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Evaluating technology options to mitigate greenhouse gas emissions

EVALUATION AND ANALYSIS OF WATER USAGE OF POWER PLANTS WITH CO_2 CAPTURE

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DISCLAIMER AND ACKNOWLEDGEMENTS

ACKNOWLEDGEMENTS AND CITATIONS

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Foster Wheeler Italiana

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EVALUATION AND ANALYSIS OF WATER USAGE OF POWER PLANTS WITH CO_2 CAPTURE

Background to the Study

All types of thermal power plant (fossil fuel, biomass, nuclear, solar thermal or geothermal) potentially require large quantities of water. In places where the availability of water is limited and there are competing demands, the choice of power generation technology could be affected by the water requirement. Including CO_2 capture in a power plant often increases the water requirement but if water availability is a concern there are techniques that could be used to reduce water usage.

The IEA Greenhouse Gas R&D Programme (IEAGHG) has undertaken a study to quantify the water requirements of power plants with and without CO_2 capture, to identify techniques that could be used to reduce the water requirements should this be necessary and to estimate the resulting impacts on thermal efficiency and costs of electricity generation. The study was carried out for IEAGHG by Foster Wheeler Italiana.

This overview presents the key results of the study.

Study Description

Scope of the study

The main scope of the study is to:

- Establish the current state of the art in water reduction technology for power plants.
- Assess the water usage, waste water output and overall performance of power plants with and without CO_2 capture in sites where water is readily available and sites where water resources are limited.
- Assess the costs of power plants with and without CO_2 capture and the costs associated with reducing water consumption.

Plant descriptions

The following five alternatives were assessed:

- Pulverised coal fired power plant with ultra-supercritical steam cycle without CO_2 capture (USC PC without CCS);
- Pulverised coal fired power plant with ultra-supercritical steam cycle with post-combustion CO_2 capture based on standard MEA solvent (USC PC with CCS);
- Pulverised coal fired power plant with ultra-supercritical steam cycle using oxyfuel combustion for CO_2 capture;
- IGCC using GE Energy's Quench type gasifier without CO_2 capture (IGCC without CCS);
- IGCC using GE Energy's Quench type gasifier with pre-combustion CO_2 capture based on physical solvent (IGCC with CCS).

Each of the alternatives was evaluated for sites where there are no limitations on water usage (wet land cases) and sites with severe limitations (dry land cases). The main differences between the wet and dry land cases are in the areas of waste water treating, the cooling water system and flue gas treating.

Basis for plant design and cost estimation

The plant designs and performance data for the reference 'wet land cases' in this study are based on earlier IEAGHG studies[1,2,3] and the dry land cases are modifications of these designs. The technical and economic assessment criteria used in the study are given in the detailed study reports. The power plants are designed to generate 600-800 MWe except for the oxyfuel case which is designed to produce around 500 MWe, based on the technical specification used in the previous study[3]. The CO_2 capture efficiency depends on the specific case, ranging from 85 to 90%. The fuel for the power plants is a bituminous coal with a lower heating value (LHV) of 25.87 MJ/kg and a sulphur content of 1.1% wt (as-received basis).

The site for the reference cases (wet land) is a green field coastal site with an average air temperature of 9°C and an average seawater temperature of 12°C (i.e. the standard plant site in most of IEAGHG's studies). The sea water return temperature from the cooling system is 19°C. The site for the dry land cases is in a dry inland region in South Africa, with an average air temperature of 14°C.

The plants were assumed to operate at base load with load factors of 85-90% depending on the case. The economic evaluation was based on a 10% annual discount rate and 25 years operating life. The coal cost is €1.5/GJ, as used in the earlier studies.

The plant costs were estimated in Euros (4th quarter 2009 base). Conversion of Euros to US Dollars was assumed to be 1.23$ to 1.00€ (this is only used for the post combustion capture cases). The accuracy of the cost estimate is set at ±35%. As the dry land case is in South Africa, the costs of all of the plants were estimated for a South African location. Foster Wheeler estimated costs for a European location and then converted to a South African location using their in-house multiplication factors. Levelised costs of electricity are calculated assuming a 10% discount rate and a 25 operating life of the plants.

In this report, the following standard terminologies related to power plant water usage analysis were used:

- Water **withdrawal** refers to the total water taken from a source and sent back to the same source;
- Water **consumption** refers to the irrecoverable loss of water that is not returned to the source;
- Water **discharge** refers to the total water (in liquid form) released by the power plant flowing out of its battery limit;
- **Effluent** refers to the water discharge released by the waste water treatment facilities of the power plant.

Overview of Results

Techniques to reduce water use

Power plants require raw fresh water for boiler feed water make-up, flue gas scrubbing and other process requirements, and cooling water to dissipate low temperature heat principally from the steam turbine condenser.

The three main techniques for reducing water consumption that were evaluated in this study are:

(a.) Use of air cooling instead of water cooling systems
(b.) Reduction of water loss from waste water treating
(c.) Water recovery from combustion flue gas

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[1] Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 Capture, IEAGHG report PH4/19, May 2003.

[2] Improvements in Power Generation with Post Combustion Capture of CO_2, IEAGHG report PH4/33, Nov. 2004.

[3] Oxy-combustion Processes for CO_2 Capture from Power Plants, IEAGHG report 2005/9, July 2005.

These techniques are applicable to all of the types of power plants.

The main study report also describes other techniques that could be used, including the following, although none of these techniques was analysed quantitatively:

(d.) Rain water utilisation (all types of power plants)
(e.) Water recovery for lignite drying (all types of lignite fired plants)
(f.) Use of dry bottom ash removal system (PC plants)
(g.) Use of shift catalysts that can accept lower steam:gas ratios (IGCC plants with CO_2 capture)
(h.) Use of a saturator/desaturator system to provide steam for shift conversion (IGCC plants with CO_2 capture)
(i.) Use of nitrogen in place of steam to dilute the fuel gas to the gas turbine (IGCC plants)
(j.) Water recovery from the gasifier slag removal system (IGCC plants)
(k.) Use of nitrogen from the ASU as a coolant (Oxy-combustion plants)

Cooling water systems

Various commercially available cooling systems are used in power plants, including:

- Once-through cooling using sea, lake or river water
- Wet cooling towers
- Dry air cooling systems

All of these cooling systems are widely used in large power plants. The type of cooling system has a significant effect on the thermal efficiency of a power plant, mainly because the cooling temperature that can be achieved affects the steam turbine condenser pressure, which in turn affects the steam turbine efficiency. The reference cases in this study use a once through sea water cooling system and a dry cooling system is evaluated for ‘dry land’ sites where water availability is severely limited. Dry cooling systems can be classified as direct or indirect systems. In a direct air cooler the stream to be cooled, for example steam exiting a steam turbine, is passed through finned tubes that are cooled by air from a forced draught fan. In an indirect cooling system the cooling is provided by clean water which is then cooled in an air cooler before being recirculated. Figure 1 shows the impact of the type of cooling system on the thermal efficiency of a typical pulverised coal power plant but the impacts depend on the ambient conditions, particularly the water and air temperature and humidity.

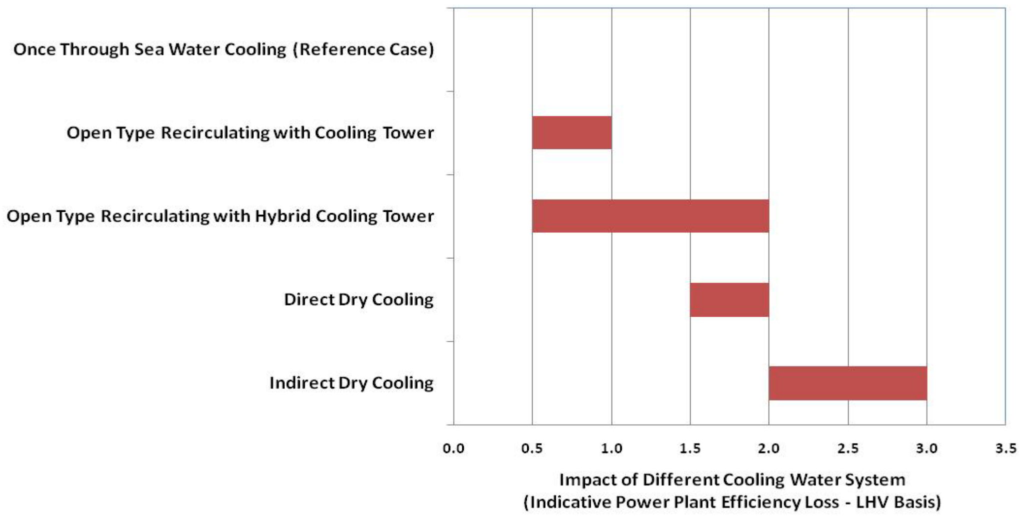

Figure 1: Indicative impact of alternative cooling water systems on the power plant efficiency

Waste water treating

Process waste water from power plants has to be treated to meet environmental emission limits. Additional stages of treating can be included to achieve zero or near zero water discharge. Waste water can be passed through ion exchange resins and reverse osmosis to produce a low salinity water, which is reused, and a high salinity reject water. The reject water can if required be evaporated to produce solid salts and distilled water.

Flue gas condensation
The water vapour content of flue gas can be reduced by means of a Direct Contact Cooler (DCC) where heat is transferred from the flue gas to a stream of water. Some of the warm water from the bottom of the DCC column is cooled in a dedicated air cooler and is recirculated to the top of the column. The column contains trays or packed beds to enable the flue gas and water to approach the thermodynamic equilibrium conditions. The amount of water that can be recovered depends on the concentration of water vapour in the flue gas and the temperature that can be achieved by the cooling system. The DCC has the advantage that there are no heat exchange surfaces in contact with the flue gas that could be fouled. A drawback is that due to the additional pressure drops the power consumption of the flue gas fan upstream is increased.

Analysis of plant performance and water consumption

Diagrams showing the detailed water flows in all of the plants are included in the main report. The water flows and techniques used to reduce water consumptions in the dry land cases are summarized below.

USC PC without CO_2 capture

Raw fresh water consumption
The main raw water consumptions of the pulverized coal plant without CO_2 capture are the following:

- Demineralised (demi) water unit: raw water is needed to produce demi water which is sent mainly to the power island to compensate for the water losses in the condensate polishing section.
- FGD: raw water is needed to compensate for the increased moisture content of the flue gas, the sour water blow down and the water content of the gypsum product.

The net raw water consumption is 104 kg/MWh of net electricity generated, as shown in Figure 2. In addition to this raw water input, about 200 kg/MWh of water enters the plant as moisture in the coal and the combustion air and is produced by combustion of the hydrogen in the coal. 279 kg/MWh of water is lost in the flue gas, as shown in Figure 4 and the water effluent discharge is 19 kg/MWh, as shown in Figure 2. The small net balance is due mainly to the water contained in the gypsum product from the FGD.

In order to minimize the overall water consumption and effluent discharge in the dry land case, the Waste Water Treatment (WWT) unit is modified to enable it to produce water that can be sent back to the demi plant and the FGD where necessary. Recovering the water that would otherwise be discharged from the WWT reduces the raw water consumption by about 18% and almost eliminates the water effluent discharge. To reduce the overall raw water consumption to zero, 31% of the water in the flue gas has to be condensed in a direct contact cooler and sent to the WWT for treatment and recycle to the demi plant and FGD.

Cooling water usage
The wet land case uses a once-through sea water cooling system, mainly for cooling of the steam turbine condenser. Water used in a once-through cooling system does not represent a consumption because it is all returned to its source. Nevertheless the water consumption can still be a concern because the higher temperature of the returned cooling water may have adverse environmental impacts. The total sea water withdrawal for the PC plant without capture is 145 t/MWh, as shown in Figure 5. In the dry land case an air cooling system is used to eliminate the requirement for cooling water.

The option of wet cooling towers was not evaluated quantitatively in this study but information on the water consumption of cooling towers is available from other studies. Based on the water consumption per unit of heat rejected given in a study by NETL[4], the cooling water evaporation of the PC plant without capture in this study would be about 1500 kg/MWh and the cooling tower blowdown water effluent would be about 500 kg/MWh, giving a total raw cooling water requirement of 2000 kg/MWh. This is about 20 times greater than the raw process water requirement shown in Figure 2.

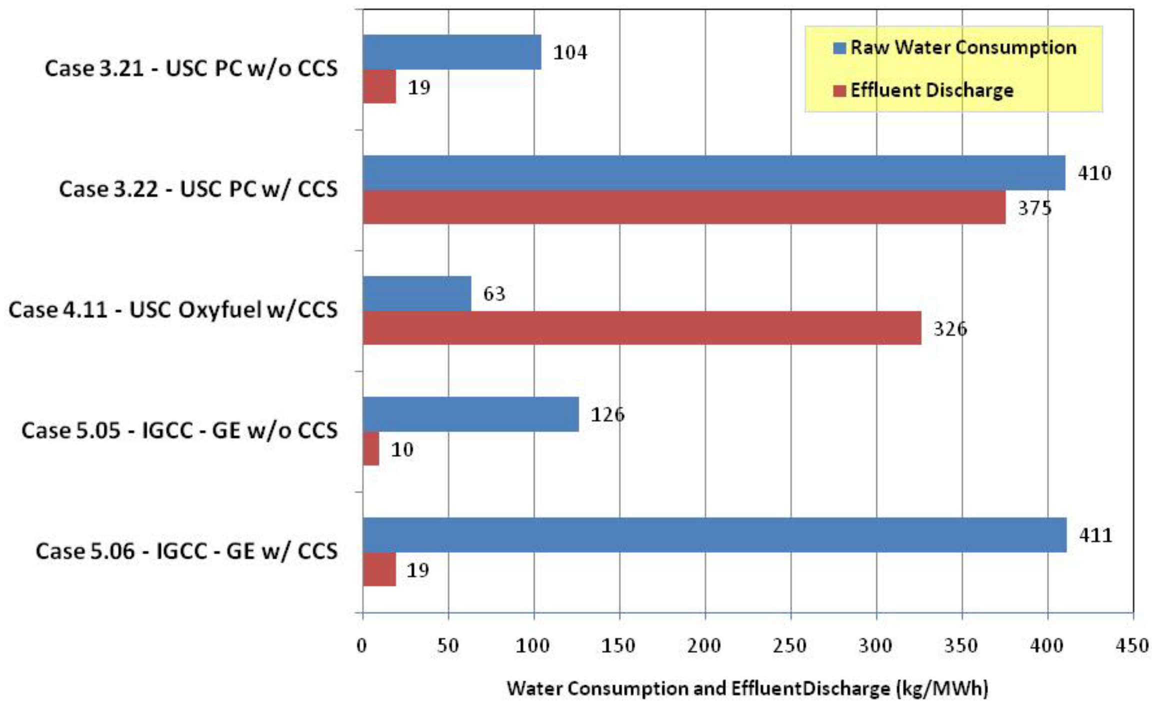

Figure 2: Specific raw water consumption and liquid effluent discharge for all the wet land cases

[4] Power Plant Water Usage and Loss Study, US Department of Energy NETL, revised report, August 2007.

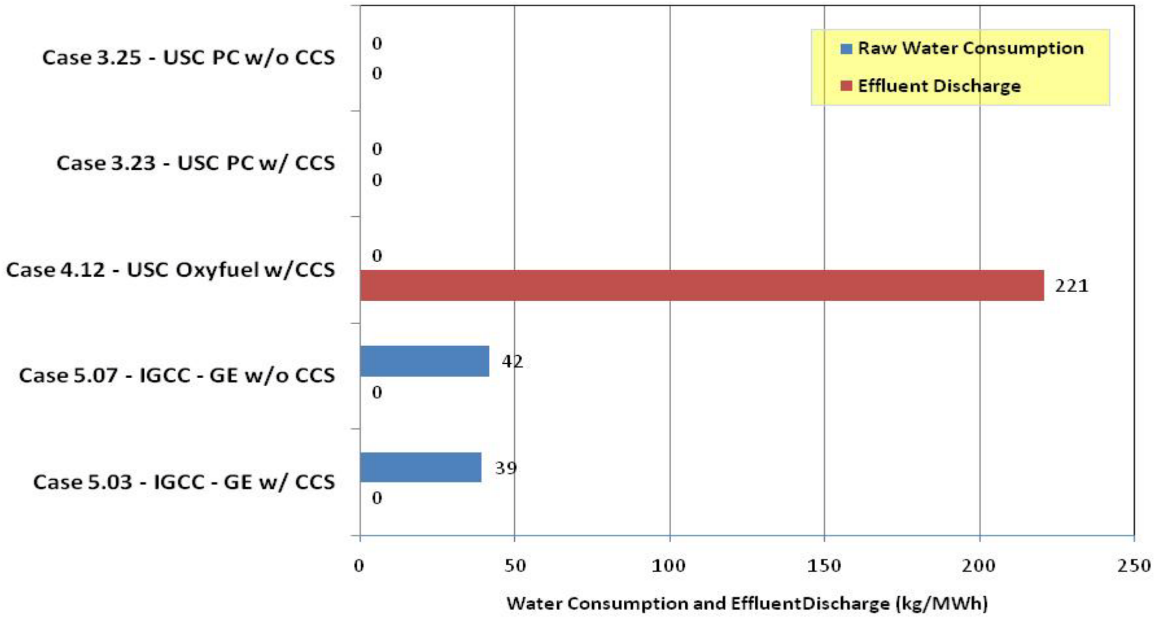

Figure 3: Specific raw water consumption and liquid effluent discharge for all the dry land cases

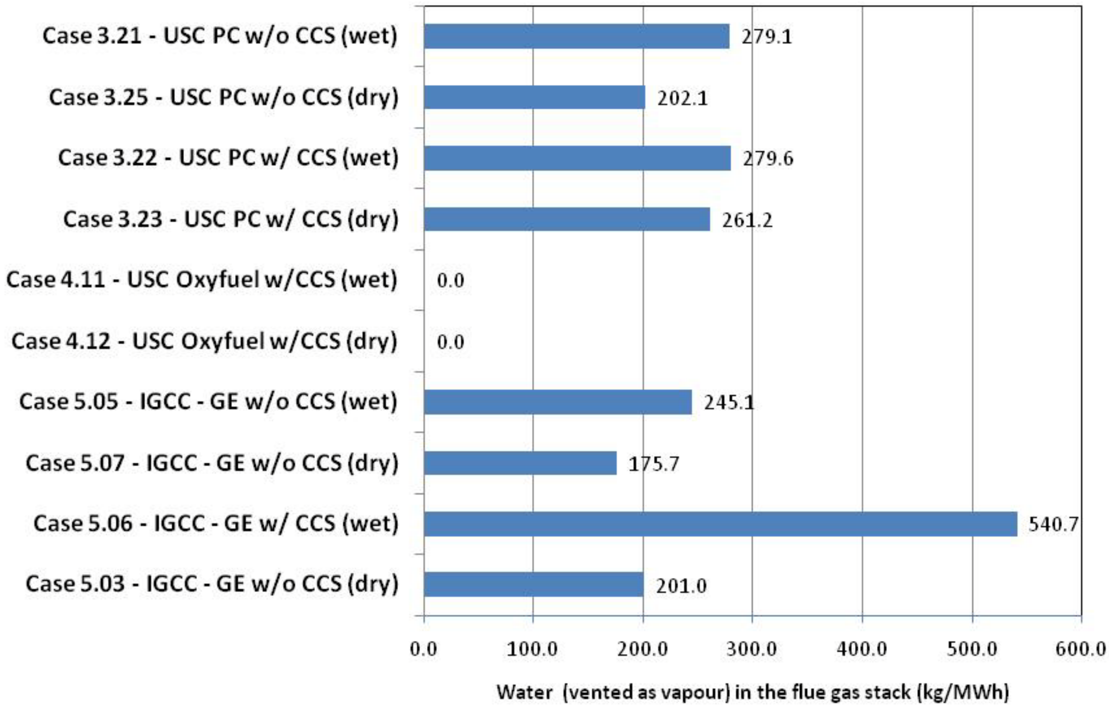

Figure 4: Specific water vented as vapour in the flue gas stack for all cases

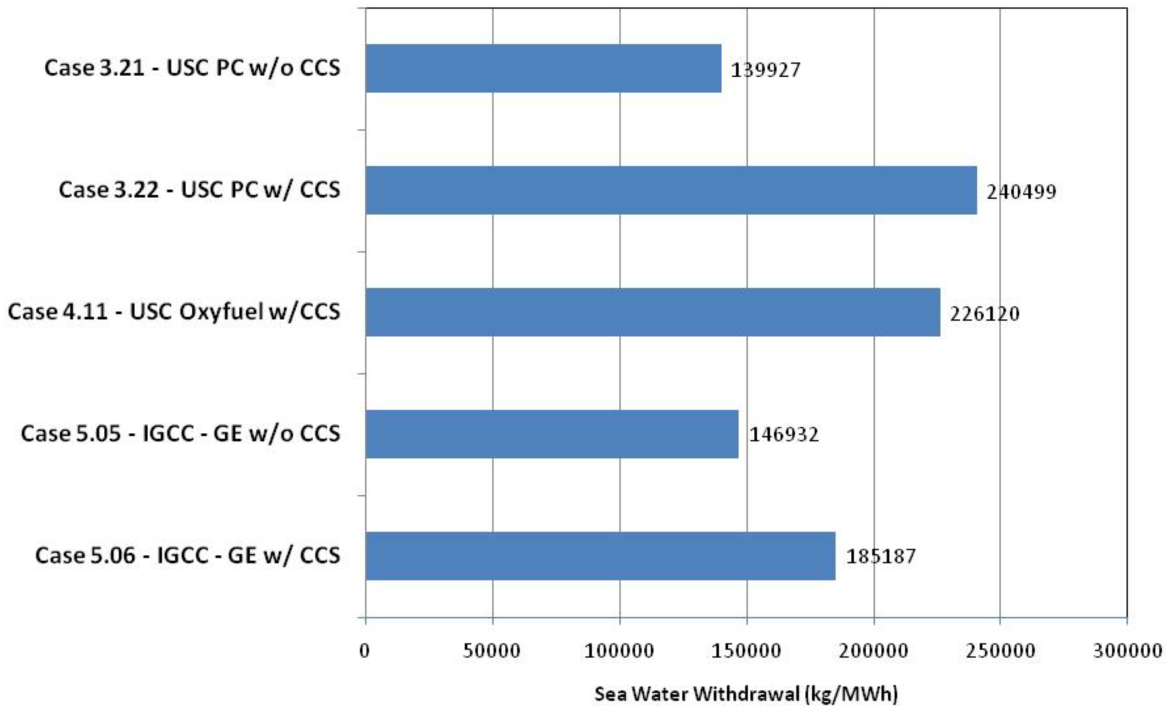

Figure 5: Specific sea water withdrawal for cooling duty in all the wet land cases[5]
<u>Note: seawater withdrawal is zero for all the dry land cases</u>

<u>Power output and thermal efficiency</u>
The power output of the dry land case is 4.3% lower than that of the wet land case and the thermal efficiency is 1.9 percentage points lower, as shown in Figure 6. The main reason for this is the 3.5% reduction in the power from the steam turbine, which is due to the increase in the steam turbine exhaust pressure resulting from the use of air cooling. The other major reasons for the lower power output and efficiency include the increased power consumption of air cooling compared to water cooling, the increased power consumption of the flue gas blower to overcome the pressure drop through the DCC and the power consumption of the water pumps and air coolers of the DCC.

[5] The flowrate in the oxyfuel case is higher than that given in the previous IEAGHG Report (2005/9), due to adjustment of the cooling water temperature rise to 7°C, consistent with the other cases.

