUED BY	NF		
CHECKED BY	PC		
APPROVED BY	LM		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP with CO_2 capture, separate removal of H_2S and CO_2, Case 2g - off peak time

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS										
1000	**Gasification Section**	**3.3** (2)								**3.3**	
2100	**Air Separation Unit**			**14.1**						**14.1**	
2200	**Syngas Treating and Conditioning Line**	**-34.5**	**-79.7**	**-346.6**	**-13.4**	**34.8**	**80.5**	**350.0**	**47.9**	**34.0**	**5.1**
2300	**Acid Gas Removal**			**47.5**						**47.5**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-0.9**	**-0.8**			**2.9**	**0.8**		**2.0**	**0.0**
3000	**POWER ISLANDS UNITS**	**31.2**	**80.6**	**273.8**	**13.4**	**-34.8**	**-83.4**	**-350.8**	**-47.9**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12.0**						**12.0**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**112.9**	**5.1**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2g - Normal operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**283.0**		**3122**	
2100	**Air Separation Unit**				**25682**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**3053**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**330**	
2500	**CO2 Compression and drying**				**(6780)**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**1742**	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**88003**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**14777**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE excluding CO2 compression	**300.3**	**0**	**8611**	**128462**
	BALANCE including CO2 compression	**300.3**	**0**	**8611**	**135242**

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	**CLIENT:** IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT: Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION: Netherlands	ISSUED BY: NF
	FWI Nº: 1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2g - Peak hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**283.0**		**3122**	
2100	**Air Separation Unit**				**8359**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**3053**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**330**	
2500	**CO2 Compression and drying**				**6780**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**				
				1742	
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**88003**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**14777**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE	**300.3**	**0**	**8611**	**117919**

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	Operating Flexibility of Power Plants with CCS
LOCATION:	Netherlands
FWI Nº:	1- BD 0530 A

Rev: Draft
Sep-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 2g - Weekday Night hours

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**185.6**		**2048**	
2100	**Air Separation Unit**				**29821**
2200	**Syngas treatment and conditioning line**			**0**	
2300	**Acid Gas Removal**			**2003**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**216**	
2500	**CO2 Compression and drying**				**4746**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**1075**	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		**11.7**		**58449**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**9782**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**17.3**	**-15.7**		
	Other Units		**4.0**	**364**	
	BALANCE	**202.9**	**0**	**5706**	**102798**

Note: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2g - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**128620**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**(38500)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4769**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2158**
3500	**Miscellanea**	**598**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10437**
	Additional consumption including CO_2 compression and drying	**(500)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE excluding CO2 compression	**203511**
	BALANCE including CO2 compression	**242511**

Notes: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
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	PROJECT:	Operating Flexibility of Power Plants with CCS	ISSUED BY: NF
	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2g - peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	**48000**
2200	**Syngas treatment and conditioning line**	**252**
2300	**Acid Gas Removal**	**33044**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	**38500**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**4769**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2129**
3500	**Miscellanea**	**595**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9249**
	Additional consumption including CO_2 compression and drying	**500**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**160670**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Operating Flexibility of Power Plants with CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 2g - off peak hours

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**237**
1000	**Gasification Section**	**9134**
2100	**Air Separation Unit**	**146700**
2200	**Syngas treatment and conditioning line**	**166**
2300	**Acid Gas Removal**	**21677**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2332**
2500	**CO2 Compression and drying**	**26950**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**2832**
3200	**Heat Recovery Steam Generator**	**2943**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1379**
3500	**Miscellanea**	**369**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**8232**
	Additional consumption including CO_2 compression and drying	**328**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE	**224364**

Notes: (1) Minus prior to figure means figure is generated

8.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following table.

Case 2g - LOX&LIN storage - Daily cycle					
OVERALL PERFORMANCES OF THE IGCC COMPLEX					
		Reference case	normal operation	peak time	off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	323.1	323.1	323.1	212.0
Coal LHV (air dried basis)	kJ/kg	25869.5	25869.5	25869.5	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**	**2321.8**	**2321.8**	**1523.1**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9	1637.9	1637.9	1074.4624
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4	1488.4	1488.4	976.4
Syngas treatment efficiency (F/E*100)	%	90.9	90.9	90.9	90.9
Gas turbines total power output	MWe	563.2	563.2	563.2	338.9
Steam turbine power output	MWe	398.0	398.0	392.7	254.3
Expander power output	MWe	11.2	11.2	11.2	7.3
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972.4**	**972.4**	**967.1**	**600.5**
IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION					
ASU power consumption	MWe	128.6	128.6	48.0	146.7
Process Units consumption	MWe	50.8	50.8	50.8	33.3
Utility Units consumption	MWe	1.7	1.7	1.7	1.6
Offsite Units consumption (including sea cooling water system)	MWe	10.2	10.2	9.0	8.0
Power Islands consumption	MWe	12.2	12.2	12.2	7.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203.5**	**203.5**	**121.7**	**197.1**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**768.9**	**768.9**	**845.4**	**403.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**	**41.7**	**39.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.1**	**33.1**	**36.4**	**26.5**
IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION					
Additional consumption					
Unit 2500: CO_2 Compression and Drying	MWe	38.5	38.5	38.5	27.0
Offsite Units consumption (sea cooling water system)	MWe	0.5	0.5	0.5	0.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242.5**	**242.5**	**160.7**	**224.3**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**729.9**	**729.9**	**806.4**	**376.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.9**	**41.9**	**41.7**	**39.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.4**	**31.4**	**34.7**	**24.7**
CO_2 emission	**kg/s**	**30.93**	**30.93**	**30.93**	**20.29**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.152**	**0.152**	**0.138**	**0.194**

8.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant.

Case 2g - ASU @ partial load during peak hours			
UNIT 2100 - Air Separation Unit - 2x50% train			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Additional main air compressor	not foreseen	2 x 18.2 MWe β = 15.8 Flow = 134'000 Nm3/h each Vol. flow = 138'500 m3 each	
Oxygen storage tank	1 x 1'800 m3 (Diameter: 13.7 m, H: 12.2 m)	1 x 2'000 m3 (Diameter: 15.2 m, H: 11 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -165°C
Nitrogen storage tank	1 x 140 m3 (Diameter: 3.0 m, H: 3.0 m)	1 x 1'450 m3 (Diameter: 13 m, H: 11 m)	Common to both trains Fixed roof storage tank Operating pressure: 5 bar, -180°C

Note: The number of equipment is referred to both trains

8.6 Investment cost

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 1.5%.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : IGCC with CO2 capture
Date : 07-ott-11
Rev. : 0

Case 2g - ASU @ partial load during peak hours

COST CODE	DESCRIPTION	UNIT 900 Coal andling & storage	UNIT 1000 Gasification section	UNIT 2100 Air separation unit	UNIT 2200 Syngas treat. & condt. Line	UNIT 2300 Acid gas removal	UNIT 2400 SRU & TGT	UNIT 2500 CO2 compression & drying	UNIT 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	10,434,000	193,574,000	151,503,000	47,339,000	43,594,000	30,917,000	29,766,000	438,499,000	122,195,000	1,067,821,000	
2	CONSTRUCTION	1,853,000	77,366,000	39,941,000	20,857,000	18,091,000	12,357,000	6,610,000	97,365,000	59,691,000	334,131,000	
3	OTHER COSTS	996,000	27,699,000	5,671,000	12,376,000	19,528,000	4,129,000	1,421,000	41,831,000	11,656,000	125,307,000	
4	EPC SERVICES	1,338,000	57,945,000	19,400,000	12,456,000	8,810,000	3,966,000	1,782,000	30,003,000	20,902,000	156,602,000	
	TOTAL INSTALLED COST	14,621,000	356,584,000	216,515,000	93,028,000	90,023,000	51,369,000	39,579,000	607,698,000	214,444,000	1,683,861,000	
5	CONTINGENCY	1,000,000	25,000,000	10,800,000	6,500,000	6,300,000	3,600,000	2,000,000	42,500,000	10,700,000	108,400,000	
6	LICENSE FEES	300,000	7,100,000	4,300,000	1,900,000	1,800,000	1,000,000	800,000	12,200,000	4,300,000	33,700,000	
7	OWNER COSTS	700,000	17,800,000	10,800,000	4,700,000	4,500,000	2,600,000	2,000,000	30,400,000	10,700,000	84,200,000	
	TOTAL INVESTMENT COST	16,621,000	406,484,000	242,415,000	106,128,000	102,623,000	58,569,000	44,379,000	692,798,000	240,144,000	1,910,161,000	

8.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**2g**	
Description	Daily LOX Storage	
Fixed costs		
Maintenance	61.4	
Operating Labour	7.68	
Labour Overhead	2.30	
Insurance & local taxes	33.7	
Total fixed cost, M€/y	105.1	
Variable costs (without fuel)		
	peak / normal	**offpeak**
Make up water	13	9
Chemicals and solvents	349	230
Catalysts	134	134
Total variable cost, €/h	362	239

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME	:	FLEXIBLE OPERATION OF USC PC WITH CCS
FWI CONTRACT	:	1-BD-0530 A

ISSUED BY	:	N. FERRARI
CHECKED BY	:	P. COTONE
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

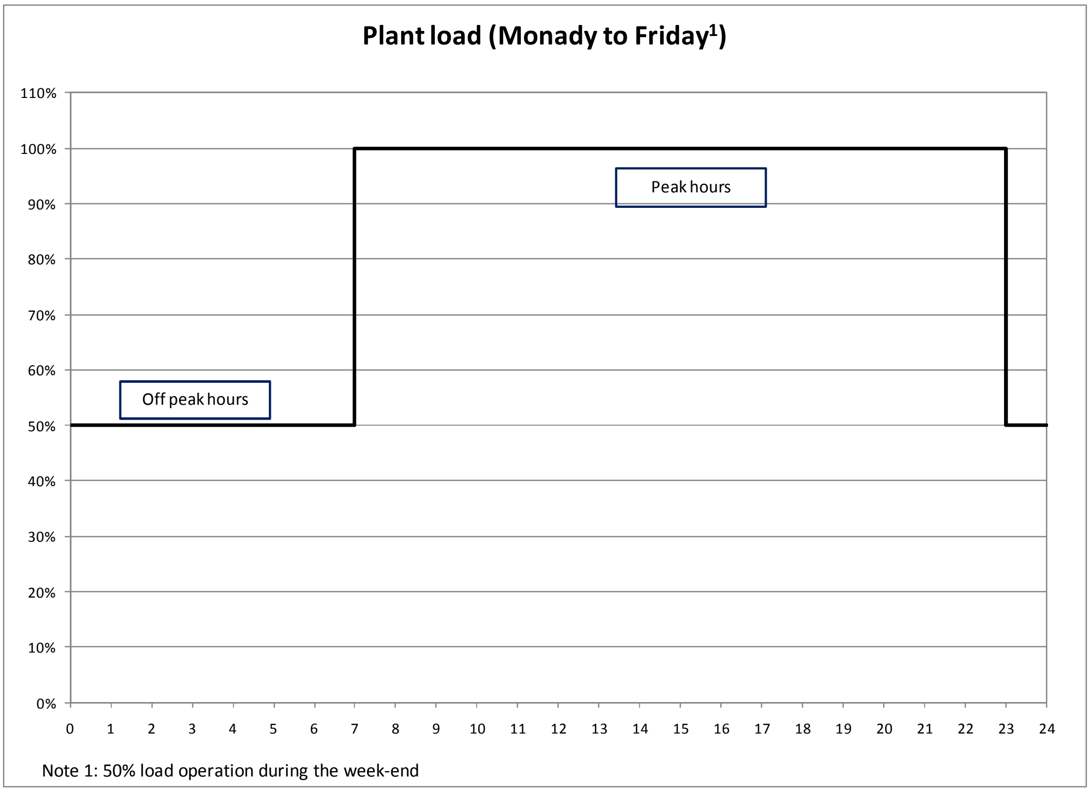
INDEX

1 Introduction

The main objective of this Section H is to assess the operating flexibility of USC-PC power plants, with post-combustion capture of the CO_2 from the boiler flue gases.

The considerations shown in this section are based on the assumption that these plant types will be requested to operate in the mid merit market, thus participating to the first step of the variable electricity and generally following a weekly demand curve as shown in Figure 1-1.

Figure 1-1: USC-PC plant load operation



From the above graph, it can be drawn that the USC-PC plants will be maintained at base load for 80 hours per week, while 50% of their overall net power production capacity shall be generated during the remaining 88 hours.

The capability of these plant types for a flexible operation is mainly affected by the constraints related to CO_2 capture and compression units, as well as the transportation pipeline. To investigate these main features, the following cases are presented in this section:

- **Case 3a**: This case assesses the constraints given by the CO_2 capture unit in relation to the start-ups/shut-downs and rapid load change requirements of conventional PC-based power plants.
- **Case 3b**: This case considers the rich solvent storage, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
- **Case 3c**: This case assesses the introduction in the power plant of a CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, despite the cycling operation of the plant, thus avoiding a two-phase flow or a significant change of the physical properties.
- **Case 3d**: This case evaluates the possibility of tuning ON/OFF the CO_2 capture in the plant, depending on the possible CO_2 allowance cost fluctuations.

In addition, the following case has been investigated using an alternative weekly demand curve, based on the assumption that the plant will need to provide two hours of peak operation per each working day, while it is turned down to 50% output during night and weekend (off-peak):

- **Case 3e**: This case considers the rich solvent storage, in order to minimize the plant power consumption and increase the overall power production during peak load demand period. Therefore, regeneration is shut down for two hours of "peak" demand during the day and the stored rich solvent is regenerated overnight, during off-peak demand.

2 Case 3a – Load changes

2.1 Introduction

As an answer to the challenges of the liberalized electricity market, similarly to the conventional natural gas combined cycles, coal plants are required to operate flexibly in response to the variable electricity demand.
Three hypothetical scenarios based on different electricity demand curves have been considered in this case 3a:

- Scenario 1
  The considerations made in this scenario are based on the assumption that USC PC power plants will be requested to operate at partial load during off-peak electricity demand period, following a cycling demand trend as the one shown in section 1.

- Scenario 2
  The considerations made in this scenario are based on the assumption that the USC PC plant is required to be shutdown during weekend and weekday night time.

- Scenario 3
  The considerations made in this scenario are based on the assumption that the USC PC plant is required to be shutdown during weekend and weekday night time and to provide two hours per working day of peak load operation.

By introducing the post-combustion capture in USC PC plants, some additional constraints of certain equipment, like the stripper and the reboiler, may limit the operating flexibility of plant, in particular during the frequent start-ups/shut-downs and the rapid load change requirements.

This case 3a assesses if the introduction of the CO_2 capture units impose additional constraints on the cycling flexibility of these plant types, in relation to their normal ramp-up and ramp-down capacity (Scenario 1), or in relation to frequent start-ups and shutdowns (Scenario 2 and 3).

It has to be noted that, in both scenarios 2 and 3, if the release of flue gases, and hence CO_2, were accepted during transient operating modes, then the operating flexibility of the plant would not be affected. However, in electricity markets where there is a hypothetical high cost related to the CO_2 emissions, this release could represent an important additional cost that should be as much as possible reduced. To overcome this problem, it is possible to consider the storage of CO_2-laden or rich solvent, which allows decoupling the boiler from the CO_2 capture unit during start-up.

In alternative, a small fired heater could be installed to provide the heat required for preheating of the regenerator column before the boiler start-up (approx. 30-40 t/h of LP steam), thus avoiding the need for solvent storage during start-up. However, in this case a certain amount of CO_2 in the flue gases from the fired heater would be released to the atmosphere.

2.2 Case description

2.2.1 Plant ramp-up (Scenario 1)

To evaluate if the CO_2 capture plant limits the capability of the USC-PC plant to follow the electrical grid demand, while maintaining a constant CO_2 capture rate, it is necessary to consider both the absorber and the regenerator behaviour during load variations.

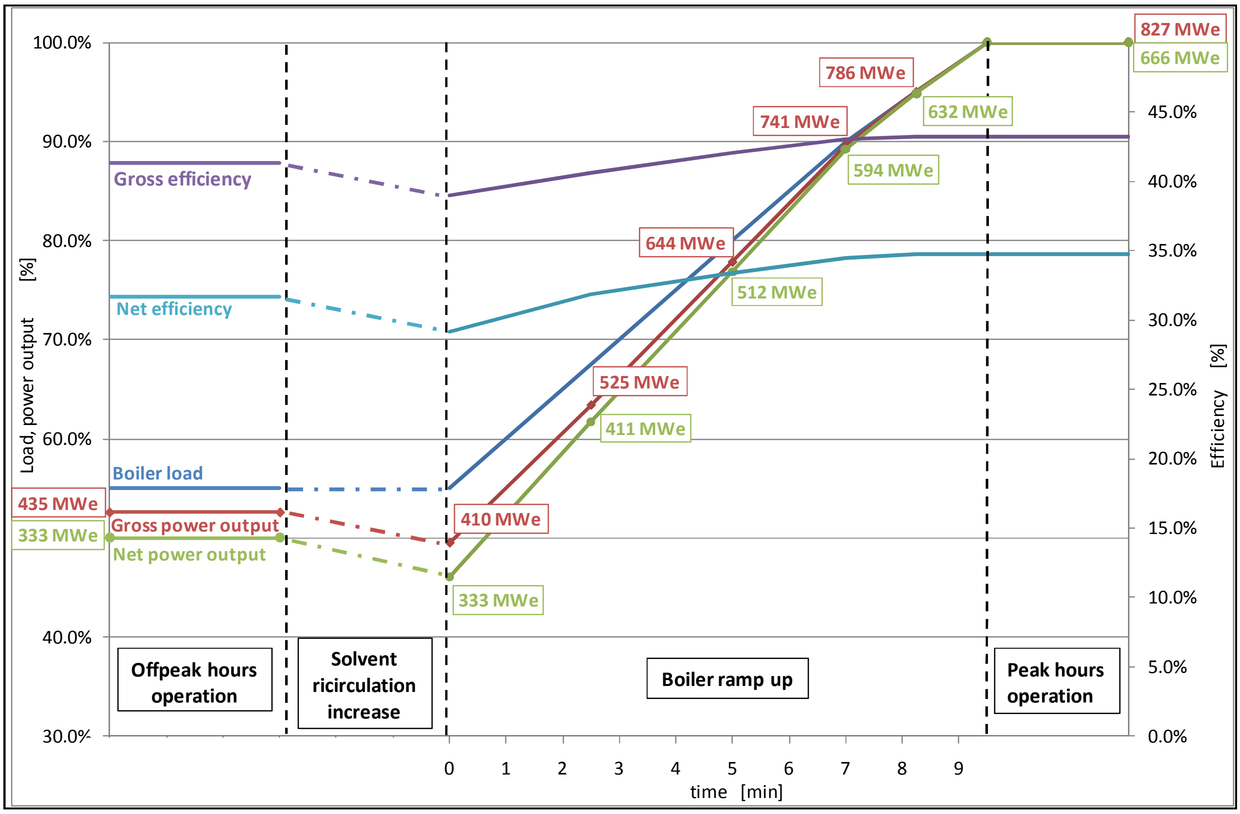
For the duration of a transient operation of the boiler, the resulting flue gases entering the absorption column have different characteristics, like flow rate and composition, while the solvent recirculation through the absorber and the regenerator is maintained unchanged with respect to the base load condition.
During this event, the absorption column is not working at its optimal design conditions, as the ratio between liquid and gas is lower than nominal, leading to potential weeping on the plate or the column packed bed, with a possible capture rate lower than required. However, modern columns are typically designed for working efficiently in a wide range of gas flowrates: lower limit for efficient operation is around 30% of the gas design flowrate for packed column and around 50% for trays column. Therefore, it can be stated that the absorption system is capable to follow the changes of the flue gases flowrate from the boiler island, in response to the cycling demand trend shown in section 1, without affecting the CO_2 capture efficiency.

With reference to the regenerator, during the transient operation of the boiler the feeding stream is characterized by a lower CO_2 concentration, because solvent recirculation is maintained at base load. However, no major issues are identified in this operating condition of the regeneration column, the main variation being the expected lower steam requirement, due to the lower CO_2 content in the feeding stream.
Although the CO_2 gaseous stream from the bottom of the regenerator head is lower, the ratio between liquid and gas is expected to remain within an acceptable range, because a higher amount of water is vaporised.

Figure 2.2-1 shows the plant performance during this transient event, assuming a ramp-up from 55% to 100% of boiler load, corresponding to a plant ramp-up from 50% to 100% of the overall power production, as required by the cycling demand trend shown in section 1. The following typical values have been considered:

Boiler ramp rate 5% /min (50-90% load)
4% /min (90-100% load)

Figure 2.2-1: Case 3a – USC PC plant ramp-up



From the considerations made in this section, it can then be concluded that the ramp-up and down capacity of USC PC power plants is not limited by the introduction of the CO_2 capture units, so no modifications of the plant design is required on this regard.

2.2.2 Plant start-up (Scenario 2 and 3)

The main factor related to the CO_2 Capture Plant that potentially limits the USC PC start-up capability is the time required to pre-heat the regeneration column and its related reboilers.

Recent designed USC PC plants can be started-up in 120 minutes, after night shutdown (hot start-up), or less than 4 hours after weekend shutdown (warm start-up). During the start-up phase, the amount of CO_2 produced in the plant is directly proportional to the fuel fed to the boiler, while the pre-heating of the regenerator column requires a few hours after steam is available from the power island.

The simplified warm and hot start-up sequences that can be followed by a conventional USC PC, without CCS, are shown respectively in Figure 2.2-2 and Figure 2.2-3.

The objective of the considerations made for this Scenario 2 is to assess the design features of a CO_2 capture plant that do not introduce limitations in both the hot and warm start-up sequences of the boiler plant.

Figure 2.2-2: Case 3a – USC PC plant warm start-up

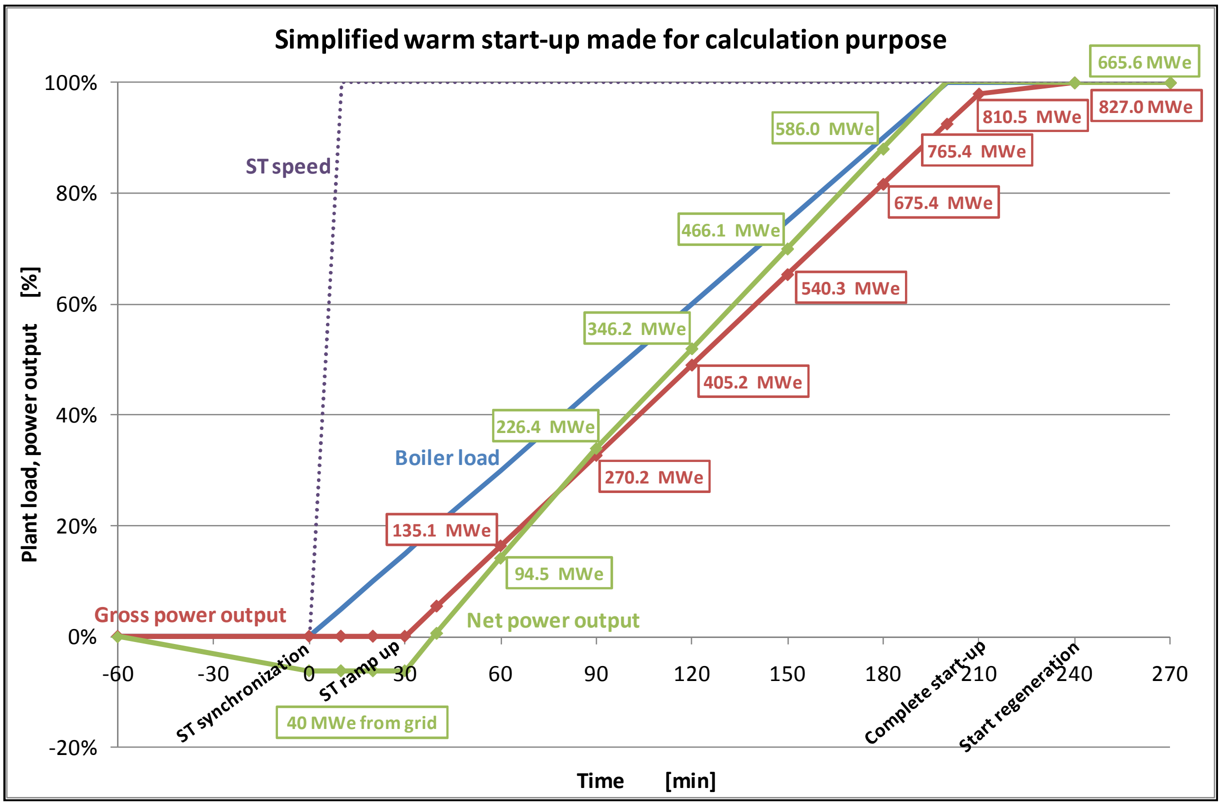
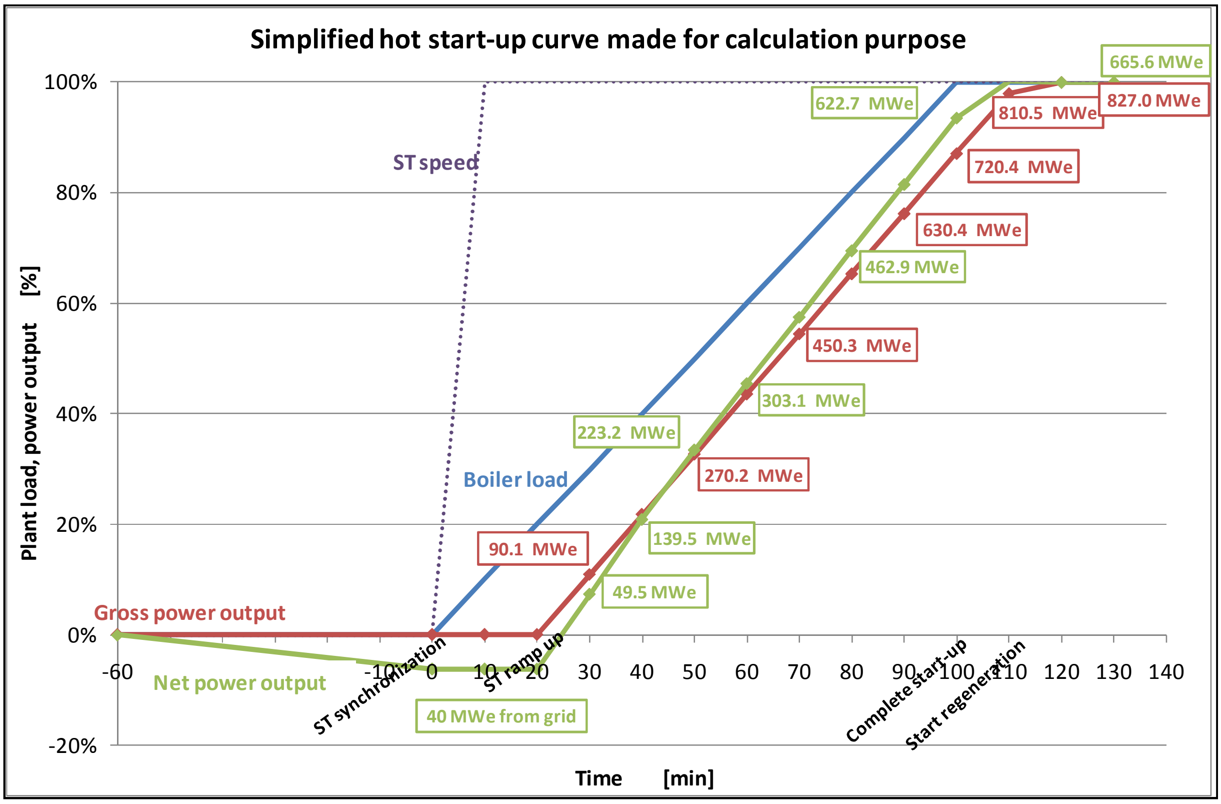


Figure 2.2-3: Case 3a – USC PC plant hot start-up



Based on the above trend, the boiler is ignited in order to have the power plant timely on base load, in accordance to the variable electricity demand curve.

The solvent circulation in the CO_2 absorber has to be started and put in operation at its minimum load (around 30%) before the boiler ignition so that, when the boiler is started-up with its own ramp-up rate, the exhaust gases can be fed to the absorption column and the CO_2 can be captured by the lean solvent.

During this phase, the column is not working at its optimal design conditions, as the ratio between liquid and gas is higher than nominal, leading to possible weeping on the plate or the column packed bed, with a possible capture rate lower than required. However, modern columns are designed for working efficiently in a wide range of gas flowrate: lower limit for efficient operation is around 30% of the gas design flowrate for packed column and around 50% for trays column.

As soon as the steam from the power island is available at the required pressure, the regeneration section can be heated up. For the purpose of the assessment, it is estimated that the regeneration section is ready for operation at full load in 120 minutes after boiler ignition during hot start-up, while 240 minutes are required in case of warm start-up. It is also noted that during boiler hot and warm start-up, the main steam generation starts from a pressure level that is already adequate for the heating of the regenerator.

In order not to limit the operating flexibility of the USC PC with CCS, the strategy considered in both scenario 2 and scenario 3 of this case 3a is that until the regenerator is not able to purify the CO_2-rich amine from the bottom of the absorber, the rich solvent is stored in a storage tank, while the lean amine and the semi-lean amine are taken from other dedicated tanks, as shown in Figure 2.2-8.

The dashed lines in the following figures show the solvent flowrate from and to the storage tanks during hot (Figure 2.2-4) and warm start-up (Figure 2.2-5) sequence, while the solid lines represent the resulting required storage volume.