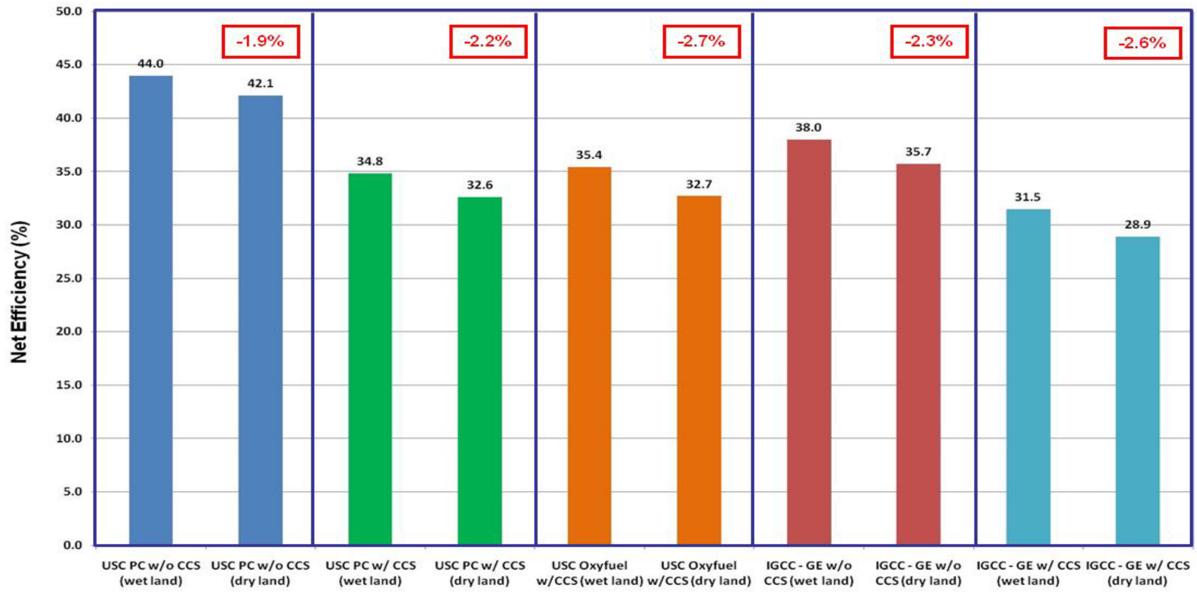

Figure 6: Power plant efficiency (LHV base) comparing both dry and wet land cases.

USCPC with post-combustion CCS

In addition to the water required to produce demi water and for FGD make-up, as described above, the plant with post combustion capture also requires raw water to scrub the gases leaving the absorber column in the CO_2 capture unit, to remove MEA and solvent decomposition products. This consumption of water can be avoided in some CO_2 capture processes where part of the water discharged into the flue gas cooling upstream of the column can be reused. For the purposes of this paper, the need of such a makeup is considered. The overall raw water consumption in the wet land case is almost four times higher than in the USC PC plant without capture, as shown in Figure 2.

Sea water cooling is required mainly for the steam turbine condenser, the CO_2 capture unit and the intercoolers of the CO_2 compression unit. The total sea water withdrawal is 249 t/MWh, which is 72% higher than in the plant without capture. This increase is because the additional energy consumed for CO_2 capture has to be dissipated mainly via the cooling water system and also because the reduction in the power output increases the specific water requirement per net MWh of electricity.

The raw water and cooling water consumptions are reduced to zero and the water effluent discharge is reduced close to zero in the dry land case, using the same techniques as in the plant without CO_2 capture, i.e. modified waste water treating, flue gas direct contact cooling and air coolers. The net power output of the dry land case with capture is 6.4% lower than that of the wet land case with capture and the thermal efficiency is 2.2 percentage points lower. As well as the impacts of water reduction described above for the plant without capture, the use of air cooling also increases the power consumption of the CO_2 compressor. The higher temperature of the intercoolers increases the power consumption and it also means that the final stage of CO_2 pressurisation has to take place in a gas compressor instead of the pump that is used in the water cooled reference case. As a consequence the overall power consumption for CO_2 compression is 25% higher. The higher cooling temperature also has an impact on the CO_2 capture unit. Both the flue gas and the lean solvent are fed to the absorber at higher temperatures, thus leading to an increase of solvent circulation and steam consumption in the regeneration section.

USC PC with Oxyfuel Combustion CO_2 Capture

The main raw water consumptions of the oxyfuel plant are for the demi water unit and the flue gas water scrubber in the CO_2 compression and purification unit. Unlike the USC PC plant without capture, the oxyfuel plant does not include an FGD, thereby avoiding the water consumption of such a unit. As a result, the overall raw water consumption is only about 60% of that of the PC plant without capture, as shown in Figure 2. Because the oxyfuel process inherently has to remove almost all of the water from the flue gas prior to or during CO_2 compression and processing, the quantity of water effluent is substantially higher than that of the plant without CO_2 capture, as shown in Figure 2.

The total sea water withdrawal for cooling is 233 t/MWh, which is 62% times higher than that of the PC plant without capture. The cooling water is mainly used for the steam turbine condenser, the water coolers of Air Separation Unit (ASU) compressors and the CO_2 compressors. In the dry land case the sea water withdrawal is reduced to zero by using an air cooling system.

The raw water consumption can be reduced to close to zero by only modifying the waste water treating unit. Most of the water is already condensed from the boiler flue gas as an inherent feature of the oxyfuel process. Having to remove all of the water from the flue gas means that, unlike the other technologies considered in this study, it is not possible to achieve near zero water discharge, as shown in Figure 3. This may be a disadvantage or it may be an advantage if other uses can be found for the water in locations where water is scarce.

The impact of the water reduction techniques on the power plant performance is slightly higher than in the post combustion case because in addition to the impacts on the steam turbine and CO_2 compression, the use of air cooling affects the ASU intercoolers and water chiller and hence the power consumption of the ASU. Compared to the plant without CO_2 capture, the net power output is approximately 7.5% lower and the overall thermal efficiency is 2.7 percentage points lower, as shown in Figure 6.

IGCC without CCS

The main raw water consumptions of the IGCC plant without capture are for the demi water unit and make-up water to the gasification unit. The overall raw water consumption is about 20% higher than that of the PC plant without capture, as shown in Figure 2. The main reason for this is that the gasifier uses wet solids removal systems while the PC plant uses dry systems. This is only partly offset by the lower loss of water in the flue gas (the flue gas from the PC plant is saturated in the FGD but the flue gas from the IGCC does not need to be scrubbed).

The total sea water withdrawal for cooling is 151 t/MWh, as shown in Figure 5. Cooling water is used mainly by the steam turbine condenser and the Air Separation Unit (ASU). The sea water withdrawal is reduced to zero in the dry land case by introducing a fully air cooled system.

The water discharge flow can be reduced to zero by using the modified waste water treating unit described earlier. The use of a modified WWT and flue gas DCC can reduce the net raw water consumption by about two thirds, as shown in Figures 2 and 3. The raw water consumption cannot be reduced to zero using these techniques because not enough water can be recovered from the flue gas in a DCC (the water concentration in the flue gas in the IGCC plant is lower than in the PC plant; 6.1% by volume compared to 11.5%, and the amount of water that can be recovered is limited by the water dew point). However, it may be possible to reduce the water consumption to zero by also using some of the other techniques mentioned earlier that were not quantitatively analysed in this study. Although the raw water consumption cannot be reduced to zero the quantity of make-up water is small, 0.3Mt/y for a notional 1000 MW plant, i.e. less than 10% of the mass of coal consumed. The water consumption may therefore not be a significant problem even in very dry locations.

The water reduction techniques in the dry land case reduce the net power output by 5.9% and reduce the thermal efficiency by 2.3% points. Compared to the PC plant with post combustion capture, the impacts on the steam turbine output are lower but the power consumption for the DCC is higher (because of the higher flue gas flow rate and water recovery) and there is an impact on the power consumption of the ASU, as described for the oxyfuel plant.

IGCC with pre-combustion CCS

In the IGCC plant with capture a substantial amount of water is chemically consumed in the shift reactors, where it reacts with CO to produce H_2 and CO_2. The resulting H_2 is combusted in the gas turbine thereby recreating water, which exits the plant in the flue gas. Mainly for this reason the raw water consumption of the IGCC plant with capture is 3.3 times greater than that of the IGCC plant without capture.

The total sea water withdrawal for cooling is 193 t/MWh, which is 27% higher than that of the IGCC plant without capture. The sea water is used mainly for cooling in the steam turbine condenser, the ASU and the CO_2 compressor. The sea water withdrawal is reduced to zero in the dry land case by introducing a fully air cooled system.

The quantity of water that can be recovered in the DCC downstream of the HRSG is substantially higher than in the IGCC without capture because the flue gas moisture content is higher (11.7% compared to 6.1%). However, as in the IGCC without capture, the net raw water consumption cannot be reduced to zero due to the limitation of the operating dew point temperature of the DCC. The raw water consumption of the dry land IGCC plant with capture is similar to that of the dry land IGCC without capture. The increased quantity of water entering the plant with the combustion air and coal, per net kWh of electricity generation, compensates for the increased emissions in the flue gas and solid wastes.

The thermal efficiency of the dry land IGCC with capture is 2.6% points lower than that of the wet land IGCC case, which is slightly higher than the 2.3% point difference between wet and dry land IGCC plants without capture. This is due mainly to the higher power consumption of the DCC and the lower efficiency of CO_2 compression.

Analysis of costs

Figure 7 shows the levelised cost of electricity for each alternative, considering as a reference case the ‘wet land’ USC PC power plant without CO_2 capture, which has a cost of electricity (COE) of 100%. For each case the percentage increase of the COE for the dry land case as compared to the relevant wet land case is shown as “%” in the box.

Eliminating or greatly reducing water consumption results in an increase in electricity generation costs, of between 8% for pulverized coal plants without capture, 12% for IGCC plants without capture and 12%-13% for plants with capture. The additional penalty for water reduction in plants with capture is unlikely to be a significant additional deterrent to adoption of CCS.

This study has only looked at two extreme cases of no restrictions on water use and minimized water use. Cases with intermediate reductions in water use, only using the most cost effective techniques, may be preferred in some circumstances.

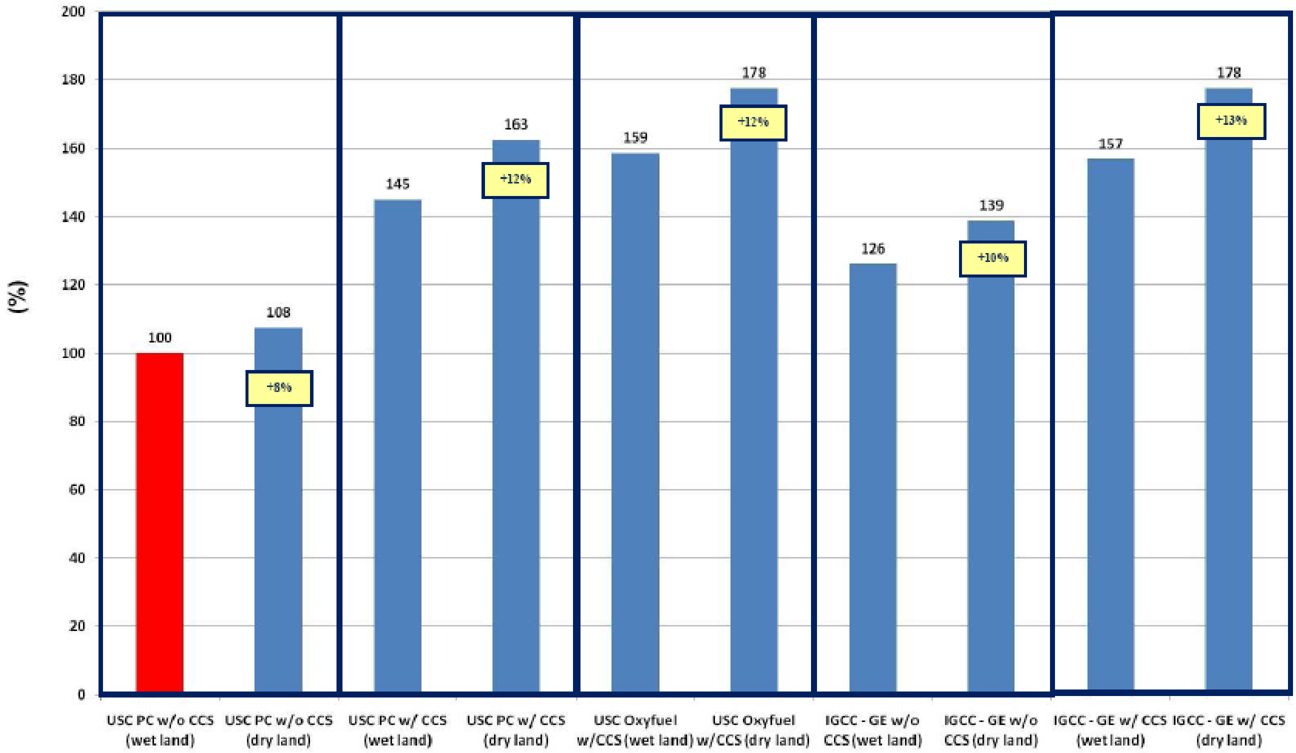

Figure 7: Normalised Cost of Electricity (COE) of each alternative
(Reference: USC PC without CO_2 Capture = 100, costs exclude CO_2 transport and storage)

Expert Reviewer's Comments

Comments on the draft study report were received from a number of expert reviewers. The reviewers' comments were taken into account as far as possible in the final version of the contractor's report, in the overview or in recommendations for future studies. In general the reviewers thought the report was comprehensive and of high quality.

There were some specific comments related to the use of once through seawater cooling instead of wet cooling towers for all the wet land cases. Several reviewers noted that once through seawater cooling withdraws significant quantities of water and as consequence should have more concerns in terms of its environmental impact. Furthermore, some reviewers also noted that the dry land cases are too constrained. It was recommended that future studies should evaluate more representative cases in which seawater or river water cooling is available but process water is restricted. This would recognize that fresh water is a resource to be managed.

Several reviewers presented their concerns regarding the use of past studies as the main engineering design basis. It was noted that some of the technologies used in the evaluation may not represent current practice in various project evaluations currently undertaken. IEAGHG recognises that these previous IEAGHG studies are already 5 to 6 years old but they were used as the basis for this study due to cost constraints.

A particular comment was received on the capital cost estimation of all the oxyfuel combustion cases. In response to this comment, it was concluded that the cost estimates for the CAPEX of oxyfuel combustion cases should be re-evaluated and the following modifications to the draft report were implemented:

- Contingency/Owners Cost/License Fees were reduced from the original 32% (based on IEAGHG Report 2005/9) down to 17%, in line with the other PC plant costs.

- The cost of the ASU was revised down, based on internal review of Foster Wheeler Italiana, although a similar revision was not made for the ASU in IGCC.
- The cost of the boiler island was noted to be still high based on the comments from FW-North America but no adjustment to this item was included in the report.

Major Conclusions

- Power plants normally require substantial quantities water: raw process water, e.g. for boiler feed water make-up and flue gas scrubbing, and cooling water to dissipate low temperature heat principally from the steam turbine condenser.
- Adding CO_2 capture significantly increases the water requirements of power plants but techniques can be used to reduce the water requirement to zero (pulverised coal plants) or close to zero (IGCC) if required. Water requirement is therefore not expected to be a constraint on the adoption of CO_2 capture technology.
- The main techniques that could be used to reduce the water requirement would be air cooling to eliminate the need for cooling water, and modified waste water treatment and flue gas condensation to eliminate the need for raw process water.
- Fully applying these water reduction techniques would reduce the thermal efficiency by 1.9-2.3 percentage points for plants without CO_2 capture and 2.2-2.7 percentage points for plants with CO_2 capture, compared to base line plants with once-through water cooling. The main reason for the efficiency reduction is the impact of using air cooling on the efficiency of the steam turbine. The efficiency penalties would be lower if plants with wet cooling towers were the base line plants.
- Fully applying these water reduction techniques would increase the cost of electricity by 8-12% for plants without CO_2 capture and 12-13% for plants with CO_2 capture, compared to base line plants with once-through water cooling. The higher cost for water reduction in plants with capture is unlikely to be a significant additional deterrent to adoption of CCS.

Recommendations

- The information presented in this report only illustrates two possible scenario of water usage in power plants with CO_2 capture. It is recommended that IEAGHG should pursue the evaluation of water usage in power plants which utilise mechanical wet cooling towers which are common when river water is used for cooling.

- The ability to achieve zero or near-zero water requirement at a range of sites with different ambient conditions should be assessed.

- Techniques which may enable the water requirement of IGCC plants to be reduced to zero, including gas turbine flue gas recycle, could be assessed if a zero water requirement is deemed to be important.

- IEAGHG should also evaluate water usage in power plants with CO_2 capture that use natural gas and low rank coal. Technologies to recover water from lignite drying may have significant potential.

- The main technical basis of this study is IEAGHG reports which are about 5-6 years old, although plant cost inflation was taken into account in the economic assessments. Since that time significant improvements in the design of power plants and CCS processes have been noted in literature. Thus, it is recommended that a new set of studies to update the performance and costs of power plants with CO_2 capture should be undertaken.

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DOCUMENT NAME	:	EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

I N D E X

1. Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage and loss of power in power plants with CO_2 capture.

The work is developed thought the establishment of a rigorous accounting of water usage throughout the power plant in order to establish an acceptable methodology that can be used to compare water usage in power plants with and without CO_2 capture. This can provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs.

Cost effective water reduction technologies that could be applied for power plants with CO_2 capture are identified. Finally, an evaluation of the performance of power plants with CO_2 capture and potential impacts on the water usage applicable to areas where water supply could be severely limited is performed.

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
These studies shall be used as a basis for present study.

In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 purposes of the study, therefore, include:

- A review and assessment of the available information of water usage from power plants such as PC, IGCC and NGCC with or without CO_2 capture from various previous studies done for IEA GHG, based on oxyfuel, pre- or post combustion CO_2 capture technologies.
- A review and assessment of the available technologies that would allow reduction of water usage from power plants;
- An evaluation and assessment of the applicable technologies for power plants with CO_2 capture in areas where water supplies could be severely limited.

The study is based on the current state-of-the-art technologies, evaluating costs and performances of plants which can be presently engineered and built.

Study is based on five volumes, with the following content.

Volume #1 details the technologies available for the treatment of the different water streams discharged or used inside the plants without and with CO_2 capture and provides an overview of the available technologies to reduce the water consumption of power plants, giving some considerations on the associated costs.

The water balance of the following seven different power plants types (with and without CO_2 capture) which are not included in the main focus of the study are evaluated:

- Case 3.24: USC PC Lignite with post combustion CO_2 Capture
- Case 4.13: USC PC Lignite with oxyfuel combustion CO_2 capture
- Case 5.01: Shell IGCC Bituminous Coal without CO_2 capture
- Case 5.02: Shell IGCC Bituminous Coal with CO_2 capture
- Case 5.04: Shell IGCC Lignite with CO_2 capture
- Case 5.05: GE IGCC Bituminous Coal with CO_2 capture
- Case 5.06: GE IGCC Bituminous Coal without CO_2 capture

The seven cases have been selected as they are the most representative for the Waste Water Treatment (WWT) configuration for each Power Plant technology although not all are then evaluated in the whole study.

Volume #2 analyses the Ultra Super Critical Pulverised Coal (USC PC) cases without and with CO_2 capture and without and with limitation on water usage.

The IEA GHG study number PH4/33, November 2004, has been taken as a reference for the configuration and performances of the plant analysed in reference cases of present report. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The following four different alternatives are therefore evaluated:

- Case 3.22: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4/33 – Case 3, dated November 2004.

- Case 3.21: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4/33 – Case 4, dated November 2004.

- Case 3.23: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (dry land case).

- Case 3.25: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

Volume #3 analyses the Ultra Super Critical Pulverised Coal (USC PC) oxyfired cases with CO_2 capture and without and with limitation on water usage.

The IEA GHG study number 2005/9, July 2005, has been taken as a reference for the configuration and performances of the plant analysed in reference case of present report. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The following two different alternatives are therefore evaluated:

- Case 4.11: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number 2005/9 – Case 2, dated July 2005.

- Case 4.12: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

Volume #4 analyses the Integrated Gasification Combined Cycle (IGCC) cases without and with CO_2 capture and without and with limitation on water usage.

The following four different alternatives are therefore evaluated:

- Case 5.05: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4-19 – Case C1, dated May 2003.
- Case 5.06: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4-19 – Case D1, dated May 2003.
- Case 5.07: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (dry land case).
- Case 5.03: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

Foster Wheeler Italiana included in the whole report the outcomes of the studies made by the other Companies (Volume #2 and #3), and made available by IEA GHG. However, FW should not be regarded as having endorsed the results of the above third-party studies.

Volume #5 makes the technical and economical evaluation of all the alternatives analysed in the whole study

For each case the following information are provided:

- ✓ Summary of main technical data;
- ✓ Technical evaluation of the alternatives;
- ✓ Investment cost estimate for each case. CAPEX is broken down to major sections (e.g. fuel handling, boiler island, steam turbine island, etc.) for the dry land cases, while a single overall figure is provided for wet land cases;
- ✓ The OPEX defined and broken down to major items;
- ✓ Economical evaluation of the alternatives.

2. Bases of design

The power plants are designed to process, in an environmentally acceptable manner, an open-cut coal from eastern Australia and produce electric energy to be delivered to the local grid.

The coal has a lower heating value (LHV) equal to 25,870 kJ/kg and a sulphur content equal to 1.1% wt (dry ash free).

Two different plant locations are assumed for the cases without and with limitation on water usage, respectively:

- ✓ **Reference cases – wet land**
  The site for the reference cases, wet land, is a green field located on the NE coast of the Netherlands, with an average air temperature of 9°C and an average seawater temperature of 12°C;
- ✓ **Dry land cases**
  The site for dry land cases is a green field located in a dry inland region in South Africa, with an average air temperature of 14°C.

For each power plant alternative, the power production is targeted at approximately 600-800 MWe.
Conventional power stations without CO_2 capture are designed to approximately provide 750 MWe of power production.
The oxyfuel case is designed to produce a significantly lower amount of electric power, close to 550 MWe.
For the alternatives with pre-combustion CO_2 capture, the design capacity is fixed to match the capacity of two frame F-250 MWe class gas turbines (GT).
The gaseous emissions from the different power plants do not exceed the limits listed in Table 1.

Table 1 – Emission limits.

	USC PC / Oxyfuel (1)	IGCC (2)
NOx (as NO_2)	≤ 200 mg/Nm^3	≤ 80 mg/Nm^3
SOx (as SO_2)	≤ 200 mg/Nm^3	≤ 10 mg/Nm^3
Particulate	≤ 30 mg/Nm^3	≤ 10 mg/Nm^3

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

The product of the power plants is electric energy. By-products are sulphur (for IGCC cases only) and carbon dioxide (for the alternatives recovering CO_2); by-

products/wastes are bottoms ash, fly ash, gypsum for USC PC and oxyfuel cases, slag and filter cake for gasification cases.
The carbon capture efficiency depends on the specific case, ranging from 85 to 90%.

The industrial water discharge limit into surface water bodies is based on Italian law (DLgs 152/2006). Discharge limits are recorded in the following **table 2**.

Analytical Parameter	Unit	Discharge limit into surface water bodies
Suspended Solids	mg/l	≤ 80 (1)
Petroleum Products (Hydrocarbons)	mg/l	≤ 5
BOD_5 as O_2	mg/l	≤ 40
COD as O_2	mg/l	≤ 160
pH	pH units	5.5-9.5
Chlorides	mg/l	≤ 1200 (10)
Sulphates	mg/l	≤ 1000 (2) (10)
Sulphides	mg/l	≤ 1 (3)
Ammonia Nitrogen	mg/l	≤ 15 (4)
Nitrates	mg/l	≤ 20 (5)
Nitrites	mg/l	≤ 0.6 (6)
Aluminium	mg/l	≤ 1
Iron	mg/l	≤ 2
Copper	mg/l	≤ 0.1
Zinc	mg/l	≤ 0.5
Nickel	mg/l	≤ 2
Chromium (6+)	mg/l	≤ 0.2
Total Chromium	mg/l	≤ 2
Arsenic	mg/l	≤ 0.5
Barium	mg/l	≤ 20
Boron	mg/l	≤ 2
Cadmium	mg/l	≤ 0.02
Mercury	mg/l	≤ 0.005
Lead	mg/l	≤ 0.2
Selenium	mg/l	≤ 0.03
Tin	mg/l	≤ 10
Total Cyanides	mg/l	≤ 0.5 (7)
Sulphites	mg/l	≤ 1 (8)
Fluorides	mg/l	≤ 6
Phosphorus	mg/l	≤ 10 (9)
NOTES:	1	Total Suspended Solids (TSS)
	2	Sulphates as SO_4^{--}
	3	Sulphides as H_2S
	4	Ammonia Nitrogen as NH_4^+
	5 - 6	Nitrate and Nitrite as N
	7	Cyanides as CN^-
	8	Sulphites as SO_3^{--}
	9	Phosphorus as P
	10	Not applicable for sea discharge

3. Description of the alternatives

The study analyses five different power plant technologies:

- Pulverised coal-fired power plant with ultrasupercritical steam cycle without CO_2 capture (USC-PC without CCS);
- Pulverised coal fired power plant with ultrasupercritical steam cycle with post-combustion CO_2 capture based on standard MEA solvent (USC-PC with CCS);
- Pulverised coal fired power plant with ultrasupercritical steam cycle using oxyfuel combustion for CO_2 capture;
- IGCC using GEE Quench type gasifier without CO_2 capture (IGCC without CCS);
- IGCC using GEE Quench type gasifier with pre-combustion CO_2 capture based on physical solvent (IGCC with CCS).

For each of the alternatives the case without and with limitation on water usage is evaluated.
Two concepts are applied in relation to water usage:

- ✓ Water **withdrawal** refers to the total water taken from a source and sent back to the same source;
- ✓ Water **consumption** refers to the irrecoverable loss of water that is not returned to the source.

<u>USC PC without CCS</u>: This case is based on an Ultra Supercritical Pulverised Coal (USCPC) boiler, once-through steam generator type, with superheating and single steam reheating. The boiler is a single-pass tower-type, with a staged low-NOx burner system. The boiler is equipped with SCR (selective catalytic reactor) based on De NOx and with electro-static precipitators (ESP). To remove the SOx content, a FGD (flue gas desulphuriser) system is provided to scrub the boiler exhaust gases prior release to the atmosphere. The power island is mainly composed by one steam turbine, with HP, MP and LP sections, all connected to the generator on a single shaft arrangement.

In order to evaluate the possible areas of intervention for saving water usage, the block flow diagram shown in the figures attached to the end of this paragraph has been developed. The figures show the plant block flow diagram with highlighted the water content of each stream.

The main raw water consumptions are the following:

- ✓ Demi water unit: raw water is needed to produce demi water, mainly sent to the power island to compensate the water losses in the condensate polishing section.

- ✓ FGD: raw water is needed to compensate the sour water blow down from the unit and to feed the limestone to the FGD scrubber for the removal of the SOx.

The water withdrawal, in the case without limitation of water usage, is represented by the cooling water taken from the sea and mainly used in the steam turbine condenser of the power island.

Looking at the dry land case, although it does not represent a consumption, the sea water withdrawal is reduced to zero as the plant is supposed to be built in an area where sea water is not available. With this aim, air cooling system shall be foreseen in place of the once thru cooling water system considered in the reference case where no limitations on water usage are imposed. This solution allows reducing to zero the water withdrawal but has a heavy impact on the overall plant performance leading to a reduction of the net power output of approximately 4%.

In order to minimize the overall water consumption, the water treated in the waste water treatment (WWT) unit is reused in the plant as raw water and partially sent back to the demi plant where necessary. To minimise the water discharged from the WWT, a concentration unit for the rejected water downstream of the treatment is considered. In this case the goal of zero liquid discharge is achieved by means of a concentration process that consists of the following main steps:

- Heating of the rejected water;
- Evaporation of water and concentration of the stream to produce salts precipitation;
- Final dewatering (crystallization) of concentrated chemical sludge.

In order to reduce the water consumption in the FGD system in could be possible to switch to a Dry FGD system using hydrated lime. This system would assure the proper SOx removal being the content of sulphur in coal sufficiently low. The dry FGD use about 30% less water than wet FGD, has lower investment costs but much higher O&M cost. The water saved would not be sufficient to satisfy the entire water balance without the need of a consumption of raw water.

From figure attached it appears clear that, even recovering the entire flowrate discharged from the WWT, it is not possible to satisfy the total raw water requirements. Therefore a section for the condensation and recovery of water from the flue gases downstream the boiler is foreseen.

Such a recovery is obtained by means of a direct contact cooler (DCC) where heat is transferred from the stream of flue gas to a stream of water. The direct contact cooler is very efficient, since both the sensible and latent heat is transferred and there are no surfaces to be fouled. Trays or packed beds are installed so that the flue gas and water streams from the column approach the thermodynamic equilibrium conditions (which means producing more condensate). The temperature of the warm water coming from the column is reduced in a dedicated air cooler. The only drawback of the DCC is that, due to the additional pressure drops, the head of the ID fan upstream needs to be increased. As it can be seen in the attached Figure 2, through the reuse of the water from the WWT and the application of the DCC, the overall raw water consumption can be reduced to zero.

<u>USCPC with post-combustion CCS</u>: The CO_2 capture plant is mainly composed of two parallel trains made of one direct contact cooler and one absorption column, followed by a common regenerator stripper. The flue gas entering the absorption column is contacted with MEA (Mono Ethanolamine). The solvent is then heated to break down the compound and release solvent and high-purity carbon dioxide. The produced CO_2 rich stream flows from the outlet of the regeneration column to the CO_2 compression unit, which is composed of different stages, with intercooling between them.

The main consumptions of raw water are the following:

- Demineralisation water unit: raw water is needed to produce demineralised water mainly sent to the power island to compensate the water losses in the condensate polishing section.
- FGD: raw water is needed to compensate the sour water blow down from the unit and to feed the limestone to the FGD scrubber for the removal of the SOx.
- CO_2 capture unit: raw water is required to scrub the gases leaving the column and remove any entrained MEA. This consumption of water can be avoided in some CO_2 capture processes where part of the water discharged into the flue gas cooling upstream the column can be reused. For the purposes of this paper, the need of such a makeup is considered.

The water withdrawal is represented by the cooling water taken from the sea in the case without limitation of water usage and mainly used in the steam turbine condenser of the power island, in the CO_2 capture unit and in the intercoolers of the CO_2 compression unit.

Looking at the dry land case, as shown in the relevant case without CO_2 capture, the sea water withdrawal is reduced to zero by introducing a fully air cooled system. The impact on the performance is much higher than in the case without CO_2 capture, as it applies to power island and to CO_2 compression intercoolers leading to a reduction of the net power output of approximately 6.5% as compared to 4.5% for the case without CO_2 capture.

The recovery of the water from the flue gases by means of a direct contact cooler and the use of the water discharged from the WWT as raw water allows also for this case for the reduction to zero of the overall plant raw water intake.

Oxycombustion USCPC with post-combustion CCS: This case is similar to the previous plant with post-combustion CCS. Oxygen (typically with a purity greater than 95%) is used for combustion of the fuel instead of air. To use existing, proven boiler technology, flue gas must be recycled and used for pulverised fuel transport and for inert dilution to moderate the peak temperature in the furnace. The boiler is equipped with ESPs. SOx and NOx are removed from gaseous CO_2 during compression: 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 sulphuric acid and nitric acid respectively that are removed from the system as aqueous solutions. The gas is then partially recirculated to the boiler and in part dehydrated and sent to the compression unit. The inert gas content, derived from excess oxygen, along with argon and nitrogen present in the oxygen feed, is mostly separated and vented. An air separation unit (ASU) provides the low pressure oxygen required by the combustion.

The main raw water consumptions are the following:
- Demi water unit: raw water is needed to produce demi water mainly sent to the power island to compensate the water losses in the condensate polishing section.
- CO_2 purification unit: raw water is required to scrub the gases in order to cool them at the required temperature upstream of the flue gas partial recirculation to the boiler, as ballast in the oxy combustion process. The quantity of water needed to polish the CO_2 rich flue gas, being already approximately 75% CO_2 on a dry basis, is much less than that of the traditional USC post combustion CO_2 capture case based on amine.

The water withdrawal is represented by the cooling water taken from the sea in the case without limitation of water usage and mainly used in the steam turbine condenser of the power island, in the water coolers of ASU compressors and CO_2 compressor.

Looking at the dry land case, the sea water withdrawal is reduced to zero by introducing a fully air cooled system. The impact on the performance is still higher than in the previous cases, as it applies to the power island, to CO_2 compression intercoolers and on ASU intercoolers leading to a reduction of the net power output of approximately 7.5%.

Due to the nature itself of the CO_2 purification unit where there is the need to separate the entire quantity of water from the flue gases, in the oxyfuel case the water discharged from the WWT unit is enough to satisfy the raw water consumption requirement. Therefore, without the addition of any further equipment, the reduction to zero of the overall plant raw water make up can be achieved.

IGCC without CCS: This case is based on an Integrated Gasification Combined Cycle (IGCC) with GEE gasification technology. Coal is crushed and a slurry with water is prepared to feed the gasifier burner, together with O_2 from the ASU. The produced raw syngas outlet from the gasification island is then treated and cleaned through a H2S removal unit (AGR), based on a physical solvent washing. The cleaned syngas is used in a combined cycle, which mainly consists of 2 GTs, 2 HRSGs and 1 single steam turbine.

The main raw water consumptions are the following:

- Demi water unit: raw water is needed to produce demi water mainly sent to the power island to compensate the water losses from the blowdown.
- Gasification: raw water is required to supply water to the syngas scrubber and for slurrying the coal fed to gasifiers.

The water withdrawal is represented by the cooling water taken from the sea in the case without limitation of water usage and mainly used in the steam turbine condenser of the power island and in the ASU.

Looking at the dry land case, the sea water withdrawal is reduced to zero introducing a fully air cooled system. The resulting reduction of the net power output is approximately 6%.

In the flue gas coming from the gas turbine, the water quantity is lower than in coal combustion process and therefore, even with the addition of an air cooled DCC, is not possible to recover a flowrate of water sufficient to cover the overall plant raw water need. The net raw water consumption cannot reduce to zero and a stream of raw water is still needed.

IGCC with pre-combustion CCS: The case is based on the same GEE gasification technology as the case without CCS. As shift is necessary to produce syngas, the quench with water provides the reagent for the chemical reaction. The produced raw syngas outlet from the gasification island is treated through a sour shift unit, increasing both the hydrogen and CO_2 content of the syngas, and H_2S and CO_2 are removed through a physical solvent washing in the AGR unit. The cleaned syngas is used in a combined cycle.

The main raw water consumptions are the following:

- Demi water unit: raw water is needed to produce demi water mainly sent to the power island to compensate the water losses from the blowdown.

- Gasification: raw water is required to supply the water to the syngas scrubber and for slurrying the coal fed to gasifiers. The water make up is higher than the one in the case without CO_2 capture due to the water consumed in the shift reaction where water and CO are converted into H_2 and CO_2.

The water withdrawal is represented by the cooling water taken from the sea in the case without limitation of water usage and mainly used in the steam turbine condenser of the power island, in the ASU and in the CO_2 compression.

Looking at the dry land case, the sea water withdrawal is reduced to zero introducing a fully air cooled system. The resulting reduction of the net power output is approximately 8%.
As in the relevant case without CO_2 capture, even with the introduction of a DCC for the recovery of water from the flue gases downstream the HRSGs, the net raw water consumption cannot be reduced to zero and a stream of raw water is still needed.

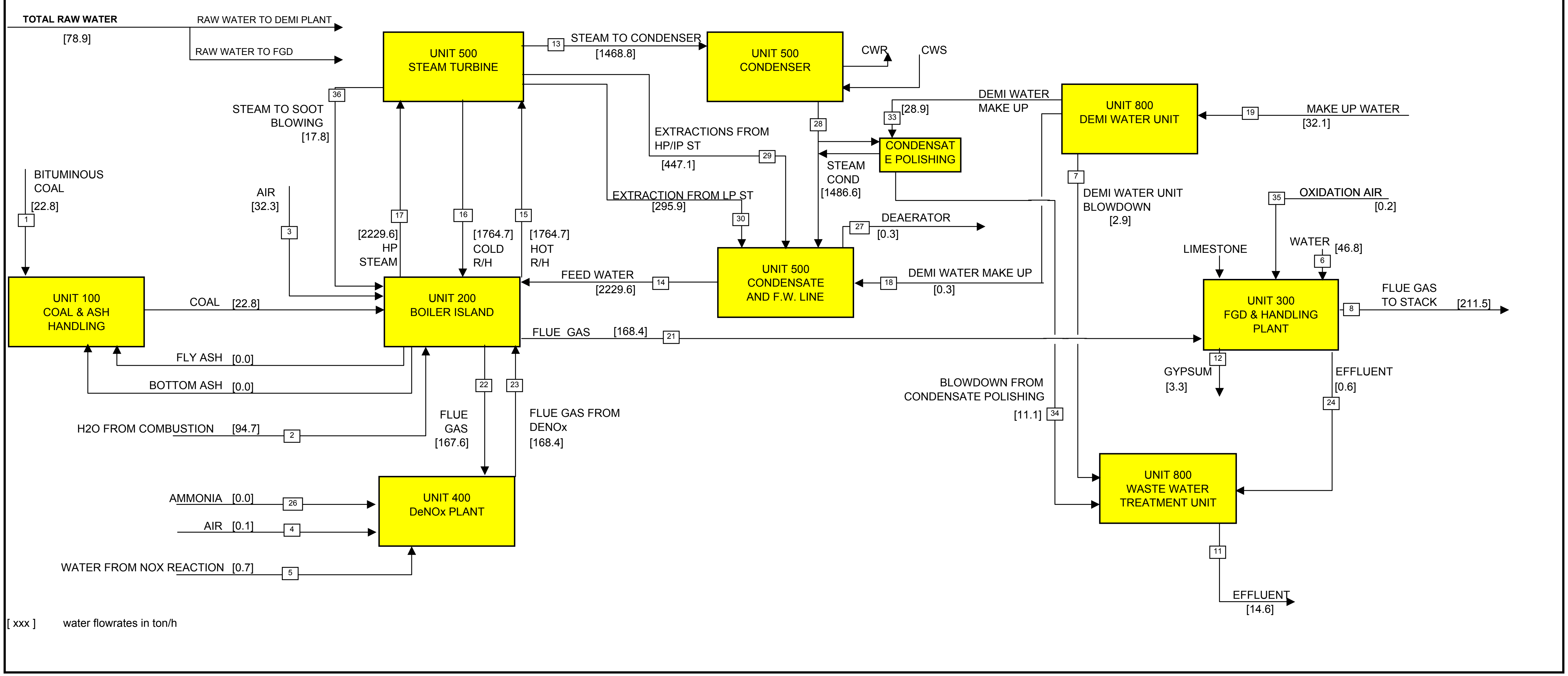
IEA GHG R&D PROGRAMME

Water Usage and Loss Analysis in Power Plants without and with CCS

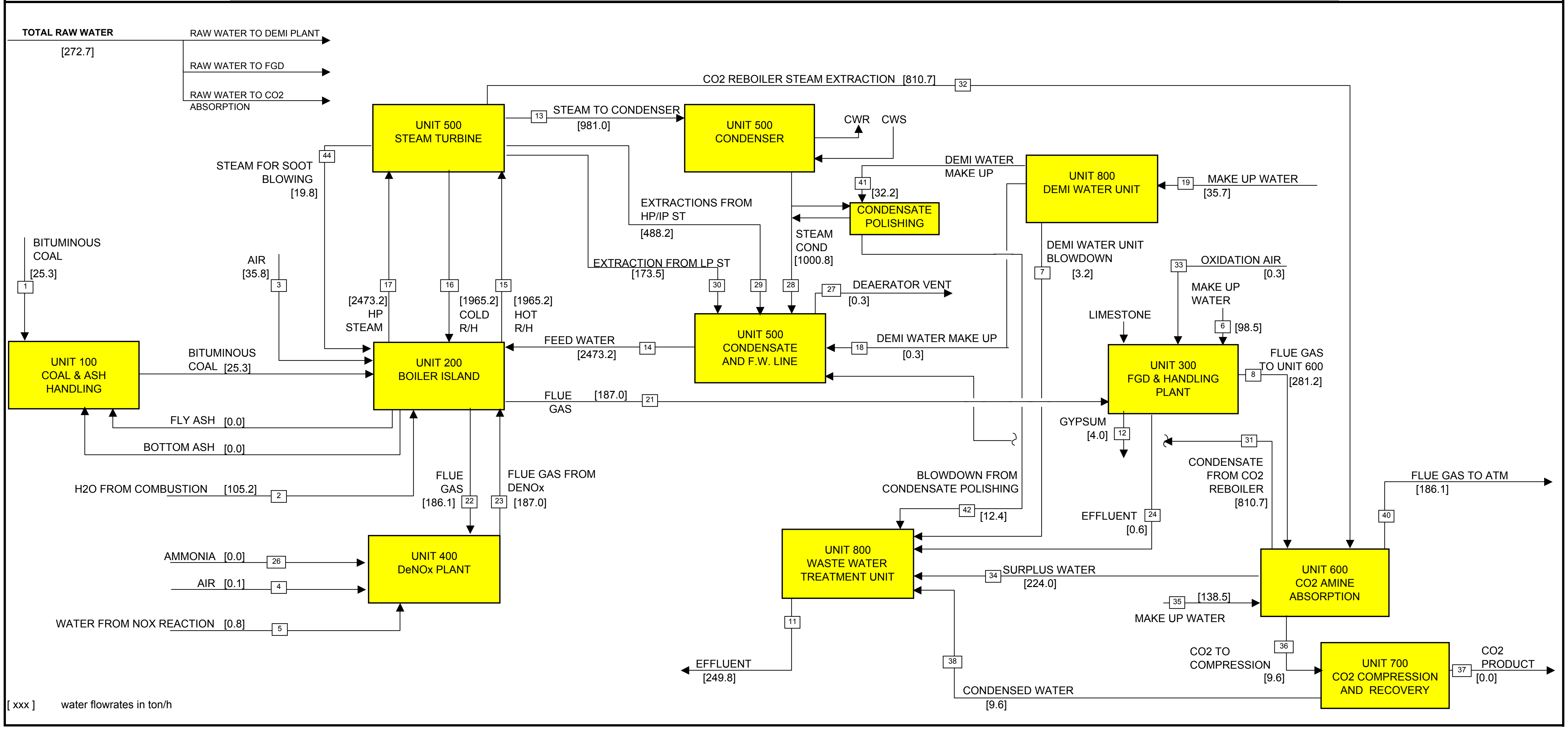
Revision no.: 1

Date: October 2010

CASE 3.21 - USC PC PLANT, BITUMINOUS COAL, WITHOUT CO2 CAPTURE - BLOCK FLOW DIAGRAM - WATER BALANCE



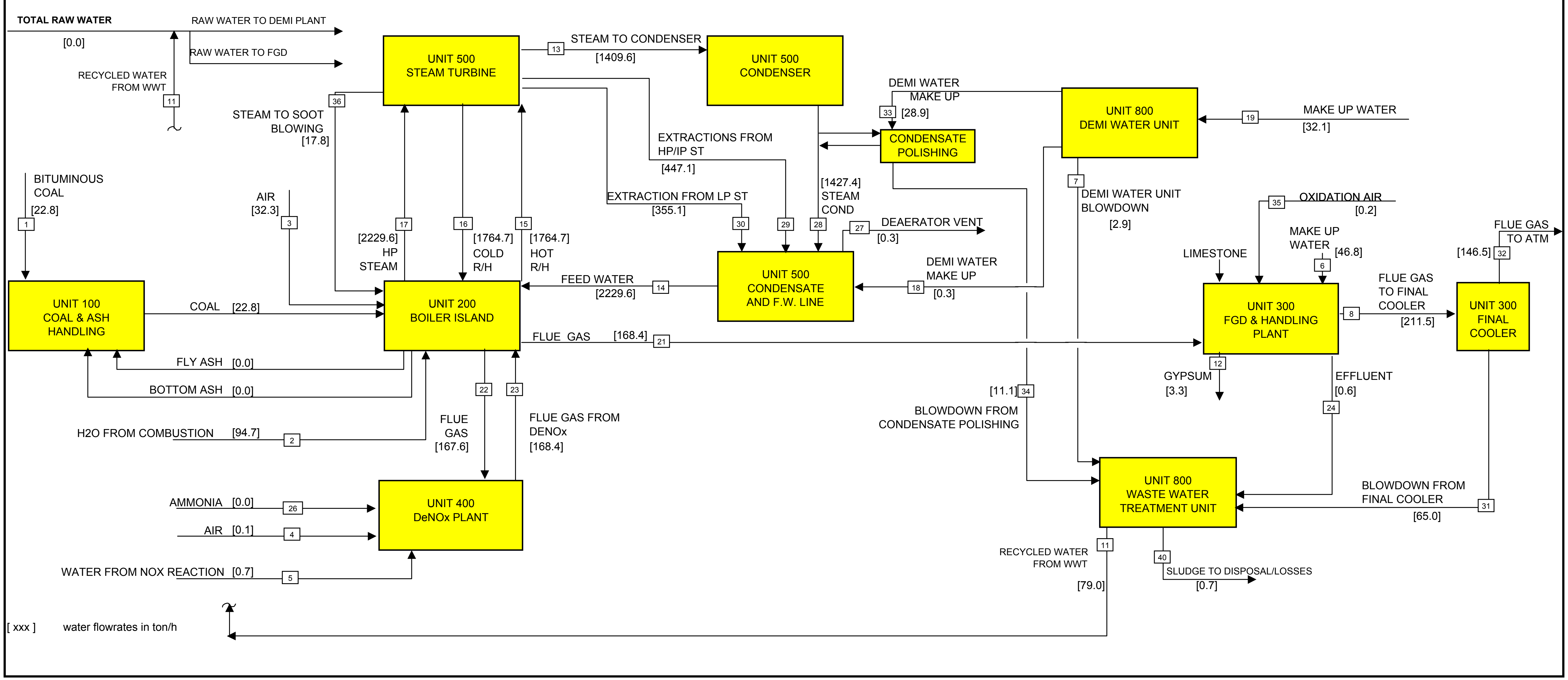
CASE 3.22 - USC PC PLANT, BITUMINOUS COAL WITH CO2 CAPTURE (NET POWER OUTPUT = 666.0 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



IEA GHG R&D PROGRAMME
Water Usage and Loss Analysis in Power Plants without and with CCS

Revision no.: 1
Date: October 2010

CASE 3.25 - USC PC PLANT, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 725 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