Figure 2.2-4: Case 3a –Stored solvent volume during hot start-up

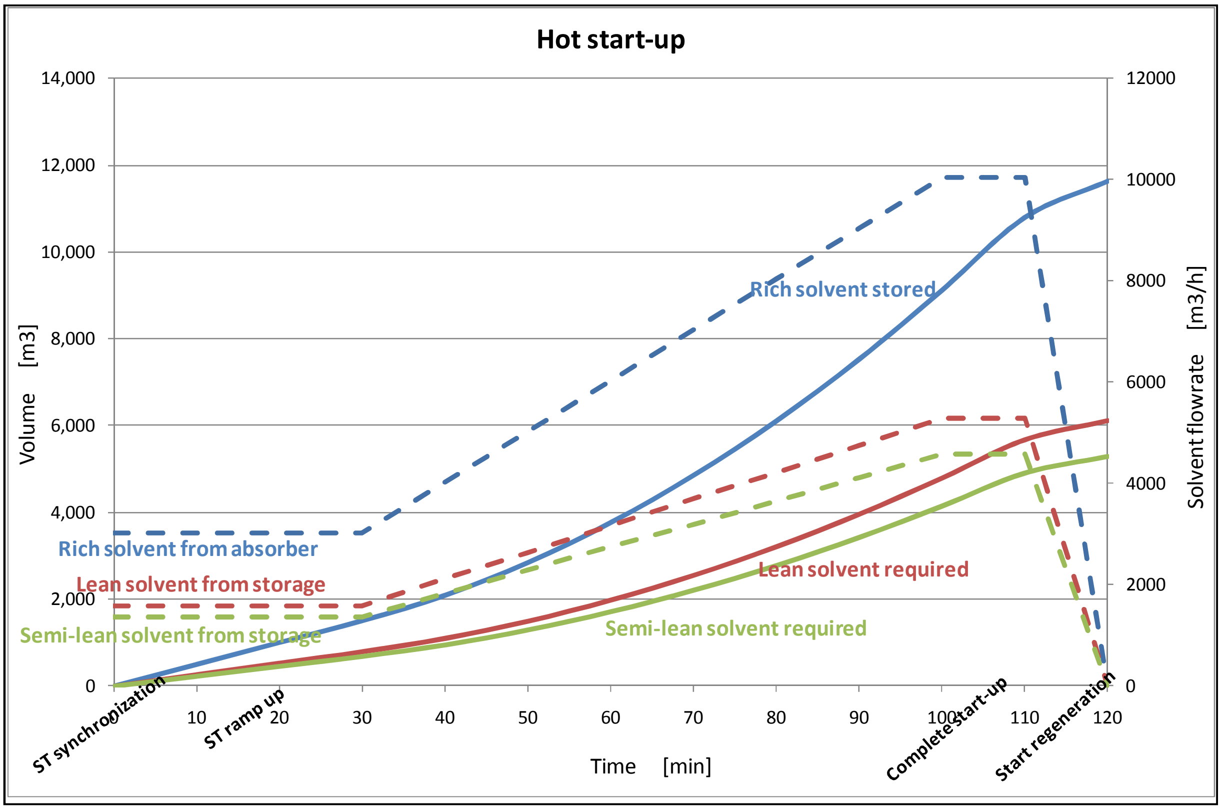
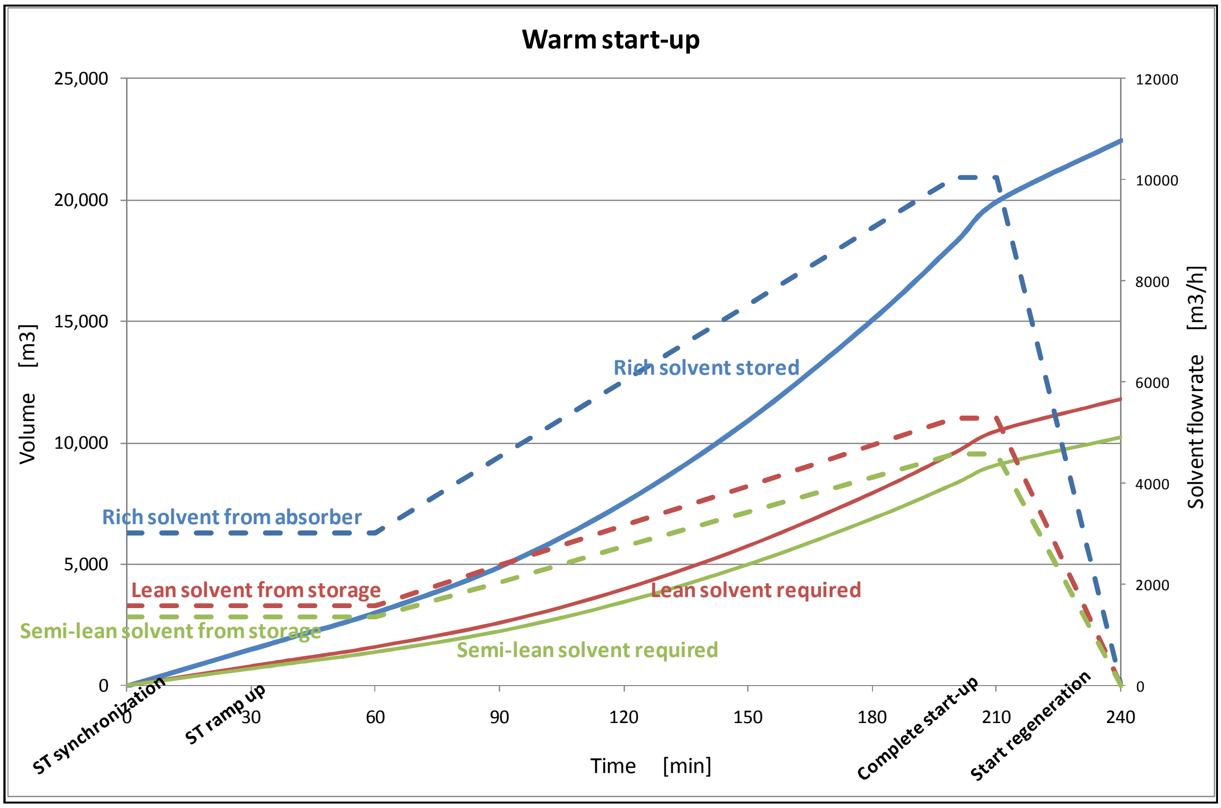


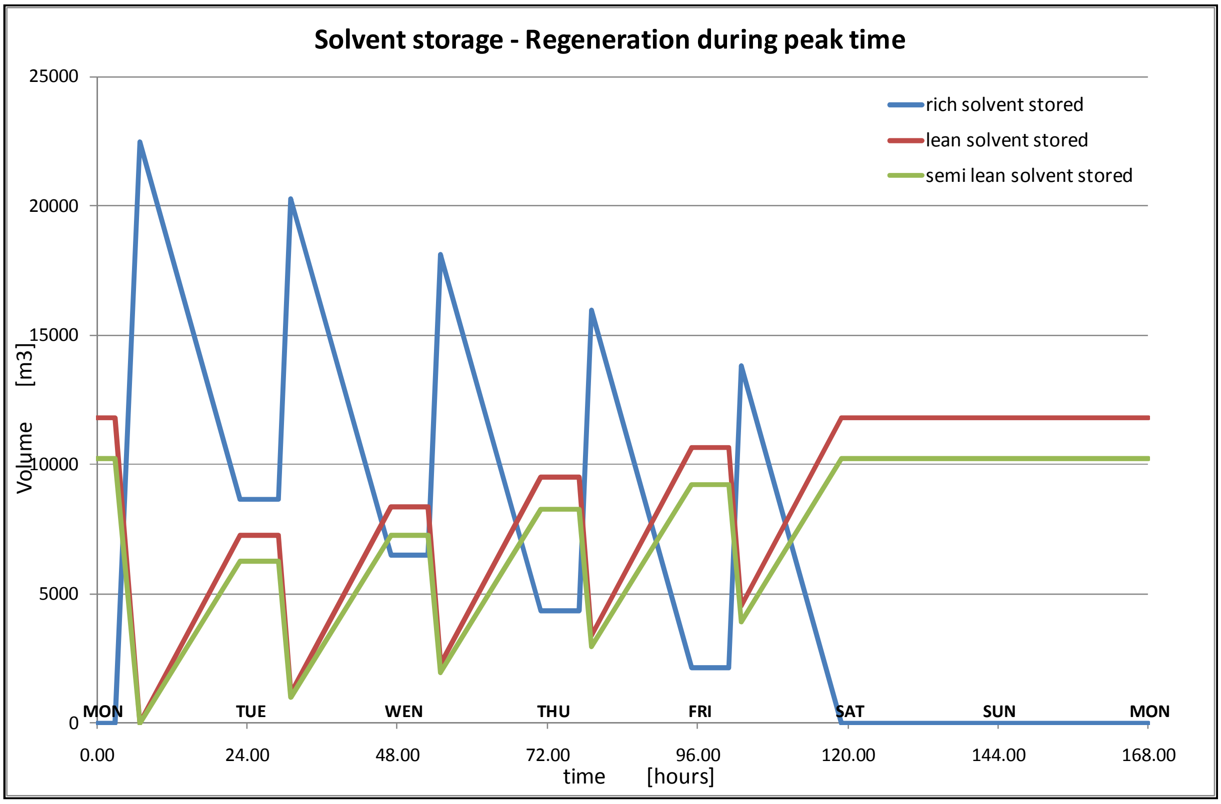
Figure 2.2-5: Case 3a –Stored solvent volume during warm start-up



The regeneration of the stored solvent is carried out during peak hours, when the plant is operated at full load, thus requiring an oversize of the regeneration and compression section. In this case, the plant power output is reduced during peak hours, when electricity price is higher, due to the greater amount of steam required in the regenerator reboiler and to the higher consumption of the CO_2 compressor. An additional investment cost related to the over sizing of the regenerator and compression section has also been considered in this case.

Figure 2.2-6 shows the dynamic trend of the stored solvent volume during the week, for Scenario 2. The design of the storage tanks is based on the amount of stored solvent required during warm start-up.
An oversize of 8.5% of the regeneration and compression section is required for regenerating during base load operation all the solvent stored during one warm and 4 hot start-ups, considering the whole week of plant operation.

Figure 2.2-6: Case 3a – Scenario 2 – Stored solvent volume during the week



In Scenario 3, a peak electricity demand period of two hours per working day has been considered. During these hours, as the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gases in the absorber column, while the solvent regeneration and the CO_2 compression sections are halted, thus reducing the energy penalties in the plant. A certain amount of steam is sent to the regenerator reboiler to keep the column warm during the two hours of shutdown.

A supplementary LP pressure steam turbine has been considered to expand the additional steam available when the regeneration is halted; this avoided to over sizing the steam turbine for the total amount of steam, as well as the inefficient operation of the machine during normal operation. In this case, the time required for shutting down the capture unit is limited by the steam turbine start-up time, which determines the steam flowrate that can be diverted from the regenerator reboiler to the steam turbine. A time around 20-30 minutes is expected after steam turbine synchronization. In case the main steam turbine is designed for the operation without solvent regeneration, the plant could have a faster ramp up of power output, achieving the maximum power output in 10 minutes.

Therefore, tanks dimension and regeneration/compression sections oversize have to take into account the additional amount of rich-solvent to be stored during high electricity demand period and of lean and semi-lean solvent fed to the absorber column when the regeneration is halted.

Figure 2.2-7 shows the dynamic trend of the stored solvent volume during the week for Scenario 3. The design of the storage tanks is based on the maximum amount of stored solvent after peak time on Monday.

An oversize of 24% of the regeneration and compression section is required during base load operation to regenerate all the solvent stored during one warm and four hot start-ups, as well as during peak time, considering the whole week of plant operation.

Figure 2.2-7: Case 3a – Scenario 3 – Stored solvent volume during the week

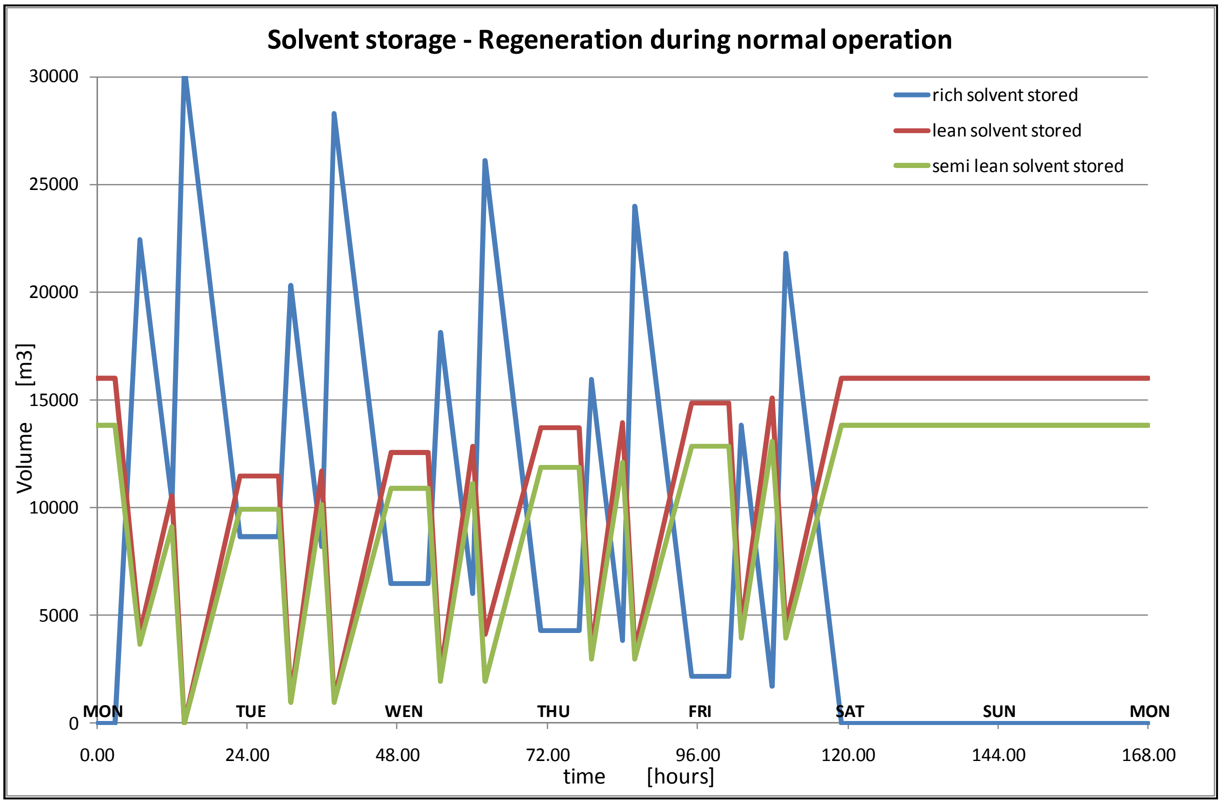
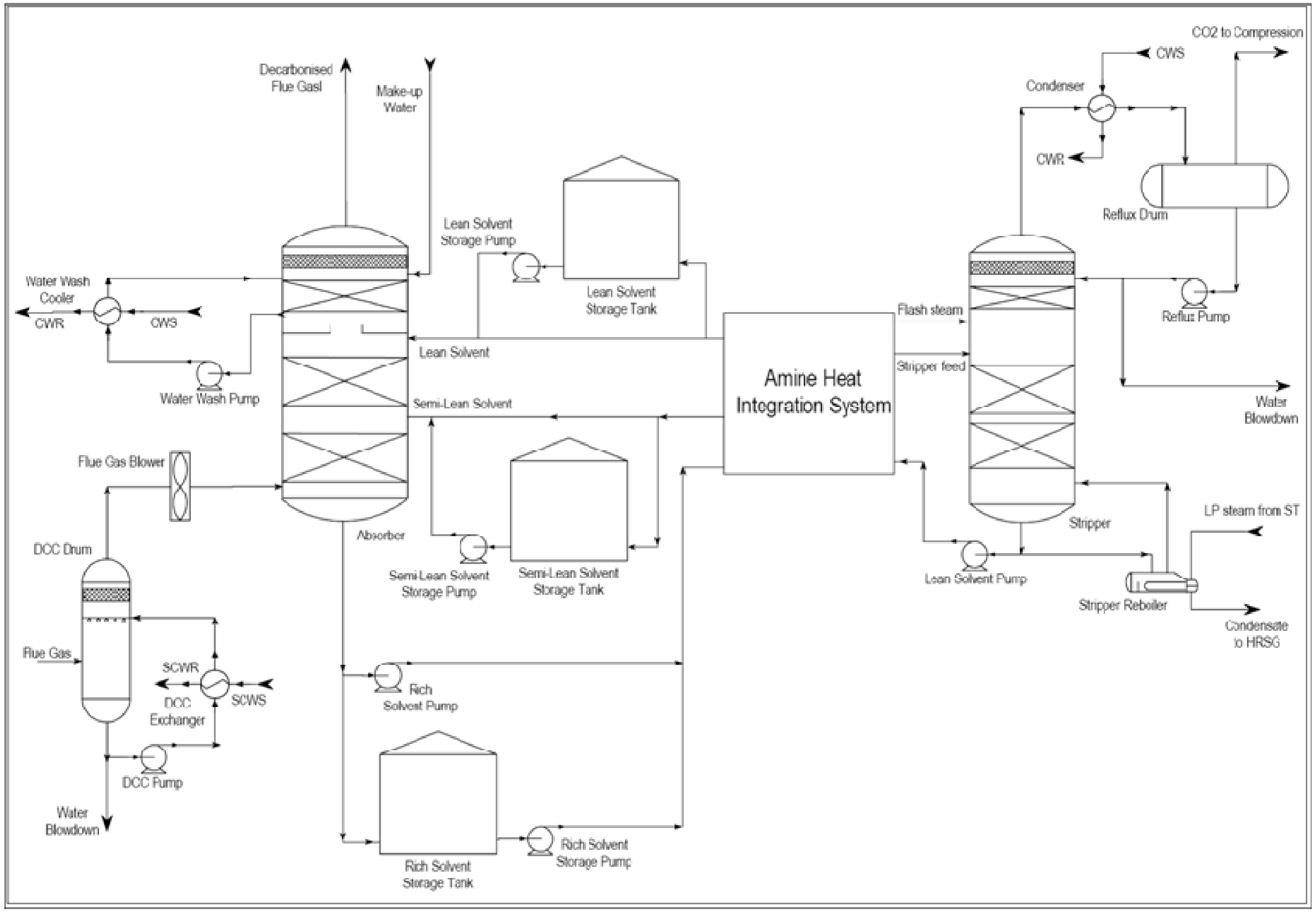


Figure 2.2-8: Post combustion unit with solvent storage



2.3 Utility consumption

The most relevant utility requirement during a ramp-up phase (Scenario 1) is the power demand of the auxiliary units, as shown in the performance table included in the next section.

The utility consumptions of the process/utility & offsite units during peak and off-peak demand periods are attached hereafter, both for scenario 2 and 3.

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
			Sep-11
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3a - Scenario 2 - WATER CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			**68**	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	**98.5**			
400	**DeNOx Plant**				
600	**CO2 Absorption**	**138.5**		**23550**	**13680**
	Amine Stripping			**7329**	**10305**
700	**CO2 Compression and Recovery System**				**5885**
200	**BOILER ISLAND**			**89**	
500	**POWER ISLAND (Steam Turbine)**		**32.5**	**2898**	**74160**
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**35.7**	**-32.5**	**75**	**58302**
	BALANCE	**272.7**	**0**	**34009**	**162332**

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FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3a - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3300**
700	**CO2 Compression and Recovery System**	**65100**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**10000**
	Additional consumption including CO_2 Compression and Drying	**5000**
	BALANCE excluding CO_2 compression	**79400**
	BALANCE including CO_2 compression	**166800**

Notes: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
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	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3a - Scenario 3 - WATER CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			**68**	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	**98.5**			
400	**DeNOx Plant**				
600	**CO2 Absorption**	**138.5**		**23550**	**13680**
	Amine Stripping			**8376**	**11777**
700	**CO2 Compression and Recovery System**				**6726**
200	**BOILER ISLAND**			**89**	
500	**POWER ISLAND (Steam Turbine)**		**32.5**	**2823**	**58871**
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**35.7**	**-32.5**	**75**	**59968**
	BALANCE	**272.7**	**0**	**34981**	**151021**

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	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3a - Scenario 3 - WATER CONSUMPTION SUMMARY - Peak

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			0	0
700	**CO2 Compression and Recovery System**				0
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	3228	106125
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	46303
	BALANCE	272.7	0	27010	166108

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FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3a - Scenario 3 - ELECTRICAL CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3700**
700	**CO2 Compression and Recovery System**	**74500**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**9000**
	Additional consumption including CO_2 Compression and Drying	**6000**
	BALANCE including CO_2 compression	**176600**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3a - Scenario 3 - ELECTRICAL CONSUMPTION SUMMARY - Peak

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**0**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9900**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**12000**
	Additional consumption including CO_2 Compression and Drying	**3000**
	BALANCE including CO_2 compression	**102300**

Notes: (1) Minus prior to figure means figure is generated

2.4 Performance

The overleaf table shows the expected performance of the plant at discrete time intervals, during the ramp-up phase from 50% (off-peak hours) to base load (peak-hours), as evaluated for scenario 1.
Plant performances tables during base load operation are also shown for both scenario 2 and 3; moreover peak load operation is included for scenario 3.

Case 3a - Plant ramp up								
OVERALL PLANT PERFORMANCES								
		Off-peak operation	time: 0.00	time: 2.50	time: 5.00	time: 7.00	time: 8.25	time: 9.50
		55% plant load	55% boiler load 100%MEA circulation	67.5% boiler load	80% boiler load	90% boiler load	95% boiler load	Base load operation
Coal Flowrate (fresh, air dried basis)	t/h	146.4	146.4	179.7	213.0	239.6	252.9	266.3
		55.0%	55.0%	67.5%	80.0%	90.0%	95.0%	100.0%
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	343.5	343.5	434.0	528.3	605.7	644.5	681.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1052.3**	**1052.3**	**1291.5**	**1530.7**	**1722.0**	**1817.7**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**434.9**	**409.7**	**524.5**	**643.7**	**740.9**	**785.6**	**827.0**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY								
BFW pumps	MWe	18.6	18.6	23.6	28.7	32.9	35.0	37.0
Draught Plant	MWe	4.9	4.9	6.1	7.2	8.1	8.5	9.0
ESP	MWe	1.1	1.1	1.3	1.6	1.8	1.9	2.0
Miscellanea	MWe	5.7	5.7	6.5	7.5	8.3	8.6	9.0
Coal mills, handling, etc.	MWe	2.7	2.7	3.4	4.0	4.5	4.7	5.0
FGD	MWe	3.3	3.3	4.0	4.8	5.4	5.7	6.0
DeNOx	MWe	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Utility Units consumption	MWe	8.0	6.0	8.0	10.0	10.0	10.0	10.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**44.5**	**42.5**	**53.1**	**64.0**	**71.3**	**74.7**	**78.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**390.4**	**367.2**	**471.4**	**579.7**	**669.6**	**710.9**	**748.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.3**	**38.9**	**40.6**	**42.1**	**43.0**	**43.2**	**43.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**37.1**	**34.9**	**36.5**	**37.9**	**38.9**	**39.1**	**39.1**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY								
Additional consumption								
CO_2 Absorption - Blower	MWe	9.8	9.8	9.8	11.2	12.6	13.3	14.0
CO_2 Absorption & Regenerator - Pumps		1.6	3.0	3.0	3.0	3.0	3.0	3.0
CO_2 Compression and Drying	MWe	42.0	42.0	42.0	48.0	54.0	57.0	60.0
Additional Process Units consumptions including CCS	MWe	0.6	0.6	0.7	0.9	1.0	1.0	1.1
Additional Utility Units consumptions including CCS	MWe	3.5	5.0	5.0	5.0	5.0	5.0	5.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**57.5**	**60.4**	**60.5**	**68.1**	**75.6**	**79.3**	**83.1**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**332.9**	**306.8**	**410.9**	**511.6**	**594.0**	**631.6**	**665.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.3**	**38.9**	**40.6**	**42.1**	**43.0**	**43.2**	**43.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.6**	**29.2**	**31.8**	**33.4**	**34.5**	**34.7**	**34.8**

Case 3a - Scenario 2			
OVERALL PLANT PERFORMANCES			
		Reference case	Normal operation
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**821.2**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY			
FW pumps	MWe	37.0	37.0
Draught Plant	MWe	9.0	9.0
Coal mills, handling, etc.	MWe	5.0	5.0
ESP	MWe	2.0	2.0
Miscellanea	MWe	9.0	9.0
Utility Units consumption	MWe	10.0	9.0
FGD	MWe	6.0	6.0
DeNOx	MWe	0.3	0.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**77.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**743.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**42.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**38.9**

POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY			
Additional consumption			
CO_2 Absorption - Blower	MWe	14.0	14.0
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	3.3
CO_2 Compression and Drying	MWe	60.0	65.1
Additional Process Units consumptions including CCS	MWe	1.1	1.1
Additional Utility Units consumptions including CCS	MWe	5.0	6.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**89.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**654.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**42.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**34.2**

CO_2 emission	**kg/s**	**25.98**	**25.98**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.143**

Case 3a - Scenario 3				
OVERALL PLANT PERFORMANCES				
		Reference case	Peak load	Normal operation
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	266.3
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**910.4**	**798.6**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
FW pumps	MWe	37.0	37.0	37.0
Draught Plant	MWe	9.0	9.0	9.0
Coal mills, handling, etc.	MWe	5.0	5.0	5.0
ESP	MWe	2.0	2.0	2.0
Miscellanea	MWe	9.0	9.9	9.0
Utility Units consumption	MWe	10.0	12.0	9.0
FGD	MWe	6.0	6.0	6.0
DeNOx	MWe	0.3	0.3	0.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**81.2**	**77.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**829.2**	**721.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**47.6**	**41.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**43.3**	**37.7**

POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY				
Additional consumption				
CO_2 Absorption - Blower	MWe	14.0	14.0	14.0
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	3.0	3.7
CO_2 Compression and Drying	MWe	60.0	0.0	74.5
Additional Process Units consumptions including CCS	MWe	1.1	1.1	1.1
Additional Utility Units consumptions including CCS	MWe	5.0	3.0	6.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**21.1**	**99.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**808.1**	**622.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**47.6**	**41.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**42.2**	**32.5**

CO_2 emission	**kg/s**	**25.98**	**25.98**	**25.98**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.116**	**0.150**

2.5 Equipment list

As described in the previous sections, no additional equipment or packages are required with respect to the reference design case for scenario 1.

The following table shows the equipment and process packages that have to be added or modified for both Scenario 2 and 3 with respect to the design of the reference case, in order not to limit the operating flexibility of a standard USC PC without CCS.

Case 3a - Scenario 2 - Impact of CCS on plant start-up

Unit 600 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regeneration section	CO_2 outlet flow = 12,200 kmol/h Rich solvent feed = 7,660 m^3/h Reboiler duty = 490.4 MW th	CO_2 outlet flow = 13,250 kmol/h Rich solvent feed = 8,320 m^3/h Reboiler duty = 532.5 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for start-up)*	not foreseen	2 x 12'000 m3 (Diameter: 30.5 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for start-up)*	not foreseen	1 x 13'000 m3 (Diameter: 31.1 m H: 17.1 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for start-up)*	not foreseen	1 x 12'000 m3 (Diameter: 30.5 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 280 kW 865 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 1800 kW 5500 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 900 kW 4500 m3 x 45 m each	One pump in operation, one spare

Unit 700 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 145'000 Nm3/h each train	CO2 flow = 157'500 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

Case 3a - Scenario 3 - Impact of CCS on plant start-up

Unit 600 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regeneration section	CO_2 outlet flow = 12,200 kmol/h Rich solvent feed = 7,660 m^3/h Reboiler duty = 490.4 MW th	CO_2 outlet flow = 15,140 kmol/h Rich solvent feed = 9,506 m^3/h Reboiler duty = 608.6 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for start-up)*	not foreseen	2 x 17'300 m3 (Diameter: 36.6 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Lean solvent storage tank *(for start-up)*	not foreseen	1 x 17'300 m3 (Diameter: 36.6 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for start-up)*	not foreseen	1 x 17'300 m3 (Diameter: 36.6 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with intenal lining
Rich solvent storage pumps	not foreseen	2 x 710 kW 2420 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 1800 kW 5500 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 900 kW 4500 m3 x 45 m each	One pump in operation, one spare

Unit 700 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 145'000 Nm3/h each train	CO2 flow = 180'000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

Case 3a - Scenario 3 - Impact of CCS on plant start-up			
Unit 500 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam Turbine	827 MWe gross	800 MWe gross	
New Steam turbine		113 MWe gross	
Steam turbine condenser	592 MWth	865 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 1120 kW	3 x 900 kW	Two operating, one spare
Condensate preheater #1	not foreseen	60 MWth surface = 1325 m2	
Condensate preheater #2	not foreseen	39.5 MWth surface = 1190 m2	
Condensate preheater #3	not foreseen	71 MWth surface = 1500 m2	
Unit 800 - Utility unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Sea water pumps	(8 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	(10 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.

An overall area of 10,500 m^2 and 12,800 m^2 is required for the storage tanks respectively for Scenario 2 and Scenario 3 of this case 3a, i.e. around 6% and 7.5% of typical area requirements for a USC PC power plant, excluding coal storage.

2.5.1 CO_2 transport pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for the reference plant, scenario 2 and 3 of this Case 3a. It can be drawn that in both scenarios, even if the regeneration and compression section capacity is increased, the pipeline diameter selected for the reference case is sufficient for the higher CO_2 flowrate.

Case 3a - Impact of CCS on plant start-up

CO_2 pipeline characteristics

		Reference plant	Flexible plant Scenario 2	Flexible plant Scenario 3
CO_2 flowrate	kg/h	536,000	582,096	665,176
Inlet pressure	barg	110	110	110
Inlet temperature	°C	30	30	30
Outlet pressure	bar	96.7	94.2	89.5
CO_2 phase condition	-	liquid	liquid	liquid
Pipeline diameter	mm	500	500	500

2.6 Investment cost

The investment cost required by this case is same as the reference design plant, as no additional equipment or packages are required for scenario 1.

The table attached to this section shows the investment cost break-down and the total investment cost of both Scenario 2 and Scenario 3 of this case.

With respect to the figures included in Section E for the reference plant, Scenario 2 and Scenario 3 show a total investment cost increase respectively of 2% and 7.5%.

FOSTER WHEELER

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 06-ott-11
Rev. : 0

Case 3a - Scenario 2 - Impact of CCS on plant start-up

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	122,884,000	56,644,000	33,170,000	189,912,000	781,037,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,408,000	67,787,000	21,909,000	53,330,000	331,542,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	166,292,000	124,431,000	55,079,000	243,242,000	1,112,579,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,489,000	1,102,000	4,865,000	22,252,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,489,000	1,102,000	4,865,000	22,252,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	831,000	622,000	275,000	1,216,000	5,562,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,315,000	6,222,000	2,754,000	12,162,000	55,630,000	
	solvent inventory for flexible operation (*)						10,000,000			10,000,000	(*) Assumed solvent inventory cost: 1000 €/t
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,663,000	1,244,000	551,000	2,432,000	11,125,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	17,461,000	23,066,000	5,784,000	25,540,000	126,821,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	19,955,000	14,932,000	6,609,000	29,189,000	133,509,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	203,708,000	162,429,000	67,472,000	297,971,000	1,372,909,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,300,000	11,400,000	3,400,000	14,900,000	89,000,000	
	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
10	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,200,000	8,100,000	3,400,000	14,900,000	68,700,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	230,008,000	183,729,000	76,072,000	329,571,000	1,545,009,000	

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 06-ott-11
Rev. : 0

Case 3a - Scenario 3 - Impact of CCS on plant start-up

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	155,074,000	61,464,000	36,217,000	200,472,000	831,654,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	46,608,000	68,037,000	22,219,000	55,970,000	337,942,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	201,682,000	129,501,000	58,436,000	256,442,000	1,169,596,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	4,034,000	2,590,000	1,169,000	5,129,000	23,392,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	4,034,000	2,590,000	1,169,000	5,129,000	23,392,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	1,008,000	648,000	292,000	1,282,000	5,848,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	10,084,000	6,475,000	2,922,000	12,822,000	58,480,000	
	solvent inventory for flexible operation (*)						13,600,000			13,600,000	
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	2,017,000	1,295,000	584,000	2,564,000	11,695,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	21,177,000	27,198,000	6,136,000	26,926,000	136,407,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	24,202,000	15,540,000	7,012,000	30,773,000	140,351,000	
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	247,061,000	172,239,000	71,584,000	314,141,000	1,446,354,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	17,300,000	12,100,000	3,600,000	15,700,000	93,700,000	
	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
10	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	12,400,000	8,600,000	3,600,000	15,700,000	72,400,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	278,561,000	194,739,000	80,584,000	347,341,000	1,626,854,000	

2.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 2 and Scenario 3.

Case	3a - Scenario 2		3a - Scenario 3	
Description	Impact of CCS on start-up		Impact of CCS on start-up	
Fixed costs				
Maintenance	51.8		54.6	
Operating Labour	7.80		7.80	
Labour Overhead	2.34		2.34	
Insurance & local taxes	27.5		28.9	
Total fixed cost, M€/y	89.4		93.6	
Variable costs (without fuel)				
	Normal oper.	**offpeak**	**peak/normal oper.**	**offpeak**
Make up water	0	0	0	0
Chemicals and consumables	1287	0	1287	0
Total variable cost, €/h	1287	0	1287	0

3 Case 3b – Solvent storage

3.1 Introduction

This Case 3b assesses how the operating flexibility of coal-fired boiler power plants with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing the solvent storage from/to the absorber and the stripper.