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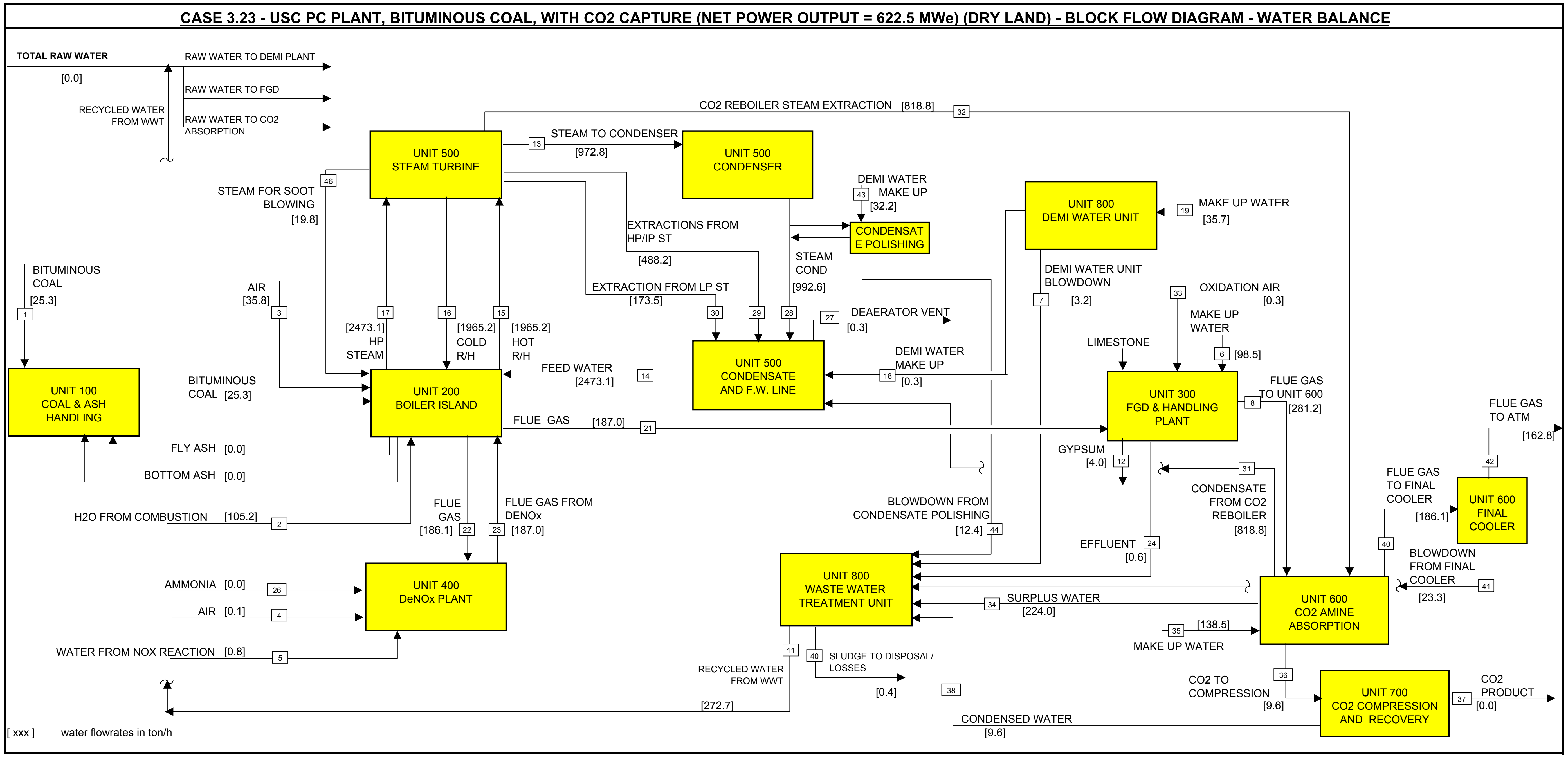
Water Usage and Loss Analysis in Power Plants without and with CCS

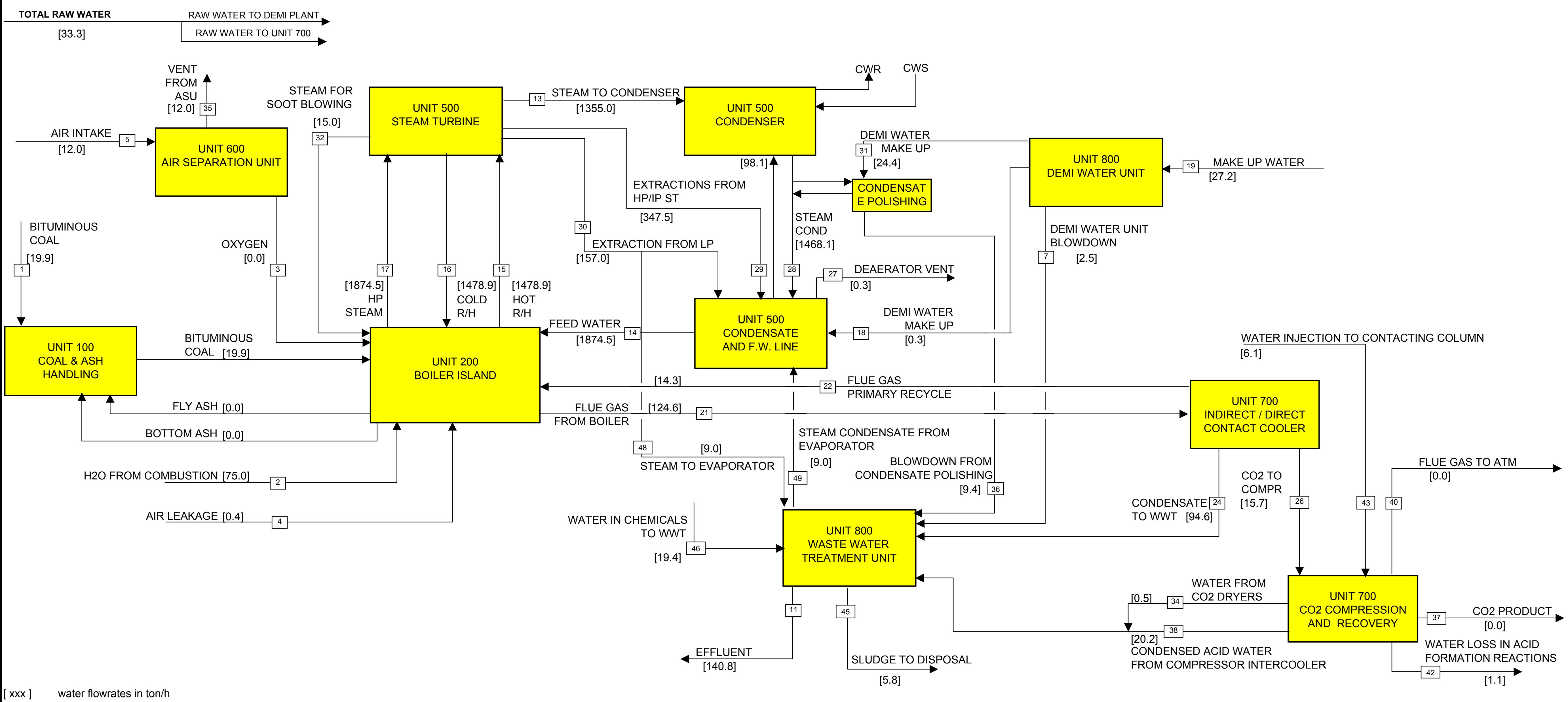
Revision no.: 1
Date: October 2010



IEA GHG R&D PROGRAMME — Revision no.: 1

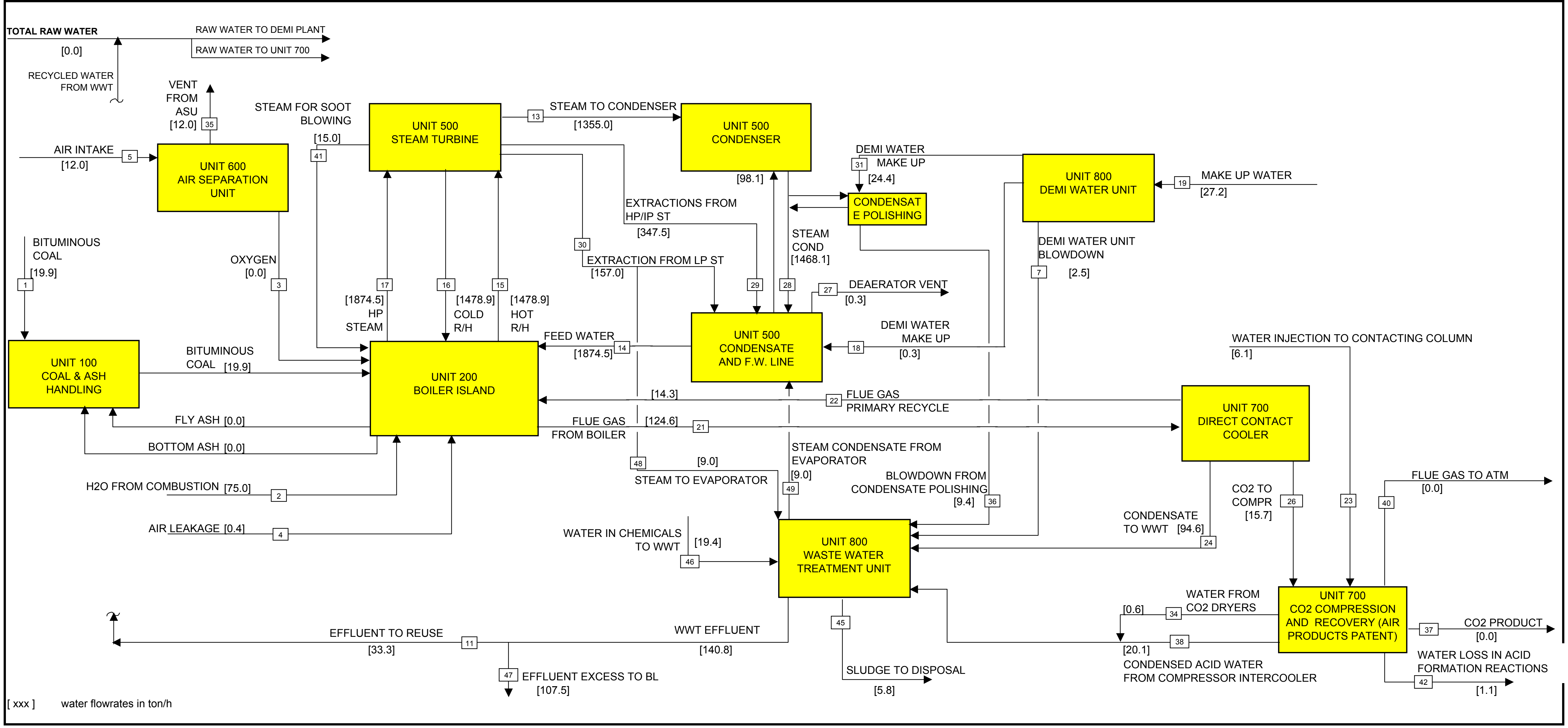
Water Usage and Loss Analysis in Power Plants without and with CCS — Date: October 2010

CASE 4.11 - USC PC PLANT, WITH OXYCOMBUSTION, BITUMINOUS COAL AND CO2 CAPTURE (NET POWER OUTPUT = 532.0 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE

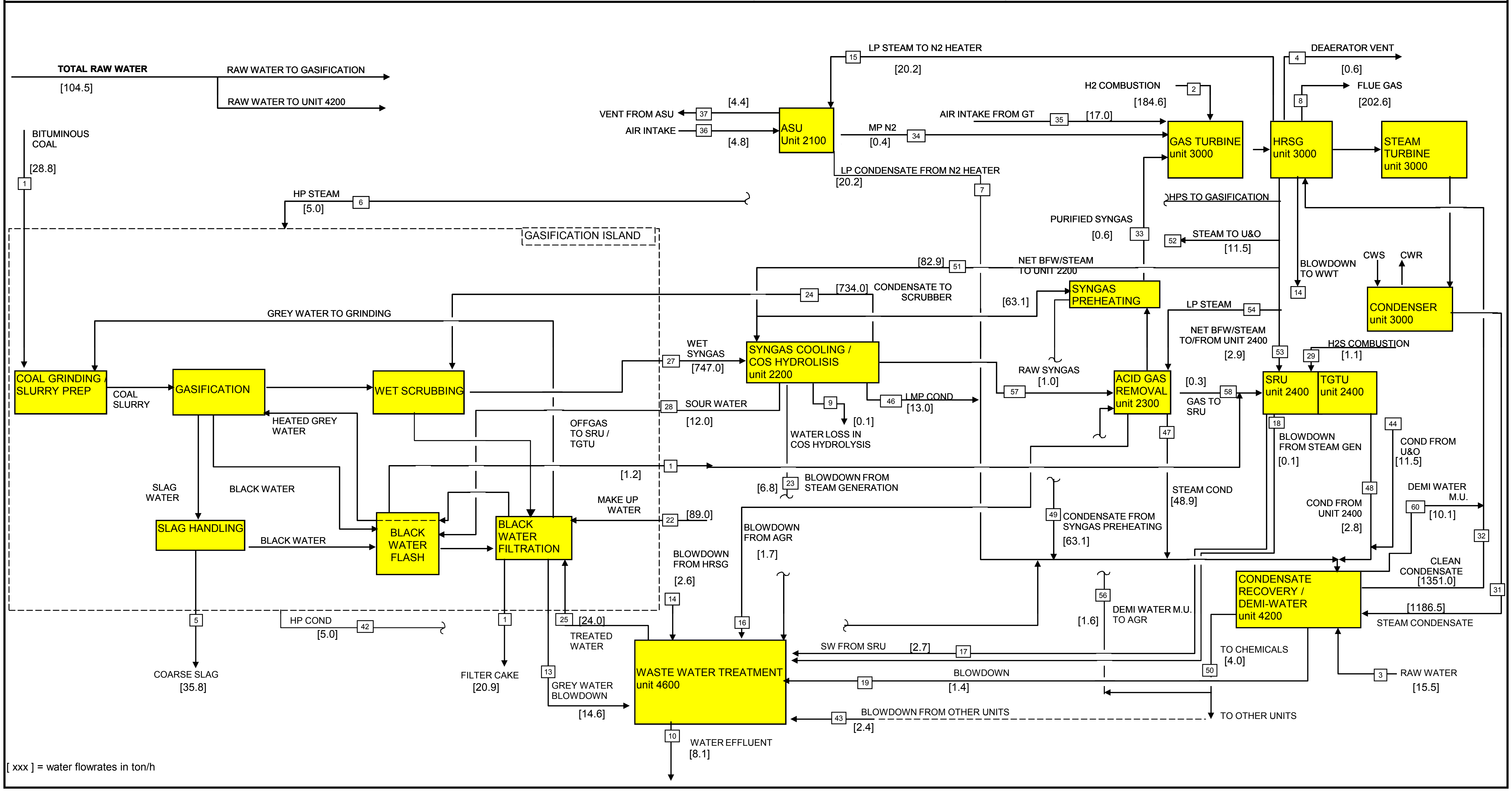


[xxx] water flowrates in ton/h

CASE 4.12 - USC PC WITH OXYCOMBUSTION PLANT, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 487 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



CASE 5.05 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 826.5 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



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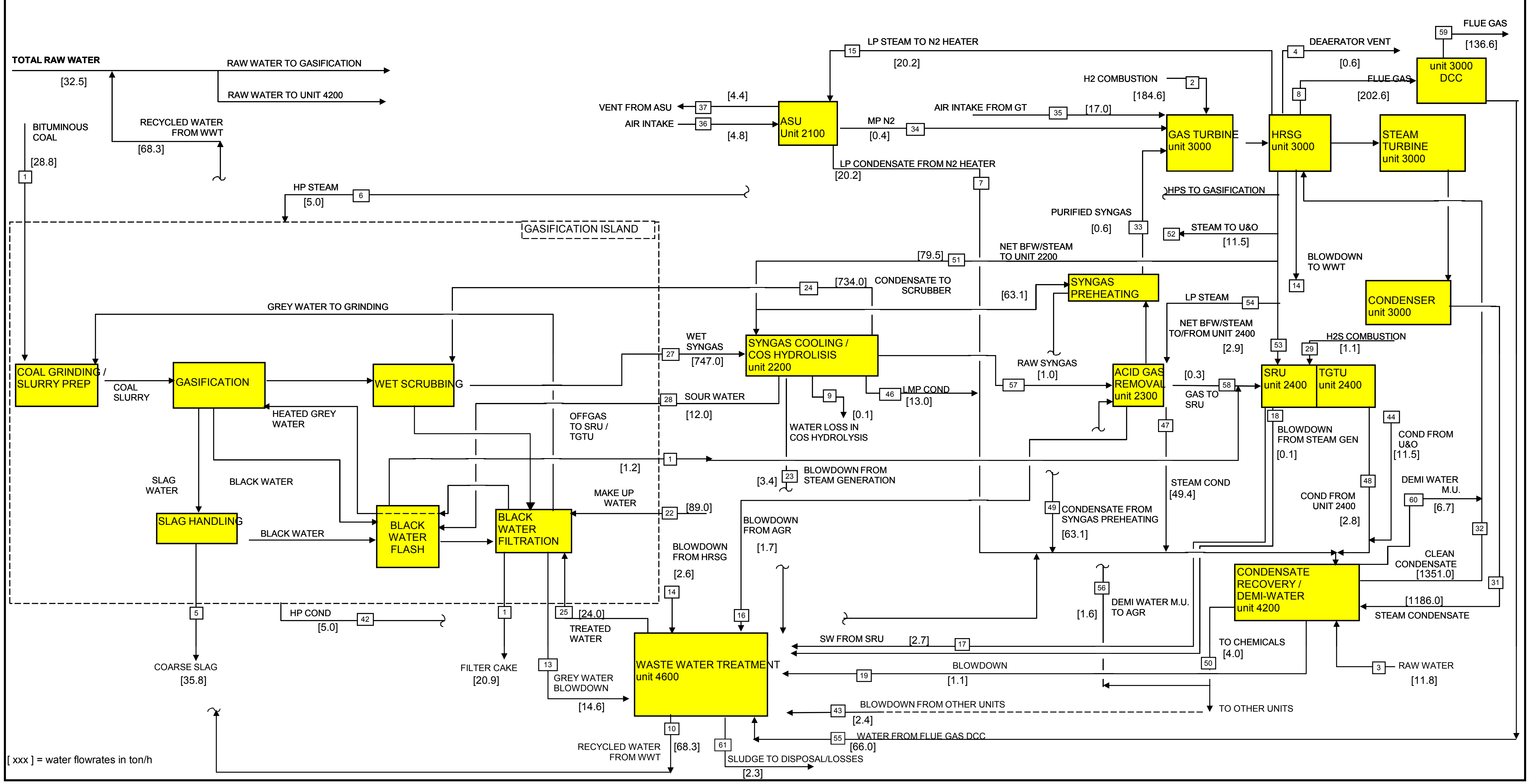
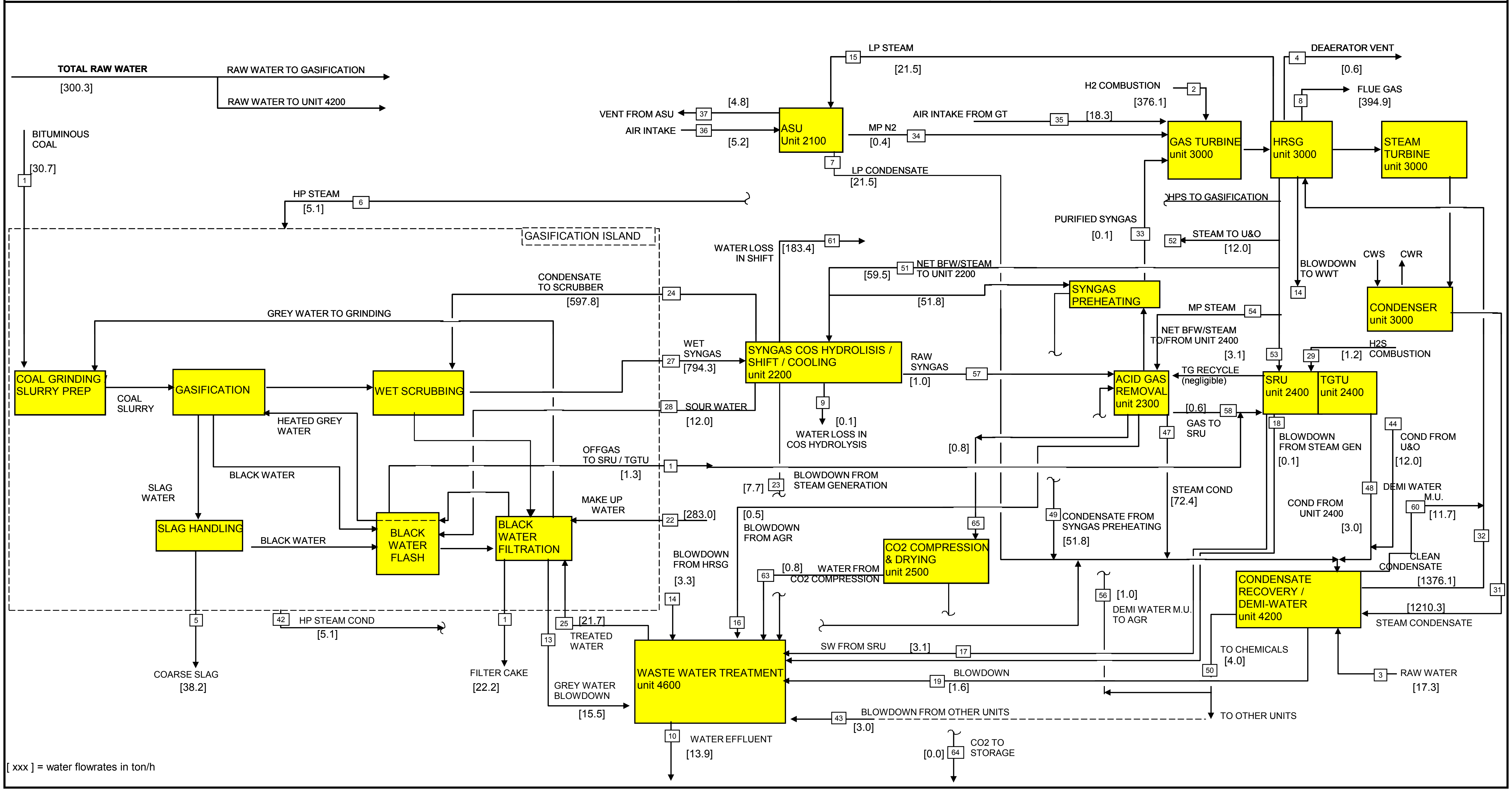
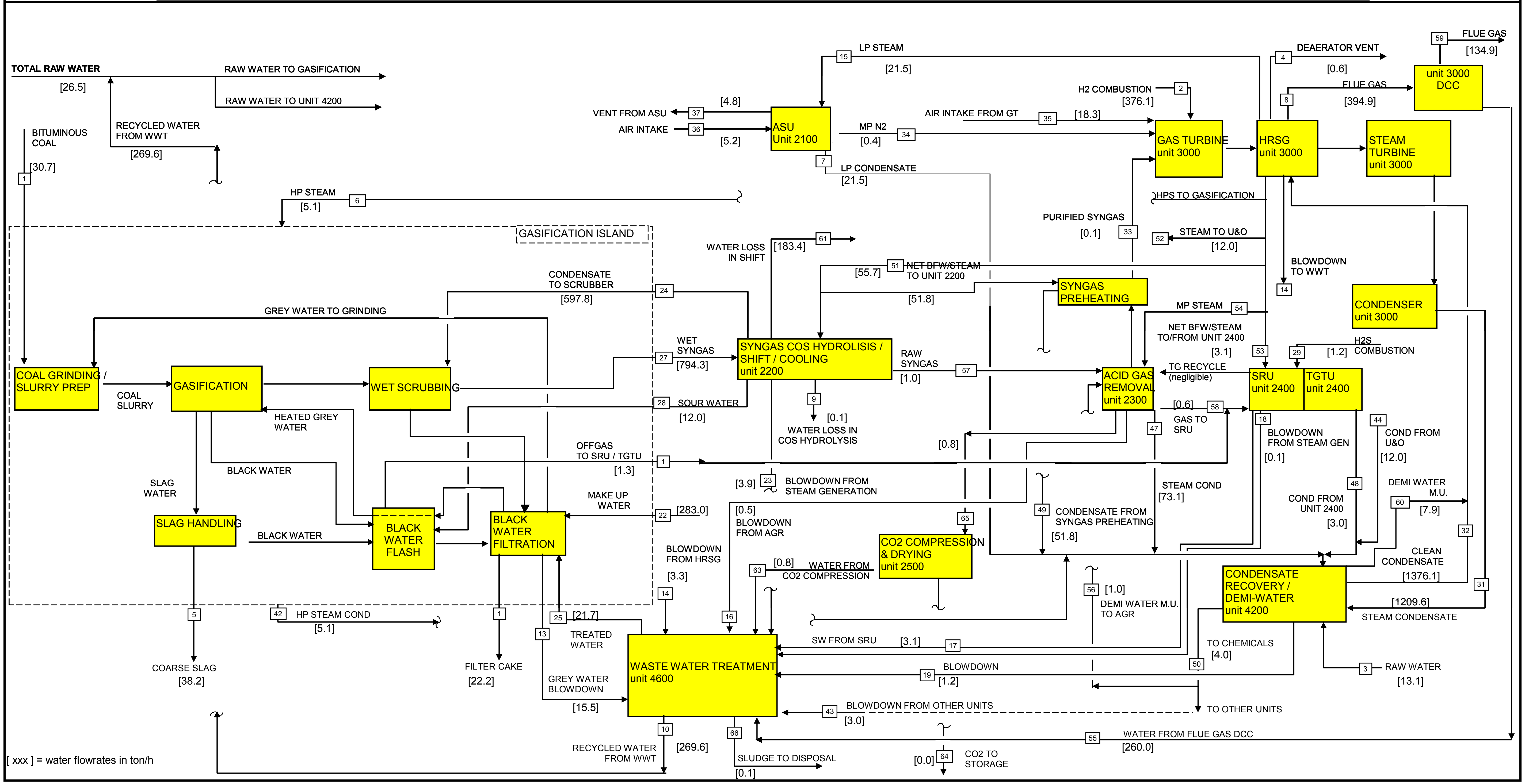
CASE 5.07 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 777.6 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



CASE 5.06 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 730.3 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



CASE 5.03 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 671.0 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



4. Performance summary

The key performance data of the ten cases studied are summarized in the following Table 3. The specific CO_2 emissions and water consumption are given per Electrical MWh.

Table 3 – Performance data

Case	Fuel MWth	Gross Power Output MWe	Auxiliary Cons. MWe	Net Power Output MWe	CO_2 capture efficiency %	Net Electrical Efficiency %	Raw water cons. t/h	Specific CO_2 emissions kg/MWh	Specific water cons. kg/MWh
3.21 USC-PC Wet land	1,723.2	831.0	73.3	757.7	-	44.0	78.9	743	104
3.25 USC-PC Dry land	1,723.2	802.0	77.0	725.0	-	42.1	0	777	0
3.22 USC-PC CCS Wet land	1,913.7	827.0	161.4	665.6	87.5	34.8	272.7	117	410
3.23 USC-PC CCS Dry land	1,913.7	799.0	175.9	623.0	87.5	32.6	0	125	0
4.11 Oxyfuel Wet land	1,502.2	737.0	205.6	531.4	90.0	35.4	33.3	85	63
4.12 Oxyfuel Dry land	1,502.2	710.0	218.6	491.4	90.0	32.7	0	92	0
5.05 IGCC Wet land	2,177.3	988.7	162.2	826.5	-	38.0	104.5	818	126
5.07 IGCC Dry land	2,177.3	955.1	177.5	777.6	-	35.7	32.5	869	42
5.06 IGCC CCS Wet land	2,321.8	972.8	242.5	730.3	85	31.5	300.3	152	411
5.03 IGCC CCS Dry land	2,321.8	937.4	266.3	671.1	85	28.9	26.5	165	39

With reference to performance summary data, the following considerations are made:

- ✓ For all the cases the penalty on net electrical efficiency due to the limitation on the water usage falls in a relatively narrow range of variation, despite the differences of the various technologies involved.

- ✓ The penalty is generally higher in the cases with CO_2 capture, as the CO_2 capture and mainly the CO_2 compression are heavily affected by the limitation on water usage. In the CO_2 capture unit, in fact, both the sour gas and the lean solvent are fed to the absorber at higher temperature, being cooled down by air instead of cooling water, thus leading to an increase of solvent circulation and steam consumption in the regeneration section. In the CO_2 compression unit, the air intercoolers lead to a higher temperature at the compressor inlet significantly affecting the compressor power absorption.

- ✓ Among the wet land cases, the lowest sea water withdrawal in oxyfuel case is also related to the higher heat integration inside the oxyfuel plant.

- ✓ The specific CO_2 emissions slightly rise in the cases with limitation on water usage due to the net electrical efficiency reduction.

5. Economics Summary

Table 4 provides the main economic data for the different alternatives.

The cost of electricity is calculated based on the following main assumptions:

- Investment cost given at 4Q2009 cost level in South Africa;
- Fuel costs: 1.5 €/GJ;
- 10% discount rate on the investment cost over 25 operating years;
- Cost of CO_2 transport and storage are excluded from the estimate;
- No selling price is attributed to the sequestered CO_2.

The cost of water saved is calculated based on the following main assumptions:

- Electricity cost: 50 c€/kWh;
- 10% discount rate on the investment cost over 25 operating years;
- Differential investment cost between the case without and with water limitation;
- Delta net power output between the case without and with water limitation;
- Delta O&M Costs between the case without and with water limitation.

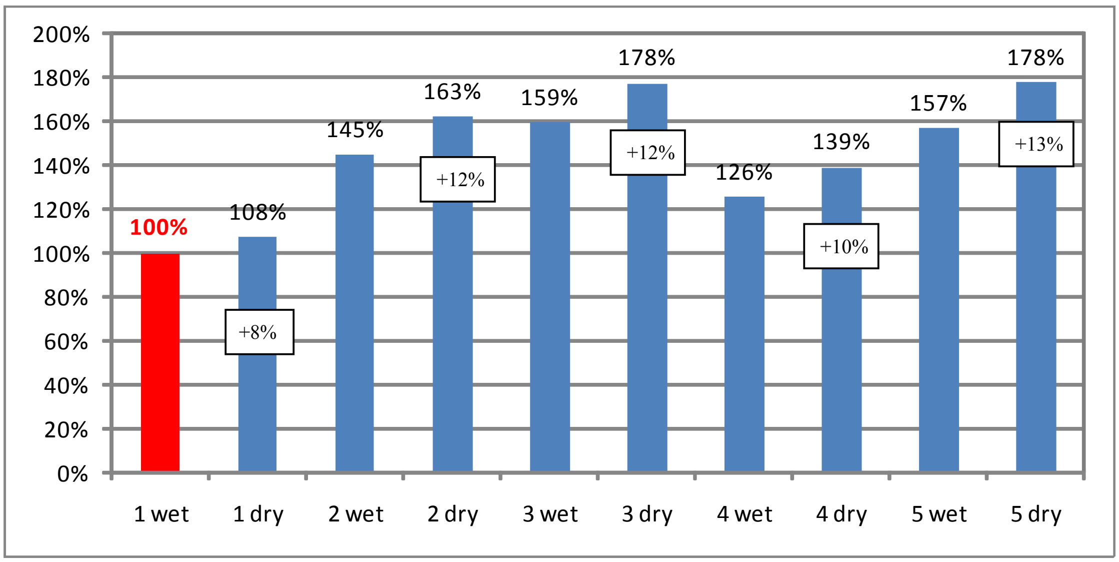
Table 4 – Economic data

CASE	Total investment cost M€	% TIC increase %	Yearly operating hours h/y	Yearly O&M costs M€/y	Specific Investment cost Euro/kWe	COE c€/kWh	Cost of water saved c€/t
3.21 USC-PC Wet land	880.1	+ 5.0%	7,884 (90%)	133.6	1,161.6	4.0	-
3.25 USC-PC Dry land	924.6		7,884 (90%)	135.9	1,275.3	4.3	3.3
3.22 USC-PC CCS Wet land	1,101.4	+7.7%	7,709 (88%)	162.1	1,654.7	5.8	-
3.23 USC-PC CCS Dry land	1,186.6		7,709 (88%)	166.3	1,904.6	6.5	0.8
4.11 Oxyfuel Wet land	1,053.7	+4.1%	7,446 (85%)	125.3	1,982.8	6.4	-
4.12 Oxyfuel Dry land	1,097.3		7,446 (85%)	127.6	2,233.0	7.1	9.0
5.05 IGCC Wet land	1,225.0	+6.0%	7,446 (85%)	162.1	1,482.1	5.0	-
5.07 IGCC Dry land	1,298.7		7,446 (85%)	165.9	1,670.1	5.6	7.3
5.06 IGCC CCS Wet land	1,378.7	+5.9%	7,446 (85%)	175.7	1,887.9	6.3	-
5.03 IGCC CCS Dry land	1,460.1		7,446 (85%)	179.8	2,175.7	7.1	0.9

The %TIC increase is given for each dry land case with respect to the relevant wet land case.

Figure 1 provides the normalized cost of electricity for each alternative, considering as reference case the USC-PC power plant without CO_2 capture and without limitation on water usage (COE = 100%).
For each case it is also shown the percentage increase (ratio between the COEs) of the COE for the dry land case with respect to the relevant wet land case.

Figure 1 – Normalised cost of electricity



With reference to economic summary data, the following considerations are made:

- ✓ The TIC percentage increase for all the dry land cases falls in a relatively narrow range of variation, between 4% and 8%, despite the differences of the various technologies involved.

- ✓ Cases without CO_2 capture: the TIC percentage increase for the dry land design is higher in the IGCC case than for the USC-PC. This is because of the different impact of cost increment in the different process units. The impact on the investment cost for USC-PC is limited to the power island and utilities, while for IGCC the dry land design also impacts the ASU.

- ✓ Cases with CO_2 capture: again, the TIC percentage increase for the dry land design is higher in USC-PC case than for the IGCC case. In fact, in the USC-PC case the dry land design strongly affects the investment cost of CO_2 capture and compression units, in addition to the units mentioned above. The impact on performance and investment cost of the CO_2 capture unit in the IGCC case is marginal. In the USC-PC case the CO_2 compression unit consumes much more power than in the IGCC due to the clear difference in the suction pressure (the CO_2 is made available from the AGR in IGCC at a much higher pressure than in the USC-PC case) and consequently the extra investment cost in the dry land case is much more evident.

- ✓ The TIC percentage increase (dry land vs. wet land) in the IGCC with and without CO_2 capture is similar. This is because the difference between the two cases is mainly limited to the CO_2 compression unit that, from an economic point of view, counts for less than one percentage point.

- ✓ The TIC percentage increase (dry land vs. wet land) in the USC PC with CO_2 capture is the highest since the cost of CO_2 capture and compression units represents a significant part of the overall investment cost.

- ✓ The TIC percentage increase for the oxyfuel case remains lower than the other cases for the following reasons:
  - The CO_2 purification system itself leads to the condensation of the water from the boiler flue gases and therefore there is no need to add any further water recovery system in the dry land cases;
  - In the oxyfuel case the oxygen from the ASU is made available at a lower pressure with respect to the IGCC case and therefore the dry land impact on ASU compressors and intercoolers is much lower.

- ✓ The O&M yearly costs are not significantly affected by the dry land design.
  Regarding the variable O&M costs, the only significant difference with respect to the dry land case is in fact, is represented by the make-up of water in the IGCC cases, and this has a very limited impact on the overall O&M costs.
  The fixed O&M costs remain partially constant (fuel, labour and consumables), while a part is increased proportionally with the investment cost of the plant on the same basis as the reference wet land case (maintenance, insurance and local taxes).
  The overall O&M cost increase is therefore limited to few percentage points.

- ✓ The main parasitic load due to the dry land design is represented both by the loss of gross electric power production and by the increase of electricity consumptions leading to a significant reduction of net electricity exported to the grid. This is not reflected in the O&M costs, but strongly reduces the incomes from the electricity sold to the market and therefore the overall plant economics.

- ✓ The cost of water saved is very low in USC-PC with CCS and in IGCC with CCS as in both cases it is possible to save a huge amount of water, although the increase in investment cost is significant (approximately +85M€ in both cases) and in the IGCC it is not possible to avoid a small raw water consumption. The cost of saving water is much higher in the oxyfuel case although the increase of investment cost is lower (+46 M€), as the water saved is limited to just 33 t/h. This is because in the oxyfuel case the water requirement is s small also in the wet land case.

CLIENT : IEA GHG R&D PROGRAMME
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO_2 CAPTURE
DOCUMENT NAME : REPORT #1

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Volume #1

INDEX

1.1 Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage in different power plants with and without CO_2 capture.

In order to perform the investigation, the primary purpose of this study is, therefore, a review of the current state of the art technology in reducing water consumption for any coal or gas fired power generation technologies with the following objectives:

a. Review of the current state of the art technology available for reducing water consumption in power plants without CO_2 capture;
b. Identify the most cost effective technologies to reduce water consumption that could be used to establish the performance of the reference plants for power plants without CO_2 capture;
c. Identify potential technologies to reduce water consumption or water recovery technologies that could be applicable to any coal or gas fired power plants installed with CO_2 capture.
   The reduction of water uses inside the plant can be achieved by selecting different processes requiring less water to satisfy the same objectives. This can be done either by increasing the overall process efficiency of the unit or by selecting different processes with lower water consumption and higher costs.

Present report details the technologies available for the treatment of the different water streams discharged or used inside the plants without and with CO_2 capture and provides an overview of the available technologies to reduce the water consumption of power plants, giving some considerations on the associated costs.

1.2 Process description

The study analyses five different power plant technologies:

- Pulverised coal-fired power plant with ultrasupercritical steam cycle without CO_2 capture (USC-PC without CCS);
- Pulverised coal fired power plant with ultrasupercritical steam cycle with post-combustion CO_2 capture based on standard MEA solvent (USC-PC with CCS);
- Pulverised coal fired power plant with ultrasupercritical steam cycle using oxyfuel combustion for CO_2 capture;
- IGCC using GEE Quench type gasifier without CO_2 capture (IGCC without CCS);
- IGCC using GEE Quench type gasifier with pre-combustion CO_2 capture based on physical solvent (IGCC with CCS).

A brief, simplified process description for each technology is shown to help in the analysis of the reduction of water usage possibilities.

USC PC without CCS: This case is based on an Ultra Supercritical Pulverised Coal (USCPC) boiler, once-through steam generator type, with superheating and single steam reheating. The boiler is a single-pass tower-type, with a staged low-NOx burner system. The boiler is equipped with SCR (selective catalytic reactor) based on De NOx and with electro-static precipitators (ESP). To remove the SOx content, a FGD (flue gas desulphuriser) system is provided to scrub the boiler exhaust gases prior release to the atmosphere. The power island is mainly composed by one steam turbine, with HP, MP and LP sections, all connected to the generator on a single shaft arrangement.

USCPC with post-combustion CCS: The CO_2 capture plant is mainly composed of two parallel trains made of one direct contact cooler and one absorption column, followed by a common regenerator stripper. The flue gas entering the absorption column is contacted with MEA (Mono Ethanolamine). The solvent is then heated to break down the compound and release solvent and high-purity carbon dioxide. The produced CO_2 rich stream flows from the outlet of the regeneration column to the CO_2 compression unit, which is composed of different stages, with intercooling between them.

Oxycombustion USCPC with post-combustion CCS: This case is similar to the previous plant with post-combustion CCS. Oxygen (typically with a purity greater than 95%) is used for combustion of the fuel instead of air. To use existing, proven boiler technology, flue gas must be recycled and used for pulverised fuel transport and for inert dilution to moderate the peak temperature in the furnace. The boiler is equipped with ESPs. SOx and NOx are removed from gaseous CO_2 during compression: 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 sulphuric acid and nitric acid respectively that are removed from the system as aqueous solutions. The gas is then partially recirculated to the boiler and in part dehydrated and sent to the compression unit. The inert gas content, derived from excess oxygen, along with argon and nitrogen present in the oxygen feed, is mostly separated and vented. An air separation unit (ASU) provides the low pressure oxygen required by the combustion.

<u>IGCC without CCS</u>: This case is based on an Integrated Gasification Combined Cycle (IGCC) with GEE gasification technology. Coal is crushed and a slurry with water is prepared to feed the gasifier burner, together with O_2 from the ASU. The produced raw syngas outlet from the gasification island is then treated and cleaned through a H_2S removal unit (AGR), based on a physical solvent washing. The cleaned syngas is used in a combined cycle, which mainly consists of 2 GTs, 2 HRSGs and 1 single steam turbine.

<u>IGCC with pre-combustion CCS</u>: The case is based on the same GEE gasification technology as the case without CCS. As shift is necessary to produce syngas, the quench with water provides the reagent for the chemical reaction. The produced raw syngas outlet from the gasification island is treated through a sour shift unit, increasing both the hydrogen and CO_2 content of the syngas, and H_2S and CO_2 are removed through a physical solvent washing in the AGR unit. The cleaned syngas is used in a combined cycle.

1.3 Water balances

Simplified Power Plant schemes showing waste water streams and relevant tables with estimated compositions and flowrates are attached hereafter as Attachment A1 to A7 for the following cases, which are the most representative for the Waste Water Treatment (WWT) configuration for each Power Plant technology, among all the cases analyzed in present report:

A. 3.24 USC PC, lignite, with CO_2 capture (reference shall be made to Volume 2 – Sections C & E, although based on bituminous coal);
B. 4.13 USC PC Oxyfuel, lignite, with CO_2 capture (reference shall be made to Volume 3 – Sections B & C, although based on bituminous coal);
C. 5.01 Shell IGCC, bituminous coal, w/o CO_2 capture;
D. 5.02 Shell IGCC, bituminous coal, with CO_2 capture;
E. 5.04 Shell IGCC, lignite, with CO_2 capture;
F. 5.05 GE IGCC, bituminous coal, w/o CO_2 capture (reference shall be made to Volume 4 – Sections B & D);
G. 5.06 GE IGCC, bituminous coal, with CO_2 capture (reference shall be made to Volume 4 – Sections C & E).

The waste water flowrates and compositions reported in the attached tables have been listed by using the information included in the reference IEA GHG reports. For the missing information FWI in-house data (simulation programs, other similar FWI projects, typical flowrates or compositions, etc) have been considered, with the following main exceptions:

- effluent from lignite (or coal) drying section: water evaporated from solid fuel is assumed to be completely condensed. The composition is as advised by the drying system Vendor, RWE;
- waste water stream from CO_2 compression / drying section for the Oxyfuel Power Plant: in accordance with Air Product patent US 7,416,716 B2, it is assumed that all the SO_2 and NO_x present in flue gas is converted in H_2SO_4 and HNO_3 respectively and collected in this water stream. Water flowrate is calculated in line with the information included in the above-mentioned Air Product patent.

A brief description of the attached schemes and tables follows:

A. 3.24 USC PC, lignite, with CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Effluent from lignite drying section;
- Condensate from CO_2 dryers/compressors section;
- Blowdown from Acid Gas Removal;

- Demi plant regeneration effluent;
- Blowdown from cooling tower system;
- Blowdown from Fuel Gas Desulfurization.

Since the fuel to be dried is lignite, i.e. fuel with high moisture content, it is to be noted the high flowrate of water that may be recovered in the drying process (around 200 t/h).
The steam generation in the USC PC Boiler Island doesn't produce any stream of blowdown since steam is generated from boiler feed water above its critical conditions, thus without boiling but passing with continuity from liquid phase to vapor phase and no blowdown is foreseen.
Presence of Cooling Towers as far as concerns the cooling system is in accordance to the reference IEA GHG study.

B. 4.13 USC PC Oxyfuel, lignite, with CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Effluent from lignite drying section;
- Condensate from CO_2 dryers/compressors sections;
- Demi plant regeneration effluent;
- Blowdown from cooling tower system;
- Condensate from flue gas cooling.

As per previous USC PC case, the flowrate of water that may be recovered in the lignite drying process is significant (around 190 t/h).
The stream of "Condensate from CO_2 dryers/compressors" contains H_2SO_4 and HNO_3 in very high concentration, in line with the process described in the Air Product patent US 7,416,716 B2.
As per the USC PC Boiler, the Blowdown from steam generation is absent due to the fact that the water evaporation in the boiler happens in supercritical conditions.
Presence of Cooling Towers as far as concerns the cooling system is in accordance to the reference IEA GHG study.

C. 5.01 Shell IGCC, bituminous coal, without CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Effluent water from Gasfication Island clarifier;
- Effluent from coal drying section.
- Blowdown from steam generation (HRSG section);
- Blowdown from steam generation (SRU section);

- Blowdown from steam generation (gasification section);
- Demi plant regeneration effluent;
- Blowdown from Acid Gas Removal;
- Sour Water from SRU.

Since the fuel to be dried is bituminous coal, i.e. fuel with already low moisture content, the flowrate of water that may be recovered in the drying process is much lower than in the previous cases (around 10 t/h).
Compared with the cases 3.24 and 4.13, in the present case (and in the following cases when the fuel is bituminous coal) there's no stream of "Blowdown from cooling tower system", since, according to the reference studies, the cooling system is provided by a once through sea water system and not by a recirculating system with cooling towers.
Furthemore, as in all the IGCC cases based on Shell gasification, a significant stream of waste water consists of the effluent from Clarifier i.e. part of the water from the slurry stripper bottom, in the clarification section, discharged to the wastewater treatment system to limit the amount of salts in the water internally recycled in the Gasification Unit.

D. 5.02 Shell IGCC, bituminous coal, with CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Effluent water from Gasfication Island clarifier;
- Effluent from coal drying section;
- Process condensate;
- Blowdown from steam generation (HRSG section);
- Blowdown from steam generation (SRU section);
- Blowdown from steam generation (syngas cooling section);
- Blowdown from steam generation (gasification section);
- Demi plant regeneration effluent;
- Blowdown from Acid Gas Removal;
- Condensate from CO_2 dryers/compressors section;
- Sour Water from SRU.

Compared with the case 5.01, in the present case the streams "Effluent from Gasification Island clarifier" and "Effluent from coal drying section" are slightly higher as the quantity of bituminous coal to be burnt is higher.
The stream "Demi plant regeneration effluent" is significantly higher than in the case 5.01, reflecting the increased capacity of the demi unit. This is due to the fact that a significant amount of steam is lost, being injected in the syngas cooling section for performing the shift reaction.

The stream of "Process condensate" is present in the present Shell case 5.02 and in the following 5.04, but not in the previous 5.01. As a consequence of the steam injection for the CO shift reaction (mentioned above), during the process of syngas cooling the excess of steam is condensed and recovered in the stream called "Process condensate". The resulting process condensate is in excess with respect to the water requirements of the gasification and therefore part of the recovered condensate shall be discharged to WWT.
In the Shell IGCC Power Plants with CO_2 capture there is a stream of "Blowdown from steam generation (syngas cooling section)", which was not present in the list of waste water streams from Shell IGCC Power Plants without CO_2 capture. Indeed, in the Plants with CO_2 capture the Shift Reaction is performed: its exothermicity heats up the syngas, which is then cooled by generating steam. On the contrary, no Shift Reaction is performed in the Plant without CO_2 capture and the syngas is produced by the Gasification Unit at low temperature (below 130°C), so that it is not possible to recover heat by generating steam.

E. 5.04 Shell IGCC, lignite, with CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Effluent water from clarifier in Gasfication Island;
- Effluent from lignite drying section;
- Process condensate;
- Blowdown from steam generation (HRSG section);
- Blowdown from steam generation (syngas cooling section);
- Blowdown from steam generation (gasification section);
- Demi plant regeneration effluent;
- Blowdown from cooling tower system;
- Blowdown from Acid Gas Removal;
- Condensate from CO_2 dryers/compressors section.