In fact, solvent storage can allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases.

In addition, the solvent regeneration and CO_2 compression, with their associated energy penalties, can be operated during low electricity demand periods, while maximizing the electricity production when the market requires a higher electricity generation.

3.2 Case description

This alternative is assessed considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 1.

To maximize the energy production, the rich solvent can be partially or even totally stored during the 80 hours per week of peak load operation, when the plant is at base-load, while the regeneration of stored solvent can be made during the remaining 88 hours per week of off-peak load operation, when the plant is required to operated at a partial load in order to produce 50% of the total net power output. With this strategy, the solvent flowrates from and to the storage are balanced in one week of plant operation.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are at low or even no load, thus reducing the energy penalties in the plant.

Depending on the regeneration load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the storage tanks, as shown in Figure 3.2-1.

During off-peak electricity demand, the power plant and the absorption unit are operated at part load in order to generate 50% of the overall net power production, while the regenerator section is in operation at the load required for the regeneration of the rich solvent stored in the tanks, while simultaneously refilling the lean amine storage tanks.

The scenarios shown in the following sections, each characterised by a different regeneration load during high electricity demand period, have been investigated in order to evaluate the most convenient operating conditions. The main operating parameters for each possible scenario are also summarised in Table 3.2-1.

3.2.1 Regeneration halted during peak time

In this scenario, the energy production during peak demand periods is maximized by shutting down both the regeneration and the CO_2 compression units. Therefore, this alternative shows the highest increase of the net power production with respect to the reference case.

However, a significant oversize of the regeneration and compression section is required for regenerating all the solvent stored during the peak time period.
In this case, the boiler load required to generate 50% of the overall power output and regenerate all the solvent stored during the high electricity demand period is about 90% of the nominal capacity. On the other hand, the resulting size of the regeneration and compression units would be about 180% of the reference case.

In addition, the volume and the area required for the storage tanks are very large, thus making this alternative not economically attractive.

3.2.2 50% regeneration load during peak time

Operating the regeneration section at 50% of the reference case load, it is possible to limit the oversize of the regenerator section to about 16%.

In this case, during peak time half of the rich solvent from the absorber is fed to the regenerator, while the remainder is stored in a dedicated tank. In the same way, half of the lean solvent required for the absorption is taken from the storage tanks.

However, the volume and the area required for the storage tanks are still very large, thus making also this alternative not economically attractive.

3.2.3 25% regeneration load during peak time

Operating the regeneration section at 25% of the reference case load, it is possible to limit the area and the volume required for the solvent storage tanks. In this case, during peak time 75% of the rich solvent from the absorber is fed to the regenerator, while the remainder is stored in a dedicated tank. In the same way, 25% of the lean solvent required for the absorption taken from the storage tanks.

The following possible scenarios are considered in this case.

1) *Scenario 1: Reduced regenerator size*
   The maximum regeneration load at which the plant is required to operate during low electricity demand period for regeneration of the stored solvent is about 85% of the reference plant capacity.
   In this case, as the regeneration and compression sections are never operated at the design capacity of the reference case, it would be possible to reduce their size, leading to an investment cost saving.
   In this configuration the CO_2 flowrate, sent to the external pipeline, is lower than the flowrate when the plant is operated at base load; therefore, it is possible to select a lower pipeline size, leading to a possible cost saving.

2) *Scenario 2: 100% regenerator size*
   In this second scenario, no reduction in the regenerator design capacity is considered with respect to the reference case. This does not limit the plant flexibility in response to possible changes in the electricity market demand trends.
   In order to reduce the storage size, the regeneration load from the turndown of Friday night to the ramp-up of Monday morning has to be minimised. For this purpose, during the remainder of the off-peak hours the regeneration section is operated at base load.

The performance and the economic data in the following sections are referred to these two scenarios.

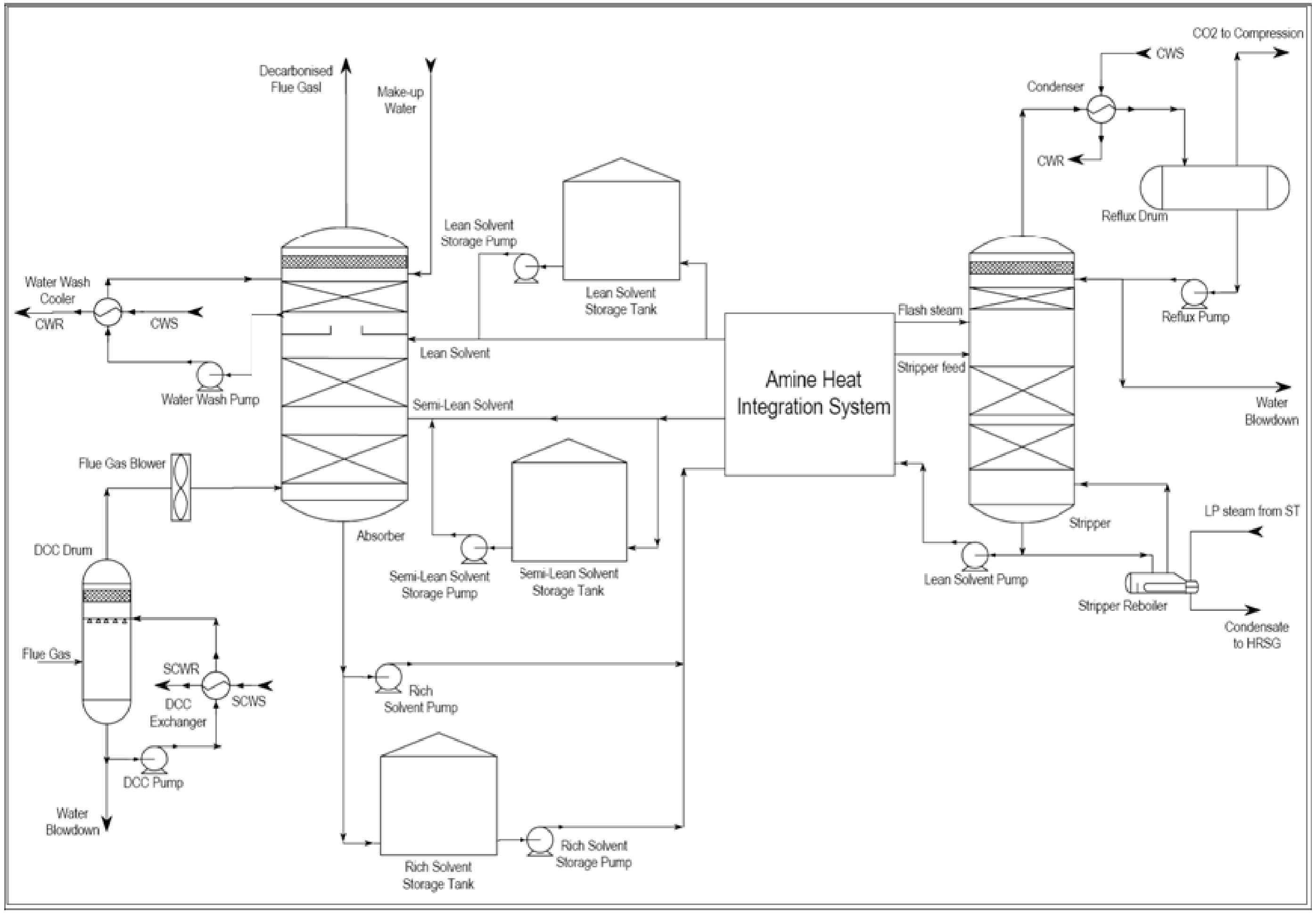


Figure 3.2-1: Post combustion unit with solvent storage

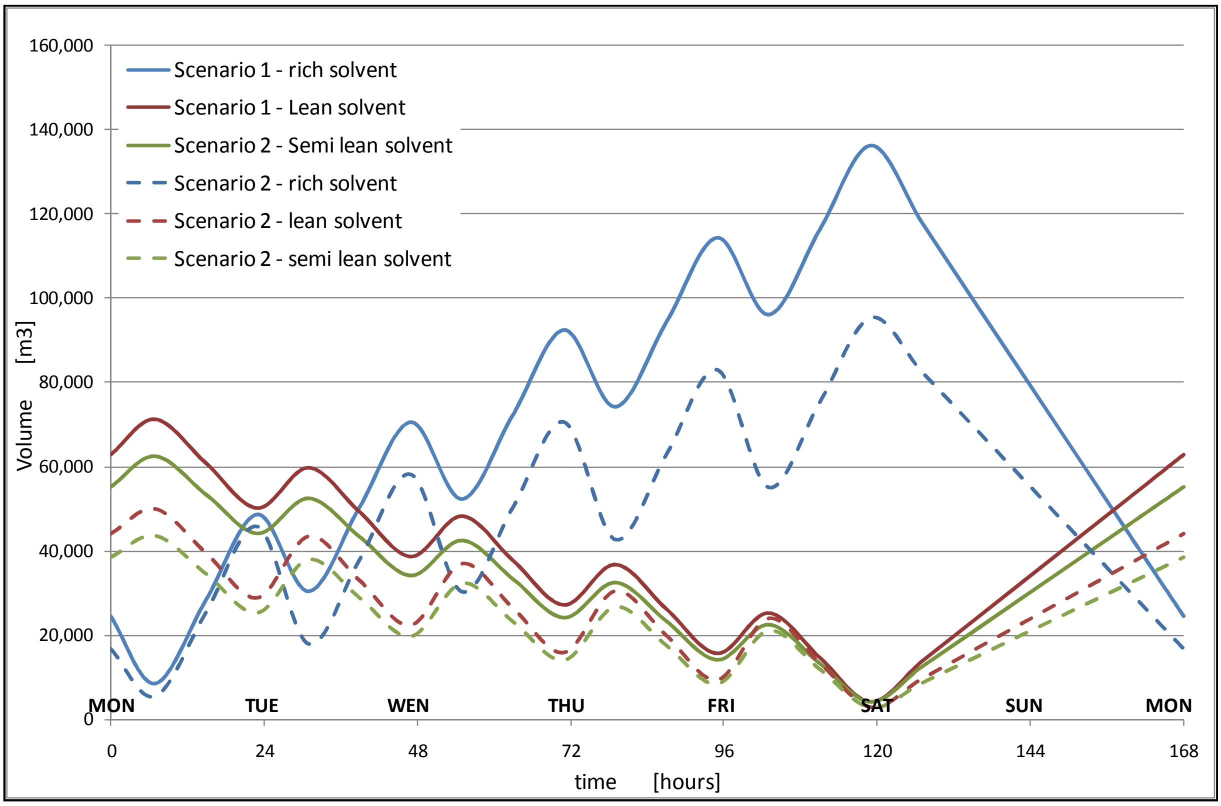
Table 3.2-1: Case 3b – Operating scenarios summary

Scenario: peak hours regenerator operating condition		100% solvent storage	50% solvent storage	25% solvent storage Sub-scenario 1	25% solvent storage Sub-scenario 2
Daily full load operation (80 hours/week)					
Power island operating condition					
Boiler load	-	100%	100%	100%	100%
ST power output	MWe	927.3	871.2	844.6	844.6
Net power output	MWe	848.0	739.7	697.4	697.4
CO2 Capture Unit operating condition		**absorber 100% regenerator 0%**	**absorber 100% regenerator 50%**	**absorber 100% regenerator 25%**	**absorber 100% regenerator 25%**
Nightly part load operation (32 hours/week)					
Power island operating condition					
Boiler load	-	90%	71%	62.5%	65.4%
ST power output	MWe	616.4	509.9	466.9	476.7
Net power output	MWe	416.4	368.1	349.8	348.5
CO2 Capture Unit operating condition		**absorber 90% regenerator 181%**	**absorber 71% regenerator 116%**	**absorber 62.5% regenerator 85%**	**absorber 65.74% regenerator 100%**
Weekend part load operation (56 hours/week)					
Power island operating condition					
Boiler load	-	90%	71%	62.5%	62.5%
ST power output	MWe	616.4	509.9	466.9	461.1
Net power output	MWe	416.4	368.1	349.8	350.5
CO2 Capture Unit operating condition		**absorber 90% regenerator 181%**	**absorber 71% regenerator 116%**	**absorber 62.5% regenerator 85%**	**absorber 62.5% regenerator 78.5%**
Regenerator design					
Regenerator size respect to reference case		181%	116%	85%	100%
Storage tanks					
Rich solvent		4 x 143'000 m3 D = 104 m x H = 17 m	2 x 143'000 m3 D = 104 m x H = 17 m	2 x 71'600 m3 D = 73 m x H = 17 m	2 x 47'700 m3 D = 60 m x H = 17 m
Lean solvent		2 x 143'000 m3 D = 104 m x H = 17 m	1 x 143'000 m3 D = 104 m x H = 17 m	1 x 71'600 m3 D = 73 m x H = 17 m	1 x 55'700 m3 D = 65 m x H = 17 m
Semi-lean solvent		2 x 127'000 m3 D = 98 m x H = 17 m	1 x 127'000 m3 D = 98 m x H = 17 m	1 x 63'600 m3 D = 69 m x H = 17 m	1 x 47'700 m3 D = 60 m x H = 17 m
Consideration					
		NOT ATTRACTIVE Regenerator and compression section oversize and area for solvent storage excessive	**NOT ATTRACTIVE** Area for solvent storage excessive	**ATTRACTIVE** Lower flexibility	**ATTRACTIVE** Higher flexibility

Figure 3.2-2 shows the stored volumes of rich, lean and semi-lean solvents during the week, for the two scenarios considered in this Case 3b. The net volume of the storage tank is the difference between the maximum and the minimum volume of solvent stored during the week. It corresponds to the solvent stored during the weekend, from the turndown of Friday night to the-ramp up of Monday morning.

The solid line corresponds to the stored volume for scenario 1, while the dashed line corresponds to the stored volume for the scenario 2.
Although both scenarios are designed for the same regeneration load during peak time, the storage tanks required for the second alternative are smaller.
In fact, as the regenerator size is not reduced, it is possible to maintain this section at the base load during the off-peak hours of the working days, while maintaining a lower load during the week-end, enough to avoid accumulations in the storage tanks.

Figure 3.2-2: Case 3b –Stored solvent volume during the week



3.3 Utility consumption

The utility consumptions of the process/utility & offsite units during peak and off-peak demand periods are attached hereafter, for the two assessed scenarios.

Scenario 1

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CASE 3b - Scenario 1 - WATER CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			5063	7118
700	**CO2 Compression and Recovery System**				4065
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2977	83054
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	54551
	BALANCE	272.7	0	31822	162468

Note: (1) Minus prior to figure means figure is generated

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CASE 3b - Scenario 1 - WATER CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			43	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	61.6			
400	**DeNOx Plant**				
600	**CO2 Absorption**	86.5		14720	8550
	Amine Stripping			5760	8090
700	**CO2 Compression and Recovery System**				4620
200	**BOILER ISLAND**			56	
500	**POWER ISLAND (Steam Turbine)**		20.3	1849	53743
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	22.3	-20.3	47	38529
	BALANCE	170.4	0	22475	113531

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CASE 3b - Scenario 1 - ELECTRICAL CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**45000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9100**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**11500**
	Additional consumption including CCS	**4200**
	BALANCE	**147200**

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CASE 3b - Scenario 1 - ELECTRICAL CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3100**
300	**FGD**	**4400**
400	**DeNOx**	**250**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**8700**
	CO2 Absorption and Amine Stripping - pumps	**2220**
700	**CO2 Compression and Recovery System**	**51100**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**28500**
	Miscellanea utilities	**6100**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7500**
	Additional consumption including CCS	**4000**
	BALANCE	**115870**

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Scenario 2

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CASE 3b - Scenario 2 - WATER CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			5063	7118
700	**CO2 Compression and Recovery System**				4065
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2977	83054
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	54551
	BALANCE	272.7	0	31822	162468

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CASE 3b - Scenario 2 - WATER CONSUMPTION SUMMARY - Night off-Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			45	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	64.4			
400	**DeNOx Plant**				
600	**CO2 Absorption**	90.6		15400	8950
	Amine Stripping			6750	9490
700	**CO2 Compression and Recovery System**				5420
200	**BOILER ISLAND**			58	
500	**POWER ISLAND (Steam Turbine)**		21.2	1682	42994
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	23.3	-21.2	50	41117
	BALANCE	178.3	0	23985	107971

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CASE 3 - WATER CONSUMPTION SUMMARY - Week end off-Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			41	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	59.6			
400	**DeNOx Plant**				
600	**CO2 Absorption**	83.8		14260	13680
	Amine Stripping			5170	7260
700	**CO2 Compression and Recovery System**				4150
200	**BOILER ISLAND**			54	
500	**POWER ISLAND (Steam Turbine)**		19.6	1627	53743
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	21.6	-19.6	46	36339
	BALANCE	165.1	0	21198	115172

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CASE 3b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**45000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9100**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**11500**
	Additional consumption including CCS	**4200**
	BALANCE	**147200**

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CASE 3b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Night off-peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3300**
300	**FGD**	**4600**
400	**DeNOx**	**260**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**9200**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**60000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**29900**
	Miscellanea utilities	**6300**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7000**
	Additional consumption including CCS	**4100**
	BALANCE	**127660**

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CASE 3b - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Week-end off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3000**
300	**FGD**	**4200**
400	**DeNOx**	**240**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**8500**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**34400**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**27500**
	Miscellanea utilities	**6000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7000**
	Additional consumption including CCS	**4100**
	BALANCE	**97940**

3.4 Performance

The overall plant performance during peak and off-peak demand periods are shown in the following table, for the two assessed scenarios.

During high electricity demand period, the net plant power output is about 32 MWe higher than the reference plant. During low electricity demand period, the plant is operated to generate the 50% of the daily net power production.

Case 3b - Scenario 1 - Solvent storage				
OVERALL PLANT PERFORMANCES				
		Reference case	Peak time	Off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	166.4
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
Main steam flow	kg/s	681.5	681.5	398.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1195.8**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**844.6**	**466.9**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
BFW pumps	MWe	37.0	37.0	21.6
Draught Plant	MWe	9.0	9.0	5.6
ESP	MWe	2.0	2.0	1.2
Miscellanea	MWe	9.0	9.1	6.1
Coal mills, handling, etc.	MWe	5.0	5.0	3.1
FGD	MWe	6.0	6.0	3.7
DeNOx	MWe	0.3	0.3	0.2
Utility Units consumption	MWe	10.0	11.5	7.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**79.9**	**48.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**764.7**	**418.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**44.1**	**39.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**40.0**	**35.0**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY				
Additional consumption				
CO_2 Absorption - Blower	MWe	14.0	14.0	9.8
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	3.0	3.0
CO_2 Compression and Drying	MWe	60.0	45.0	51.1
Additional Process Units consumptions including CCS	MWe	1.1	1.1	0.7
Additional Utility Units consumptions including CCS	MWe	5.0	4.2	4.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**67.3**	**68.6**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**697.4**	**349.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**44.1**	**39.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**36.4**	**29.3**
CO_2 emission	**kg/s**	**25.98**	**25.98**	**16.23**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.134**	**0.167**

Case 3b - Scenario 2 - Solvent storage					
OVERALL PLANT PERFORMANCES					
		Reference case	Peak time	Off-peak time night	Off-peak time week end
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	174.1	161.2
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	681.5	681.5	419.0	383.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1251.3**	**1158.5**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**844.6**	**476.7**	**461.1**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY					
BFW pumps	MWe	37.0	37.0	22.7	20.8
Draught Plant	MWe	9.0	9.0	5.9	5.4
ESP	MWe	2.0	2.0	1.3	1.2
Miscellanea	MWe	9.0	9.1	6.3	6.0
Coal mills, handling, etc.	MWe	5.0	5.0	3.3	3.0
FGD	MWe	6.0	6.0	3.9	3.6
DeNOx	MWe	0.3	0.3	0.2	0.2
Utility Units consumption	MWe	10.0	11.5	7.0	6.9
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**79.9**	**50.6**	**47.1**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**764.7**	**426.1**	**414.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**44.1**	**38.1**	**39.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**40.0**	**34.1**	**35.7**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY					
Additional consumption					
CO_2 Absorption - Blower	MWe	14.0	14.0	9.8	9.8
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	3.0	3.0	3.0
CO_2 Compression and Drying	MWe	60.0	45.0	60.0	45.9
Additional Process Units consumptions including CCS	MWe	1.1	1.1	0.7	0.7
Additional Utility Units consumptions including CCS	MWe	5.0	4.2	4.1	4.1
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**67.3**	**77.6**	**63.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**697.4**	**348.5**	**350.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**44.1**	**38.1**	**39.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**36.4**	**27.8**	**30.3**
CO_2 emission	**kg/s**	**25.98**	**25.98**	**16.99**	**15.73**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.134**	**0.175**	**0.162**

3.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to improve the operating flexibility of plant with post-combustion capture.

Case 3b - Scenario 1 - Solvent storage - Reduced regeneretor size

Unit 500 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	827 MWe gross	845 MWe gross	
Steam turbine condenser	592 MWth	663 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 1120 kW	2 x 1250 kW	One operating, one spare

Unit 600 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regeneration section	CO_2 outlet flow = 12,200 kmol/h Rich solvent feed = 7,660 m^3/h Reboiler duty = 490.4 MW th	CO_2 outlet flow = 10,400 kmol/h Rich solvent feed = 6,525 m^3/h Reboiler duty = 418 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 71'600 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 71'600 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 63'600 m3 (Diameter: 69 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Rich solvent storage pumps	not foreseen	2 x 670 kW 2250 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 425 kW 1300 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 220 kW 1175 m3 x 45 m each	One pump in operation, one spare

Unit 700 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 145'000 Nm3/h each train	CO2 flow = 125'000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

Case 3b - Scenario 2 - Solvent storage - Regeneration size 100%

Unit 500 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	827 MWe gross	845 MWe gross	
Steam turbine condenser	592 MWth	663 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 1120 kW	2 x 1250 kW	One operating, one spare

Unit 600 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 47'700 m3 (Diameter: 60 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 55'700 m3 (Diameter: 65 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 47'700 m3 (Diameter: 60 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Rich solvent storage pumps	not foreseen	2 x 1000 kW 3430 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 425 kW 1300 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 220 kW 1175 m3 x 45 m each	One pump in operation, one spare

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.

An overall area of 34,600 m^2 and 27,000 m^2 is required for the storage tanks respectively for Scenario 1 and Scenario 2 of this case 3b, i.e. around 20% and 16% of typical area requirements for a USC PC power plant, excluding coal storage.

3.5.1 Scenario 1: CO_2 transport pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 3b – Scenario 1. Reducing the regenerator capacity, the pipeline diameter is 50 mm lower than the reference case.

Case 3b - Scenario 1 - Solvent storage - Reduced regenerator size

CO_2 pipeline characteristics

		Reference plant	**Flexible plant Scenario 1**
CO_2 flowrate	kg/h	536,000	456,818
Inlet pressure	barg	110	110
Inlet temperature	°C	30	20
Outlet pressure	bar	96.7	94.2
CO_2 phase condition	-	liquid	liquid
Pipeline diameter	mm	500	450

3.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, scenario 1 and scenario 2 show a total investment cost increase of respectively 7.5% and 6.1%.

In addition, it has been estimated that the reduction of the pipeline diameter in Scenario 1 leads to a saving on the cost per unit length of the pipeline of around 105,000 €/km, i.e. about 10% lower than the reference case. Therefore, a cost saving of 10 M€ is expected for the pipeline by considering an overall length of 100 km.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 13-Jun-11
Rev.: 0

CASE 3b - Scenario 1 - Solvent storage - Reduced regenerator size

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	129,434,000	79,514,000	28,353,000	189,912,000	805,640,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,948,000	66,987,000	21,419,000	53,330,000	330,792,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	173,382,000	146,501,000	49,772,000	243,242,000	1,136,432,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,468,000	2,930,000	995,000	4,865,000	22,728,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,468,000	2,930,000	995,000	4,865,000	22,728,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	867,000	733,000	249,000	1,216,000	5,683,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,669,000	7,325,000	2,489,000	12,162,000	56,822,000	
	solvent inventory for flexible operation (*)						54,300,000			54,300,000	(*) Assumed solvent inventory cost: 1000 €/t
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,734,000	1,465,000	498,000	2,432,000	11,364,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	18,206,000	69,683,000	5,226,000	25,540,000	173,625,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	20,806,000	17,580,000	5,973,000	29,189,000	136,372,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	212,394,000	233,764,000	60,971,000	297,971,000	1,446,429,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,900,000	16,400,000	3,000,000	14,900,000	94,200,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,600,000	11,700,000	3,000,000	14,900,000	72,300,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	239,694,000	263,664,000	68,771,000	329,571,000	1,627,329,000	

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 13-Jun-11
Rev. : 0

CASE 3b - Scenario 2 - Solvent storage - Regenerator size 100%

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	129,434,000	72,864,000	31,377,000	189,912,000	802,014,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,948,000	67,217,000	21,729,000	53,330,000	331,332,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	173,382,000	140,081,000	53,106,000	243,242,000	1,133,346,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,468,000	2,802,000	1,062,000	4,865,000	22,667,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,468,000	2,802,000	1,062,000	4,865,000	22,667,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	867,000	700,000	266,000	1,216,000	5,667,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,669,000	7,004,000	2,655,000	12,162,000	56,667,000	
	solvent inventory for flexible operation (*)						38,100,000			38,100,000	(*) Assumed solvent inventory cost: 1000 €/t
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,734,000	1,401,000	531,000	2,432,000	11,333,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	18,206,000	52,809,000	5,576,000	25,540,000	157,101,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	20,806,000	16,810,000	6,373,000	29,189,000	136,002,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	212,394,000	209,700,000	65,055,000	297,971,000	1,426,449,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,900,000	14,700,000	3,300,000	14,900,000	92,800,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,600,000	10,500,000	3,300,000	14,900,000	71,400,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	239,694,000	236,700,000	73,455,000	329,571,000	1,605,049,000	

3.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	**3b - Scenario 1**		**3b - Scenario 2**	
Description	Solvent storage Reduced regenerator size		Solvent storage Regenerator size 100%	
Fixed costs				
Maintenance	54.6		53.8	
Operating Labour	7.80		7.80	
Labour Overhead	2.34		2.34	
Insurance & local taxes	28.9		28.5	
Total fixed cost, M€/y	93.7		92.5	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak** (mean value)
Make up water	0	0	0	0
Chemicals and consumables	2340	1462	2340	1489
Total variable cost, €/h	2340	1462	2340	1489

4 Case 3c – Constant CO_2 flowrate in transport pipeline

4.1 Introduction

The cycling operation of the power plant, required to meet the variable grid demand, leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating conditions in the pipeline.

As a consequence, a two-phase flow or a significant change of the physical properties could occur in the pipeline, if pressure and temperature were not maintained close to the conditions of the capture plant. Furthermore, for some applications like the Enhanced Oil Recovery (EOR) it would be preferred to have a constant flowrate rather than a fluctuating stream.

Two different approaches have been considered in this Case 3c, in order to produce a constant CO_2 stream flowrate, sent to the external pipeline for storage, thus avoiding pressure fluctuations and consequent possible changes of the CO_2 physical state.

- *Scenario 1* (CO_2 buffer storage)
  The introduction in the power plant of a properly designed CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, is considered.

- *Scenario 2* (Reduced regenerator capacity)
  The regeneration and compression sections are operated at a constant reduced load. Therefore, these sections are designed for the new required capacity, while solvent storage tanks are provided to compensate the difference between the absorber and the regenerator load.

In this configuration a constant CO_2 flowrate, lower than peak production when the plant is operated at base load, is sent to the external pipeline; therefore, it is possible to select a lower pipeline size, leading to a possible significant cost saving. For this reason, a comparison between the additional costs of the two above scenarios versus the saved cost of a larger pipeline is also made in this Case 3c.

4.2 Case description

The considerations made in this section refer to the whole week of plant operation, on the basis of the grid demand cycling trend summarised in section 1.

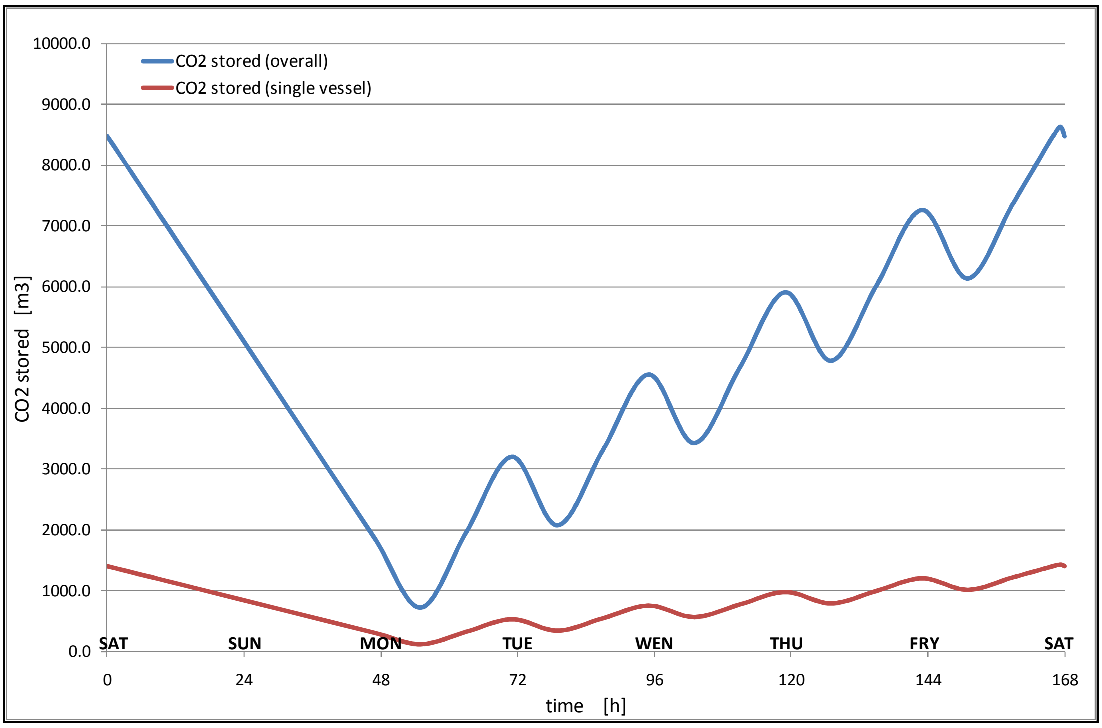
4.2.1 Scenario 1: CO_2 buffer storage

The required CO_2 buffer storage volume is evaluated considering that the power plant is operated at base load for 80 hours per week, and at 55% load during the remaining 88 hours, when the plant is called to generate 50% of its overall net power production capacity.

The constant CO_2 flow in the pipeline is a consequence of the balance of the CO_2 flowrate from and to the storage system during the whole week of operation, made to avoid any accumulation in the buffer vessels and resulting in about 76% of the CO_2 captured when the plant is operated at its maximum capacity.

Figure 4.2-1 shows the whole volume of stored CO_2 during the week and the single vessel volume trend (six vessels in total are considered). The required net volume of the storage vessels is the difference between the maximum and the minimum volume of stored CO_2 during the week. From the graph, it can be drawn that it corresponds to the CO_2 accumulated during the weekdays, and mainly discharged during the partial load operation from Friday night to Monday morning.

Figure 4.2-1: Case 3c – Scenario 1 – Stored CO_2 volume during the week



The CO_2 from the cooling water exchanger, downstream the last compression stage, is stored, in liquid phase, at 85 bar and 20°C, i.e. above its critical pressure and below its critical temperature. Storing and maintaining the CO_2 in liquid form below its critical pressure, even if it is easily practicable at the ambient condition selected for the study, i.e. ambient temperature around 9°C, could be a more critical aspect in hotter countries.