Compared with the Shell IGCC Power Plants fed with bituminous coal (cases 5.01 and 5.02), in the present case the stream "Effluent water from Gasfication Island" is slightly higher and the stream "Effluent from coal drying section" is significantly higher due to the very high moisture content in lignite.
Furthermore, in the present case the AGR section removes CO_2 and H_2S simultaneously and delivers them together to the Unit battery limit without the need of a Sulphur Recovery Unit (SRU) (in accordance with the reference study). As a consequence, no stream of waste water from SRU is foreseen.
Since the cooling medium in the present case is cooling water from Cooling Towers, in accordance to all the lignite fed cases in reference studies, a waste water stream of "Blowdown from cooling tower system" is present.

F. 5.05 GE IGCC, bituminous coal, without CO_2 capture

The following waste water streams to be treated by Waste Water Treatment have been identified:

- Grey water blowdown from Gasification Island;
- Blowdown from steam generation (syngas cooling section);
- Blowdown from steam generation (SRU section);
- Blowdown from steam generation (HRSG section);
- Demi plant regeneration effluent;
- Blowdown from Acid Gas Removal;
- Sour Water from SRU.

Compared with the Shell IGCC Power Plants previously considered, in the GE IGCC Power Plants the flowrate of the stream "Demi plant regeneration effluent" is lower. This is mainly due to the fact that raw water is sent into gasification process and not steam or boiler feed water, so the nominal capacity of the Demiwater Plant is reduced.
Furthermore, there is no stream of "Process condensate" sent to Waste Water Treatment, since the steam condensate recovered in the syngas cooling section is entirely re-routed to the gasification island, in part directly and in part after being stripped in a Sour Water Stripper.
As in all the IGCC cases based on GEE gasification, a significant stream of waste water consists of the grey water blowdown i.e. part of the water from the black water Filtration and Settlement, discharged to the wastewater treatment system to limit the amount of salts in the water internally recycled in the Gasification Unit.
Finally there is no stream of "Blowdown from steam generation (gasification section)" since in the GEE IGCC configuration no steam is generated in the Gasification section.

G. 5.06 GE IGCC, bituminous coal, with CO_2 capture

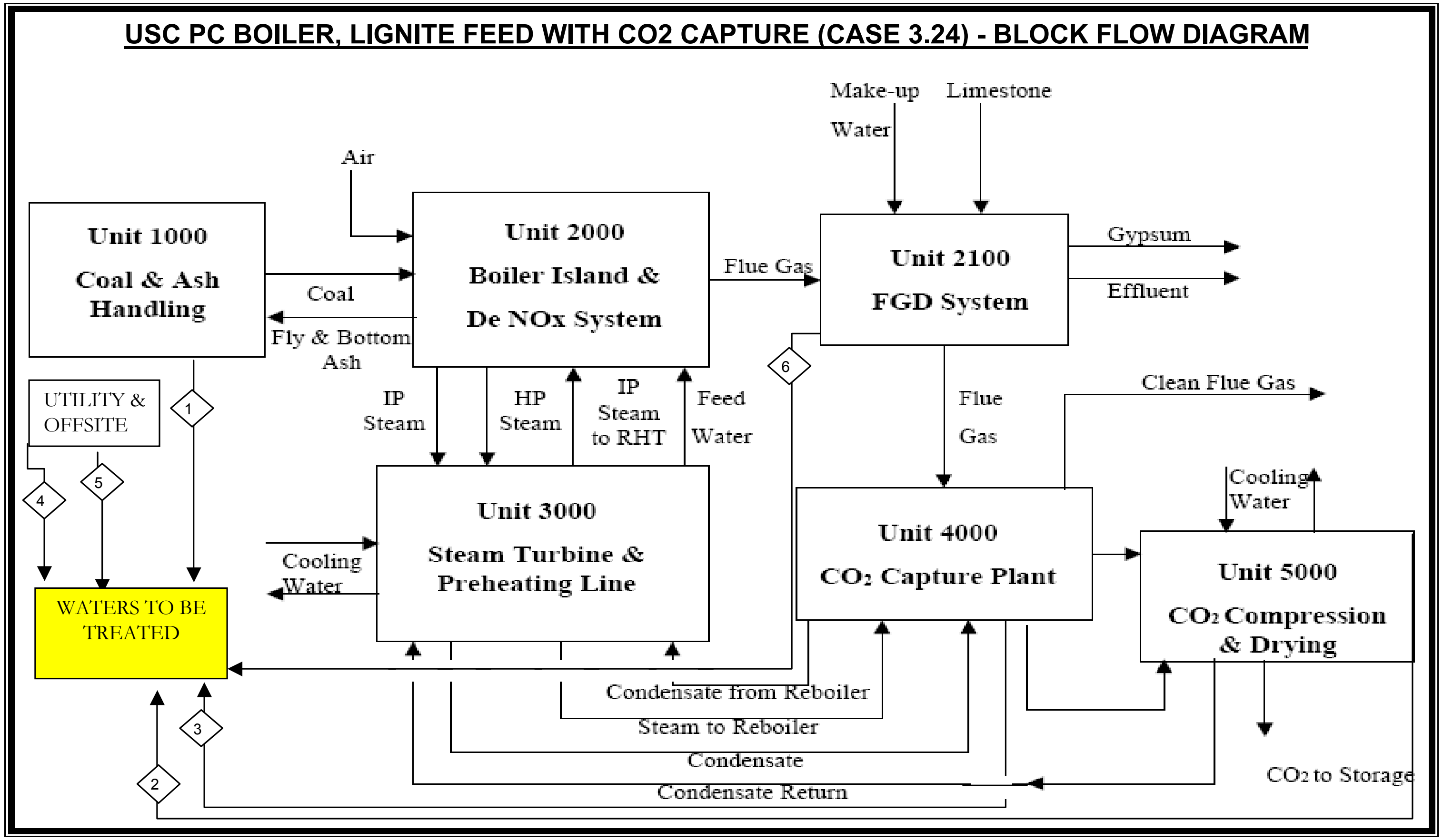
The following waste water streams to be treated by Waste Water Treatment have been identified:

- Grey water blowdown from Gasification Island;
- Blowdown from steam generation (syngas cooling section);
- Blowdown from steam generation (SRU section);
- Blowdown from steam generation (HRSG section);
- Demi plant regeneration effluent;
- Blowdown from Acid Gas Removal;
- Condensate from CO_2 dryers/compressors section.
- Sour Water from SRU.

Compared with the GE IGCC without CO_2 capture (case 5.06) in the GE IGCC with CO_2 capture the waste water flowrates are slightly higher reflecting the higher quantity of fuel required.

Moreover the water content in syngas is high enough to properly operate the shift reactor and therefore no need of additional steam injection is foreseen.

ATTACHMENT A1



IEA GHG R&D PROGRAMME

Water Usage and Loss Analysis in Power Plants without and with CCS

Revision no.: 1
Date: October 2010

ATTACHMENT A1

USC PC BOILER, LIGNITE FEED WITH CO2 CAPTURE (CASE 3.24) - WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5	6					
SERVICE	lignite drying effluent	cond from CO2 compr	BD from AGR	demi plant regen.	cooling tower system BD	FGD BD					
Temperature (°C):	50	35	40	amb	11	50					
Total flowrate (kg/h):	201848	12525	40000	32700	334000	600					
Composition (ppm wt)											
H2											
H2S											
CO2	REFER TO ATTACHED TABLE	150	1709			REFER TO ATTACHED TABLE					
NH3											
Na+				1090	200						
Cl-				4560							
PO4---											
SiO2				110	10						
CaCO3				406	800						
SO4--				830	700						
NO3-				510	5						
Ca AAS				1410	300						
Mg AAS				420	200						
MEA											
Dissolved solids			384 (***)		5000						
K				30							
HCO3-				250							
H2O (% wt)		99.9850	99.7780	99.0384	99.2785						
TOTAL (%wt)		100	100	100	100						

NOTES: ** *

(*) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

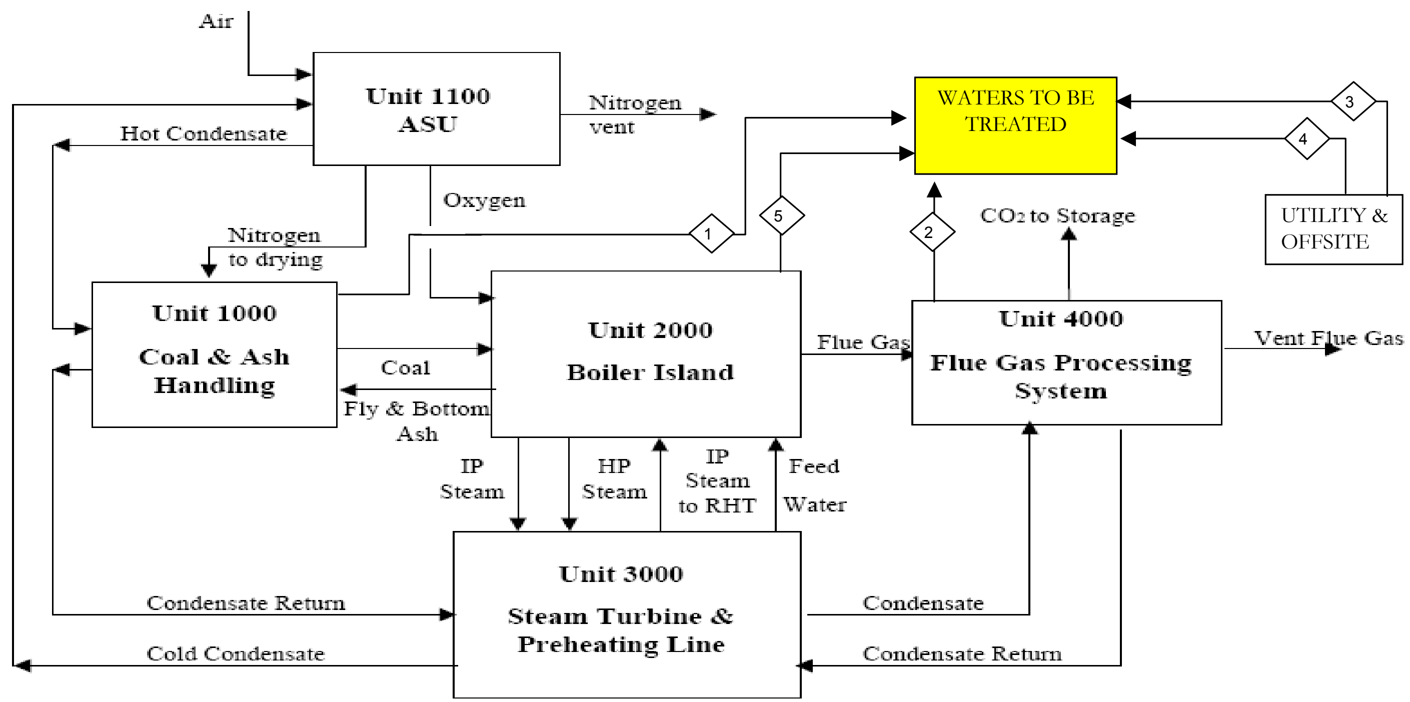
(**) = BD from AGR contains also: Ar (0.4 ppm wt); N2 (124.3 ppm wt); O2 (1.8 ppm wt)

(***) = solids consist of coal fines

NET ELECTRIC POWER OUTPUT = 761.0 MW

ATTACHMENT A2

OXYFUEL BOILER, LIGNITE FEED WITH CO2 CAPTURE (CASE 4.13) - BLOCK FLOW DIAGRAM



ATTACHMENT A2

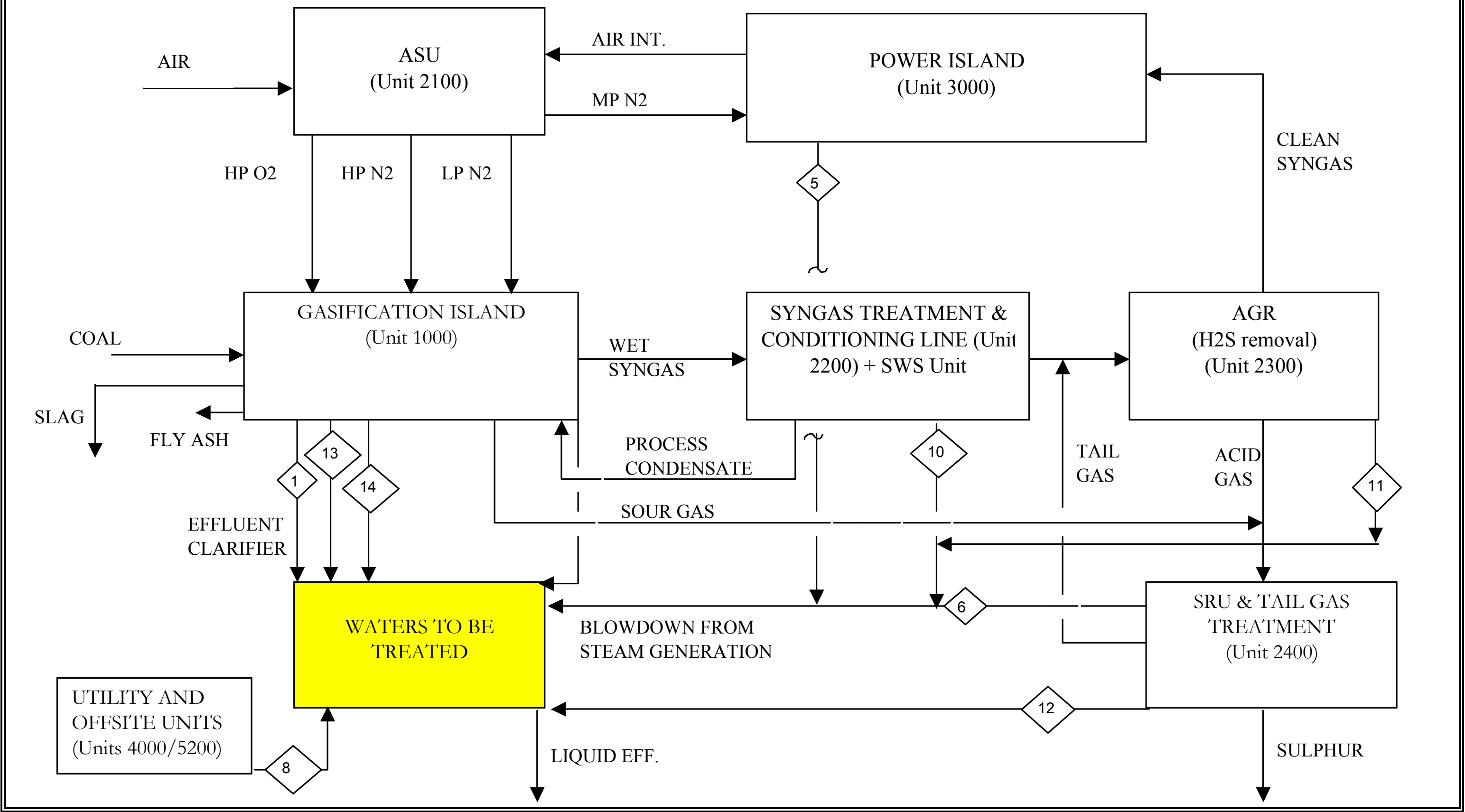
OXYFUEL PC BOILER, LIGNITE FEED WITH CO2 CAPTURE (CASE 4.13) - WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5								
SERVICE	lignite drying effluent	cond from CO_2 compr	demi plant regen.	cooling tower system BD	cond from flue gas cooling								
Temperature (°C)	50	35	amb	11	35								
Mass flow (kg/h)	186337	9991	100	420000	267300								
Composition (ppm wt)	REFER TO ATTACHED TABLE												
H2													
H2S													
CO2					1480								
NH3													
Na+			1090	200									
Cl-			4560										
PO4---													
SiO2			110	10									
CaCO3			406	800									
SO4--			830	700									
NO3-			510	5									
Ca AAS			1410	300									
Mg AAS			420	200									
MEA													
Dissolved solids				5000									
K			30										
HCO3-			250										
H2SO4		462484			157								
HNO3		17716											
SO2 (as HSO3-)					330								
H2O (% wt)		51.5600	99.0384	99.2785	99.8033								
TOTAL (%wt)		100	100	100	100								

NOTES:
NET ELECTRIC POWER OUTPUT = 741.3 MW

ATTACHMENT A3

SHELL IGCC, BITUMINOUS COAL FEED W/O CO2 CAPTURE (CASE 5.01) – BLOCK FLOW DIAGRAM



ATTACHMENT A3

SHELL IGCC, BITUMINOUS COAL FEED W/O CO2 CAPTURE (CASE 5.01) – WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14
SERVICE	Effluent clarifier	Deleted	Deleted	Deleted	BD: steam gen (HRSG)	BD: steam gen (SRU)	Deleted	demi plant regen.	Deleted	BD: steam gen (syngas cooling)	BD from AGR	SW from SRU	BD steam gen (gasification)	BD from coal drying
Temperature (°C)	50				100	100		AMB		100	120	50	100	50
Total flow (kg/h)	38935				7176	50		16600		0	1700	1450	4400	10024
Composition (%wt)	REFER TO ATTACHED TABLE													REFER TO ATTACHED TABLE
H2														
H2S											0.0032	0.0030		
CO2												0.0100		
NH3											0.0005	0.0010		
Na+								0.1090						
Cl-								0.4560						
PO4---					0.0001	0.0005				0.0005			0.0001	
SiO2					0.0001	0.0005		0.0110		0.0005			0.0001	
CaCO3					0.0020	0.0100				0.0100			0.0020	
SO4--								0.0830						
NO3-								0.0510						
Ca AAS								0.1410						
Mg AAS								0.0420						
MDEA											0.3224			
H2O					99.9978	99.9890		99.0790		99.9890	99.6739	99.9860	99.9978	
Dissolved solids														
K								0.0030						
HCO3-								0.0250						
TOTAL					100	100		100		100	100	100	100	
NOTES:	NOC				*	*		**						

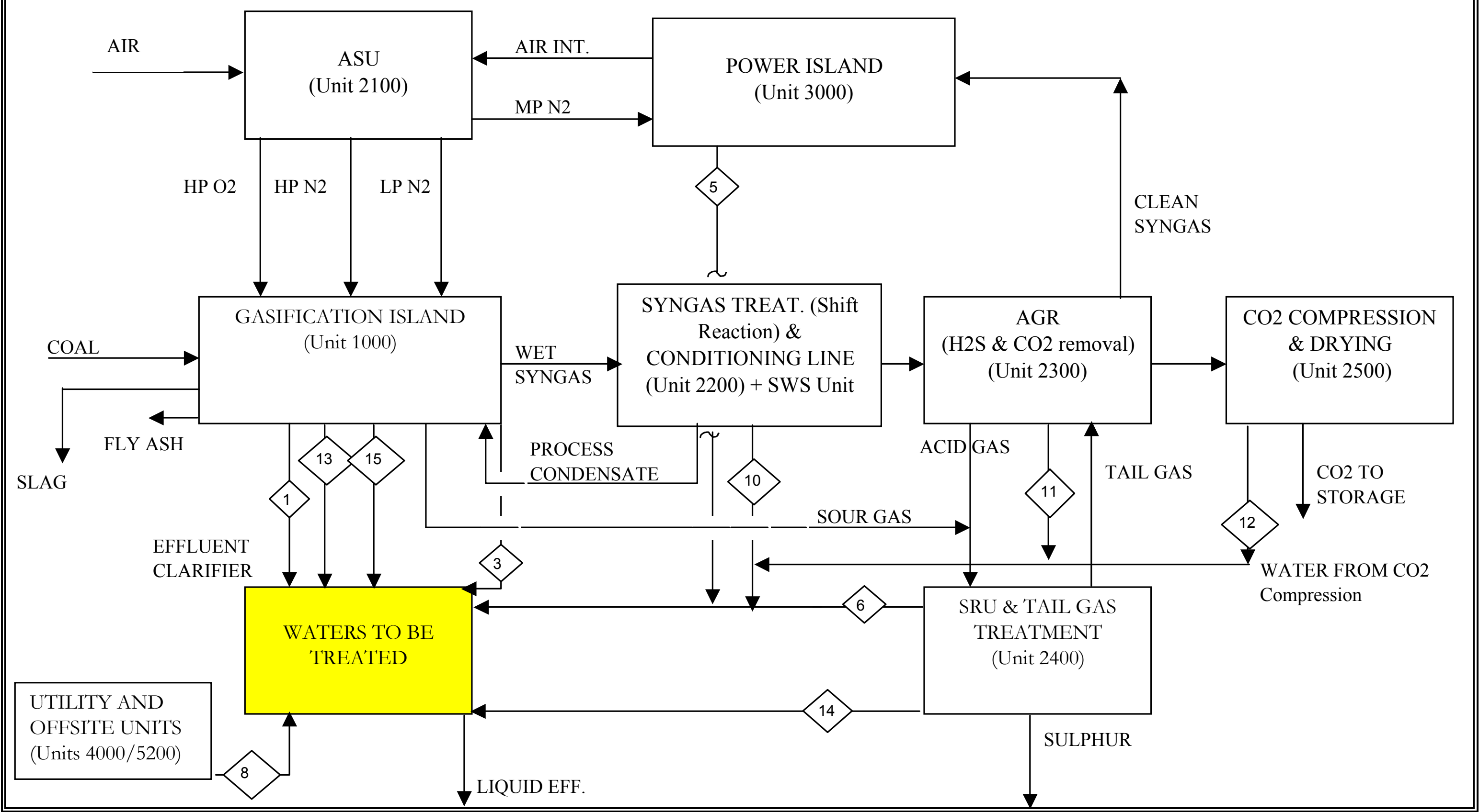
(*) = blowdown flowrate assumed equal to 1% steam production

(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

NET ELECTRIC POWER OUTPUT = 775.9 MW

ATTACHMENT A4

SHELL IGCC, BITUMINOUS COAL FEED WITH CO2 CAPTURE (CASE 5.02) – BLOCK FLOW DIAGRAM



ATTACHMENT A4

SHELL IGCC, BITUMINOUS COAL FEED WITH CO2 CAPTURE (CASE 5.02) – WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SERVICE	Effluent clarifier	Deleted	process condensate	Deleted	BD: steam gen (HRSG)	BD: steam gen (SRU)	Deleted	demi plant regen.	Deleted	BD: steam gen (syngas cooling)	BD from AGR	Water from CO2 compr	BD steam gen (gasification)	SW from SRU	BD from coal drying
Temperature (°C)	50		100		100	100		AMB		100	120	30	100	50	50
Total flow (kg/h)	42322		113100		6798	53		47400		3920	500	640	4100	1750	10924
Composition (%wt)	REFER TO ATTACHED TABLE														REFER TO ATTACHED TABLE
H2			0.0144												
H2S			0.0020								0.0800			0.003	
CO2			0.0800								0.0400	0.0150		0.01	
NH3			0.0120											0.001	
Na+								0.1090							
Cl-								0.4560							
PO4---					0.0001	0.0005				0.0005			0.0001		
SiO2					0.0001	0.0005		0.0110		0.0005			0.0001		
CaCO3					0.0020	0.0100		0.0406		0.0100			0.0020		
SO4--								0.0830							
NO3-								0.0510							
Ca AAS								0.1410							
Mg AAS								0.0420							
Selexol											0.3224				
H2O			99.8916		99.9978	99.9890		99.0384		99.9890	99.5576	99.9850	99.9978	99.986	
Dissolved solids															
K								0.0030							
HCO3-								0.0250							
Total			100		100	100		100		100	100	100	100	100	
NOTES:	NOC				*	*		**							