A constant flow is pumped from the vessels to the pipeline by means of properly designed pumps, smaller than those required in the reference case.

4.2.2 Scenario 2: Reduced regenerator capacity

In this scenario, the constant CO_2 flowrate results from operating the regeneration and compression system at constant load. Hence, solvent storage is required to decouple the boiler and absorber operation from the regeneration and CO_2 compression, allowing the power plant to operate flexibly in response to the electricity demand.

In this case, the regeneration and compression sections are required to operate at a constant reduced load, allowing to design these units for a lower capacity with respect to the reference case.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are operated at their base load, properly designed for this scenario, thus reducing the energy penalties in the plant.

As the regenerator is smaller than the size required to treat the whole solvent from the absorber operated at base load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from dedicated storage tanks.

During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the power plant is required to generate the 50% of the daily power output, regenerating the rich solvent stored in the tanks and refilling the lean amine storage tanks. The estimated boiler load is around 62%.

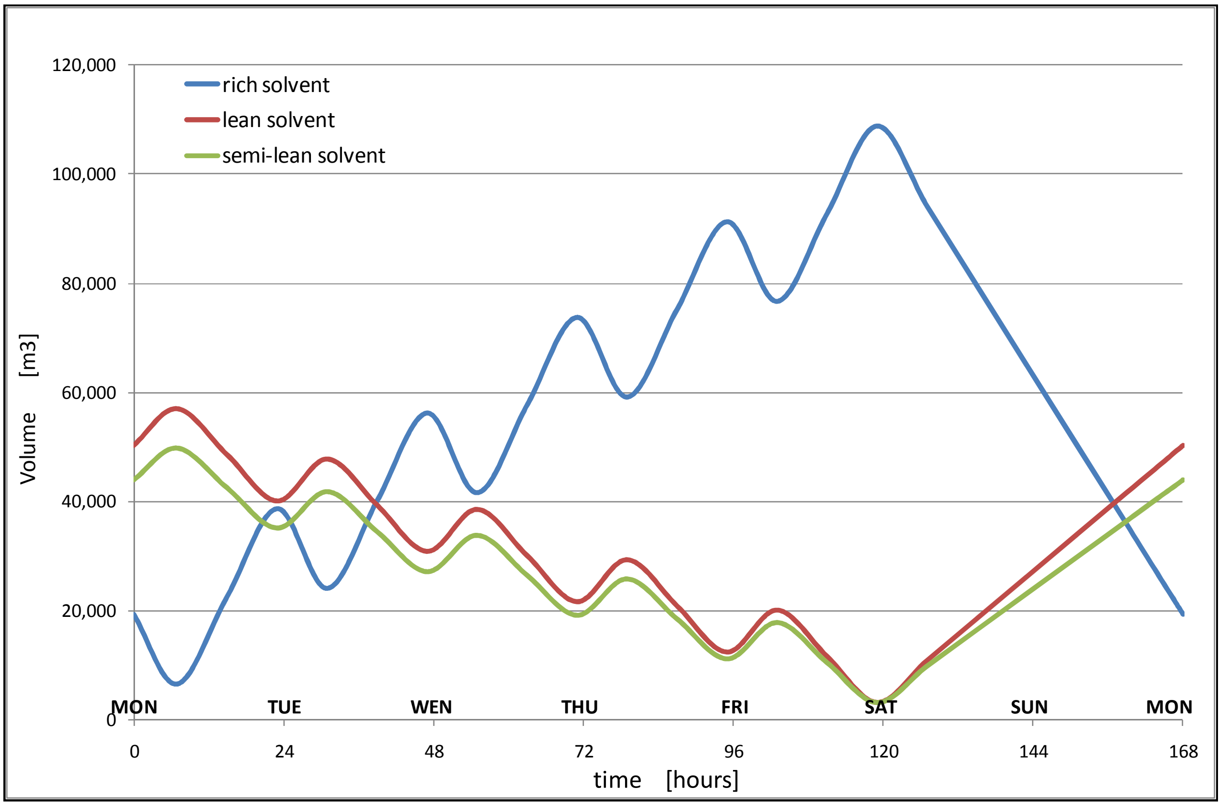
The regeneration section is properly designed to avoid stored product accumulation within the week of plant operation, resulting in about 80% of the reference case design capacity.

This means that, by operating the regenerator at the new selected design capacity, the rich solvent stored during the 80 hours per week of peak load operation, when the plant is at base-load, is balanced by the rich solvent from the storage regenerated during the 88 hours per week of off-peak load operation, when the boiler is at operated at partial load.

As a consequence, also the lean and semi-lean solvent flowrates from and to the storage are balanced in one week of plant operation.

Figure 4.2-2 shows the stored volumes of rich, lean and semi-lean solvents during the week, for the Scenario 2 considered in this Case 3c. The net volume of the storage tank corresponds to the difference between the maximum and the minimum volume of solvent stored during the week. That corresponds to the solvent stored during the weekend, from the turndown of Friday night to the-ramp up of Monday morning.

Figure 4.2-2: Case 3c – Scenario 2 –Stored solvent volume during the week



4.3 Utility consumption

Considering the plant operation as described in Scenario 1, during peak electricity demand period the utility consumption is same as the reference case because the operating modes of the plant are identical. The utility consumption during off-peak demand periods are attached here after.

For Scenario 2, the utility consumption of the process/utility & offsite units during peak and off-peak demand periods are shown in the following tables.

Scenario 1

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
		feb-11
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
LOCATION:	Netherlands	CHECKED BY: PC
FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3c - Scenario 1 - WATER CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			38	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	54.2			
400	**DeNOx Plant**				
600	**CO2 Absorption**	76.2		12950	7530
	Amine Stripping			3720	5220
700	**CO2 Compression and Recovery System**				2990
200	**BOILER ISLAND**			49	
500	**POWER ISLAND (Steam Turbine)**		17.8	2142	74160
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	19.6	-17.8	42	32470
	BALANCE	150.0	0	18941	122370

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3c - Scenario 1 - ELECTRICAL CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2700**
300	**FGD**	**3800**
400	**DeNOx**	**220**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**7700**
	CO2 Absorption and Amine Stripping - pumps	**1600**
700	**CO2 Compression and Recovery System**	**42000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**24700**
	Miscellanea utilities	**5700**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**8000**
	Additional consumption including CCS	**3500**
	BALANCE	**99920**

Scenario 2

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft feb-11
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3c - Scenario 2 - WATER CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			5400	7592
700	**CO2 Compression and Recovery System**				4336
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2958	107486
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	55097
	BALANCE	272.7	0	32140	188191

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	feb-11
	LOCATION:	Netherlands	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

CASE 3c - Scenario 2 - WATER CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			42	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	60.9			
400	**DeNOx Plant**				
600	**CO2 Absorption**	85.6		14550	8460
	Amine Stripping			5400	7600
700	**CO2 Compression and Recovery System**				4340
200	**BOILER ISLAND**			55	
500	**POWER ISLAND (Steam Turbine)**		20.1	1640	53743
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	22.1	-20.1	47	37258
	BALANCE	168.5	0	21734	111401

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3c - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**48000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9100**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**11500**
	Additional consumption including CCS	**4200**
	BALANCE	**150200**

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	feb-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3c - Scenario 2 - ELECTRICAL CONSUMPTION SUMMARY - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3100**
300	**FGD**	**4300**
400	**DeNOx**	**250**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**8700**
	CO2 Absorption and Amine Stripping - pumps	**2130**
700	**CO2 Compression and Recovery System**	**48000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**28100**
	Miscellanea utilities	**6100**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7500**
	Additional consumption including CCS	**4000**
	BALANCE	**112180**

4.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following tables, for the two assessed scenarios.

It is noted that, for Scenario 2, during high electricity demand period the net plant power output is about 23 MWe higher than the reference plant.

Case 3c - Scenario 1 - Constant CO_2 flowrate			
OVERALL PLANT PERFORMANCES			
		Reference case Peak time	Off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	266.3	146.4
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0
Main steam flow	kg/s	681.5	343.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1052.3**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**434.9**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY			
BFW pumps	MWe	37.0	18.6
Draught Plant	MWe	9.0	4.9
ESP	MWe	2.0	1.1
Miscellanea	MWe	9.0	5.7
Coal mills, handling, etc.	MWe	5.0	2.7
FGD	MWe	6.0	3.3
DeNOx	MWe	0.3	0.2
Utility Units consumption	MWe	10.0	8.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**44.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**390.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**37.1**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY			
Additional consumption			
CO_2 Absorption - Blower	MWe	14.0	9.8
CO_2 Absorption & Regenerator - Pumps		3.0	1.6
CO_2 Compression and Drying	MWe	60.0	42.0
Additional Process Units consumptions including CCS	MWe	1.1	0.6
Additional Utility Units consumptions including CCS	MWe	5.0	3.5
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**57.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**332.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**31.6**
CO_2 emission	**kg/s**	**25.98**	**14.29**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.154**

Case 3c - Scenario 2 - Constant CO_2 flowrate				
OVERALL PLANT PERFORMANCES				
		Reference case	Peak time	Off-peak time
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	164.5
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
Main steam flow	kg/s	681.5	681.5	393.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1182.4**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**838.4**	**464.6**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
BFW pumps	MWe	37.0	37.0	21.3
Draught Plant	MWe	9.0	9.0	5.6
ESP	MWe	2.0	2.0	1.2
Miscellanea	MWe	9.0	9.1	6.1
Coal mills, handling, etc.	MWe	5.0	5.0	3.1
FGD	MWe	6.0	6.0	3.7
DeNOx	MWe	0.3	0.3	0.2
Utility Units consumption	MWe	10.0	11.5	7.5
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**79.9**	**48.7**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**758.5**	**415.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**43.8**	**39.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**39.6**	**35.2**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY				
Additional consumption				
CO_2 Absorption - Blower	MWe	14.0	14.0	9.8
CO_2 Absorption & Regenerator - Pumps		3.0	3.0	3.0
CO_2 Compression and Drying	MWe	60.0	48.0	48.0
Additional Process Units consumptions including CCS	MWe	1.1	1.1	0.7
Additional Utility Units consumptions including CCS	MWe	5.0	4.2	4.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**70.3**	**65.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**688.2**	**350.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**43.8**	**39.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**36.0**	**29.6**
CO_2 emission	**kg/s**	**25.98**	**25.98**	**16.05**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.136**	**0.165**

4.5 Equipment list

For the two scenarios assessed in this case, the following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to avoid the flowrate fluctuations in the CO_2 pipeline in relation to the flexible operation of the plant.

Case 3c - Scenario 1 - CO_2 buffer storage

UNIT 700 - CO2 compression - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
CO2 buffer storage vessel	not foreseen	6 x 1'450 m3 (Diameter: 8.5 m, H: 25.5 m)	Nitrogen blanketed vessel Material: SS
CO_2 pump	(1 + 1) x 1250 kW 660 m3 x 450 m each	(2 + 2) x 355 kW 250 m3/h x 450 m each	Two operating, two spare
CO2 final cooler	not foreseen	Duty = 11.4 Mwth Surface = 410 m2	

Note: The number of equipment is referred to both trains

Case 3c - Scenario 2 - Constant CO_2 flow to storage - Reduced regenerator size

Unit 500 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	827 MWe gross	838 MWe gross	
Steam turbine condenser	592 MWth	648 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 1120 kW	2 x 1250 kW	One operating, one spare

Unit 600 - CO_2 Capture Unit

Equipment	Reference plant	Flexible plant	Remarks
Regeneration section	CO_2 outlet flow = 12,200 kmol/h Rich solvent feed = 7,660 m^3/h Reboiler duty = 490.4 MW th	CO_2 outlet flow = 9,745 kmol/h Rich solvent feed = 6,130 m^3/h Reboiler duty = 392 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 55'700 m3 (Diameter: 65 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 55'700 m3 (Diameter: 65 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 47'700 m3 (Diameter: 60 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Rich solvent storage pumps	not foreseen	2 x 530 kW 1800 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 335 kW 1040 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 185 kW 940 m3 x 45 m each	One pump in operation, one spare

Unit 700 - CO_2 Compression Unit

Equipment	Reference plant	Flexible plant	Remarks
Compression package *(2x50% train)*	CO2 flow = 145'000 Nm3/h each train Compressor power consumption: 2 x 30 MWe	CO2 flow = 116'000 Nm3/h each train Compressor power consumption: 2 x 24 MWe	Including: - four stage compressor - intercoolers - dryers - CO2 pumps
CO2 final cooler	not foreseen	Duty = 9.1 Mwth Surface = 325 m2	

4.5.1 CO_2 pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the "Upgraded calculator for CO_2 pipeline system" (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 3c. It can be drawn that with a plant designed to provide a constant CO_2 flowrate to the pipeline, despite the cyclic operation of the plant, the pipeline diameter is 50 mm lower than the one of the reference case, both for scenario 1 and scenario 2.

Case 3c - Constant CO_2 flowrate

CO_2 pipeline characteristics

		Reference plant	Flexible plant Scenario 1	Flexible plant Scenario 2
CO_2 flowrate	kg/h	536,000	409,657	428,800
Inlet pressure	barg	110	110	110
Inlet temperature	°C	30	20	20
Outlet pressure	bar	96.7	97.5	96.2
CO_2 phase condition	-	liquid	liquid	liquid
Pipeline diameter	mm	500	450	450

4.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, Scenario 1 and Scenario 2 show a total investment cost increase of respectively 1.8% and 5.8%.

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 105,000 k€/km for both scenarios, i.e. about 5% lower than the reference case. Therefore, depending on the overall length, the investment increase of the plant may be offset by the lower cost of the pipeline. For example, in Scenario 1, the plant investment cost is expected to be 30 M€ (90 M€ in scenario 2) higher than the reference case, while a cost saving of 10 M€ is expected for the pipeline by considering an overall length of 100 km.

FOSTER WHEELER

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 16 May 2011
Rev. : 0

CASE 3c - Scenario 1 - CO2 buffer storage

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	122,884,000	44,824,000	47,727,000	189,912,000	783,774,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,408,000	66,477,000	25,829,000	53,330,000	334,152,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	166,292,000	111,301,000	73,556,000	243,242,000	1,117,926,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,226,000	1,471,000	4,865,000	22,358,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,326,000	2,226,000	1,471,000	4,865,000	22,358,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	831,000	557,000	368,000	1,216,000	5,590,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,315,000	5,565,000	3,678,000	12,162,000	55,897,000	
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,663,000	1,113,000	736,000	2,432,000	11,179,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	17,461,000	11,687,000	7,724,000	25,540,000	117,382,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	19,955,000	13,356,000	8,827,000	29,189,000	134,151,000	BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	203,708,000	136,344,000	90,107,000	297,971,000	1,369,459,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,300,000	9,500,000	4,500,000	14,900,000	88,200,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,200,000	6,800,000	4,500,000	14,900,000	68,500,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	230,008,000	154,444,000	100,907,000	329,571,000	1,540,559,000	

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 13-Jun-11
Rev. : 0

CASE 3c - Scenario 2 - CO2 constant flow - Reduced regenerator size

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	127,134,000	72,414,000	27,513,000	189,912,000	795,400,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	43,738,000	66,857,000	21,379,000	53,330,000	330,412,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	170,872,000	139,271,000	48,892,000	243,242,000	1,125,812,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,417,000	2,785,000	978,000	4,865,000	22,515,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,417,000	2,785,000	978,000	4,865,000	22,515,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	854,000	696,000	244,000	1,216,000	5,628,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	8,544,000	6,964,000	2,445,000	12,162,000	56,292,000	
	solvent inventory for flexible operation (*)						43,400,000			43,400,000	(*) Assumed solvent inventory
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,709,000	1,393,000	489,000	2,432,000	11,258,000	cost: 1000 €/t
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	17,941,000	58,023,000	5,134,000	25,540,000	161,608,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	20,505,000	16,713,000	5,867,000	29,189,000	135,098,000	
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	209,318,000	214,007,000	59,893,000	297,971,000	1,422,518,000	**BUSINESS CONFIDENTIAL**
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	14,700,000	15,000,000	3,000,000	14,900,000	92,600,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	10,500,000	10,700,000	3,000,000	14,900,000	71,200,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	236,318,000	241,507,000	67,693,000	329,571,000	1,600,718,000	

4.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	3c - Scenario 1		3c - Scenario 2	
Description	CO_2 buffer storage		CO_2 constant flow Reduced regenerator size	
Fixed costs				
Maintenance	51.7		53.7	
Operating Labour	7.80		7.80	
Labour Overhead	2.34		2.34	
Insurance & local taxes	27.4		28.5	
Total fixed cost, M€/y	89.2		92.3	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak**
Make up water	0	0	0	0
Chemicals and consumables	2340	1287	2340	1446
Total variable cost, €/h	2340	1287	2340	1446

5 Case 3d – Turning CO_2 capture ON/OFF

5.1 Introduction

This Case 3d shows how USC PC plants with post-combustion capture of the CO_2 can be also maintained in continuous operation without making the capture and compression of the carbon dioxide for transportation outside plant battery limits.

Depending on possible CO_2 emission allowances cost, this operating flexibility may improve the economics of the plant, because of its resulting higher power production, as shown in the following sections.

5.2 Description

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems, as it is possible to totally by-pass the CO_2 capture unit, directly venting to atmosphere the flue gas through the boiler stack, similarly to a conventional power plant without CO_2 capture. When the CO_2 capture unit is bypassed, around 536 t/h of CO_2 are released to atmosphere instead, of being captured and compressed, considering the plant operating at base load.

In this operating mode, the energy penalties related to the CO_2 capture and compression units, as well as the steam requirement for solvent regeneration, are avoided, leading to an overall higher plant net power production.

As no heat is required by the regenerator reboiler, the low pressure steam from the steam generators and the exhaust steam from the MP module of the Steam Turbine are used to generate additional power in the LP module of the Steam Turbine.

The resulting LP steam entering this section of the machine is increased with respect to the reference case of about 65%. Therefore, the low pressure steam turbine module, the condenser and condensate system shall be properly designed for the increased steam flow during the CO_2 venting operating mode. The power plant shall be designed to operate efficiently in this condition, while allowing partial load operation when CO_2 is captured and compressed.

5.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME PROJECT: OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS LOCATION: Netherlands FWI Nº: 1- BD 0530 A	Rev: Draft mar-11 ISSUED BY: NF CHECKED BY: PC APPR. BY: LM

CASE 3d - WATER CONSUMPTION SUMMARY - NO CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	0.0		0	0
	Amine Stripping			0	0
700	**CO2 Compression and Recovery System**				0
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	3274	107486
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	6010
	BALANCE	134.2	0	3506	113496

Note: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
			feb-11
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	LOCATION:	Netherlands	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

CASE 3d - WATER CONSUMPTION SUMMARY - with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			6750	9490
700	**CO2 Compression and Recovery System**				5420
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2876	107486
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	57271
	BALANCE	272.7	0	33408	193347

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	Netherlands	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

CASE 3d - ELECTRICAL CONSUMPTION SUMMARY - NO CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**0**
	CO2 Absorption and Amine Stripping - pumps	**0**
700	**CO2 Compression and Recovery System**	**0**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9500**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7750**
	Additional consumption including CCS	**0**
	BALANCE	**77650**

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CASE 3d - ELECTRICAL CONSUMPTION SUMMARY - with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**60000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7750**
	Additional consumption including CCS	**8500**
	BALANCE	**162650**

5.4 Performance

The overall plant performances, with and without CO_2 capture are shown in the following table.

In case of venting the CO_2, the plant net power output is expected to be around 190 MWe higher than the base case with full capture and compression of the CO_2, due to the reduction of the internal power demand, leading to an expected net electrical efficiency of 44.3%.

As the power plant is designed also for operation without CCS, the plant net power production is around 10 MWe lower than the reference case, when the capture and compression units are operated.

Case 3d - Turning ON/OFF CO_2 capture				
OVERALL PLANT PERFORMANCES				
		Reference case	Design case NO CCS	with CCS
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	266.3
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
Main steam flow	kg/s	681.5	681.5	681.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**927.3**	**815.8**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
BFW pumps	MWe	37.0	37.0	37.0
Draught Plant	MWe	9.0	9.0	9.0
ESP	MWe	2.0	2.0	2.0
Miscellanea	MWe	9.0	9.5	9.5
Coal mills, handling, etc.	MWe	5.0	5.0	5.0
FGD	MWe	6.0	6.0	6.0
DeNOx	MWe	0.3	0.3	0.3
Utility Units consumption	MWe	10.0	10.5	10.5
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**79.3**	**79.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**848.0**	**736.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**48.5**	**42.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**44.3**	**38.5**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY				
Additional consumption				
CO_2 Absorption - Blower	MWe	14.0	-	14.0
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	-	3.0
CO_2 Compression and Drying	MWe	60.0	-	60.0
Additional Process Units consumptions including CCS	MWe	1.1	-	1.1
Additional Utility Units consumptions including CCS	MWe	5.0	-	3.5
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**0.0**	**81.6**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**848.0**	**654.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**48.5**	**42.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**44.3**	**34.2**

CO_2 emission	**kg/s**	**25.98**	**175.18**	**25.98**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.744**	**0.143**

5.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to allow the plant to operate either capturing or venting the CO_2.

Case 3d - CO2 capture ON-OFF

Unit 500 - Steam turbine island package

Equipment	Reference plant	Flexible plant	Remarks
Steam turbine	827 MWe gross	928 MWe gross	
Steam turbine condenser	592 MWth	875 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 1120 kW	2 x 1800 kW	One operating, one spare
Condensate preheater #1	not foreseen	61 MWth surface = 1360 m2	
Condensate preheater #2	not foreseen	39.5 MWth surface = 1185 m2	
Condensate preheater #3	not foreseen	72.8 MWth surface = 1550 m2	

Unit 800 - Utility unit

Equipment	Reference plant	Flexible plant	Remarks
Sea water pumps	(8 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	(10 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.
An overall area of 30,000 m^2 is required for the storage tanks of Scenario 2 of this case 3c, i.e. around 18% of typical area requirements for a USC PC power plant excluding coal storage.

5.6 Investment costs

The table attached to this section shows the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 4%.

ESTIMATE SUMMARY

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 16 May 2011
Rev. : 0

CASE 3d - CO2 capture ON-OFF

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	150,054,000	44,824,000	31,377,000	200,472,000	805,154,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	46,108,000	66,477,000	21,729,000	55,970,000	335,392,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	196,162,000	111,301,000	53,106,000	256,442,000	1,140,546,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,923,000	2,226,000	1,062,000	5,129,000	22,810,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,923,000	2,226,000	1,062,000	5,129,000	22,810,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	981,000	557,000	266,000	1,282,000	5,704,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	9,808,000	5,565,000	2,655,000	12,822,000	57,027,000	
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,962,000	1,113,000	531,000	2,564,000	11,405,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	20,597,000	11,687,000	5,576,000	26,926,000	119,756,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	23,539,000	13,356,000	6,373,000	30,773,000	136,865,000	BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	240,298,000	136,344,000	65,055,000	314,141,000	1,397,167,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	16,800,000	9,500,000	3,300,000	15,700,000	90,300,000	
10	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
11	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	12,000,000	6,800,000	3,300,000	15,700,000	69,900,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	270,898,000	154,444,000	73,455,000	347,341,000	1,571,767,000	

5.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**3d**	
Description	On-Off CO_2 capture	
Fixed costs		
Maintenance	52.7	
Operating Labour	7.80	
Labour Overhead	2.34	
Insurance & local taxes	27.9	
Total fixed cost, M€/y	90.8	
Variable costs (without fuel)		
	with CCS	**without CCS**
Make up water	0	0
Chemicals and consumables	2340	819
Total variable cost, €/h	2340	819

6 Case 3e – Daily solvent storage with an alternate demand curve

6.1 Introduction

This case is based on the assumption that the weekly demand curve is different from the one shown in Figure 1-1 and characterised by the following three different electricity demand periods:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (50% of net power output): night and weekend.

As discussed in Case 3b, the operating flexibility of USC PC plants with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing the solvent storage from/to the absorber and the stripper.

In fact, solvent storage can allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases.

The solvent regeneration and CO_2 compression, with their associated energy penalties, can be operated during low electricity demand periods, while maximizing the electricity production when the market requires a higher electricity generation.

6.2 Case description

To maximize the energy production, the rich solvent is entirely stored during the 2 hours per day of peak load operation, when the plant is at base-load, while the regeneration of stored solvent is made during the 8 night hours per day of off-peak load operation, when the plant is required to operate at a partial load in order to produce 50% of the normal net power output. With this strategy, the solvent flowrates from and to the storage are balanced within each day of plant operation.

During normal electricity demand period, the power plant is operated at base load as in the reference case conditions (refer to section E of this report).

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gases in the absorber column, while the solvent regeneration and the CO_2 compression sections are halted, thus reducing the energy penalties in the plant. A certain amount of steam is sent to the regenerator reboiler to keep the column warm during the two hours of shutdown.

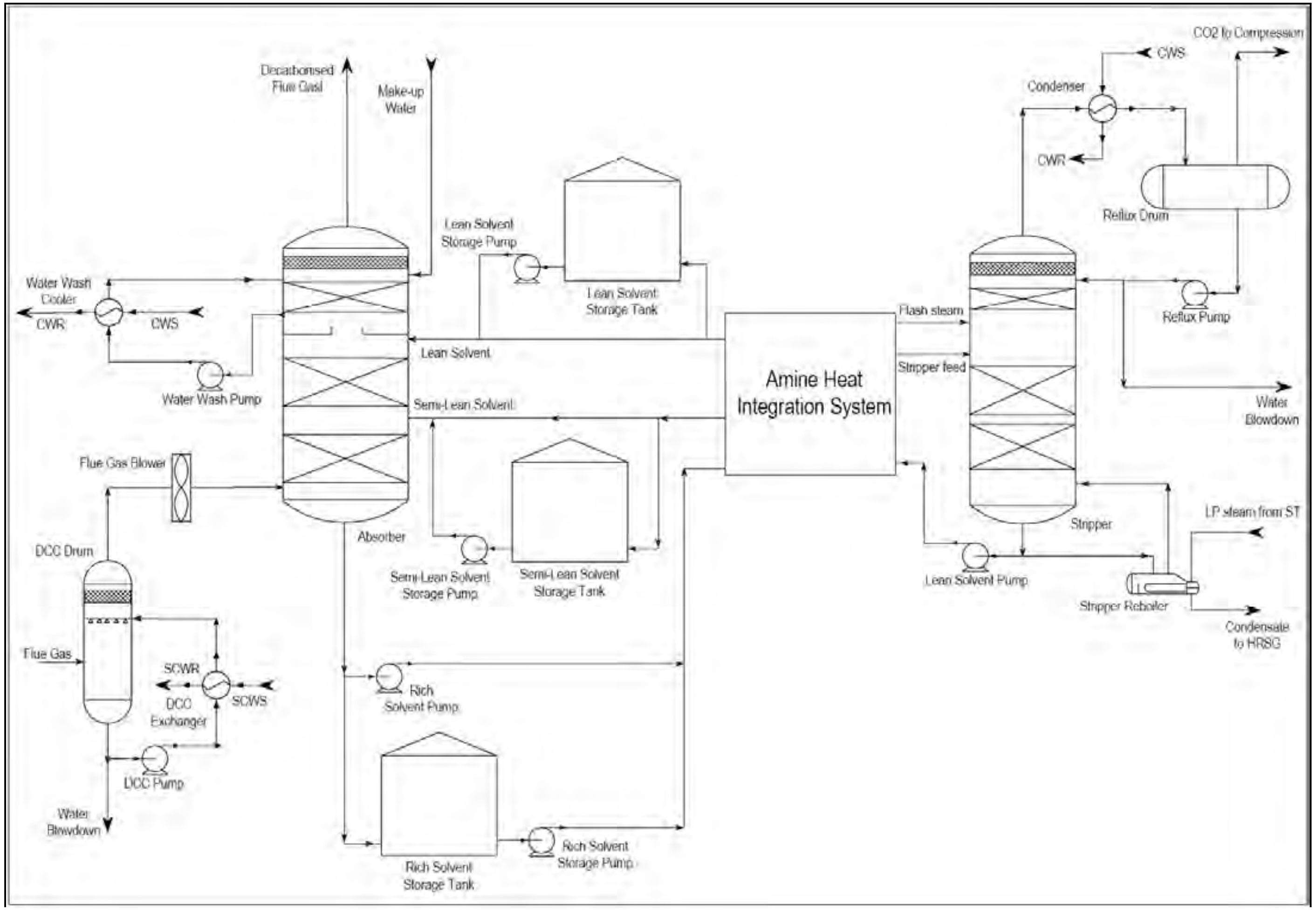
A supplementary LP pressure steam turbine has been considered to expand the additional steam available when the regeneration is halted; this avoided to over sizing the steam turbine for the total amount of steam, as well as the inefficient operation of the machine during normal operation. In this case, the time required for shutting down the capture unit is limited by the steam turbine start-up time, which determines the steam flowrate that can be diverted from the regenerator reboiler to the steam turbine. A time around 20-30 minutes is expected after steam turbine synchronization. In case the main steam turbine is designed for the operation without solvent regeneration, the plant could have a faster ramp up of power output, achieving the maximum power output in 10 minutes.

The CO_2-rich solvent from the absorber column is stored in dedicated storage tanks. The lean and semi-lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the storage tanks, as shown in Figure 6.2-1.

During off peak demand period the boiler is operated at the partial load corresponding to a net power output of approximately 50% of the normal operation production, as required by the grid during off-peak hours, i.e. around 55% during the weekend and 61% during weekday night time, when the solvent stored during peak load operation has to be regenerated to avoid any product accumulation.

Therefore, during weekday night time the regenerator and compression sections are required to operate at around 86% in order to regenerate all the rich solvent stored during the two hours of peak demand.

Figure 6.2-1: Post combustion unit with solvent storage



6.3 Utility consumption

The utility consumption of the process/utility & offsite units during peak, off-peak and normal electricity demand periods are attached hereafter.

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CASE 3e - WATER CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			**68**	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	**98.5**			
400	**DeNOx Plant**				
600	**CO2 Absorption**	**138.5**		**23550**	**13680**
	Amine Stripping			**0**	**0**
700	**CO2 Compression and Recovery System**				**0**
200	**BOILER ISLAND**			**89**	
500	**POWER ISLAND (Steam Turbine)**		**32.5**	**3228**	**106169**
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**35.7**	**-32.5**	**75**	**46303**
	BALANCE	**272.7**	**0**	**27010**	**166152**

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CASE 3e - WATER CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			68	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	98.5			
400	**DeNOx Plant**				
600	**CO2 Absorption**	138.5		23550	13680
	Amine Stripping			6750	9490
700	**CO2 Compression and Recovery System**				5420
200	**BOILER ISLAND**			89	
500	**POWER ISLAND (Steam Turbine)**		32.5	2918	70268
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	75	57343
	BALANCE including CO_2 compression	272.7	0	33450	156201

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CASE 3e - WATER CONSUMPTION SUMMARY - Off-Peak load operation (weekday night time)

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			42	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	60.1			
400	**DeNOx Plant**				
600	**CO2 Absorption**	84.5		14370	8350
	Amine Stripping			5810	8170
700	**CO2 Compression and Recovery System**				4670
200	**BOILER ISLAND**			54	
500	**POWER ISLAND (Steam Turbine)**		19.8	1588	42161
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	21.8	-19.8	46	37560
	BALANCE	166.3	0	21910	100911

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CASE 3e - WATER CONSUMPTION SUMMARY - Off-Peak load operation (weekend)

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**			38	
300	**Flue Gas Desulphurization (FGD) and Handling Plant**	54.2			
400	**DeNOx Plant**				
600	**CO2 Absorption**	76.2		12950	7530
	Amine Stripping			3720	5220
700	**CO2 Compression and Recovery System**				3800
200	**BOILER ISLAND**			49	
500	**POWER ISLAND (Steam Turbine)**		17.9	1535	56215
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	19.6	-17.9	42	31430
	BALANCE	150.0	0	18334	104194

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CASE 3e - ELECTRICAL CONSUMPTION SUMMARY - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**0**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9400**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**11000**
	Additional consumption including CCS	**3500**
	BALANCE	**101300**

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CASE 3e - ELECTRICAL CONSUMPTION SUMMARY - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**7000**
400	**DeNOx**	**400**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**14000**
	CO2 Absorption and Amine Stripping - pumps	**3000**
700	**CO2 Compression and Recovery System**	**60000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**9000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**10000**
	Additional consumption including CO_2 Compression and Drying	**5000**
	BALANCE including CO_2 compression	**161400**

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CASE 3e - ELECTRICAL CONSUMPTION SUMMARY - Off-Peak load operation (weekday night time)

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**3100**
300	**FGD**	**4300**
400	**DeNOx**	**240**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**8500**
	CO2 Absorption and Amine Stripping - pumps	**2600**
700	**CO2 Compression and Recovery System**	**51600**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**27700**
	Miscellanea utilities	**6200**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6600**
	Additional consumption including CCS	**4600**
	BALANCE	**115440**

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CASE 3e - ELECTRICAL CONSUMPTION SUMMARY - Off-Peak load operation (weekend)

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2800**
300	**FGD**	**3900**
400	**DeNOx**	**220**
600	**CO2 Absorption and Amine Stripping - DCC blower**	**7700**
	CO2 Absorption and Amine Stripping - pumps	**1700**
700	**CO2 Compression and Recovery System**	**42000**
	POWER AND BOILER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**48000**
	Miscellanea utilities	**5700**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**8000**
	Additional consumption including CCS	**4300**
	BALANCE	**124320**

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6.4 Performance

The overall plant performance during peak, off-peak and normal electricity demand periods are shown in the following table.

During peak electricity demand period, the net plant power output is about 150 MWe higher than the reference plant.

Case 3e - daily cycle solvent storage - OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX						
		Reference case	Peak time	Normal operation	Off-peak time (weekday night time)	Off-peak time (weekend)
Coal Flowrate (fresh, air dried basis)	t/h	266.3	266.3	266.3	162.4	146.4
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	681.5	681.5	681.5	387.0	343.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**	**1913.7**	**1913.7**	**1167.1**	**1052.3**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**	**914.7**	**827.0**	**450.0**	**435.0**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY						
BFW pumps	MWe	37.0	37.0	37.0	21.0	18.6
Draught Plant	MWe	9.0	9.0	9.0	5.5	4.9
ESP	MWe	2.0	2.0	2.0	1.2	1.1
Miscellanea	MWe	9.0	9.4	9.0	6.2	5.7
Coal mills, handling, etc.	MWe	5.0	5.0	5.0	3.0	4.9
FGD	MWe	6.0	6.0	6.0	3.7	3.3
DeNOx	MWe	0.3	0.3	0.3	0.2	0.2
Utility Units consumption	MWe	10.0	11.0	10.0	6.6	8.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**	**79.7**	**78.3**	**47.4**	**46.7**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**	**835.0**	**748.7**	**402.6**	**388.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**47.8**	**43.2**	**38.6**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**	**43.6**	**39.1**	**34.5**	**36.9**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY						
Additional consumption						
CO_2 Absorption - Blower	MWe	14.0	14.0	14.0	8.5	7.7
CO_2 Absorption & Regenerator - Pumps	MWe	3.0	3.0	3.0	2.6	1.6
CO_2 Compression and Drying	MWe	60.0	-	60.0	51.6	42.0
Additional Process Units consumptions including CCS	MWe	1.1	1.1	1.1	0.7	0.7
Additional Utility Units consumptions including CCS	MWe	5.0	3.5	5.0	4.6	4.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.1**	**21.6**	**83.1**	**68.0**	**56.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**	**813.4**	**665.6**	**334.7**	**332.1**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**	**47.8**	**43.2**	**38.6**	**41.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**	**42.5**	**34.8**	**28.7**	**31.6**
CO_2 emission	**kg/s**	**25.98**	**25.98**	**25.98**	**15.85**	**14.29**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.141**	**0.115**	**0.141**	**0.170**	**0.155**

6.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to improve the operating flexibility of USC PC plant with post-combustion capture.

Case 3e - Daily cycle solvent storage

Unit 500 - Steam turbine island package			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
New Steam turbine		91 MWe gross	
New Steam turbine condenser		295 MWth	Sea water heat exchanger tubes: titanium; shell: CS
New condensate pump		2 x 750 kW	One operating, one spare
Condensate preheater #1	not foreseen	60 MWth surface = 1325 m2	
Condensate preheater #2	not foreseen	39.5 MWth surface = 1190 m2	
Condensate preheater #3	not foreseen	71 MWth surface = 1500 m2	

Unit 600 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 12'000 m3 (Diameter: 30.5 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 12'000 m3 (Diameter: 30.5 m H: 16.5 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Semi lean solvent storage tank *(for flexible operation)*	not foreseen	1 x 10'100 m3 (Diameter: 27.4 m H: 17.1 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Rich solvent storage pumps	not foreseen	2 x 750 kW 2500 m3 x 70 m each	One pump in operation, one spare
Lean solvent storage pumps	not foreseen	2 x 1800 kW 5500 m3 x 80 m each	One pump in operation, one spare
Semi lean solvent storage pumps	not foreseen	2 x 900 kW 4500 m3 x 45 m each	One pump in operation, one spare

Unit 800 - Utility unit			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Sea water pumps	(8 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	(10 + 1 spare) x 1600 kW each: 20000 m3/h x 20m	

Tanks size has been selected based on FW standard design that refers to typical tank size available for refinery industries.
An overall area of 21,900 m^2 is required for the storage tanks of this case 3f, i.e. around 13% of typical area requirements for a USC PC power plant excluding coal storage.

6.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for this case.

With respect to the figures included in Section E for the reference plant, this alternative shows a total investment cost increase of 6%.

FOSTER WHEELER

ESTIMATE SUMMARY

Case 3e - Daily cycle solvent storage

Contract : 1-BD-0530A
Client : IEA
Plant : USC PC with CO2 capture
Date : 07-ott-11
Rev. : 0

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO2 capture	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,064,000	196,894,000	110,316,000	18,153,000	150,574,000	55,944,000	31,377,000	200,472,000	816,794,000	
2	CONSTRUCTION	19,844,000	121,543,000	-	3,721,000	46,438,000	67,837,000	21,729,000	55,970,000	337,082,000	
	DIRECT FIELD COST	72,908,000	318,437,000	110,316,000	21,874,000	197,012,000	123,781,000	53,106,000	256,442,000	1,153,876,000	
3	CONSTRUCTION MANAGEMENT	1,458,000	6,369,000	2,206,000	437,000	3,940,000	2,476,000	1,062,000	5,129,000	23,077,000	
4	COMMISSIONING	1,458,000	6,369,000	2,206,000	437,000	3,940,000	2,476,000	1,062,000	5,129,000	23,077,000	
5	COMMISSIONING SPARES	365,000	1,592,000	552,000	109,000	985,000	619,000	266,000	1,282,000	5,770,000	
6	TEMPORARY FACILITIES	3,645,000	15,922,000	5,516,000	1,094,000	9,851,000	6,189,000	2,655,000	12,822,000	57,694,000	
	solvent inventory for flexible operation (*)						9,000,000			9,000,000	
7	FREIGHT, TAXES & INSURANCE	729,000	3,184,000	1,103,000	219,000	1,970,000	1,238,000	531,000	2,564,000	11,538,000	
	INDIRECT FIELD COSTS	7,655,000	33,436,000	11,583,000	2,296,000	20,686,000	21,998,000	5,576,000	26,926,000	130,156,000	
8	ENGINEERING COSTS	8,749,000	38,212,000	13,238,000	2,625,000	23,641,000	14,854,000	6,373,000	30,773,000	138,465,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	89,312,000	390,085,000	135,137,000	26,795,000	241,339,000	160,633,000	65,055,000	314,141,000	1,422,497,000	
9	CONTINGENCY	6,300,000	27,300,000	9,500,000	1,900,000	16,900,000	11,200,000	3,300,000	15,700,000	92,100,000	
	LICENSE FEES	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	14,400,000	
10	OWNER COSTS	4,500,000	19,500,000	6,800,000	1,300,000	12,100,000	8,000,000	3,300,000	15,700,000	71,200,000	
	OVERALL PROJECT COST	101,912,000	438,685,000	153,237,000	31,795,000	272,139,000	181,633,000	73,455,000	347,341,000	1,600,197,000	

6.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**3e**	
Description	Daily solvent storage	
Fixed costs		
Maintenance	53.7	
Operating Labour	7.80	
Labour Overhead	2.34	
Insurance & local taxes	28.4	
Total fixed cost, M€/y	92.3	
Variable costs (without fuel)		
	peak/normal oper.	**offpeak (avarage)**
Make up water	0	0
Chemicals and consumables	1287	743
Total variable cost, €/h	1287	743

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME : FLEXIBLE OPERATION OF OXY-COMB. PC PLANTS WITH CCS
FWI CONTRACT : 1-BD-0530 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

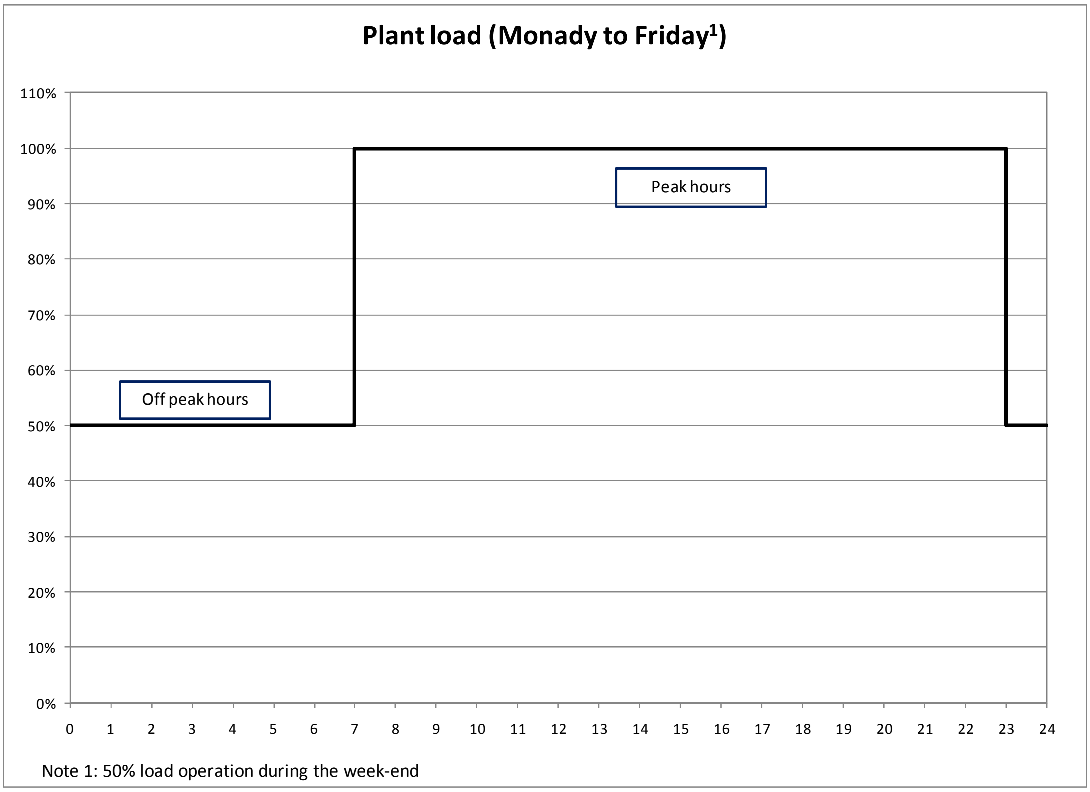
INDEX

1 Introduction

The main objective of this Section I is to assess the operating flexibility of oxy-combustion PC power plants, with cryogenic purification of the flue gases for the capture of the CO_2.

Similarly to the conventional air-fired boiler plants evaluated in Section H, the considerations shown in this section are based on the assumption that the oxy-combustion plants will be requested to operate in the mid merit market, thus participating to the first step of the variable electricity and generally following a weekly demand curve as shown in Figure 1-1.

Figure 1-1: Oxy-combustion PC plant load operation



From the above graph, it can be drawn that the oxy-combustion plants will be maintained at base load for 80 hours per week, while 50% of their overall net power production capacity shall be generated during the remaining 88 hours.

The capability of these plant types for a flexible operation is mainly affected by the constraints related to the ASU, the CO_2 purification unit and transportation pipeline. To investigate these main features, the following cases are presented in this section:

- **Case 4a**: This case assesses the constraints given by the ASU in relation to the normal load change capacity of conventional PC-based power plants, investigating the use of a oxygen storage system to overcome this limitation.
- **Case 4b**: This case considers the liquid oxygen (LOX) storage, in conjunction with either ASU partial load operation or reduced ASU design capacity, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
- **Case 4c**: This case assesses the introduction in the power plant of a CO_2 storage system, which allows to maintain a constant CO_2 flowrate in the pipeline, despite the cycling operation of the plant, thus avoiding a two-phase flow or a significant change of the physical properties.

In addition, the following case has been investigated using an alternative weekly demand curve, based on the assumption that the plant will need to provide two hours of peak operation per each working day, while it is turned down to 50% output during night and weekend (off-peak):

- **Case 4d**: This case considers liquid oxygen (LOX) storage, in conjunction with ASU partial load operation, in order to minimize the plant power consumption and increase the overall power production during peak load demand period. Stored oxygen is supplied to the boiler for two hours of peak demand during the day and is stored overnight, during off-peak demand.

2 Case 4a – Load changes

2.1 Introduction

The main limitation for the flexible operation of an oxy-fuel combustion plant with respect to a conventional PC boiler plant is given by the ramp-rate of the Air Separation Unit, which is generally lower than that of a conventional boiler. In fact, the maximum ramp rate of an ASU is typically 3% per min, while it is generally 4-5% per min for the PC boiler.

This Case 4a assesses the introduction of a properly designed oxygen storage and vaporization system, so to have a ramp-rate capacity same as the conventional boiler plant.

2.2 Case description

When the electricity demand increases, both the Boiler and Air Separation Unit ramp-up with their own rates. The following typical values have been considered:

Boiler ramp rate	5% /min	(50-90% load)
	4% /min	(90-100% load)
ASU ramp rate	3% /min.	

The stored oxygen requirement is evaluated by assuming a ramp-up from 56% to 100% of boiler load, corresponding to a plant ramp-up from 50% to 100% of the overall power production, as required by the cycling demand trend shown in section 1.

With the above assumptions, the boiler reaches full load in less than ten minutes, while nearly 15 minutes are required by the ASU, as also graphically shown in Figure 2.2-1, together with the plant net power output during this transient event. It has to be noted that, while the boiler is operated at base load and the Air Separation Unit is still ramping-up, a net power output higher than nominal can be achieved, due to the lower ASU internal consumption.

Figure 2.2-1: Case 4a – Oxy-combustion PC plant ramp-up

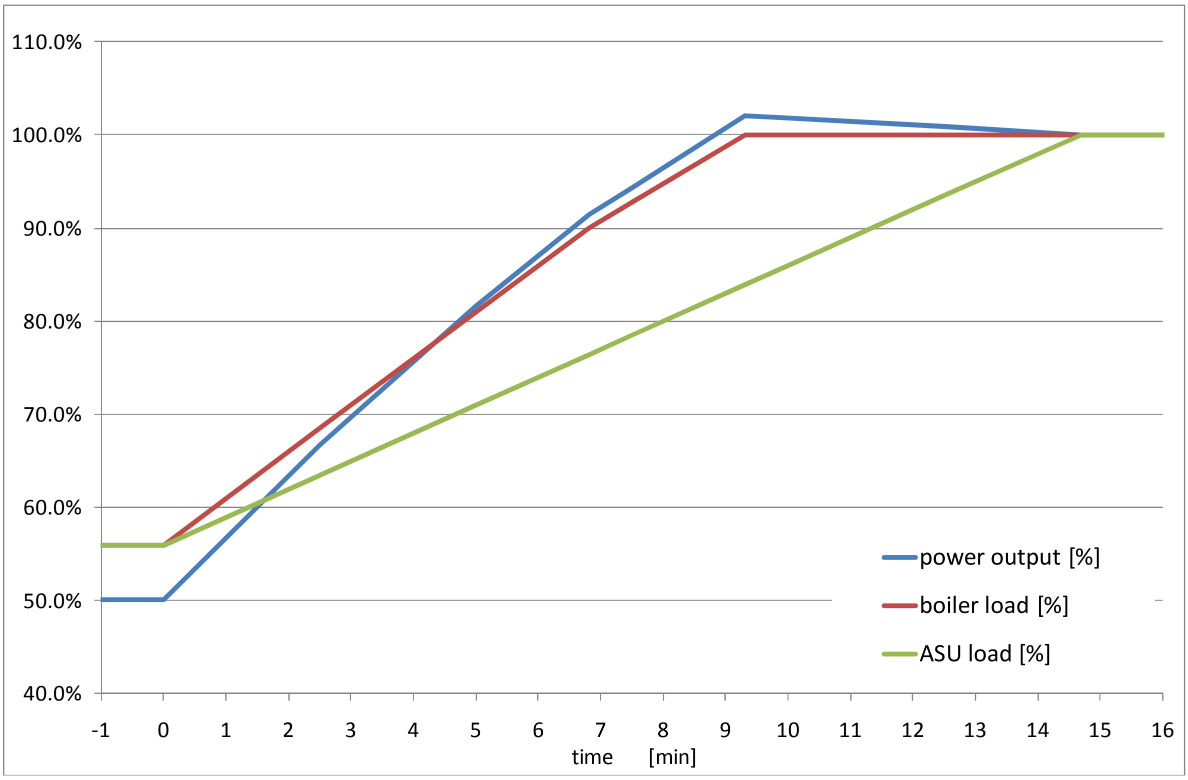
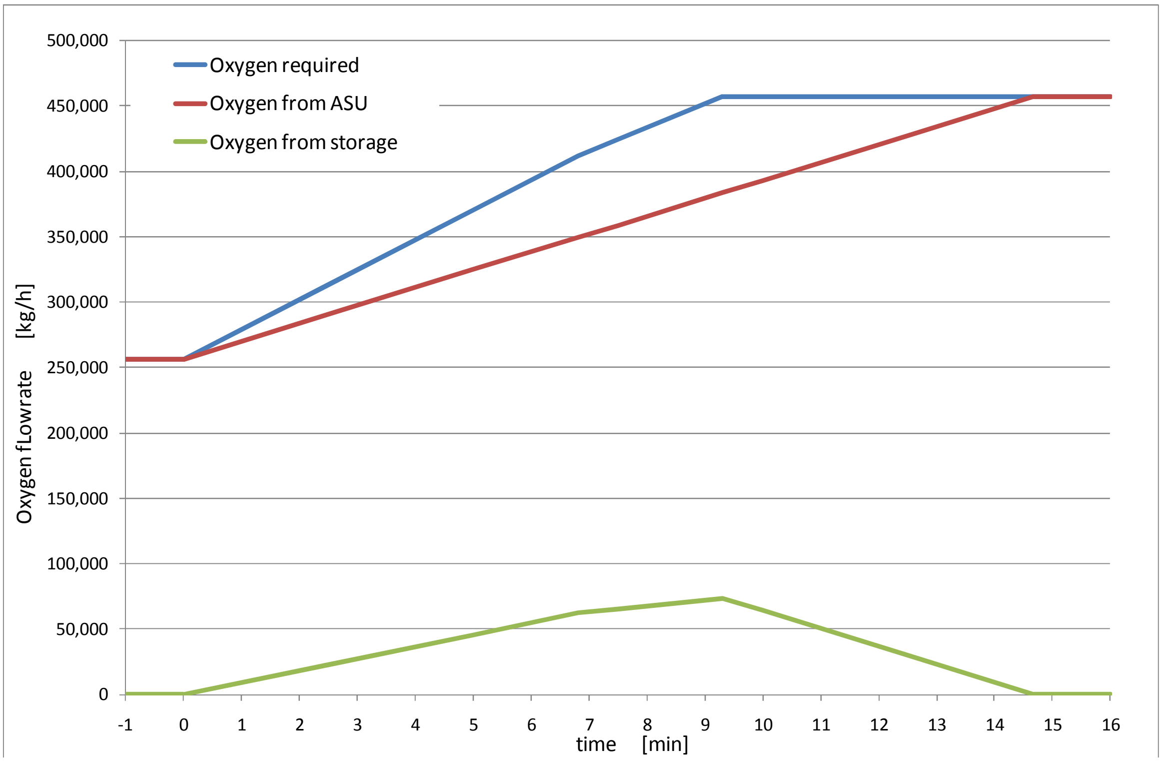


Figure 2.2-2 shows the plant oxygen requirements, the ASU supply rate and the consequent oxygen flow required from the storage facilities in order not to limit the ramp-up rate capacity of the boiler.

The difference between the ASU supply rate and the demand of the boiler is less than 10 tonnes of oxygen for each ramp-up phase. The filling of the storage tank can be carried out when the plant is required to ramp down to 50% of the power output, during off-peak demand hours operation.

Therefore, the 200 tonnes back-up LOX storage tank and vaporiser system, already included in the reference design case for the safe changeover from oxygen firing to air firing in case of a ASU trip, are also adequate to comply with this requirement.

Figure 2.2-2: Case 4a – Oxygen flowrate during plant ramp-up



From the considerations made for Case 4a, it can then be concluded that, due to the presence of oxygen storage in the reference plant, the operating flexibility of the oxy-combustion plant is not limited by the lower ramp-rate of the ASU.

2.3 Utility consumption

The most relevant utility requirement during a ramp-up phase is the power demand of the auxiliary units, as shown in the performance table included in the next section.

2.4 Performance

The following table shows the expected performance of the plant at discrete time intervals, during the ramp-up phase from 50% (off-peak hours) to base load (peak-hours).

Case 4a: Plant ramp-up										
OVERALL PLANT PERFORMANCES										
		time: 0.00	time: 2.50	time: 5.00	time: 6.80	time: 7.50	time: 9.30	time: 10.00	time: 12.50	time: 15.00
		Off-peak operation			90% boiler load		100% boiler load			Base load operation
Coal Flowrate (fresh, air dried basis)	t/h	117.0	143.1	169.3	188.2	194.0	209.1	209.1	209.1	209.1
		55.9%	68.4%	80.9%	90.0%	92.8%	100.0%	100.0%	100.0%	
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0	25860.0	25860.0	25860.0	25860.0	25860.0	25860.0
Main steam flow	kg/s	270.8	341.0	413.0	466.5	483.0	528.2	528.2	528.2	0.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**840.5**	**1028.2**	**1216.0**	**1352.0**	**1393.4**	**1502.2**	**1502.2**	**1502.2**	**1502.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**405.6**	**500.6**	**594.2**	**662.3**	**682.5**	**736.7**	**737.2**	**738.9**	**740.0**
Expander power output	**MWe**	**6.3**	**7.7**	**9.1**	**10.1**	**10.4**	**11.2**	**11.2**	**11.2**	**11.2**
POWER PLANT PERFORMANCES										
ASU	MWe	60.7	60.7	61.5	66.2	68.0	72.7	74.5	81.0	86.7
FW pumps	MWe	17.9	22.6	27.4	30.9	32.0	35.0	35.0	35.0	35.0
Draught Plant	MWe	2.8	3.4	4.0	4.5	4.6	5.0	5.0	5.0	5.0
Coal mills, handling, etc.	MWe	2.2	2.7	3.2	3.6	3.7	4.0	4.0	4.0	4.0
ESP	MWe	1.1	1.4	1.6	1.8	1.9	2.0	2.0	2.0	2.0
Miscellanea	MWe	7.4	9.0	9.2	9.4	9.5	9.6	9.6	9.6	9.6
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	53.2	53.3	61.6	68.5	70.6	76.1	76.1	76.1	76.1
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**145.4**	**153.0**	**168.6**	**184.9**	**190.3**	**204.4**	**206.2**	**212.7**	**218.4**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**266.5**	**355.2**	**434.7**	**487.5**	**502.6**	**543.5**	**542.2**	**537.4**	**532.8**
		50.0%	**66.7%**	**81.6%**	**91.5%**	**94.3%**	**102.0%**	**101.8%**	**100.9%**	
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**48.3**	**48.7**	**48.9**	**49.0**	**49.0**	**49.0**	**49.1**	**49.2**	**49.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31.7**	**34.5**	**35.7**	**36.1**	**36.1**	**36.2**	**36.1**	**35.8**	**35.5**

2.5 Equipment list

As described in the previous sections, no additional equipment or packages are required with respect to the reference design case.

2.6 Investment cost

The investment cost required by this case is same as the reference design plant, as no additional equipment or packages are required.

2.7 Operating and Maintenance Costs

Not Applicable.

3 Case 4b – LOX storage

3.1 Introduction

The ASU significantly reduces the overall net electricity production of the plant, mainly due to its high auxiliary power demand. By reducing the energy requirement of this unit, at least during peak-demand hours, it would be possible to increase the overall net power export during remunerative hours and improve the overall economics of the plant.

Two different approaches have been considered in this Case 4b, in order to reduce the ASU internal consumption when the market requires a higher electricity generation. In both cases, oxygen storage is required in the plant, sized to cover the oxygen production fluctuations. The two scenarios assessed in this Case 4b are listed in the following:

- *Scenario 1*(partial load)
  The ASU is operated at partial load during peak hours, while the rest of the plant is running at full load, thus reducing the auxiliary consumption and increasing the overall net electricity production.

- *Scenario 2* (reduced capacity)
  The ASU is design at reduced capacity, with a consequent lower investment cost, while the plant load is changing in response to the variable electricity market requirements.

In both scenarios, during peak demand period, compressed air is liquefied to provide the heat required for liquid oxygen from storage vaporisation. Liquid air is stored in pressurised vessel and vaporised during off-peak operation to replace the liquid oxygen sent to storage, in the main ASU exchanger.

3.2 Case description

The considerations made in this section refer to the whole week of plant operation, on the basis of the grid demand cycling trend summarised in section 1. From this trend, during peak electricity demand the power plant is operated at base load to maximise the electricity production, while during off-peak electricity demand the plant is required to produce 50% of the overall net electricity production capacity.

For the two scenarios listed above, the oxygen from and to the storage system has to be balanced during the cyclic weekly operation, in order to avoid any accumulation of the product.

The need of balancing the oxygen flow to and from the storage determine a relation between the air separation unit, running at low load during high electricity demand hours, and the boiler, running at partial load during low electricity demand period.
In fact, during off-peak operation the plant auxiliary demand and the consequent boiler load strongly depend on the ASU load, which shall ensure as a minimum the oxygen required by the boiler to produce 50% of the daily power output, and the oxygen to be sent to storage, to fulfil the peak-hours demand.

3.2.1 Scenario 1: partial load

The main technical constrain to be considered in this scenario is the minimum efficient turndown of the main air compressors, because the minimum turndown of the cold box represents a less stringent limitation for the minimum load of the ASU.

In fact, as written in section C and D of this report, the minimum technical load for the cold box operation is around 50% of the design capacity, while the minimum efficient load of the compressors is around 70%. At lower loads, the main air compressors generally operate by introducing the air recycle system, with a significant impact on the power requirement. In fact, when the recycle is in operation, the cold box of the ASU is operating at partial load, while the compressor is still running at high load, without a significant reduction of the electric power consumption.

As a consequence, by reducing the Air Separation Unit load below 70% of design capacity, the net power production is not significantly increased, unless multiple train configuration were selected for the ASU main air compressors, leading to a higher investment cost.

The following alternatives have been considered for this scenario:

- Operation of the air separation unit at the minimum load of the cold box (50%): in this case the plant power output during peak load operation is maximized with respect to the reference design, whilst a dual train configuration for the air compressors of each ASU train shall be considered. However, during low electricity demand period, the plant net power production is lower than the required 50% and the plant load cannot be increased further, because it is limited by the amount of oxygen available for the boiler, resulting from the difference between the oxygen produced at maximum load of the ASU and the oxygen required by the storage system.
  Because of the above, this operating configuration cannot comply with the electricity demand trend assumed for this plant type and is not further assessed in the study.

- Operation of the air separation unit at the minimum load of the main air compressors (70%): in this case the ASU power demand is minimized, without changing the design of the reference plant, i.e. using one single compressor per each of the two unit trains.
  However, the plant load during low electricity demand period is higher than the required 50%, when the Air Separation Unit is maintained at base load.
  The required net power output is obtained by operating the boiler at nearly 60% and the Air Separation Unit at part load, even during off-peak demand period.
  In this case the ASU is never required to operate at base load during the whole week of plant operation, so it could be reasonable to design the Air Separation Unit for a lower capacity, as already analysed in Scenario 2 of this case.

- Multiple compression train configuration for efficient operation at partial load: in order to produce 50% of the net power output and at the same time operating the Air Separation Unit at full load during off-peak hours, the estimated ASU load during high electricity demand hours is around 57%.
  The efficient operation at this load can be achieved using a 2x60% train configuration for the compressors of each Air Separation Unit train. During peak hours, one of the two compressor trains is shut down, while the other is operated at full load.

From the above considerations, the last alternative has been selected to make the technical and economic assessment of this Scenario 1 (the 2nd alternative is assessed in Scenario 2). However, performance tables of all the different alternatives are shown in Section 3.4.

3.2.2 Scenario 2: reduced capacity

This scenario is characterised by the ASU operating steadily at base load, whilst the unit is designed for a lower capacity with respect to the reference case.

The estimated design capacity of the ASU that allows the plant to follow the grid demand cycling trend, i.e. 50% of the net power output during low electricity demand hours, is about 78% of the reference case.

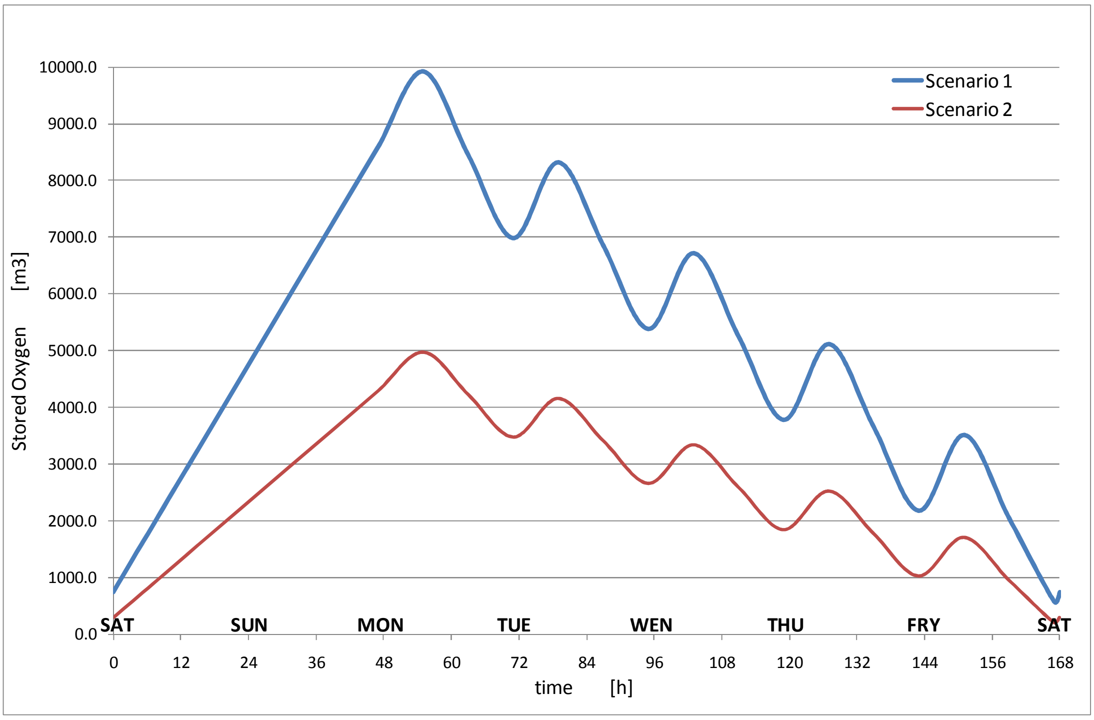
3.2.3 LOX storage

For the two scenarios considered in this Case 4b, during peak demand period, oxygen from the ASU is integrated with the liquid oxygen from the storage, after vaporisation, using condensing air as heating medium. It is noted that, as the ASU design currently proposed by most quoted Vendors is based on the liquid oxygen production, then liquid oxygen storage is not regarded as critical.