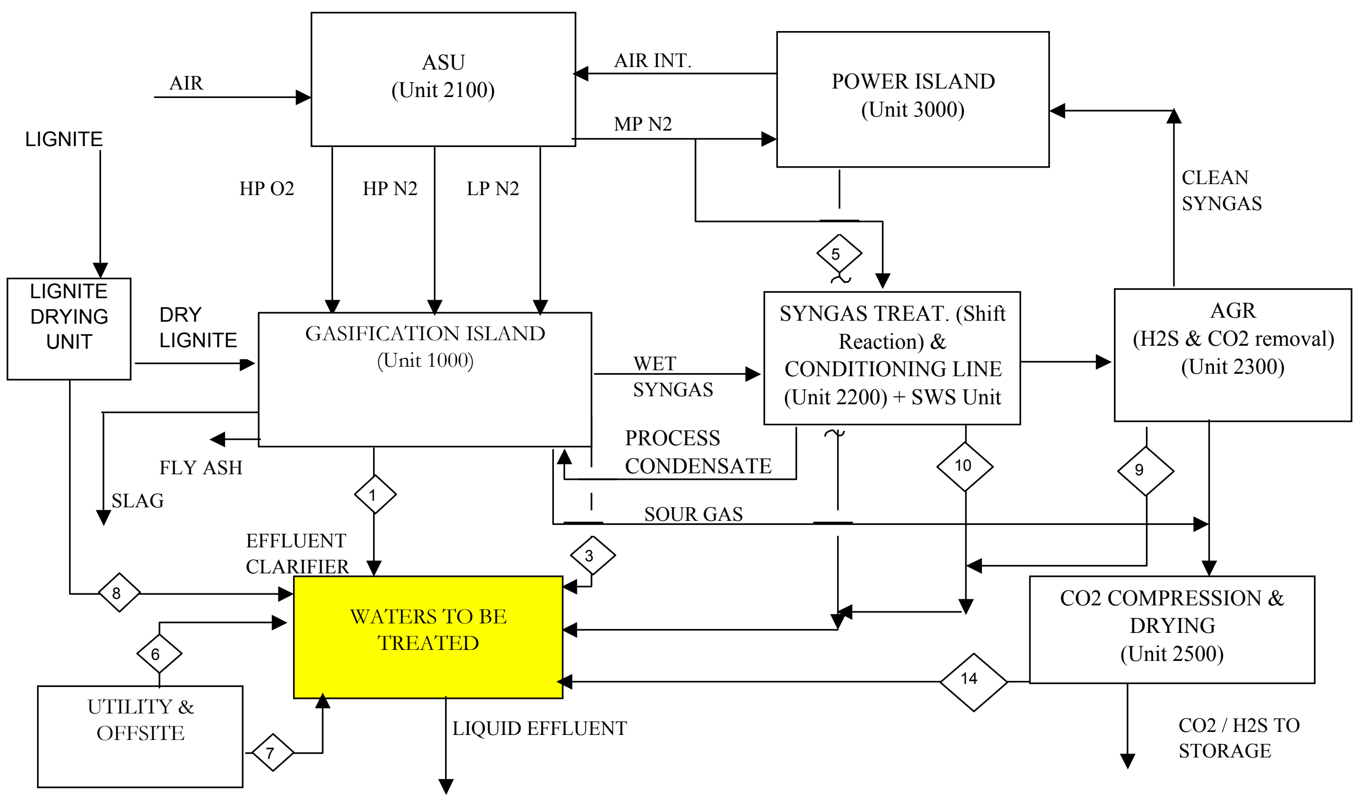
(*) = blowdown flowrate assumed equal to 1% steam production

(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

NET ELECTRIC POWER OUTPUT = 676.2 MW

ATTACHMENT A5

SHELL IGCC, LIGNITE FEED WITH CO2 CAPTURE (CASE 5.04) – BLOCK FLOW DIAGRAM



ATTACHMENT A5

SHELL IGCC, LIGNITE FEED WITH CO2 CAPTURE (CASE 5.04) - WATER STREAMS TO BE TREATED

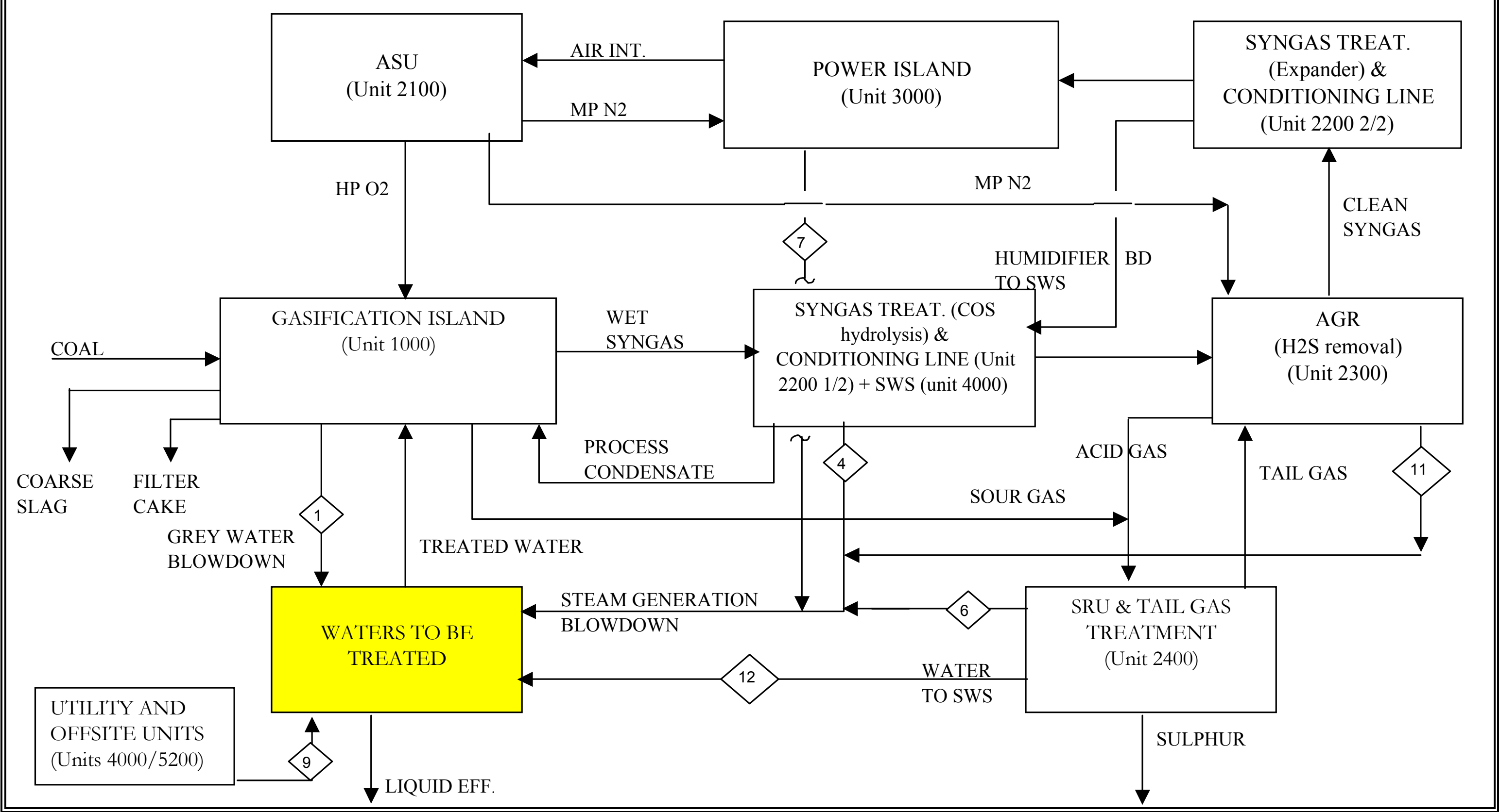
STREAM	1	2	3	4	5	6	7	8	9	10	13	14	
SERVICE	Effluent clarifier	Deleted	process condensate	Deleted	BD: steam gen (HRSG)	demi plant regen.	Cooling tower system BD	lignite drying effluent	BD from AGR	BD: steam gen (syngas cooling)	BD steam gen (gasification)	cond from CO2 compr	
Temperature (°C)	50				100	AMB	11	50	120	100	100	30	
Total flowrate (kg/h)	52730		119160		3112	32400	140000	300300	1700	6686	4600	1530	
Composition (%wt)	REFER TO ATTACHED TABLE							REFER TO ATTACHED TABLE					
H2			0.0144										
H2S			0.0020						0.0800			0.0005	
CO2			0.0800									0.0260	
NH3			0.0120						0.0005				
Na+						0.1090	0.0200						
Cl-						0.4560							
PO4---					0.0001					0.0005	0.0001		
SiO2					0.0001	0.0110	0.0010			0.0005	0.0001		
CaCO3					0.0020	0.0406	0.0800			0.0100	0.0020		
SO4--						0.0830	0.0700						
NO3-						0.0510	0.0005						
Ca AAS						0.1410	0.0300						
Mg AAS						0.0420	0.0200						
MDEA									0.3224				
H2O			99.8916		99.9978	99.0384	99.2785		99.5971	99.9890	99.9978	99.9735	
Dissolved solids							0.5000						
K						0.0030							
HCO3-						0.0250							
TOTAL			100		100	100	100		100	100	100	100	

NOTES: * **

(*) = blowdown flowrate assumed equal to 1% steam production
(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate
NET ELECTRIC POWER OUTPUT = 628.8 MW

ATTACHMENT A6

GE IGCC, BITUMINOUS COAL FEED W/O CO2 CAPTURE (CASE 5.05) - BLOCK FLOW DIAGRAM



ATTACHMENT A6

GE IGCC, BITUMINOUS COAL FEED W/O CO2 CAPTURE (CASE 5.05) - WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5	6	7	8	9	10	11	12
SERVICE	grey water blowdown	Deleted	Deleted	BD: steam gen (syngas cool)	Deleted	BD: steam gen (SRU)	BD: steam gen (HRSG)	Deleted	demi plant regen.	Deleted	BD from AGR	SW from SRU
Temperature (°C)	50			100		100	100		AMB		120	50
Total flowrate (kg/h)	14564			6765		52	7000		3000		1700	2650
Composition (%wt)												
H2												
H2S	0.0002										0.0032	0.0030
CO2	0.0000											0.0100
NH3	0.0025										0.0005	0.0010
Na+	0.0097								0.1090			
Cl-	0.0148								0.4560			
PO4---				0.0005		0.0005	0.0001					
SiO2				0.0005		0.0005	0.0001		0.0110			
CaCO3				0.0100		0.0100	0.0020		0.0406			
SO4--	25 ppmw								0.0830			
Sulfides	10 ppmw											
CN-	< 5 ppmw											
Formates	740 ppmw											
NO3-									0.0510			
Ca AAS									0.1410			
Mg AAS									0.0420			
MDEA											0.3224	
H2O	99.9727			99.9890		99.9890	99.9978		99.0384		99.6739	99.9860
Dissolved solids												
TSS	100 ppmw											
K									0.0030			
HCO3-									0.0250			
TOTAL	100			100		100	100		100		100	100
NOTES:	NOC			*		*	*		**			

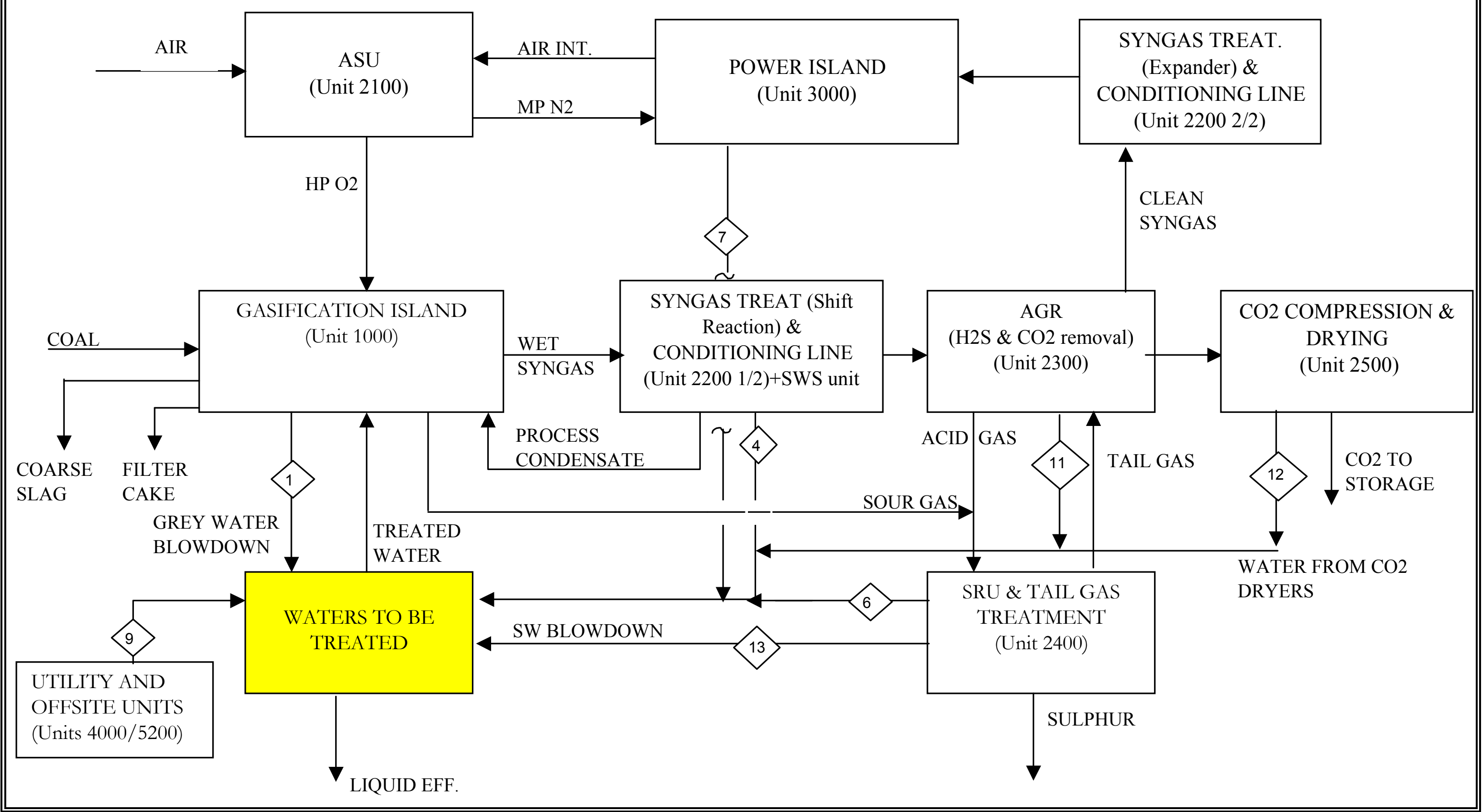
(*) = blowdown flowrate assumed equal to 1% steam production

(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

NET ELECTRIC POWER OUTPUT = 826.5 MW

ATTACHMENT A7

GE IGCC, BITUMINOUS COAL FEED WITH CO2 CAPTURE (CASE 5.06) - BLOCK FLOW DIAGRAM



ATTACHMENT A7

GE IGCC, BITUMINOUS COAL FEED WITH CO2 CAPTURE (CASE 5.06) - WATER STREAMS TO BE TREATED

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13
SERVICE	grey water blowdown	Deleted	Deleted	BD: steam gen (syngas cool)	Deleted	BD: steam gen (SRU)	BD: steam gen (HRSG)	Deleted	demi plant regen.	Deleted	BD from AGR	cond from CO2 dryers	SW from SRU
Temperature (°C)	50			100		100	100		AMB		120	30	50
Total flowrate (kg/h)	15535			7747		56	6400		2600		500	790	3070
Composition (%wt)													
H2													
H2S	0.0002										0.0800		0.003
CO2	0.0000										0.0400	0.0150	0.01
NH3	0.0025												0.001
Na+	0.0097								0.1090				
Cl-	0.0148								0.4560				
PO4---				0.0005		0.0005	0.0001						
SiO2				0.0005		0.0005	0.0001		0.0110				
CaCO3				0.0100		0.0100	0.0020		0.0406				
SO4--	25 ppmw								0.0830				
Sulfides	10 ppmw												
CN-	< 5 ppmw												
Formates	740 ppmw												
NO3-									0.0510				
Ca AAS									0.1410				
Mg AAS									0.0420				
Selexol											0.3224		
H2O	99.9727			99.9890		99.9890	99.9978		99.0384		99.5576	99.9850	99.986
Dissolved solids													
TSS	100 ppmw												
K									0.0030				
HCO3-									0.0250				
TOTAL	100			100		100	100		100		100	100	100

NOTES:	NOC			*		*	*		**				

(*) = blowdown flowrate assumed equal to 1% steam production
(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate
NET ELECTRIC POWER OUTPUT = 730.3 MW

Vapour condensate quality for Rhenish lignite drying (before treatment):

Temperature	< 30°C	
pH	~ 5.0	
Conductivity	= 35-45 µS/cm	
Solids	= 10-30 mg/l	
COD (filtered)	= 45-70 mg/l	(chemical oxygen demand)
BOD5	= 30-40 mg/l	(biological oxygen demand)
DOC	= 14-25 mg	(dissolved organic carbon)
Cl (-)	= 3-8 mg/l	
SO4 (2-)	= 3-8 mg/l	
NH4 (-)	= 0.4-0.6 mg/l	
K (+)	= 0.3-0.5 mg/l	
Na (+)	< 3 mg/l	
Ca (2+)	= 0.5-3.0 mg/l	
PO4 (2-)	< 1 mg/l	

Typical composition from mail "AW: Request for Information on Drying system",
sent by nikolaus.bargen@rwe.com on 24/07/09.

FGD - Waste Water characteristics

		Waste Water from FGD
Mass Flow Rates		
Total Flow	kg/hr	9000
H_2O	% wt	93.13
Solids	ppm wt	28460
$CaSO_4 * 2 H_2O$ solid	ppm wt	7300
$CaSO_3 * 0,5 H_2O$ solid	ppm wt	
$CaCO_3$ solid	ppm wt	110
$MgCO_3$ solid	ppm wt	200
CaO	ppm wt	
MgO	ppm wt	
$Ca(OH)_2$	ppm wt	
$Mg(OH)_2$	ppm wt	
CaF_2 solid	ppm wt	3870
Inerts from limestone	ppm wt	15720
Fly ash , solid	ppm wt	1260
Ions :	ppm wt	38420
Cl^-	ppm wt	28130
SO_4^{--}	ppm wt	1320
Ca^{++}	ppm wt	2180
K^+	ppm wt	
Mg^{++}	ppm wt	6790
Na^+	ppm wt	
NH_4^+	ppm wt	
$CaSO_4$ dissolved	ppm wt	1860
Solid - concentration	ppm wt	

Characteristics of Waste Water to be treated (SHELL gasification - effluent clarifier stream)		
Parameter	**Unit**	**Quantity/Value**
Flow rate	m^3/d	411
Temperature	°C	50
Pressure minimal	MPag	0.35
pH	-	6.5 – 7.5
TIC	mg/l	30
TOC	mg/l	125
TSS	mg/l	100
COD	mg/l	300
BOD	mg/l	200
CN^- -free	mg/l	20
CN^- -complex	mg/l	25
SCN	mg/l	5
Cl^-	mg/l	4700
NH3/$NH4^+$	mg/l	100
Sulfides-total	mg/l	10
Trace elements		
Br^-	mg/l	6
F^-	mg/l	500
B	mg/l	5
Se^{2-}/H_2Se	mg/l	30
SO_4^{2-}	mg/l	50
Na^+	mg/l	2500
K^+	mg/l	10
Ca^{2+}	mg/l	400
Mg^{2+}	mg/l	40
Fe	mg/l	50
As	mg/l	0.1
Ba	mg/l	0.4
Co	mg/l	0.1
Cd	mg/l	0.01
Cr	mg/l	1
Cu	mg/l	0.02
Hg	mg/l	0.003
Mn	mg/l	0.03
Mo	mg/l	0.4
Ni	mg/l	0.5
P	mg/l	1
Pb	mg/l	0.1
U	mg/l	0.3
V	mg/l	0.05
Zn	mg/l	0.02

1.4 State of art technology in reducing water consumption in different power plants

1.4.1 All power plants

This paragraph presents an overview of the technologies that may be used for reducing the water consumption in all the types of Power Plants examined in the present study. The following analyses will primarily focus the effect of the technologies upon water consumption/generation/reutilization. Main pros and cons of each technology are listed on a qualitative basis.

1.4.1.1 Cooling Water System design

Cooling water is needed primarily for condensation of steam in the condensers of steam turbines, in the Air Separation Units (ASU, only for IGCC and oxycombustion cases) and in the CO_2 compression and drying unit, if any. Further cooling water is needed for heat exchangers in all the other process units.
Two types of Cooling Water systems have been considered in the studies taken as reference for the present study: once through system and open type recirculating system (Cooling Towers).

1) In the once through system, sea water is pumped from the sea, directly used in the heat exchangers and then discharged back to sea.
This system has the advantage of using a "free" coolant medium and not to generate a real stream of waste water, since actually sea water is returned to the sea without any significant change in composition, but only few Celsius degrees warmer. Anyway, this system allows only a reduced water temperature increment in cooling water, in order to minimize thermal pollution of the sea. Furthermore, the once through system with sea water can be installed only if the Power Plant is built at a short distance from the sea to limit the investment cost (piping, pumps, intake and outfall) and the electric power consumption. Another disadvantage of sea water cooling is an increment of cost of heat exchangers, since they are to be manufactured in Titanium or special alloys in order to resist against sea water corrosiveness.
The once through cooling system assure the higher performance in terms of Power Output as it allows the lower condensing pressure and therefore the higher expansion in the steam turbine.

2) In the open type recirculating system, the water is cooled by evaporation, exposing its surface to air and then returned to users. For allowing the water evaporation, cooling towers are used which may be of the following types: natural draught, induced mechanical draught or forced mechanical draft. As ambient air passes through a flow of warm water, evaporation occurs taking air to saturation

conditions, lowering the temperature of the water to the wet bulb air temperature, which is lower than the ambient dry bulb air temperature. The difference between dry and wet bulb air temperature depends on the humidity of the ambient air. Therefore the Cooling Towers are more effective with dry climates when the difference between the dry and the wet bulb temperature is higher. Wet cooling towers (also called evaporative cooling towers) require a significant amount of make-up water for compensating losses for evaporation, wind/drift losses and blowdown. This water blowdown is required to avoid an excessive concentration of salts in the circulating water due to pure water that evaporates during the cooling process and that is released to atmosphere. Another disadvantage of the wet cooling towers is that the moist lost for evaporation generates a plume on top of the cooling towers with consequent visual impact.

The differential temperature of the cooling water across the cooling towers can be significantly higher (approx 60-70%) than the one allowed in once through system. Therefore the cooling water flowrate, and the associated investment (heat exchangers, pumps, etc) and operating costs (pump electrical consumption), needed for the steam condenser and the internal users can be significantly reduced.

With respect to the once through cooling system, the Cooling Towers assure lower performance as the cold water is provided at a temperature that depends on ambient air humidity, but is generally higher than the sea water. The efficiency reduction related to the higher cold water temperature is around 0.5-1%.

From the point of view of investment costs, the once through system and open type recirculating system (Cooling Towers) are generally comparable. In fact, the cost of sea water intake, the connection between the intake and the plant and the higher cooling water flowrate generally compensate the higher cost of the Cooling Towers. In case the sea water intake is significantly distant from the plant, the impact of the investment cost of the pipeline can make the once through system more expensive than the Cooling Towers.

In order to reduce the amount of water drawn from the sea or river with respect to the solutions described above, the following two alternatives can be followed:

Alternative 1) An alternative to the once through system with sea water and to the open type recirculating system with wet cooling towers is the <u>open type recirculating system with hybrid cooling towers</u> (also called "wet/dry cooling towers"), which allows reducing water consumptions. Hybrid cooling towers combine finned tube heat exchangers (dry sections) and conventional evaporative cooling (wet sections). There exists many configurations of hybrid cooling towers. In a typical configuration, the ambient air flows in parallel through the dry section and through the wet section, whereas the hot water is cooled down to the required discharge temperature as it passes in series first through the dry section and then through the wet section of the tower. The low-humidity warm air stream from the dry system is mixed with the moist warm air, leaving the tower at humidity levels sufficiently low to prevent the formation of visible plumes. The wet and dry components can be used separately or simultaneously in different proportions for cooling the water down to the required tempearture, saving water and controlling the plume formation. At low ambient temperatures, the hybrid cooling tower can even be operated as a dry cooling tower, by using only the dry sections and completely by-passing the wet sections. In this way the maximum water saving is achieved, as the system is operated as a close type recirculating system (conventional Air Cooling system).