The liquid oxygen from the storage is balanced by the oxygen produced during off peak hours, considering a whole week of plant operation. Therefore, the oxygen required from storage during the 80 hours per week of peak load operation, when the plant is operated at base load, is balanced by the oxygen stored during the 88 hours per week of off-peak load operation, when the plant is operated at partial load.

Figure 3.2-1 shows the volume of stored oxygen during the week, for the two scenarios of Case 4b. The required net volume of the storage tank is the difference between the maximum and the minimum volume of stored oxygen during the week. From the graph, it can be drawn that it corresponds to the oxygen stored during the weekend, from the turndown of Friday night to the ramp up of Monday morning.
A minimum LOX storage volume corresponding to the 200 ton required for allowing the safe changeover from oxygen firing to air firing in case of ASU trip has been also considered while defining the tank size.

Figure 3.2-1: Case 4b – Stored Oxygen volume during the week

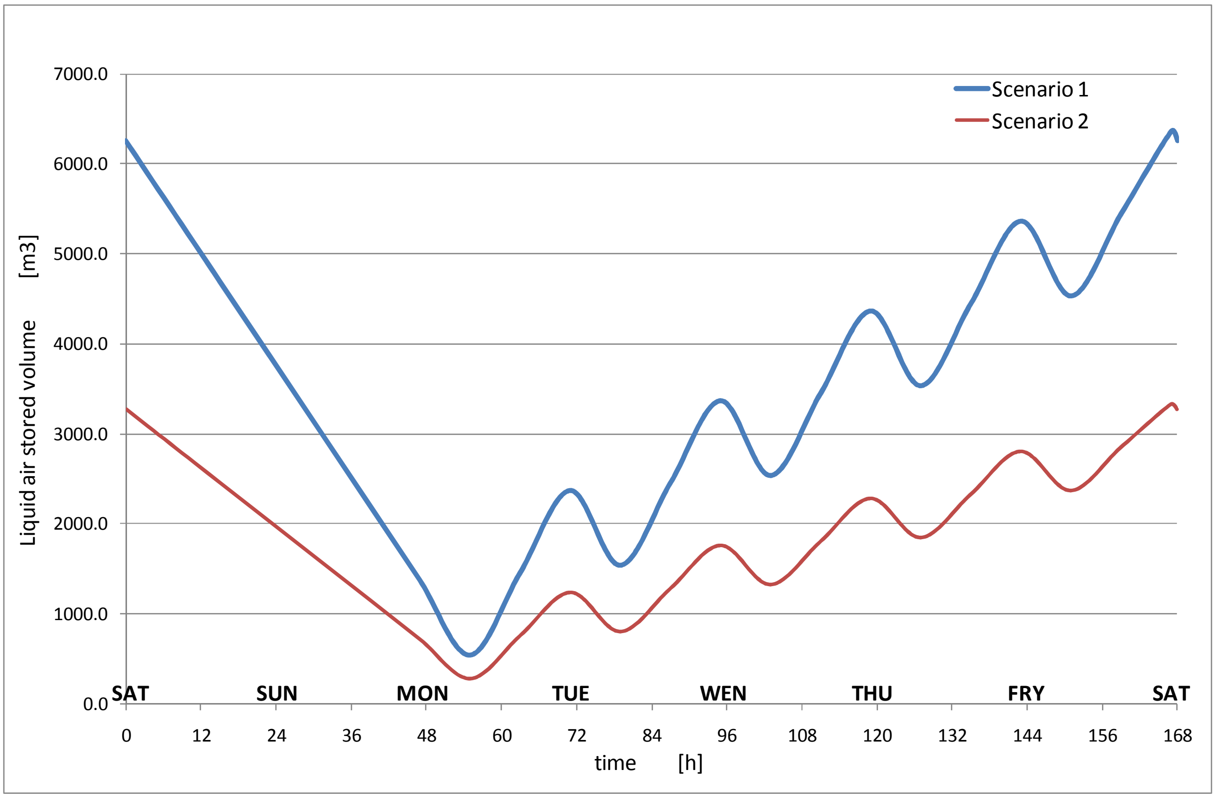

Scenario 1
Scenario 2
Stored Oxygen [m3]
10000.0
9000.0
8000.0
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
SAT
SUN
MON
TUE
WEN
THU
FRY
SAT
0
12
24
36
48
60
72
84
96
108
120
132
144
156
168
time [h]

3.2.4 Air liquefaction

When the plant is operated at base load, liquid oxygen from the bottom of the distillation column of the ASU is vaporised in the main ASU exchanger, using its refrigeration capacity for cooling air to be fed to the column.
During peak demand operation, air is liquefied to provide the heat required for liquid oxygen from storage vaporisation. As air vapour pressure is higher than oxygen vapour pressure, air compression up to 8.5 bar is required for using air to vaporise oxygen, implying the installation of a booster air compressor.
Liquid air is stored during peak demand period to be fed to the ASU column during off-peak hours, compensating the lack of refrigerating capacity in the main air compressor due to the liquid oxygen diverted from the bottom of the column to the storage tank.

Figure 3.2-2 shows the volume of liquid stored air during the week, for the two scenarios of Case 4b.

Figure 3.2-2: Case 4b – Liquid air stored volume during the week



3.3 Utility consumption

The most relevant utility requirements for the two Scenarios of this case are shown in the following tables.

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
			set-11
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
	LOCATION:	NETHERLANDS	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4b (Scenario 1) - Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	54.0	-
600	**Air Separation Unit**	-	-	506.2	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	6.1	-	1635.0	13110
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	24.7	2362.0	98574.6
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	7913.6
	BALANCE	33.3	0.0	4616.2	119598.2

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
LOCATION:	NETHERLANDS
FWI Nº:	1- BD 0530 A

Rev: 0
set-11
ISSUED BY: NF
CHECKED BY: PC
APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4b (Scenario 1) - Off-Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	32.0	-
600	**Air Separation Unit**	-	-	798.8	-
700	**CO_2 Compression and Inerts Removal**	3.7	-	981.9	7873.3
	(including Air Products package)				
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	14.9	1419.0	78831.1
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	16.3	-14.9	35.4	5600.8
	BALANCE	20.0	0.0	3267.1	92305.2

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4b (Scenario 1) - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit + New Air Compressor**	**54051**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**76100**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE	**185751**

Notes: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4b (Scenario 1) - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2402**
600	**Air Separation Unit**	**83082**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53162**
	Exhaust gas expander	(-6109)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**23751**
	Miscellanea utilities	**1201**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE	**169999**

Notes: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
	LOCATION:	NETHERLANDS	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4b (Scenario 2) - Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	54.0	-
600	**Air Separation Unit**	-	-	666.7	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	6.1	-	1635.0	13110
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	24.7	2362.0	98538.9
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	8188.7
	BALANCE including CO_2 compression	33.3	0.0	4776.7	119837.6

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4b (Scenario 2) - Off-Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	33.0	-
600	**Air Separation Unit**	-	-	629.4	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	3.5	-	995.9	7503.7
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	14.2	1352.0	82115.4
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	15.6	-14.2	33.8	5218.4
	BALANCE including CO_2 compression	19.1	0.0	3044.1	94837.5

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
		set-11
PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
LOCATION:	NETHERLANDS	CHECKED BY: PC
FWI Nº:	1- BD 0530 A	APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4b (Scenario 2) - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit**	**70104**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**76100**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE	**201804**

Notes: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: 0
			set-11
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
	LOCATION:	NETHERLANDS	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4b (Scenario 2) - Off-Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2289**
600	**Air Separation Unit**	**65462**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53181**
	Exhaust gas expander	(-6496)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**22428**
	Miscellanea utilities	**1200**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE	**150959**

Notes: (1) Minus prior to figure means figure is generated

3.4 Performance

The overall plant performances during peak and off-peak demand periods are shown in the following tables, for the two assessed scenarios.

It is noted that during high electricity demand period, the net power production gain with respect to the reference plant is about 28 MWe and 15 MWe, respectively for Scenario 1 and Scenario 2.

Case 4b - Scenario 1 - ASU @ 57% load during peak hours				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Reference case	peak time	off-peak time
Boiler load			100%	60.1%
ASU cold box load			56.1%	100%
ASU compressor load			60.7%	96%
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	125.6
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**902.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**735.5**	**443.3**
Expander power output	**MWe**	**11.2**	**11.2**	**6.7**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
ASU + new air compressor	MWe	86.7	54.1	83.1
FW pumps	MWe	35.0	35.0	19.5
Draught Plant	MWe	5.0	5.0	3.0
Coal mills, handling, etc.	MWe	4.0	4.0	2.4
ESP	MWe	2.0	2.0	1.2
Miscellanea	MWe	9.6	9.6	7.6
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	76.1	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**185.8**	**170.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**560.9**	**280.0**
				49.9%
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**49.0**	**49.1**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**37.3**	**31.0**

CO_2 emission	**kg/s**	**12.46**	**12.46**	**7.48**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.080**	**0.096**

Case 4b - Scenario 2 - ASU cold box capacity 78%				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Reference case	peak time	off-peak time
Boiler load			100%	57.2%
ASU cold box capacity (compared with reference case)			78%	78%
ASU compressor load (compared with reference case)			80%	75%
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	119.7
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**859.8**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**738.1**	**418.0**
Expander power output	**MWe**	**11.2**	**11.2**	**6.4**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
ASU	MWe	86.7	70.1	65.5
FW pumps	MWe	35.0	35.0	18.4
Draught Plant	MWe	5.0	5.0	2.9
Coal mills, handling, etc.	MWe	4.0	4.0	2.3
ESP	MWe	2.0	2.0	1.1
Miscellanea	MWe	9.6	9.6	7.6
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	76.1	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**201.8**	**151.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**547.5**	**273.5**
				49.9%
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**49.1**	**48.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**36.4**	**31.8**
CO_2 emission	**kg/s**	**12.46**	**12.46**	**7.13**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.082**	**0.094**

For Scenario 1, the performance tables of the not selected operating condition are also attached.

Case 4b - Scenario 1 - ASU @ 50% load during peak hours				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Reference case	peak time	off-peak time
Boiler load			100%	54.5%
ASU cold box load			50%	100%
ASU compressor load			50%	96%
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	114.1
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**819.4**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**734.6**	**399.8**
Expander power output	**MWe**	**11.2**	**11.2**	**6.1**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
ASU + new air compressor	MWe	86.7	50.4	83.2
FW pumps	MWe	35.0	35.0	17.4
Draught Plant	MWe	5.0	5.0	2.7
Coal mills, handling, etc.	MWe	4.0	4.0	2.2
ESP	MWe	2.0	2.0	1.1
Miscellanea	MWe	9.6	9.6	7.2
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	76.1	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**182.1**	**167.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**563.7**	**238.9**
				42.4%
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**48.9**	**48.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**37.5**	**29.2**

CO_2 emission	**kg/s**	**12.46**	**12.46**	**6.79**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.080**	**0.102**

Case 4b - Scenario 1 - ASU compressor @ 70% load during peak hours					
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX					
		Reference case	peak time	off-peak time	off-peak time
Boiler load			100%	69.5%	59.0%
ASU cold box load			66%	100%	89%
ASU compressor load			70%	97%	86%
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	145.4	123.4
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**1044.2**	**886.3**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**736.9**	**514.6**	**433.1**
Expander power output	**MWe**	**11.2**	**11.2**	**7.8**	**6.6**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY					
ASU + new air compressor	MWe	86.7	61.8	86.7	74.8
FW pumps	MWe	35.0	35.0	23.1	19.1
Draught Plant	MWe	5.0	5.0	3.5	3.0
Coal mills, handling, etc.	MWe	4.0	4.0	2.8	2.4
ESP	MWe	2.0	2.0	1.4	1.2
Miscellanea	MWe	9.6	9.6	9.0	7.3
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	76.1	52.9	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**193.5**	**179.3**	**160.9**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**554.6**	**343.1**	**278.8**
				61.9%	**50.3%**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**49.1**	**49.3**	**48.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**36.9**	**32.9**	**31.5**

CO_2 emission	**kg/s**	**12.46**	**12.46**	**8.66**	**5.11**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.081**	**0.091**	**0.066**

3.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for the two scenarios of this case with respect to the design of the reference plant.

Case 4b - Scenario 1 - ASU @ partial load during peak hours

UNIT 2100 - Air Separation Unit - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
Main air compressors	37.8 MWe per train	2 x 23 MWe per train	
Booster air compressor		1 x 1.4 MWe β = 1.6 Flow = 69'500 Nm3/h Vol. flow = 14'500 m3 each	Common to both trains
Oxygen vaporiser		Duty = 11.2 MWth Surface: 150 m2	Material: SS
Oxygen storage tank	1 x 215 m3 (Diameter: 6.1 m, H: 7.3 m)	1 x 10'500 m3 (Diameter: 33.5 m, H: 12.2 m)	Common to both trains Fixed roof, vacuum insulated storage tank Operating pressure: 2.5 bar, -180°C
Liquid air storage vessel		4 x 1'600 m3 (Diameter: 8.8 m, H: 26.4 m)	Common to both trains Nitrogen blanketed vessel Material: SS Operating condition: 8.5 bar, -170°C

Case 4b - Scenario 2 - ASU design: 78%

UNIT 2100 - Air Separation Unit - 2x50% train

Equipment	Reference plant	Flexible plant	Remarks
Air Separation Unit Package *(two parallel trains,* *each sized for 50% of the capacity)*	O2 flow rate from each ASU = 230 t/h	O2 flow rate from each ASU = 180 t/h	Including: - main air compressors (80% ref capacity) - air purification system - main heat exchanger - ASU compander - ASU column system - pumps - ASU chiller
Booster air compressor		1 x 760 kWe β = 1.6 Flow = 35'000 Nm3/h Vol. flow = 7'350 m3 each	Common to both trains
Oxygen vaporiser		Duty = 5.7 MWth Surface: 75 m2	Material: SS
Oxygen storage tank	1 x 215 m3 (Diameter: 6.1 m, H: 7.3 m)	1 x 5'500 m3 (Diameter: 23.8 m, H: 12.8 m)	Common to both trains Fixed roof, vacuum insulated storage tank Operating pressure: 2.5 bar, -180°C
Liquid air storage vessel		2 x 1'680 m3 (Diameter: 9.0 m, H: 27.0 m)	Common to both trains Nitrogen blanketed vessel Material: SS Operating condition: 8.5 bar, -170°C

3.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for the two scenarios of this case.

With respect to the figures included in Section E for the reference plant, Scenario 1 and Scenario 2 show a total investment cost variation of respectively +2.5% and -2%.

Contract : 1-BD-0530 A
Client : IEA
Plant : Oxyfuel USC PC with CO2 capture
Date : 07-ott-11
Rev. : 1

ESTIMATE SUMMARY

Case 4b - Scenario 1 - ASU @ partial load during peak hours

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 500 Steam turbine	UNIT 600 ASU	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,246,000	199,242,000	135,690,000	182,906,000	66,986,000	166,435,000	804,505,000	
2	CONSTRUCTION	19,832,000	122,040,000	47,291,000	56,064,000	35,087,000	47,977,000	328,291,000	
3	OTHER COSTS	3,277,000	13,108,000	9,831,000	13,620,000	4,916,000	11,142,000	55,894,000	
4	EPC SERVICES	4,407,000	16,159,000	11,752,000	11,944,000	10,283,000	14,984,000	69,529,000	
	TOTAL INSTALLED COST	80,762,000	350,549,000	204,564,000	264,534,000	117,272,000	240,538,000	1,258,219,000	
5	CONTINGENCY	5,700,000	24,500,000	14,300,000	13,200,000	5,900,000	12,000,000	75,600,000	
6	LICENSE FEES	1,600,000	7,000,000	4,100,000	5,300,000	2,300,000	4,800,000	25,100,000	
7	OWNER COSTS	4,000,000	17,500,000	10,200,000	13,200,000	5,900,000	12,000,000	62,800,000	
	TOTAL INVESTMENT COST	92,062,000	399,549,000	233,164,000	296,234,000	131,372,000	269,338,000	1,421,719,000	

FOSTER WHEELER

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : Oxyfuel USC PC with CO2 capture
Date : 07-ott-11
Rev. : 1

Case 4b - Scenario 2 - ASU design: 78%

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 500 Steam turbine	UNIT 600 ASU	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,246,000	199,242,000	135,690,000	138,206,000	66,986,000	166,435,000	759,805,000	
2	CONSTRUCTION	19,832,000	122,040,000	47,291,000	46,764,000	35,087,000	47,977,000	318,991,000	
3	OTHER COSTS	3,277,000	13,108,000	9,831,000	13,620,000	4,916,000	11,142,000	55,894,000	
4	EPC SERVICES	4,407,000	16,159,000	11,752,000	11,944,000	10,283,000	14,984,000	69,529,000	
	TOTAL INSTALLED COST	80,762,000	350,549,000	204,564,000	210,534,000	117,272,000	240,538,000	1,204,219,000	
5	CONTINGENCY	5,700,000	24,500,000	14,300,000	10,500,000	5,900,000	12,000,000	72,900,000	
6	LICENSE FEES	1,600,000	7,000,000	4,100,000	4,200,000	2,300,000	4,800,000	24,000,000	
7	OWNER COSTS	4,000,000	17,500,000	10,200,000	10,500,000	5,900,000	12,000,000	60,100,000	
	TOTAL INVESTMENT COST	92,062,000	399,549,000	233,164,000	235,734,000	131,372,000	269,338,000	1,361,219,000	

3.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table, for both Scenario 1 and Scenario 2.

Case	**4b - Scenario 1**		**4b - Scenario 2**	
Description	LOX Storage, ASU @ part load		LOX Storage, reduced ASU size	
Fixed costs				
Maintenance	47.5		45.4	
Operating Labour	8.16		8.16	
Labour Overhead	2.45		2.45	
Insurance & local taxes	25.2		24.1	
Total fixed cost, M€/y	83.3		80.1	
Variable costs (without fuel)				
	peak	**offpeak**	**peak**	**offpeak**
Make up water	0	0	0	0
Miscellanea	37	22	37	21
Total variable cost, €/h	37	22	37	21

4 Case 4c – Constant CO_2 flowrate in transport pipeline

4.1 Introduction

The cycling operation of the power plant, required to meet the variable grid demand, leads to an uneven captured CO_2 flowrate and a consequent fluctuation of the operating conditions in the pipeline.

As a consequence, a two-phase flow or a significant change of the physical properties could occur in the pipeline, if pressure and temperature were not maintained close to the conditions of the capture plant. Furthermore, for some applications like the Enhanced Oil Recovery (EOR) it would be preferred to have a constant flowrate rather than a fluctuating stream.

This Case 4c assesses the introduction in the power plant of a properly designed CO_2 storage system, which allows maintaining a constant CO_2 flowrate in the pipeline, thus avoiding pressure fluctuations and consequent possible changes of the CO_2 physical state.

In this configuration a constant CO_2 flowrate lower than peak production, when the plant is operated at base load, is sent to the external pipeline; therefore, it is possible to select a lower pipeline size, leading to a possible significant cost saving. For this reason, a comparison between the additional costs of a buffer storage versus the saved cost of a larger pipeline is also made in this Case 4c.

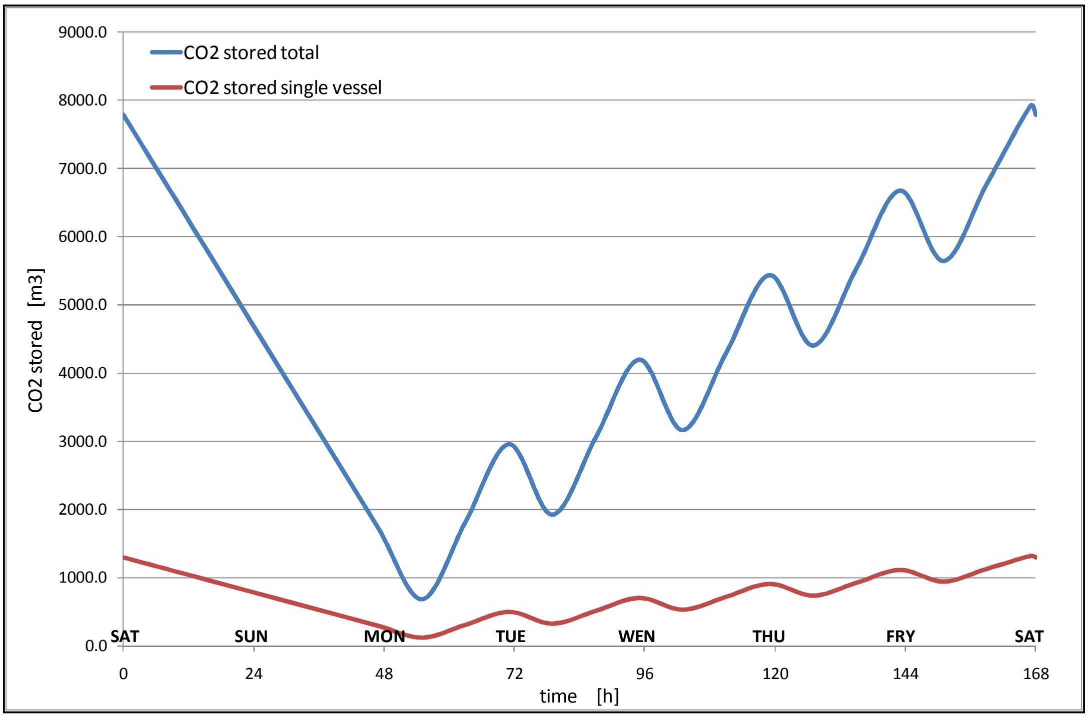
4.2 Case description

The required CO_2 buffer storage volume is evaluated considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 1. This means that the CO_2 capture plant is operated at base load for 80 hours per week and at 56% load during the remaining 88 hours, when the plant is called to generate 50% of its overall net power production capacity.

The constant CO_2 flow in the pipeline is a consequence of the balance of the CO_2 flowrate from and to the storage system during the whole week of operation, made to avoid any accumulation in the buffer vessels and resulting in about 77% of the CO_2 captured when the plant is operated at its maximum capacity.

Figure 4.2-1 shows the whole volume of stored CO_2 during the week and the single vessel volume trend (six vessels in total are considered). The required net volume of the storage vessels is the difference between the maximum and the minimum volume of stored CO_2 during the week. From the graph, it can be drawn that it corresponds to the CO_2 accumulated during the weekdays, and mainly discharged during the partial load operation from Friday night to Monday morning.

Figure 4.2-1: Case 4c – Stored CO_2 volume during the week



The CO_2 is stored, in liquid phase, at 85 bar and 20°C, i.e. above its critical pressure and below its critical temperature. Storing and maintaining the CO_2 in liquid form below its critical pressure, even if it is easily practicable at the ambient condition selected for the study, i.e. ambient temperature around 9°C, could be a more critical aspect in hotter countries.

Therefore, the size and configuration of the CO_2 compression unit are also modified, to allow storing the CO_2 at these conditions. The CO_2 stream from the last stage compressor, at 85 bar, is cooled down in the existing flue gas exchanger and condensate exchanger. A cooling water cooler is added to drop down the temperature below its critical value. The cold CO_2 stream is sent to the dedicated buffer storage vessels, while a constant flow is pumped from the vessels to the pipeline by means of properly designed pumps.

4.3 Utility consumption

The utility consumptions of the process/utility & offsite units during peak and off-peak demand periods are shown in the following table.

FOSTER WHEELER	CLIENT: IEA GHG R&D PROGRAMME PROJECT: OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS LOCATION: NETHERLANDS FWI Nº: 1- BD 0530 A		Rev: Draft mar-11 ISSUED BY: NF CHECKED BY: PC APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4c - Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	Coal and Ash Handling	-	-	54.0	-
600	Air Separation Unit	-	-	834.0	-
700	CO_2 Compression and Inerts Removal (including Air Products package)	6.1	-	1635.0	15600
200 - 500	POWER ISLAND UNITS (Boiler and Steam Turbine)	-	24.7	2362.0	98574.6
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	8475.4
	BALANCE	33.3	0.0	4944.0	122650.0

Note: (1) Minus prior to figure means figure is generated

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	mar-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
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		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4c - Off-peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	30.0	-
600	**Air Separation Unit**	-	-	583.8	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	3.4	-	1144.5	10920
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	13.8	1322.0	82121.2
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	15.2	-13.8	33.0	5337.1
	BALANCE	18.6	0.0	3113.3	98378.3

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4c - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit**	**86740**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**72600**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE	**214940**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	set-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4c - Off-peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2238**
600	**Air Separation Unit**	**60718**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**50872**
	Exhaust gas expander	(-6266)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**21860**
	Miscellanea utilities	**1120**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE including CO_2 compression	**143208**

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4.4 Performance

The overall plant performance during peak and off-peak demand periods are shown in the following table.

Case 4c - CO_2 buffer storage				
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX				
		Reference case	Peak operation	Off-peak operation
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	117.0
				56%
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**840.5**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**740.0**	**405.6**
Expander power output	**MWe**	**11.2**	**11.2**	**6.3**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
ASU	MWe	86.7	86.7	60.7
FW pumps	MWe	35.0	35.0	17.9
Draught Plant	MWe	5.0	5.0	2.8
Coal mills, handling, etc.	MWe	4.0	4.0	2.2
ESP	MWe	2.0	2.0	1.1
Miscellanea	MWe	9.6	9.6	7.5
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	72.6	50.9
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**214.9**	**143.2**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**536.3**	**268.7**
				50.1%
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**49.3**	**48.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**35.7**	**32.0**
CO_2 emission	**kg/s**	**12.46**	**12.46**	**6.97**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.084**	**0.093**

4.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified with respect to the design of the reference case, in order to avoid flowrate fluctuations in the CO_2 pipeline, related to the flexible operation.

Case 4c - CO_2 buffer storage - Plant design changes			
UNIT 700 - CO2 compression			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
CO_2 compressor *(last stage)*	1 x 18.4 MWe β = 5.92 Flow = 235'000 Nm3/h Vol. flow = 12'870 m3	1 x 15.4 MWe β = 4.57 Flow = 235'000 Nm3/h Vol. flow = 12'870 m3	
CO_2 cooling water cooler	not foreseen	20.2 MWth 750 m2	**Sea water exchanger** tubes: titanium shell: SS
CO_2 pump	not foreseen	4 x 280 kW 237 m3/h x 400 m each	Two operating, two spares
CO_2 buffer storage vessel	not foreseen	6 x 1'325m3 (Diameter: 8.3 m, H: 24.9 m)	Nitrogen blanketed vessel Material: SS

4.5.1 CO_2 pipeline

The considerations made in this section refer to an offshore pipeline, with an overall length of 100 km and without intermediate booster compression stations.

Considering the CO_2 inlet pressure (110 barg), the pipeline diameter is selected in order to ensure that the entire pipeline length remains well above the CO_2 critical pressure (74 bar), typically falling in the range from 85 to 90 bar.
A maximum allowed velocity of 3 m/s is also considered for the selection of the pipeline diameter, for a CO_2 stream that is in a supercritical phase condition. This velocity is recommended in the “Upgraded calculator for CO_2 pipeline system” (IEA GHG, Technical study, report number 2009/3), and used for the calculation of this case.

The following table summarises the main characteristics of the CO_2 pipeline selected for both the reference plant and this Case 4c. It can be drawn that with a plant designed to provide a constant CO_2 flowrate to the pipeline, despite the cyclic operation of the plant, the pipeline diameter is 100 mm lower than the one of the reference case.

Case 4c - CO_2 buffer storage			
CO_2 pipeline characteristics			
		Reference plant	**Flexible plant**
CO_2 flowrate	kg/h	455,760	350,593
Inlet pressure	barg	110	110
Inlet temperature	°C	50	20
Outlet pressure	bar	90.0	92.5
CO_2 phase condition	-	supercritical	liquid
Pipeline diameter	mm	500	400

4.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost of this case.

With respect to the figures included in Section E for the reference plant, this case shows a total investment cost increase of 1.5%.

In addition, it has been estimated that the reduction of the pipeline diameter leads to a saving on the cost per unit length of the pipeline of around 210,000 €/km, i.e. about 10% lower than the reference case. Therefore, depending on the overall length, the investment increase of the plant may be offset by the lower cost of the pipeline. For this alternative, the plant investment cost is expected to be 20 M€ higher than the reference case, while a cost saving of 21 M€ is expected for the pipeline by considering an overall length of 100 km.

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : Oxyfuel USC PC with CO2 capture
Date : 16 May 2011
Rev. : 0

Case 4c - CO2 buffer storage

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 500 Steam turbine	UNIT 600 ASU	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,246,000	199,242,000	135,690,000	153,416,000	79,766,000	166,435,000	787,795,000	
2	CONSTRUCTION	19,832,000	122,040,000	47,291,000	51,684,000	38,527,000	47,977,000	327,351,000	
3	OTHER COSTS	3,277,000	13,108,000	9,831,000	15,140,000	5,416,000	11,142,000	57,914,000	
4	EPC SERVICES	4,407,000	16,159,000	11,752,000	13,574,000	11,523,000	14,984,000	72,399,000	
	TOTAL INSTALLED COST	80,762,000	350,549,000	204,564,000	233,814,000	135,232,000	240,538,000	1,245,459,000	
5	CONTINGENCY	5,700,000	24,500,000	14,300,000	11,700,000	6,800,000	12,000,000	75,000,000	
6	LICENSE FEES	1,600,000	7,000,000	4,100,000	4,700,000	2,700,000	4,800,000	24,900,000	
7	OWNER COSTS	4,000,000	17,500,000	10,200,000	11,700,000	6,800,000	12,000,000	62,200,000	
	TOTAL INVESTMENT COST	92,062,000	399,549,000	233,164,000	261,914,000	151,532,000	269,338,000	1,407,559,000	

4.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	4c	
Description	CO_2 buffer storage	
Fixed costs		
Maintenance	47.0	
Operating Labour	8.16	
Labour Overhead	2.45	
Insurance & local taxes	24.9	
Total fixed cost, M€/y	82.5	
Variable costs (without fuel)		
	peak	**offpeak**
Make up water	0	0
Miscellanea	37	21
Total variable cost, €/h	37	21

5 Case 4d – LOX daily storage with an alternate demand curve

5.1 Introduction

This case is based on the assumption that the weekly demand curve is different from the one shown in Figure 1-1 and characterised by the following three different electricity demand periods:

- *Peak* electricity demand period: 2 hours per working day.
- *Normal* operation: 14 hours per working day.
- *Off-peak* electricity demand period (50% of net power output): night and weekend.

As discussed in Case 4b, the ASU significantly reduces the overall net electricity production of the plant, mainly due to its high auxiliary power demand. By reducing the energy requirement of this unit, at least during peak-demand hours, it is possible to increase the overall net power export during remunerative hours, thus improving the overall economics of the plant.

To reduce internal consumption, the ASU is operated at partial load, while the rest of the plant runs at full load and the oxygen required by the process units is taken from a purposely designed storage, sized to cover production fluctuations.

5.2 Case description

During *normal operation* the whole plant is operated at base load, as in the reference case conditions (refer to section E of this report).

On the other hand, during the two hours of *peak electricity demand* the ASU is operated at its minimum load. This is represented by the minimum technical load of the ASU cold box, which is approximately 50% of the design capacity. However, as the minimum efficient load of the air compressor is around 70%, then when the cold box is at 50% load the main air compressor operates by opening the recycle system, with a negative effect on the power requirement of the machine. Therefore, to increase the flexibility of the plant it has been considered to have a dual train air compressors configuration for each of the two ASU trains. During peak demand period, two out of the four compressors are shutdown, while the other two compressors are operated at base load.

During *off peak demand period* the boiler is operated at partial load, so to have a net power output of 50% of the normal production and corresponding to approximately 56% of the boiler load.

During weekday night time, the ASU has to operate at around 68% in order to store all the oxygen required during peak load operation, following a daily cycle operation. The product required from the storage during the 2 hours per day of peak load operation, when the plant is operated at base load, is balanced by the product stored during the 8 night hours per day of off-peak load operation, when the plant is operated at partial load. To define the size of the oxygen tank, the oxygen required for two hours of part load operation is added to the LOX storage volume (200 tons) considered for the safe changeover from oxygen firing to air firing mode in case of ASU trip.

5.2.1 Air liquefaction

When the whole plant is operated at base load, liquid oxygen from the bottom of the distillation column of the ASU is vaporised in the main ASU exchanger, using its refrigeration capacity for cooling of the air fed to the column.

During peak demand operation, air is liquefied to provide the heat required for liquid oxygen from storage vaporisation. As air vapour pressure is higher than oxygen vapour pressure, air compression up to 8.5 bar is required for using air to vaporise oxygen, implying the installation of a new air compressor.

Liquid air is stored during peak demand period and fed to the ASU column during off-peak hours, compensating the lack of refrigerating capacity in the main air compressor, due to the liquid oxygen diverted from the bottom of the column to the storage tank.

5.3 Utility consumption

The most relevant utility requirements for this case are shown in the following tables.

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME			Rev: Draft
	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS			Sep-11
	LOCATION:	NETHERLANDS			ISSUED BY: NF
	FWI Nº:	1- BD 0530 A			CHECKED BY: PC
					APPR. BY: LM
WATER CONSUMPTION SUMMARY - Case 4d - Normal operation					
UNIT	**DESCRIPTION UNIT**	**Raw Water** [t/h]	**Demi Water** [t/h]	**Machinery Cooling Water** [t/h]	**Sea Cooling Water** [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	54.0	-
600	**Air Separation Unit**	-	-	834.0	-
700	**CO_2 Compression and Inerts Removal**	6.1	-	1635.0	13110
	(including Air Products package)				
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	24.7	2362.0	98574.6
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	8475.4
	BALANCE excluding CO_2 compression	33.3	0.0	3309.0	107050.0
	BALANCE including CO_2 compression	33.3	0.0	4944.0	120160.0

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

WATER CONSUMPTION SUMMARY - Case 4d - Peak hours operation

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	54.0	-
600	**Air Separation Unit**	-	-	417.0	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	6.1	-	1635.0	13110
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	24.7	2362.0	98574.6
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	59.0	7760.6
	BALANCE	33.3	0.0	4527.0	119445.2

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LOCATION:	NETHERLANDS
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Sep-11
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WATER CONSUMPTION SUMMARY - Case 4d - Off-Peak hours operation - Night time

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	-	-	30.0	-
600	**Air Separation Unit**	-	-	583.8	-
700	**CO_2 Compression and Inerts Removal (including Air Products package)**	3.4	-	915.6	7341.6
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	-	13.8	1323.0	78859.7
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	15.2	-13.8	33.0	4946.4
	BALANCE	18.6	0.0	2885.4	91147.7

Note: (1) Minus prior to figure means figure is generated

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	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
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	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
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WATER CONSUMPTION SUMMARY - Case 4d - Off-Peak hours operation - Weekend

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
100	**Coal and Ash Handling**	**-**	**-**	**29.0**	**-**
600	**Air Separation Unit**	**-**	**-**	**446.2**	**-**
700	**CO_2 Compression and Inerts Removal**	**3.3**	**-**	**874.7**	**3927.8**
	(including Air Products package)				
200 - 500	**POWER ISLAND UNITS (Boiler and Steam Turbine)**	**-**	**13.2**	**1264.0**	**63087.8**
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	**14.6**	**-13.2**	**31.6**	**4535.2**
	BALANCE	**17.8**	**0.0**	**2645.5**	**71550.7**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4d - Normal operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit**	**86740**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**76100**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE including CO_2 compression	**218440**

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	LOCATION:	NETHERLANDS	ISSUED BY: NF
	FWI Nº:	1- BD 0530 A	CHECKED BY: PC
			APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4d - Peak load operation

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit + New Air Compressor**	**50370**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**76100**
	Exhaust gas expander	(-11200)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**42000**
	Miscellanea utilities	**2000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**7600**
	BALANCE	**182070**

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	PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	ISSUED BY: NF
	LOCATION:	NETHERLANDS	CHECKED BY: PC
	FWI Nº:	1- BD 0530 A	APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4d - Off-Peak load operation - Night time

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2240**
600	**Air Separation Unit**	**60718**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53172**
	Exhaust gas expander	(-6109)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**21877**
	Miscellanea utilities	**1120**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE	**145527**

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PROJECT:	OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS	Sep-11
LOCATION:	NETHERLANDS	ISSUED BY: NF
FWI Nº:	1- BD 0530 A	CHECKED BY: PC
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - Case 4d - Off-Peak load operation - Weekend

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**2140**
600	**Air Separation Unit**	**48833**
700	**CO_2 Compression and Recovery System (including Air Products package)**	**53172**
	Exhaust gas expander	(-6109)
	POWER ISLANDS UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**21093**
	Miscellanea utilities	**1070**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**6400**
	BALANCE	**132708**

Notes: (1) Minus prior to figure means figure is generated

5.4 Performance

The overall plant performances during peak, off-peak and normal electricity demand periods are shown in the following tables.

During high electricity demand period, the net power production gain with respect to the reference plant is about 30 MWe.

Case 4d - LOX storage - Daily cycle					
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX					
		Reference case (Normal operation)	peak time	off-peak time weekday night time	off-peak time weekend
Boiler load			100%	56.0%	53.5%
ASU cold box load			50%	68.5%	53.5%
ASU compressor load			50%	67.4%	50.0%
Coal Flowrate (fresh, air dried basis)	t/h	209.1	209.1	117.1	111.9
Coal LHV (air dried basis)	kJ/kg	25860.0	25860.0	25860.0	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**	**1502.2**	**841.2**	**803.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**740.0**	**734.6**	**407.2**	**392.8**
Expander power output	**MWe**	**11.2**	**11.2**	**6.3**	**6.0**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY					
ASU + new air compressor	MWe	86.7	50.4	60.7	48.8
FW pumps	MWe	35.0	35.0	18.0	17.3
Draught Plant	MWe	5.0	5.0	2.8	2.7
Coal mills, handling, etc.	MWe	4.0	4.0	2.2	2.1
ESP	MWe	2.0	2.0	1.1	1.1
Miscellanea	MWe	9.6	9.6	7.2	7.5
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	76.1	76.1	53.2	53.2
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.4**	**182.1**	**145.2**	**132.7**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**532.8**	**563.7**	**268.3**	**266.1**
				50.4%	**49.9%**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.3**	**48.9**	**48.4**	**48.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5**	**37.5**	**31.9**	**33.1**
CO_2 emission	**kg/s**	**12.46**	**12.46**	**6.97**	**6.66**
Specific CO_2 emissions per MW net produced	**t/MWh**	**0.084**	**0.080**	**0.094**	**0.090**

5.5 Equipment list

The following table shows the equipment and process packages that shall be added or modified for this case with respect to the design of the reference plant.

Case 4d - LOX storage - Daily cycle			
UNIT 2100 - Air Separation Unit - 2x50% train			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Main air compressors	37.8 MWe per train	2 x 18.9 MWe per train	
Booster air compressor		1 x 7.0 MWe β = 8.4 Flow = 67'050 Nm3/h Vol. flow = 69'500 m3 each	Common to both trains
Oxygen vaporiser		Duty = 12.75 MWth Surface: 1685 m2	Material: SS
Oxygen storage tank	1 x 215 m3 (Diameter: 6.1 m, H: 7.3 m)	1 x 600 m3 (Diameter: 9.1 m, H: 9.8 m)	Common to both trains Fixed roof, vacuum insulated storage tank Operating pressure: 2.5 bar, -180°C
Liquid air storage vessel		1 x 230 m3 (Diameter: 4.8 m, H: 14.4 m)	Common to both trains Nitrogen blanketed vessel Material: SS Operating condition: 8.5 bar, -170°C

5.6 Investment cost

The tables attached to this section show the investment cost break-down and the total investment cost for this case.

With respect to the figures included in Section E for the reference plant, this alternative shows a total investment cost variation lower than 1%.

FOSTER WHEELER

ESTIMATE SUMMARY

Contract : 1-BD-0530 A
Client : IEA
Plant : Oxyfuel USC PC with CO2 capture
Date : 07-ott-11
Rev. : 0

Case 4d - LOX storage - Daily cycle

COST CODE	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 500 Steam turbine	UNIT 600 ASU	UNIT 700 CO2 comp drying	UNIT 800 BOP	TOTAL EURO	REMARKS / COMMENTS
1	DIRECT MATERIAL	53,246,000	199,242,000	135,690,000	166,106,000	66,986,000	166,435,000	787,705,000	
2	CONSTRUCTION	19,832,000	122,040,000	47,291,000	52,704,000	35,087,000	47,977,000	324,931,000	
3	OTHER COSTS	3,277,000	13,108,000	9,831,000	13,620,000	4,916,000	11,142,000	55,894,000	
4	EPC SERVICES	4,407,000	16,159,000	11,752,000	11,944,000	10,283,000	14,984,000	69,529,000	
	TOTAL INSTALLED COST	80,762,000	350,549,000	204,564,000	244,374,000	117,272,000	240,538,000	1,238,059,000	
5	CONTINGENCY	5,700,000	24,500,000	14,300,000	12,200,000	5,900,000	12,000,000	74,600,000	
6	LICENSE FEES	1,600,000	7,000,000	4,100,000	4,900,000	2,300,000	4,800,000	24,700,000	
7	OWNER COSTS	4,000,000	17,500,000	10,200,000	12,200,000	5,900,000	12,000,000	61,800,000	
	TOTAL INVESTMENT COST	92,062,000	399,549,000	233,164,000	273,674,000	131,372,000	269,338,000	1,399,159,000	

5.7 Operating and Maintenance Costs

The Operating and Maintenance Costs of this alternative are summarised in the following table.

Case	**4d**	
Description	Daily LOX storage	
Fixed costs		
Maintenance	46.7	
Operating Labour	8.16	
Labour Overhead	2.45	
Insurance & local taxes	24.8	
Total fixed cost, M€/y	82.1	
Variable costs (without fuel)		
	peak/normal oper.	**offpeak (avarage)**
Make up water	0	0
Miscellanea	37	20
Total variable cost, €/h	37	20

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS
DOCUMENT NAME : ALTERNATIVE ENERGY STORAGE TECHNIQUES
FWI CONTRACT : 1-BD-0530 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

INDEX

1 Introduction

Scope of this Section J is to make a high-level techno-economic review of some advanced energy storage techniques, different from the ones already assessed in the previous sections of this report. These alternative techniques are becoming a realistic option in response to the challenges of the liberalized electricity market and the need to cover intermediate and peak load constraints, as well as to follow the daily and seasonal variation of the electricity demand. As a consequence, these energy storage technologies have potential for significantly reducing the need for operating power plants flexibly.

By introducing a power buffer storage for the electric grid, it is possible to store energy when production is higher than demand, while using it in the opposite situation.

Depending on the storage device, power and storage capacities and reaction time, several grid requests can be met, as also summarised in the following Table 1.1-1 and further discussed in this section.

Table 1.1-1: Energy storage applications

Application	**Load management**	**Spinning reserve**	**Back-up power**	**Renewable technologies integration**	**Power quality**
Discharged power	10 – 100s MW	10-400 MW	1-200 MW	20 kW – 10 MW	1 kW – 20 MW
Response time	< 10 min	< 10 ms (prompt) < 10 min (conventional)	< 10 ms (prompt) < 10 min (conventional)	< 1 s	< 20 ms
Energy stored	1 – 1000 MWh	1 – 1000 MWh	1 – 1000 MWh	10 – 200 kWh	50 – 500 kWh
Need of high efficiency	high	medium	medium	high	Low
Need long cycle or calendar life	high	high	high	high	Medium

Load management
Two different aspects have to be considered for load management application, both significantly reducing the need for power plants to operate flexibly.

Load levelling consists in storing the electricity produced during off-peak hours and using it later, to meet peak demand. As a result, the overall power production requirements becomes flatter and thus cheaper base-load power production can be increased.

In *load following* application, the energy storage device acts as a sink when power required falls below production levels and acts as a source when power required is above production levels.

Spinning reserve

Energy storage devices used for spinning reserve usually require power ratings of 10 MW to 400 MW and are required between 20 to 50 times per year.
Depending on the response characteristics, the energy storage device can participate to the fast response spinning reserve, characterised by a quick response of the power capacity to network abnormalities, or the conventional spinning reserve if a slower response is required to the power capacity.

Back-up power

Energy storage devices can provide stabilization to the grid in case of electricity outage, until backup generation sources can be brought online, by absorbing or delivering power to generators when needed to keep them turning at the same speed. These faults induce phase, voltage and frequency irregularities that can be corrected by the storage device. This reduces the costs of electrical grid failure.
Fast response and high power ratings are required.

Transmission Upgrade Deferral

Transmission line upgrades are required to manage the generating expansions. Energy storage devices can be used instead of upgrading the transmission line until it becomes economical to do so.
Typically, transmission lines must be built to handle the maximum load required and hence it is only partially loaded for the majority of each day.
Therefore, by installing a storage device, the power across the transmission line can be maintained constant, even during periods of low demand. Then, when demand increases, the storage device is discharged preventing the need for extra capacity on the transmission line to supply the required power, and consequently avoiding upgrades in the transmission line capacities.

Peak Generation

Energy storage devices can be charged during off-peak hours and then used to provide electricity during short peak production periods.

Renewable Energy Integration

Energy storage technologies can also improve the availability of energy from renewable and intermittent sources, as the sun and the wind, characterized by a wide variation of the energy that they can provide. Electricity storage can smooth this variability, acting as a 'renewable source back-up' storing unused electricity to be dispatched at a later time.

A storage system used with renewable technology must have fast response times (less than a second), excellent cycling characteristics and a good lifespan (100 to 1,000 cycles per year).

End-Use Applications
The most common end-use application is power quality, which primarily consists of voltage and frequency control. These applications require short power durations and fast response times, in order to level fluctuations, prevent voltage irregularities and provide frequency regulation.

1.1 Energy storage technologies

There are currently several promising energy storage technologies, characterized by different power and storage capacities and reaction time, as shown in Figure 1.1-1:

- Pumped hydropower and compressed air energy storage are characterised by large power and storage capacities;

  In Pumped-Hydropower Energy Storage (PHES) systems water is pumped into a storage reservoir at high elevation during times when electricity is inexpensive and in low demand. Stored water is then released and used to power hydroelectric turbines when demand for power is high. New developments in pumps and turbines, allowing for adjustable water flowrates have increased the flexibility and efficiency of pumped storage hydroelectric power. However, some limitations, such as suitable geographic location and facility size/capacity still exist.

  In Compressed Air Energy Storage (CAES) system, high efficiency compressors can be used to force air into underground reservoirs, such as mined caverns. When the commercial demand for power is high, the stored air is allowed to expand to atmospheric pressure through turbines connected to electric generators that provide power to the grid.

- Battery Energy Storage (BES) devices are characterised by a wide range of power and storage capacity;

  Batteries can be used in a lot of energy storage applications due to their portability, ease of use and variable storage capacity. In particular, they can stabilize electrical systems by rapidly providing extra power and by leveling oscillation in voltage and frequency. Currently, numerous batteries including lead-acid, flow, sodium-sulfur, and lithium-ion all have commercial applications.
  However, many battery types have only limited market penetration, as they are expensive, or have short lifetimes.

- Flywheels, superconducting magnetic energy storage (SMES) and electrochemical capacitors are characterised by small power and/or storage capacities.

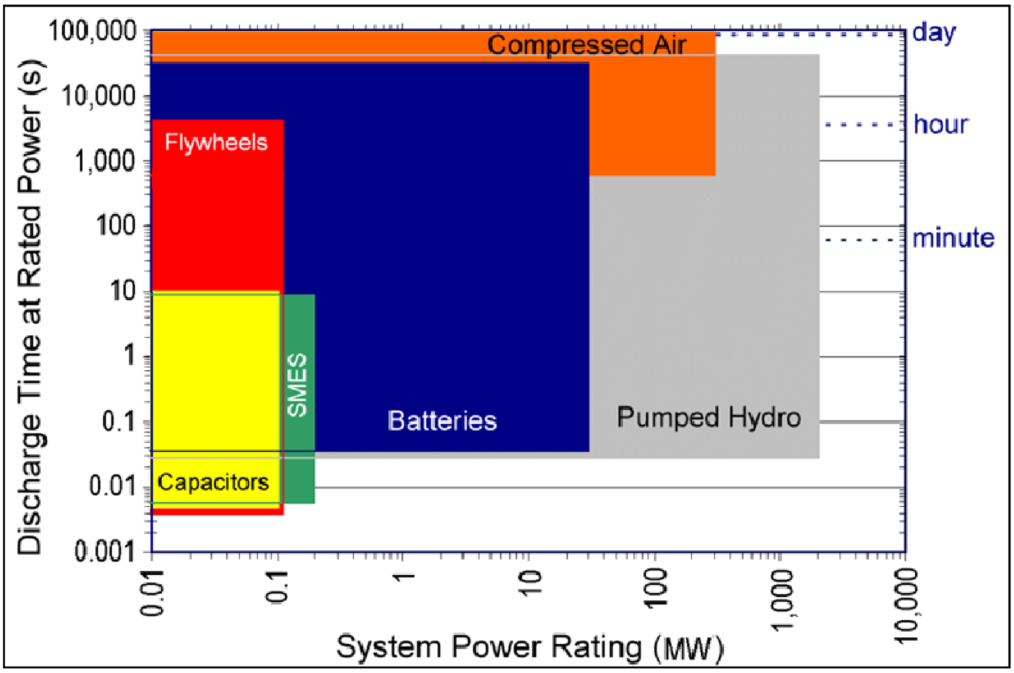
  Flywheels store energy in a spinning disk on a metal shaft. Two generations of flywheels have raised storage capacity through increased disk mass (using steel) and increased rotation speeds (using light weight composite materials for the disk), but technical limitations are still present. New prototypes utilize magnetic levitation to increase speed and mass while minimizing previous technical issues. Wide commercial energy storage application of flywheels is primarily limited by materials properties and cost.

  Superconducting Magnetic Energy Storage devices are composed of superconducting windings that allow electric current to be stored indefinitely with little resistive energy losses. When the stored energy is needed, these devices can be discharged almost instantaneously with high power output over short time periods.
  Increasing the size of the windings can increase the amount of stored energy, but the increased magnetic field associated to the larger coils becomes difficult to be contained.
  In addition, as low temperature is needed to have superconducting property, expensive coolants are required.

  Electrochemical capacitors store energy in the form of two oppositely charged electrodes separated by an ionic solution. They are suitable for fast-response, short-duration applications, such as backup power during brief outages, and for stabilizing voltage and frequency. They have a temperature-independent response, low maintenance and long projected lifetimes (up to 20 years), but relatively high cost.

Power conversion systems (PCS), even if they do not represent a storage device explicitly, are essential for electricity storage applications, as they constitute the interface between the storage system and the electricity grid. A PCS is able to make the necessary conversions so that the stored energy can be taken from or returned to the grid in the correct phase, frequency and level of demand.

Figure 1.1-1: Capabilities of Existing Electricity Storage Technologies



Main characteristics of these technologies, which are further assessed in the following sections, and their applications are also summarised in Table 1.1-2.

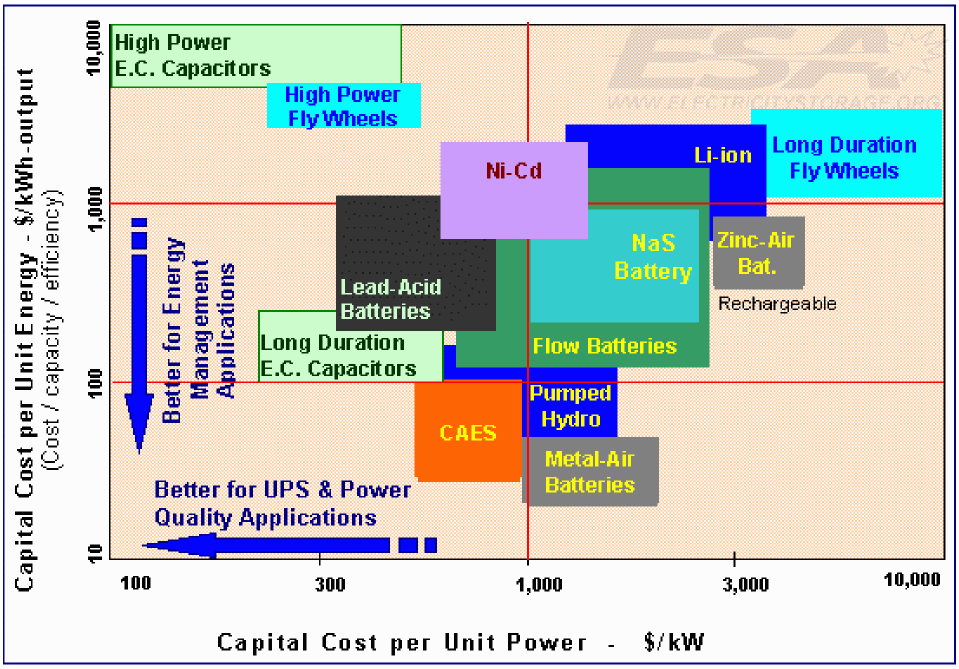
Table 1.1-2: Energy storage technologies characteristics

Storage device	Storage medium	Power Capacity	Storage capacity	Applications
Pumped-Hydroelectric Energy Storage	Mechanical	Large	Large	Load levelling, frequency regulation, peak generation…
Compressed Air Energy Storage	Mechanical	Large	Large	Load following, frequency regulation, voltage control
Lead-Acid Battery	Chemical	Medium	Medium	Back up power USP system
Nickel-Cadmium Battery	Chemical	Medium	Medium	storage for solar generation engine start-up
Sodium-Sulphur Battery	Chemical	Medium	Medium	Load management Power quality
Vanadium Redox Flow Battery	Chemical	Medium	Medium	Integration of renewable resources

Storage device	Storage medium	Power Capacity	Storage capacity	Applications
Polysulphide Bromide Flow Battery	Chemical	Medium	Medium	frequency regulation voltage control
Zinc-Bromine Flow Battery	Chemical	Medium	Medium	Integration of renewable resources frequency regulation
Flywheels	Mechanical	Small	Small	USP system Integration of wind farms
Supercapacitor Energy Storage	Electrical	Small	Small	Power quality
Superconducting Magnetic Energy Storage	Magnetic	Small	Small	Integration of renewable resources Transmission upgrade deferral

Cost figures of the different storage technologies are shown in Figure 1.1-2. Cost ranges in this chart are referred to 2Q2001, so approximately 1.45 escalation factor should be considered for these data.
It is also noted that costs of these energy storage techniques might be changed, as a result of the normal technological development of last years.

Figure 1.1-2: Costs of Existing Electricity Storage Technologies



2 Case 5a – Battery energy storage

2.1 Introduction

Batteries are a well known type of energy storage devices that store electric energy in electrochemical form. There are two main types of battery energy storage devices, as described in the following.

Battery Energy Storage (BES) systems operate in the same way as conventional batteries, except on a large scale. Two electrodes are immersed in an electrolyte, while a chemical reaction generates a current when required.
There are three important types of large-scale BES. These are:

- Lead-Acid (LA)
- Nickel-Cadmium (NiCd)
- Sodium-Sulphur (NaS).

In *Flow Battery Energy Storage (FBES)* two charged electrolytes are pumped to the cell stack where a chemical reaction occurs, generating a current when required.
There are three primary types of FBES:

- Vanadium Redox (VR)
- Polysulphide Bromide (PSB)
- Zinc Bromine (ZnBr).

In Flow Batteries Energy Storage devices the energy storage capacity and power capacity are independent. With respect to the conventional batteries they are based on a less mature technology and have higher maintenance costs.

Using a battery energy storage device, a Power Conversion System (PCS) is required to convert from alternating current (AC) to direct current (DC) while the energy device is charged, and vice versa, when the device is discharged.

The following sections give an overview of the above listed energy devices.

2.2 Lead-Acid batteries

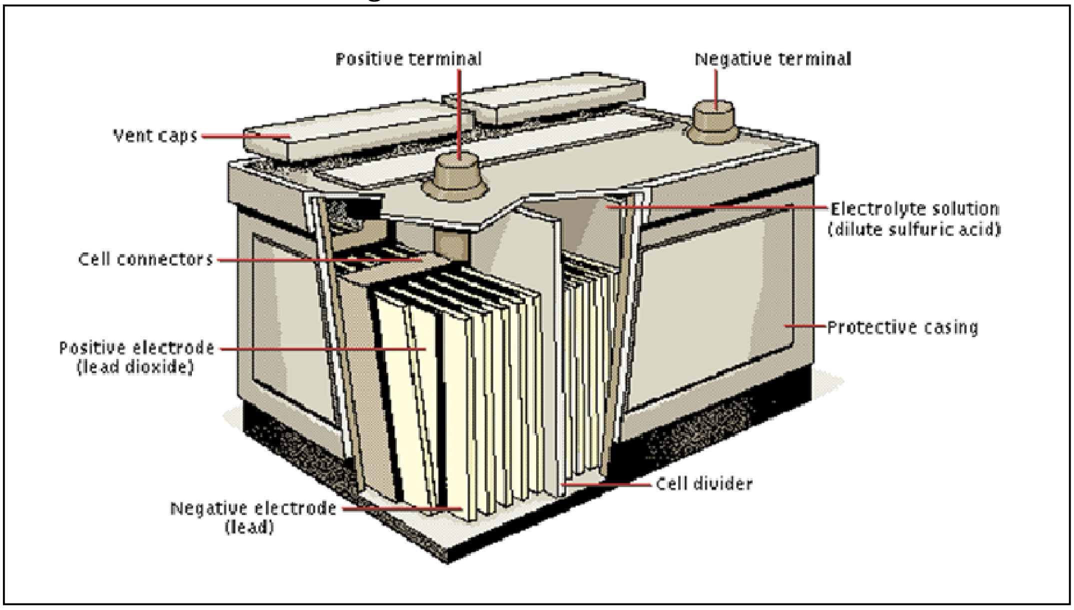
Lead-Acid (LA) battery is the most common energy storage device in use. It is a mature technology as research has been ongoing for about 140 years.

2.2.1 Description

There are two types of lead-acid batteries; flooded lead-acid (FLA) and valve-regulated lead-acid (VRLA).

FLA battery consists of two lead plates acting as electrodes, immersed in a mixture of water (65%) and sulphuric acid (35%), as shown in Figure 2.2-1.

Figure 2.2-1: Lead-acid batteries



VRLA batteries have the same operating principle as FLA batteries, but they are sealed with a pressure-regulating valve. This eliminates air from entering the cells and also prevents venting of the hydrogen, generated during the chemical reaction.
VRLA batteries are smaller and lighter and require lower maintenance costs. However, these advantages are coupled with higher initial costs and shorter lifetime.

LA batteries can respond within milliseconds at full power.
The average efficiency of a LA battery is 75% to 85% during normal operation, with a life of approximately 5 years or 250-1,000 charge/discharge cycles, depending of the Depth of Discharge (DoD).

LA batteries are extremely sensitive to their environments: change of the operating temperature of more than 5°C can cut the life of the battery by 50%.
The charging rate is limited to maximum five times the rate of discharge, otherwise the cell will be damaged.

The batteries must be replaced every six years for flooded cells and every five years for VRLA.

2.2.2 Applications

Flooded lead-acid batteries are used for critical back-up applications, while VRLA batteries are low-maintenance batteries used for power quality application like UPS systems.

2.2.3 Costs

The estimated energy storage cost of the batteries is in the range of 150-300$/kWh.
Large battery plants have extensive costs associated with the balance of plant (BoP), which have about the same cost of the batteries themselves. These costs include building construction, battery installation, interconnections, heating, ventilating, and air conditioning (HVAC) equipment, etc.

In addition, the cost of the power conversion system (PCS) for a battery based storage system is expected to be in the rage of 125-250$/kW, depending on the capacity required.

2.3 Nickel-Cadmium batteries

2.3.1 Description

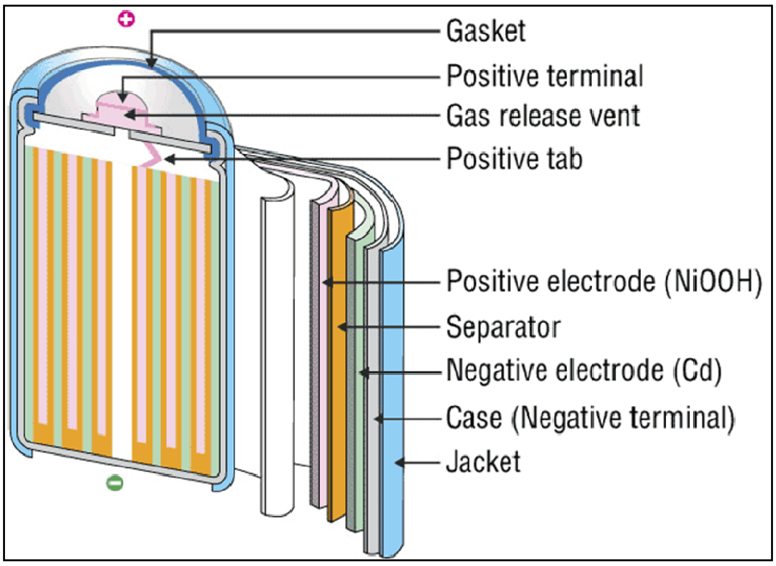
Nickel-Cadmium Batteries (NiCd) batteries consist of a positive electrode in nickel oxy-hydroxide and a negative electrode composed of metallic cadmium, separated by a nylon divider, as shown in Figure 2.3-1. The electrolyte is aqueous potassium hydroxide.

During discharge, the nickel oxy-hydroxide combines with water and produces nickel hydroxide and a hydroxide ion. Cadmium hydroxide is produced at the negative electrode. To charge the battery the process can be reversed.
During charging, oxygen can be produced at the positive electrode and hydrogen can be produced at the negative electrode.

The efficiency of a NiCd battery is 60%-70% during normal operation with a lifespan of 10-15 years (1,000-3,500 charge/discharge cycles at 100% DoD).

NiCd batteries can respond at full power within milliseconds.
They can operate over a wider temperature range than LA batteries: some are able to withstand occasional temperatures of 50°C.

Figure 2.3-1: Nickel-Cadmium batteries



2.3.2 Applications

Nowadays, a single Nickel/Cadmium battery storage facility almost meets the minimum size capabilities for load levelling applications.
In addition to the low capacity, they do not perform well for spinning reserve applications, and consequently are generally avoided for energy management systems.
They are commonly used for start-up and, recently, have been proposed as storage for solar generation because they can withstand high temperatures.

2.3.3 Costs

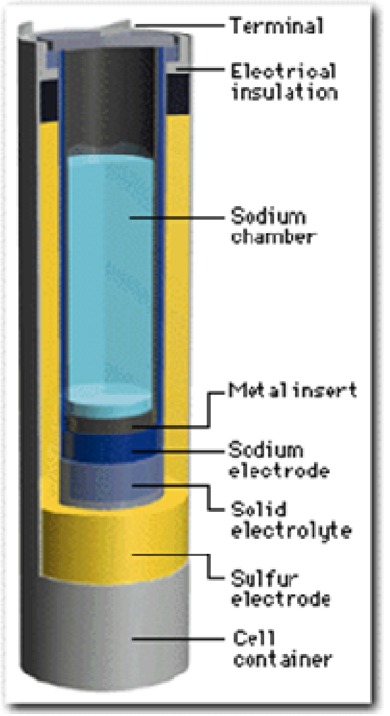
NiCd battery manufacturer projected costs of about $600/kWh. However, despite the slightly higher initial cost with respect to the LA batteries, NiCd batteries have lower maintenance costs and longer lifespan due to their environmental tolerance.

2.4 Sodium-Sulphur Batteries

2.4.1 Description

These batteries are made up of a cylindrical electrochemical cell that contains a molten-sodium negative electrode and a molten-sulphur positive electrode, as shown in Figure 2.4-1. The electrolyte used is solid β-alumina.

Figure 2.4-1: NaS batteries



During discharging, sodium ions react at the positive electrode with the sulphur to form sodium polysulfide. During charging, the reaction is reversed so that the sodium polysulfide decomposes, and the sodium ions are converted to sodium at the positive electrode.
In order to keep the sodium and sulphur molten in the battery, and to obtain adequate conductivity in the electrolyte, they are thermally-insulated and kept above 270°C, usually at 320°C to 340°C.

This requirement represents the major disadvantage of NaS batteries as it is energy consuming and it causes problems with safety and thermal management. Also, due to harsh chemical environments, the insulators, usually alpha-alumina, can be a problem as they slowly become conducting and self-discharge the battery.

The lifecycle is much better than for LA or NiCd batteries. At 100% DoD, the NaS batteries can last approximately 2,500 cycles.

2.4.2 Applications

One of the greatest characteristics of NaS batteries is their ability to provide power in a single, continuous discharge or else in shorter larger pulses. This flexibility makes it very advantageous both for load management and power quality applications. NaS batteries have also been used for deferring transmission lines upgrades.

2.4.3 Costs

Currently, NaS batteries cost 600-810$/kW, including packaging, installation, and balance of plant and power conversion system (PCS).

2.5 Vanadium Redox flow battery

2.5.1 Description

A VR battery is made up of a cell stack, electrolyte tank system, control system and a PCS. These batteries store energy by interconnecting two forms of vanadium ions in a sulphuric acid electrolyte at each electrode; with V^{2+}/ V^{3+} in the negative electrode, and V^{4+}/ V^{5+} in the positive electrode.

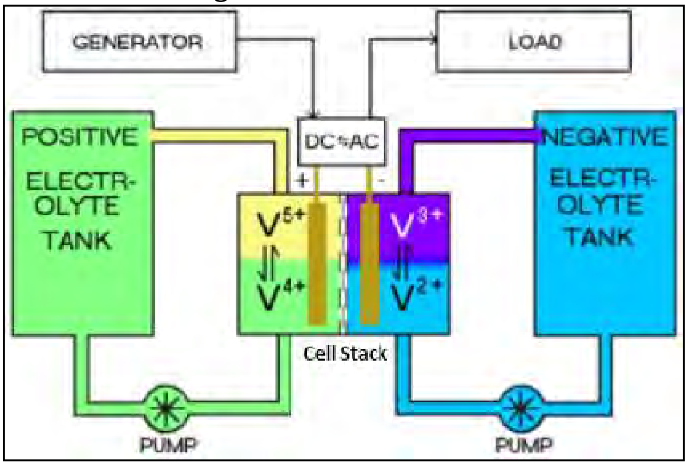
Figure 2.5-1 shows a schematic representation of a Vanadium Redox Flow Battery.

As the battery discharges, the two electrolytes flow from their separate tanks to the cell stack where H^+ ions are passed between the two electrolytes through the permeable membrane. This process induces the changing of the ionic form of the vanadium, converting the potential energy to electrical energy. During recharge this process is reversed.

VR batteries operate at normal temperature with an efficiency as high as 85%. As the same chemical reaction occurs for charging and discharging, the charge/discharge ratio is 1:1. The VR battery has a fast response, from charge to discharge in milliseconds and also can reach twice its rated capacity for several minutes.

VR batteries can operate for 10,000 cycles giving them an estimated life of 7-15 years. At the end of its life (10,000 cycles), only the cell stack needs to be replaced as the electrolyte has an indefinite life and thus can be reused.
VR batteries have been designed as modules so they can be constructed on-site.

Figure 2.5-1: VR batteries



2.5.2 Applications

As the power and energy capacities are decoupled, the VR flow battery is a very versatile device in terms of energy storage.

It can be used for every energy storage requirement including UPS, load levelling, peak-shaving, telecommunications, electric utilities and integrating renewable resources.
However, as other storage device perform better for their specific application, VR batteries are only considered where versatility is important, such as the integration of renewable resources.

2.5.3 Costs

The cost of flow batteries vary in a wide range from 300 to 1000 $/kWh, depending on the system design.

2.6 Regenesys flow battery

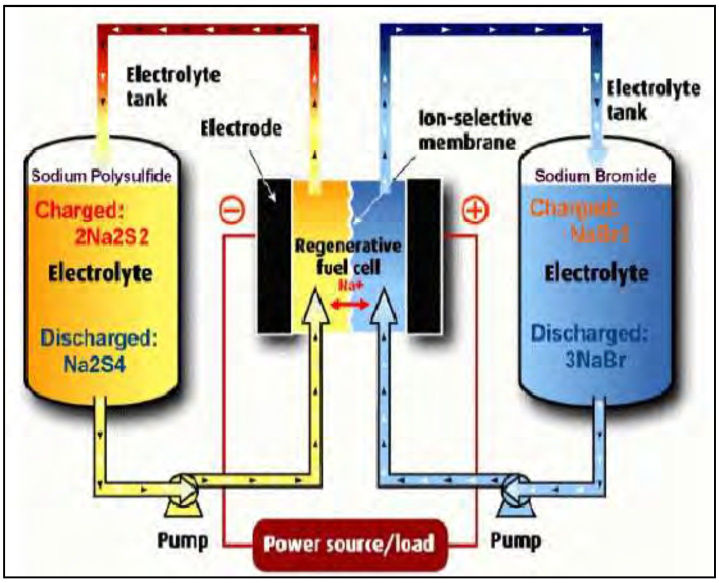
2.6.1 Description

The Regenesys flow battery or Polysulphide Bromide Flow Battery (PSB) device consists of the cell stack, the electrolyte tank system, the control system and a PCS. The PSB flow batteries electrolytes are sodium bromide as the positive electrolyte, and sodium polysulphide as the negative electrolyte.

During discharge, the two electrolytes flow from their tanks to the cell where the reaction takes place: a polymer membrane allows sodium ions to pass through.

Figure 2.6-1 shows a schematic representation of a Regenesys Flow Battery.

Figure 2.6-1: Regenesys Flow batteries



PSB batteries operate between 20°C and 40°C, but a wider range can be accepted introducing a plate cooler in the system.
The efficiency of PSB flow batteries approaches 75%. The charge/discharge ratio is 1:1, since the same chemical reaction is taking place during charging and discharging. The life span is expected around 2,000 cycles.

2.6.2 Applications

PSB flow batteries can be used for all energy storage requirements including load levelling, peak shaving, and integration of renewable resources.
However, PSB batteries due to their very fast response time, PSB batteries are particularly useful for frequency and voltage control.

2.6.3 Costs

The cost of flow batteries vary in a wide range from 300 to 1000 $/kWh, depending on the system design.

2.7 Zinc Bromine flow battery

2.7.1 Description

The unit consists of the cell stack, the electrolyte tank system, the control system and a PCS.
Both the electrolytes consist in a solution of zinc and bromine ions, differing only in their concentration of elemental bromine.
During charging the electrolytes of zinc and bromine ions flow to the cell stack. The electrolytes are separated by a microporous membrane. As the reaction occurs, zinc is deposited in a charge state on the negative electrode and bromine is evolved at the positive electrode.
During discharge the reaction is reversed; zinc dissolves from the negative electrode and bromide is formed at the positive electrode.

ZnBr batteries can operate in a temperature range of 20°C to 50°C. Heat must be removed by a small chiller if necessary.
No electrolyte is discharged as a result of the reaction and hence the electrolyte has an indefinite life. The membrane however, suffers from slight degradation during the operation, giving the system a cycle life of approximately 2,000 cycles.
The efficiency of the system is about 75% - 80%. As the same reaction occurs during charging and discharging, the charge/discharge ratio is 1:1.

2.7.2 Applications

The ZnBr batteries are relatively small and light in comparison to other conventional and flow batteries.

They are applied in the renewable energy backup market, as capable of smoothing the fluctuations in the energy production of a wind farm, or a solar panel, as well as providing frequency control.

2.7.3 Costs

The cost of flow batteries vary in a wide range from 300 to 1000 $/kWh, depending on the system design.

3 Case 5b – Pumped-Hydroelectric Energy Storage

3.1 Introduction

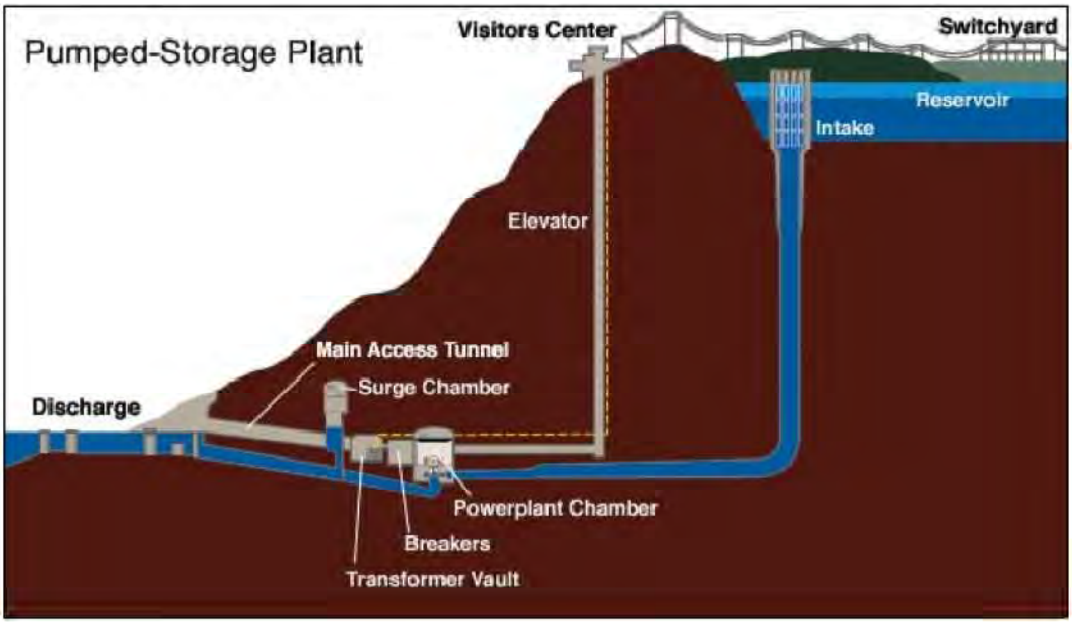
Pumped hydroelectric energy storage (PHES) is the most mature and largest storage technique available. These systems have been in use since 1929, primarily to level the daily load on the network between night and day.

Currently, there is over 90 GW in more than 240 PHES facilities in the world, equivalent to roughly 3% of the world's global generating capacity. Single facility capacity vary in the range from 30 MW to 4,000 MW of stored electrical energy.

3.2 Description

PHES plants are based on a conventional hydroelectric technology, consisting of two large reservoirs located at different elevations and a number of pump and hydraulic turbine units, as shown in the following Figure 3.2-1.

Figure 3.2-1: Case 5b – Pumped-Hydroelectric Energy Storage layout



During off-peak electrical demand, water is pumped, using excess energy generated by other sources, from the lower reservoir to the higher reservoir where it is stored until it is needed.

Once required, i.e. during peak electrical production, the water in the upper reservoir is released through the turbines, which are connected to generators that produce electricity.

Generation and pumping can be accomplished either by single-unit, reversible pump-turbines, or by separate pumps and turbines. Mode changes between pumping and generating can occur within a period of minutes, and up to more than 40 times daily.

Hydroelectric power requires a considerable volume of water to produce energy. Until recently, PHES units have always used fresh water as the storage medium. However, in 1999 a PHES facility using seawater as the storage medium was constructed, preventing corrosion by using paint and cathodic protection.

A typical PHES facility has 200-300 m of hydraulic head. The power capacity is a function of the flow rate and the hydraulic head, while the energy stored is a function of the reservoir volume and hydraulic head.

Both power and storage capacities are dependent on the head and the volume of the reservoirs. However, facilities should be designed with the greatest possible hydraulic head, rather than largest upper reservoir possible.
In fact, constructing a facility with a large hydraulic head and small reservoirs is cheaper, with respect to a facility of equal capacity with a small hydraulic head and large reservoirs. This is mainly related to the smaller size of equipment, pump and turbine, as well as piping and the lower amount of material that shall be removed to create the reservoirs.

The efficiency of modern pumped storage facilities is in the region of 70% - 85%. The efficiency is limited by the efficiency of the pump/turbine unit used in the facilities. Currently, a lot of work is being carried out to upgrade old PHES facilities, introducing adjustable-speed or variable-speed turbine, which can increase capacity by 15% to 20%, and efficiency by 5% to 10%, thus increasing the energy storage capacity without the high initial construction costs.

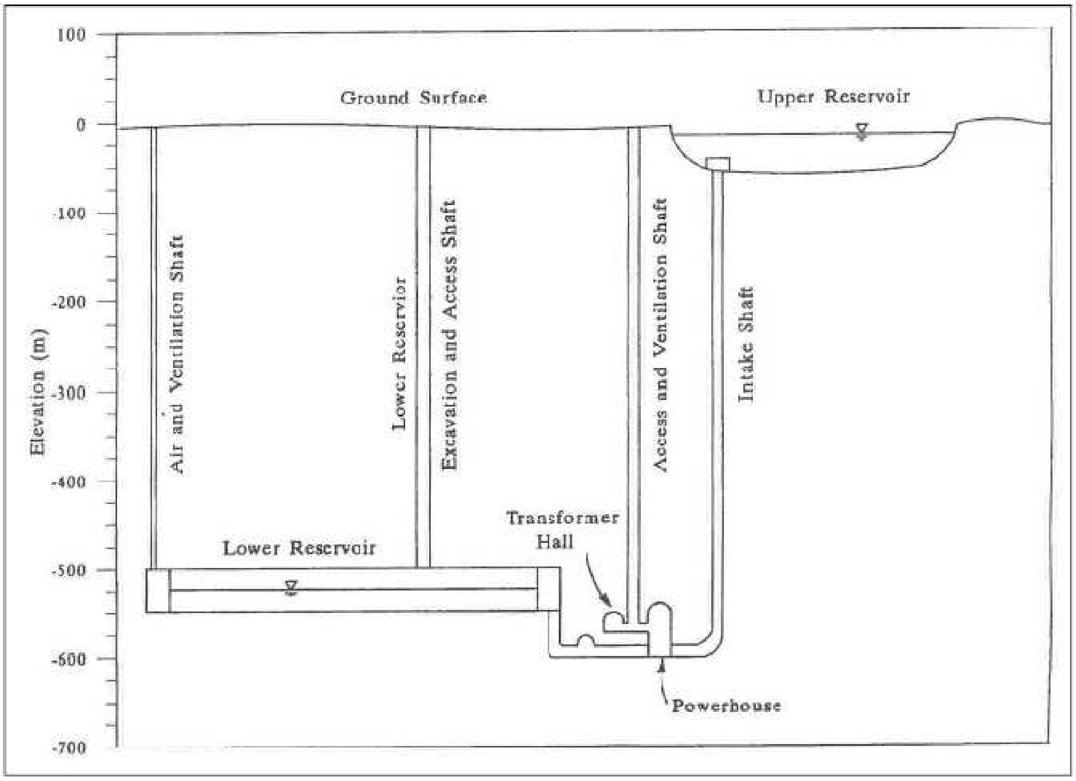
The variable-speeds pump turbines are able to operate over a range of rotation speeds (±10% the speed of a conventional pump turbine), depending upon the supply and demand of electricity, which allows to vary the amount of generated electricity by 70% and the amount stored energy by 40%.

Due to the design requirements of a PHES facility, the main disadvantage is its dependence on specific and rare geological formations: in fact, two large reservoirs with a sufficient amount of hydraulic head between them must be located within close proximity to build a PHES system.

In addition, these geological formations normally exist in remote locations such as mountains, where construction is difficult and the power grid is generally not present.

A new concept that is showing a lot of theoretical potential in overcoming this drawback is Underground Pumped-Hydroelectric Energy Storage (UPHES).
The operating principle of an UPHES facility is the same of PHES system: two reservoirs with a large hydraulic head between them. The two designs differ for the locations of their respective reservoirs. UPHES facilities are designed with the upper reservoir at ground level and the lower reservoir below the earth's surface, as shown in the following Figure 3.2-2.
The depth depends on the amount of hydraulic head required for the specific application.

Figure 3.2-2: Case 5b –Underground Pumped-Hydroelectric Energy Storage layout



Introducing the UPHES technologies allows avoiding dependence on geological formation. The major disadvantage for UPHES is its commercial youth: nowadays there are very few, if any, UPHES facilities in operation. Therefore, it is very difficult to analyse and to verify the performance of this technology.

3.3 Applications

PHES facilities are characterised by large power and storage capacities and fast reaction time, thus identifying load-levelling as the ideal application.
Facilities can have a reaction time as short as 10 minutes or less from complete shutdown (or from full reversal of operation) to full power. In addition, if kept on stand-by, full power can even be reached within 10 to 30 seconds.

With the recent introduction of variable speed machines, PHES systems can now be used for frequency regulation in both pumping and generation modes.

PHES can also be used for peak generation due to its large power capacity and sufficient discharge time. Finally, PHES provides a sink for base-load generating facilities, as coal-fired power plants, during off-peak production, reducing the need of operating these units in cycling mode, which improves their lifetime as well as their efficiency.

3.4 Costs

The cost of a PHES plant depend on a variety of factors including size, location and connection to the power grid, the head of water, the civil costs of excavation, tunnelling, dam building, etc.

Costs for the power-related part of the installations vary in the range from 600$/kW to 2000$/kW, while the cost of the storage component is relatively inexpensive, at about $10/kWh.
Costs related to the motor/generator/ turbine increase for variable-speed machines of about 10% with respect to the conventional turbine.

Although the cost per kWh of storage is relatively economical in comparison to other techniques, the large scale, required by this facility, results in a very high initial construction cost.

Currently, no costs have been identified for UPHES, primarily due to the lack of facilities constructed. A possibility for cost-saving is using old mines for the lower reservoir of the facility. In particular, an alternative could be obtaining the lower reservoir removing something valuable that can be sold to recover part of the cost.

3.5 Case study: Bath County Pumped Storage Station

The Bath County Pumped Storage Station is a pumped storage hydroelectric power plant with a generation capacity of nearly 2,800 MW. The station is located in the northern corner of Bath County, Virginia.

It went into operation in 1985 and is still the largest-capacity pumped-storage power station in the world.

It costed $1.6 billion, and was constructed with 2,100 MW capacity. In 2004 upgrades started, increasing power generation to 462 MW per turbine and pumping power to 480 MW per unit. Bath County Station is jointly owned by Dominion Generation (60%) and the Allegheny Power System (40%), while it is managed by Dominion.

The station consists of two reservoirs separated by about 380 m in elevation, six turbine generators and pumping unit, and the huge tunnels that connect them. When demand is low, water is pumped from the lower reservoir to the upper one.
When demand is high, water flows through the tunnels to the lower reservoir at a rate as high as 850 m^3/s, moving six 462 MW turbine generators.

Main design details of the plant are summarized in the following table.

Power capacity	
Net Generating Capacity	2,772 MW
Turbine Generators	6 x 462 MW Francis-type units
Maximum Pumping Power	479,300 kW per unit
Water flow	
Water Flow - Pumping	800 m^3/s
Water Flow - Generating	852 m^3/s
Lower Reservoir	
Capacity	$3.1 \cdot 10^6$ m^3
Surface	2.25 km^2
Depth	41 m
Water level fluctuation during operation	18 m
Upper Reservoir	
Capacity	$13.8 \cdot 10^6$ m^3
Surface	1.07 km^2
Depth	140 m
Water level fluctuation during operation	32 m

4 Case 5c – Compressed air energy storage

4.1 Introduction

A Compressed Air Energy Storage (CAES) plant stores electrical energy as the potential energy of a compressed air, then recovers this energy as an input for subsequent power generation.

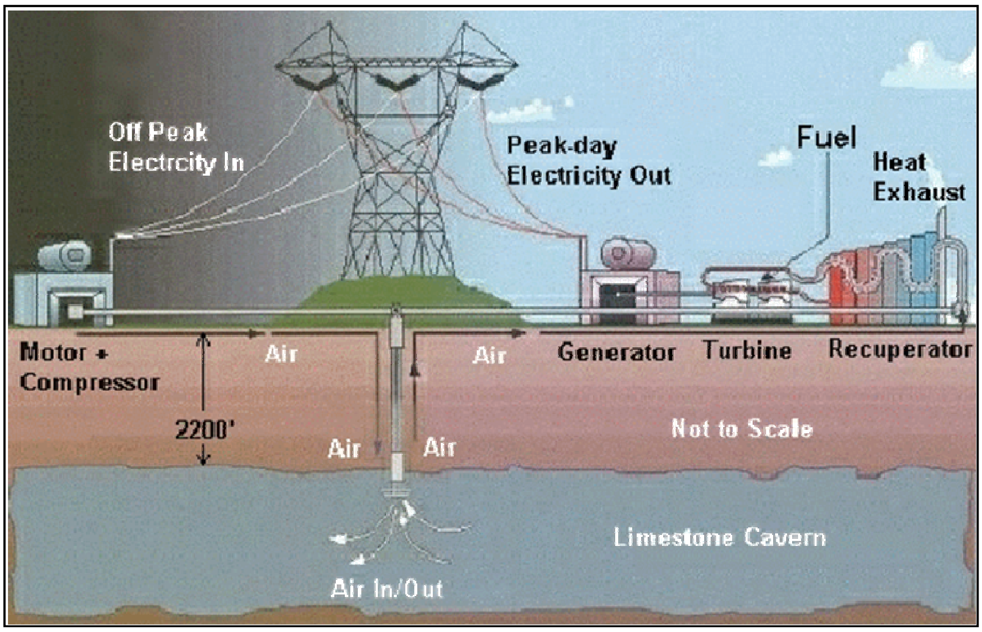
CAES technology has been in use for 30 years. Two CAES plants are in operation today: a 290 MWe plant in Huntorf, Germany, constructed in the late 1970s, and a 110 MWe plant in McIntosh, Alabama, constructed in the early 1990s.

4.2 Description

The basic idea of CAES is to transfer off-peak energy produced by base nuclear or coal fired units to the high demand periods, using only a fraction of the gas or oil that would be used by a standard peaking machine, such as a conventional gas turbine.

The facilities include three major components, as shown in Figure 4.2-1: a compressor, driven by a motor during off-peak periods, an underground storage medium, such as a salt dome, an empty mine, or an aquifer and a combustion turbine that drives a generator during high electricity demand periods.

Figure 4.2-1: Case 5c – Compressed Air Energy Storage system



The CAES cycle is essentially a variation of a standard gas turbine generation cycle. In a typical gas fired generation cycle, the turbine is physically connected to an air compressor. When gas is combusted in the turbine, approximately two-thirds of the turbine's energy is required to compress the air.

Therefore, in CAES facilities, the compression cycle is separated from the combustion and generation cycle. Air is compressed using off-peak electrical power, which is taken from the grid to drive a motor, and stored in large storage reservoirs.
During peak demand period, the CAES plants generate power. The compressed air is released from the storage facility, heated through a recuperator and used to burn natural gas in the combustion chambers. The resulting combustion gas is then expanded in the turbine expander to produce electricity.

If no gas is added, the temperature and pressure of the air would be a critical aspect. In fact, if the air pressure is high enough to achieve a significant power output, even if expanded alone, the air temperature would be too low for being tolerated by the materials and connections.

As no compression is needed during turbine operation, the power output of a CAES system is about three times the power generated by a turbine in a simple cycle configuration, burning the same amount of natural gas.

Furthermore, traditional gas turbine efficiency decreases of about 10% for a 5°C ambient temperature increase, due to a reduction of the air density. As compressed air is used, CAES do not suffer from this effect. Also, while traditional gas turbines suffer from excessive heat when operating at partial load, CAES facilities do not.

The reservoir can be man-made but this is expensive, so CAES locations are usually decided by identifying natural geological formations that suit these facilities. These include salt-caverns, hard-rock caverns, depleted gas fields or aquifers.
Both existing CAES systems use solution-mined, salt caverns as gas storage reservoir.

Salt-caverns can be designed to suit specific requirements. Fresh water is pumped into the cavern and left until the salt dissolves and saturates the fresh water. The water is then returned to the surface and the process is repeated until the required volume cavern is created. This process is expensive and can take up to two years.
Hard-rock caverns are even more expensive, usually 60% higher than salt-caverns.
Finally, aquifers cannot store the air at high pressures and therefore have a relatively lower energy capacity.

4.3 Applications

CAES is the other very large scale storage technology besides PHES. It is characterised by a fast reaction time, as plants are capable to go from 0% to 100% in less than ten minutes, from 10% to 100% in approximately four minutes and from 50% to 100% in less than 15 seconds.
As a result, it is ideal for load following applications as it can act as a large sink for bulk energy supply and demand, and also it is able to undertake frequent start-ups and shutdowns.
As it is capable of operating efficiently at a wide load range, CAES can be used for ancillary services such as frequency regulation, load following, and voltage control.

As for these characteristics, it has been considered to integrate a CAES facility with wind farms within the same region. The excess off-peak power from these wind farms could be used to compress air for a CAES facility.

4.4 Costs

CAES plant costs can be split into two main components.

The costs of the storage media is generally very low, in locations where it is available, whether it is salt domes, hard rock (mines or other caverns) or porous rock (aquifers or old gas/oil areas). The energy-related costs are approximately 3$/kWh, based on historical experience.

The power-related costs are based on the cost of conventional gas combustion turbines, and ancillary equipment for generation, gas compression, etc.

4.5 Case study: Huntorf CAES plant

The 290 MWe Huntorf plant, in North Germany, was the first compressed air storage-gas turbine power station in the world.

Main design details of the Huntorf plant are summarized in the following table.

Power capacity	
Turbine operation (≤ 3 hours operation)	290 MW
Compression operation (≤ 12 hours operation)	60 MW
Air flow	
Turbine operation	417 kg/s
Compression operation	108 kg/s

Salt caverns design	
Number	2
Single cavern capacity	140,000 m^3 170,000 m^3
Total storage capacity	310,000 m^3
Cavern location – top bottom	650 m 800 m
Maximum diameter	60 m
Salt caverns pressure	
Minimum allowable	1 bar
Minimum operational (emergency)	20 bar
Minimum operational (regular)	43 bar
Maximum allowable	70 bar
Maximum allowable pressure reduction rate (during operation)	15 bar/h

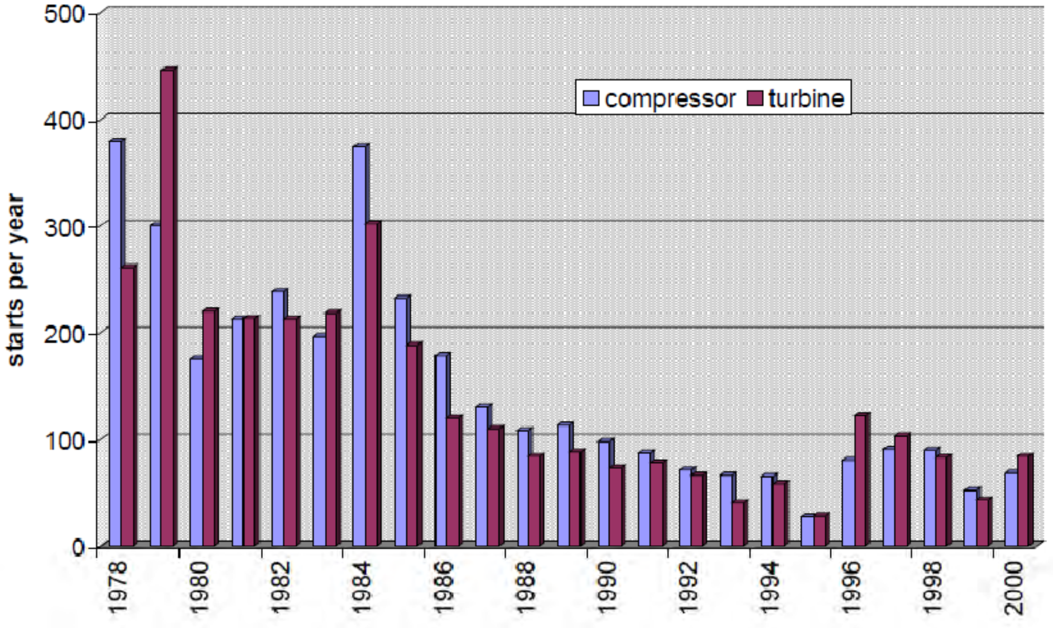
A 60 MWe electrically driven air compressor is operated during low electricity demand period, while electricity is delivered to the grid by a 290 MWe sized gas turbine.
Compression operation period is about 4 times the turbine operation period, depending on compressor and turbine generator sizes.

The Huntorf plant consists of two caverns, although the total volume of 300,000 m^3 could have been realized with just one cavern.
The advantages of splitting the volume between two caverns include redundancy during maintenance or cavern shut-down and easier cavern refilling after drawing down the pressure in a cavern to atmospheric pressure.

The Huntorf plant was commissioned in 1978 and is still in operation today, even if the number of start required per years is decreasing, as shown in Figure 4.5-1.

This is mainly related to the connection to a larger network in 1985, which added pumped hydro capacity. Therefore, the CAES plant is typically used today as for spinning reserve and peak shaving applications, as well as emergency reserve in case of unplanned failure of other power plants.
An additional application is associated with the strong increase in the number of wind power plants in North Germany in recent years: because the availability of this type of power cannot be reliably forecast, the plant in Huntorf is able to quickly compensate for any unexpected shortage in wind power.

Figure 4.5-1: Case 5c – Huntorf CAES plant: number of starts per year



In the first 20 years of operation the Huntorf plant runs reliably on a daily cycle and has successfully accumulated 7000 starts. The plant has reported an availability of 90% and a starting reliability of 99%.

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