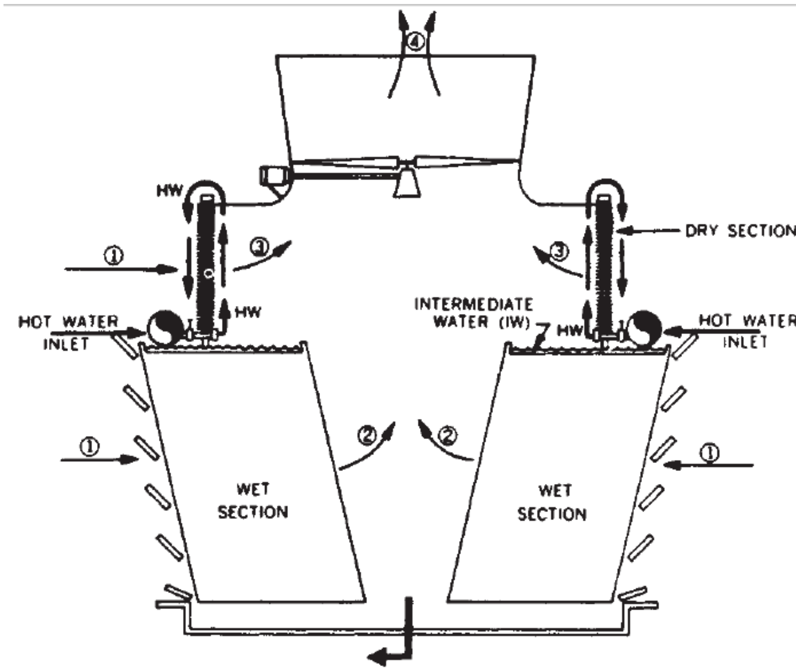
In general, compared with the wet cooling towers, the hydrid cooling towers consume less make-up water, have higher investment and operating costs and have lower performance (i.e.: the cooling water is provided at higher temperature and therefore the temperature of the steam condensate downsteam of the steam turbine and as a consequence the steam turbine discharge pressure are higher).
The ratio between the duty discharged in the wet and in the dry sections significantly affects design, performance and costs of the hybrid cooling towers, as follows:

- the higher is the ratio between duty exchanged in dry and wet section, the lower is the make-up water consumption;
- the higher is the ratio between duty exchanged in dry and wet section, the higher is the overall investment and operating cost;
- the higher is the ratio between duty exchanged in dry and wet section, the higher is the temperature of the cold water provided and the steam turbine discharge pressure.

In the following figure, a sketch of a typical hybrid cooling tower as described above is shown. Numbers 1 in the figure indicate the cold ambient air inlet, numbers 2 indicate the moist warm air from the wet sections, numbers 3 indicate the dry warm air stream from the dry system and number 4 indicates the mixture of wet and dry components going out from the cooling tower.

A “series path” air flow arrangement, in which dry coil sections are located before or after the wet sections, can also be used. However, such configuration has the disadvantage of water impingement, which could result in coil scaling and restricted air flow.

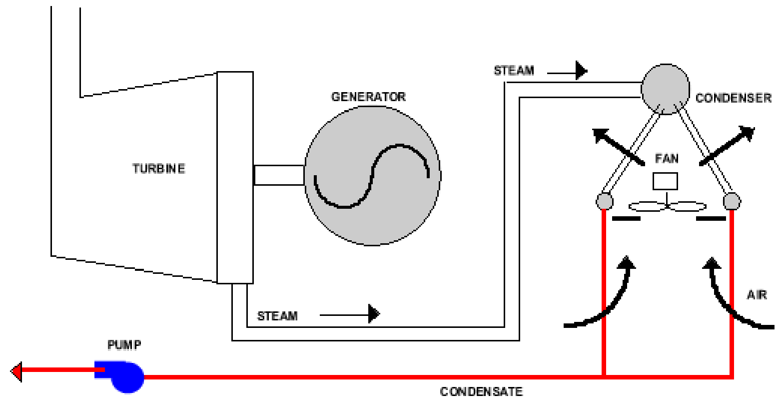
The hybrid cooling towers present the drawback of a more complicated design and a more expensive investment cost, when compared with a traditional wet cooling tower.



Alternative 2) A further alternative to the once through system with sea water and to the open type recirculating system with wet cooling towers is dry cooling: the heat transfer is achieved by convection, not by evaporation as in the wet cooling systems, and the performance depends upon the ambient air dry bulb temperature, instead of depending upon the wet bulb temperature as in the wet cooling towers. There are two types of dry cooling: direct and indirect.

In the direct dry cooling system, the turbine exhaust steam is piped directly to the air-cooled, finned tube, condenser. The finned tubes are usually arranged in the form of an 'A' frame or delta over a forced draught fan to reduce the land area. The steam trunk main has a large diameter and is as short as possible to reduce pressure losses, so that the cooling banks are usually as close as possible to the turbine.
With respect to the once through cooling system, the direct dry cooling system has higher investment costs and lower performance. In fact, the condensing pressure that can be achieved in the air cooling system is much higher than with the water cooled once through condenser. The efficiency reduction related to the higher condensing pressure is around 1.5-2%.

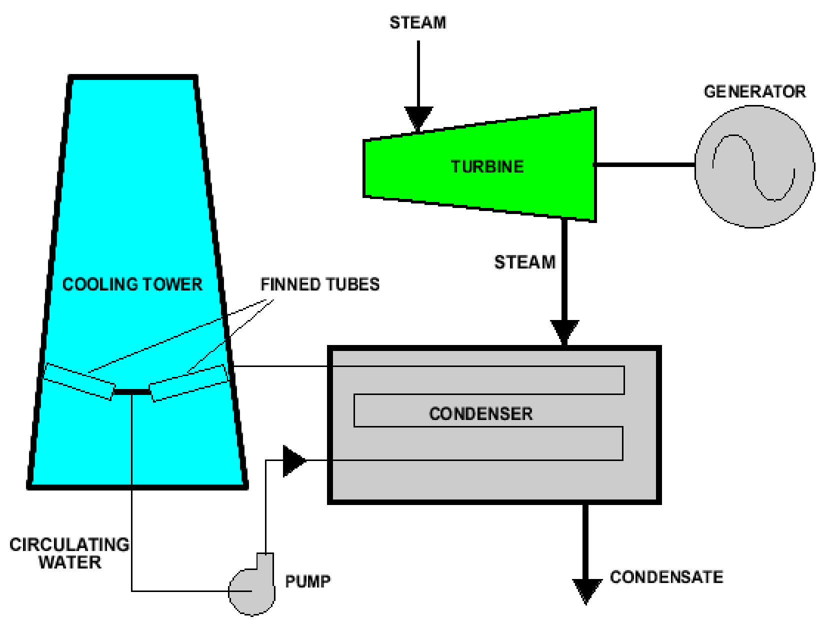
A sketch drawing of the direct dry cooling system configuration is reported here below:



DIRECT AIR-COOLED SYSTEM

Indirect dry cooling systems have a condenser and turbine exhaust system as for wet systems, with the circulating water being passed through finned tubes in a cooling tower (either natural draught or forced draught type). The water pipework allows the towers to be sited away from the station.

A sketch of the indirect dry cooling system configuration is reported here below:



INDIRECT DRY-COOLING SYSTEM

With respect to the direct dry cooling system, the indirect dry cooling system has higher investment costs and lower performance, due to the presence of an intermediate cooling medium (cooling water) and relevant exchange surfaces between ambient air and condensing steam from Steam Turbine. The condensing pressure that can be achieved in the Steam Condenser is much higher than with the water cooled once through condenser and higher than with the direct dry-cooling system. Compared with the Power Plant with once through cooling system, the efficiency reduction related to the higher condensing pressure is around 2-3%.

Some of the advantages of the dry cooling systems are that they do not require make-up water, nor water treatments, and they do not generate plumes and blowdown water disposal issues, as associated with wet cooling.
On the other hand, the steam condensing pressures and temperatures of a dry cooled unit are usually significantly higher than in a wet cooled unit and, as a consequence, the steam turbine efficiency is penalized (as an example, consider that in a typical summer afternoon in South Europe, when the air dry bulb temperature may be as high as 30 - 40°C, the air wet bulb temperature may still be around 20°C). Furthermore, since dry cooling is not as effective as wet cooling, the dry cooling towers have to be larger to achieve the comparable heat rejection and the power required to operate the air fans of these systems may be several times that required for wet towers.

The following Table 1.4-1 summarizes the expected typical impact of the above-described cooling systems on the Power Plants efficiency:

Table 1.4-1: Cooling system impact on plant efficiency

Type of cooling system	Indicative efficiency loss
Once through with sea water	Reference case
Open type recirculating with Cooling Towers	0.5-1%
Open type recirculating with Hybrid Cooling Towers	0.5-2.5 (1)
Direct dry cooling	1.5-2%
Indirect dry cooling	2-3%

Note 1: The efficiency reduction may range from the reduction typical of an “Open type recirculating system with Cooling Towers” to the reduction typical of a “Direct dry cooling system”, depending upon how the system is operated.

1.4.1.2 Water recovery from Lignite Drying

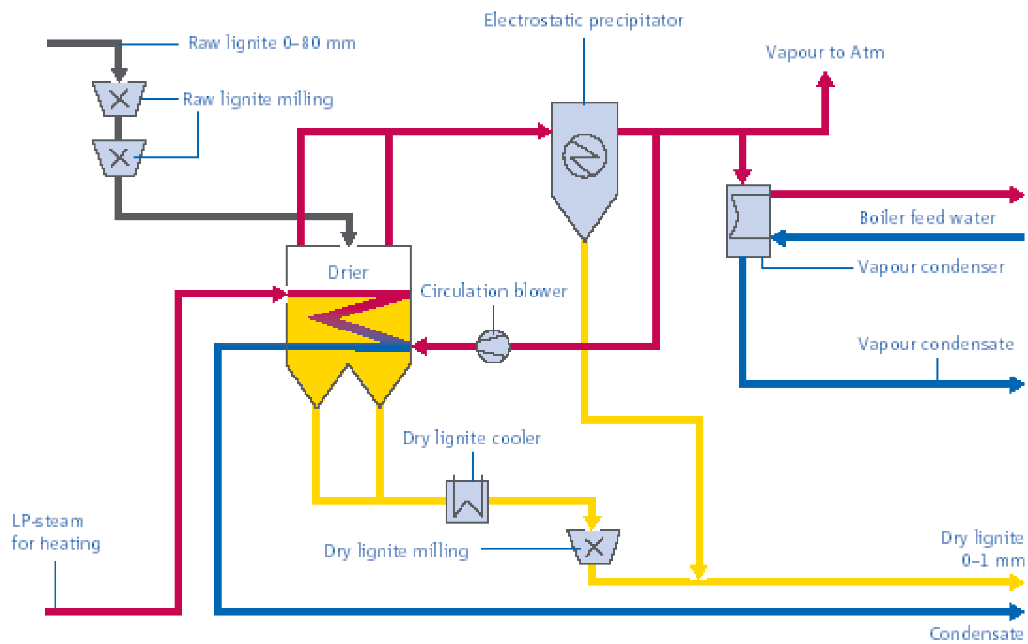
Significant amount of water may be recovered from the process of coal drying. Such process may sometimes be used when the feed is bituminous coal (for example, in the present study, in the case 5.01 Shell IGCC, the bituminous coal is dried for lowering its moisture from 9.5 to 5%wt), but it's required whenever the power plant is fed by lignite. Indeed, run-of-mine lignite is characterized by high moisture contents, compared to the high rank bituminous coals. In the lignite selected as the basis for carrying out the IEA study report 2006/1 the moisture content is 50.7 %wt, whereas in the bituminous coal selected as the basis for carrying out the IEA study (PH4/33) it is 9.5 %wt. A lignite drying process is needed, since the efficiency of a power generation plant is enhanced by reducing the moisture content in the feed stream.
The process alternatives for coal drying are:

- Direct drying with combustion flue gases;
- Indirect drying;
- Indirect drying proposed by RWE.

Direct drying with combustion flue gases would envisage a bubbling bed of coal, through which the flue gas is pushed. The expected pressure drop of such a system would be very high and consume substantial energy. Furthermore, a significant entrainment of coal fines into the flue gas is expected and it appears difficult to keep under control the drying temperature for preventing loss of volatiles. For these reasons the indirect drying of the lignite is the most promising technology.

The indirect drying process involves the use of a bubbling fluidised bed of lignite. Heat energy to evaporate moisture is supplied by circulating hot water, which preheat air, fed to the bubbling bed and also supply additional heat to the bed by a coil submerged in the bed. The hot water is heated to about 85°C to prevent loss of volatiles (CO, H_2, CH_4 and light hydrocarbons) contained in the lignite. Hot air carries away part of the coal moisture. Before discharge to the atmosphere the warm and humid air is passed through bag filters to stop entrained coal powder. Passing through a cooler the humidity may be condensed and recovered. Since water is to be condensed from an air stream (i.e. water vapour pressure is relatively low), the cooler will operate at low temperatures, requiring a significant flowrate of cooling water. Moreover, the flowrate of the gaseous stream to be cooled and partially condensed (air + steam) is significant, having a strong impact on exchanger surface and therefore on investment cost.

The indirect drying process proposed by RWE is also based on a bubbling bed of fine grain lignite. The energy required for drying is supplied via heat exchangers that are integrated in the fluidised bed drier and heated with steam. Drying takes place in an almost pure steam stream, which is slightly superheated. At constant pressure, equilibrium is reached between the steam temperature and the residual moisture of the dried lignite. By controlling the fluidised bed temperature, the moisture can be adjusted at the desired value. Compared with the previous processes, lignite drying in a steam atmosphere has the advantage that the evaporated coal water can be condensed isothermally and hence utilized in an energetically efficient way. For example, vapour may be condensed by preheating a stream of boiler feed water in the power plant, as shown in the following picture. Moreover, due to the absence of air in the gaseous stream from the dryer, the size and investment cost of the vapour condenser are reduced.



1.4.1.3 Water recovery from Flue Gas (Direct Contact Cooler)

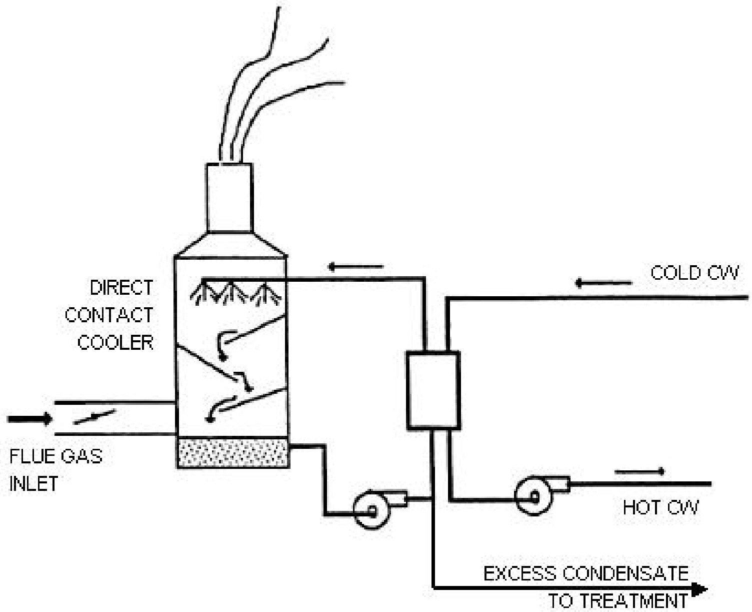
In the Power Plants considered in the present study, the combustion gas produced by the Gas Turbine or the Furnace passes through the various sections of the Heat Recovery Steam Generator or the Boiler, exchanging sensible heat by preheating and evaporating water or superheating steam, and it is finally sent to the stack to be released to atmosphere at a temperature greater than 120°C. No water condensation has occurred yet at this temperature, so all the water generated in the combustion is relived to the atmosphere. The condensation of the water contained in the flue gases is normally avoided as it can cause problems of acid condensate.

In order to reduce the amount of raw water consumed by the Power Plant, an alternative could be the condensation and recovery of the steam contained in the exhaust flue gases at stack.
Most of the water vapour condenses at a temperature between 50°C and 30°C.

For reaching such a low temperatures with a cooling water heat exchanger, it would be necessary to utilize a high flowrate of cooling water and to install a large exchange area, due to the reduced temperature approach. The use of air cooler heat exchangers may require large exchanging surfaces, due to the high volumetric rate of the flue gas and the reduced temperature approach and may not be always sufficient to reduce the flue gas to condensation temperature, for example during the summer season, when ambient air temperature is high.
Thus, the use of direct contact heat exchangers may be investigated. In a direct contact cooler, heat is transferred between the stream of flue gas and a stream of water, without an intermediate wall as typical of other heat exchangers. The direct contact cooler is very efficient, since both the sensible and latent heat is transferred and there are no surfaces to be fouled. The heat exchanger is a vertical column in which the two streams move counter currently: the flue gases enter at the bottom and water is sprayed at the top. The column may be void inside, or for increasing the intimate contact between gas and liquid, either trays or packed beds may be installed. The advantage of installing trays or packed beds is that the flue gas and water streams, going out the column, may really approach the thermodynamic equilibrium conditions (which means producing more condensate), but with the drawback of increasing the flue gas pressure drops. Due to the additional pressure drops in the direct contact cooler, an external fan shall be provided upstream the scrubber tower. As an alternative, in the boilers, the head of the ID fan upstream can be increased properly.
The water circuit includes pumps for disposing of the excess of condensed water from the column bottom to the water treatment unit (or to another destination, depending upon water quality and use) and recycling part of the water to the spray nozzles at the top of the column, passing through a cooling water heat exchanger (the use of an aircooler may even be investigated).

In the oxyfuel cases, the DCC can be fed with alkaline water (by means of dosing a controlled amount of NaOH) in order to capture in the scrubber washing part of the SOx in the form of Na_2SO_3.

The following Figure shows a scheme of direct contact flue gas condensing system.



1.4.1.4 Rain water re-utilization

The possibility of collecting and treating rainy water fallen inside the Power Plant battery limit may be studied.
In general, two possible destinations for the rainy water may be envisaged:
- Not Contaminated Water Treatment. Rainy water which is only slightly polluted with hydrocarbons and suspended solids and uncontaminated with chemical products or sanitary effluent (for example: water from roads, building roofs, parking areas, clean process areas, etc) is collected into a dedicated basin and sent to this treatment. Such "not contaminated" water may be treated by filtration for removing the suspended solids and floatation for separating the hydrocarbons.
- Contaminated Water Treatment. Rain water from the Process units, where the risk of contamination with solids, hydrocarbons and chemicals is high, is collected into a dedicated basin and sent to this treatment, which includes more sections than the previous "Not Contaminated Water Treatment" for covering the wider variety of pollutants potentially present. Generally, is the level of pollutants is significant, the contaminated rainy water can be sent to the Waste Water Treatment.

The treated water from the two treatment section above mentioned, has the same quality of the water discharged by the Waste Water Treatment section and therefore can be discharged to the receiver body or reused as raw water.

1.4.1.5 Reduction of water loss from waste water treatment plant

In the paragraph 1.4 various power plants are studied and for each plant a summary table reports the water loss generated by the waste water treatment.
The results of the study show that for the reduction of pollutants there is a loss of water less than 0.5%, due to the produced chemical and biological sludge.
When desalination unit is foreseen to comply with discharge limit to river for chlorides and sulphates (USC PC with lignite and CO_2 capture, USC PC with oxyfuel technology and CO_2 capture, Shell IGCC with lignite and CO_2 capture), the loss of water is of about 33%. This increase is due to the rejected water from ultrafiltration and reverse osmosis.
Rejected water contains a high concentration of salts. The flowrate depends on salts concentration in the water to be treated.

It is possible to reduce this loss by adding a concentration unit for the rejected water downstream of the tertiary treatment.
In this case the goal of zero discharge can be achieved.

The concentration process consists of the main following steps:

- Heating of the rejected water;
- Evaporation of water and concentration of the stream to produce salts precipitation;
- Final dewatering (crystallization) of concentrated chemical sludge.

Concentration unit can achieves a flowrate recovery up to 99%, depending on inlet stream salts concentration. Salts, which are separated from water, can be sent to disposal with a very low water content (about the 15% by weight).

However, the evaporation and crystallization technology could have important disadvantages:

- an important additional energy consumption:
    - steam requested for water heating;
    - power requested for additional items;
- equipment made of special materials because of high temperatures and high salts concentration;
- high investment cost.

As several technologies of evaporators are in commerce, additional cost and utilities requested greatly depend on applicable type of evaporator, which depends on the flowrate to be treated.

1.4.2 Ultra Super Critical PC Boiler (USC PC)

In order to reduce the raw water consumption in the USC PC Boiler, all the general technologies mentioned in the previous paragraph 1.3.1 can be applied.

In the Boilers fired by Lignite, the drying of the feedstock is necessary for lowering its moisture content from 50.7% down to about 30%, making available a significant amount of water.

The cooling system of the USC PC Plants analysed in present study are based on once through cooling water or cooling towers, depending on plant location. In order to reduce the water consumption, both alternative solutions (described in paragraph 1.3.1.1) can be applied, depending on the degree of raw water that shall be saved and the loss of efficiency that can be accepted.

Finally, recovery of steam in flue gases and collection of rainy water can be applied, if needed.

Generally, with the exception of the cooling water system, the consumption of raw water in USC PC is not significant. Therefore, not all the above-mentioned technologies to reduce water consumption are needed.
The greater effort shall be focused on cooling water system, where the significant consumption of raw/cooling water can be minimised or completely avoided.

1.4.2.1 Dry bottom ash removal

The method adopted in the past to remove bottom ash was the water-impounded hopper type. This water-impounded hopper system receives, quenches, stores crushes and removes bottom ash using hydraulic means. This type of technology collects ash over a predetermined period before discharging on a batch basis.
More modern systems adopt a continuous removal philosophy. Essentially, a heavy duty chain conveyor submerged in a water trough below the furnace which quenches hot ashes as they fall from the combustion chamber and removes the wet ash continuously on a de-watering slope before discharge into mechanical conveyors or directly to storage silos.
The major advantages of this second system, with respect to water-impounded hopper systems are:

- Reduced water usage (no transport water required)
- Reduced power consumption (by eliminating the high pressure sluicing water required by jet pumps)
- Reduced complexity of de-watering bins when used
- Reduced operational and maintenance costs

Actually, a totally dry bottom ash system, air cooled, is available. The system adopts a steelplate conveyor using a high strength chain allowing the increase of conveyor width and length. The air cooling surface is therefore higher and the need of a secondary or post water cooling is eliminated.

1.4.3 Oxyfuel Ultra Super Critical PC Boiler (Oxyfuel USC PC)

The same technologies mentioned for the USC PC also apply to the Oxyfuel USC PC.

Usually, Activated Carbon Injection (ACI) is one method of removing mercury from gas streams. This occurs upstream of the particulate control device which consists of an electrostatic precipitator (ESP) and/or a fabric filter (FF) where mercury absorbed on the active carbon injected is captured.
As an alternative, using a technology developed to remove mercury from natural gas streams, mercury can be removed from the 30 bar compressed cycle CO_2 stream by adsorption on a charcoal impregnated with sulphur.
In this second alternative, part of the mercury contained in the flue gases can partially condense in the upstream direct contact cooler and flow to the WWT plant. The quantity of mercury that condenses in the DCC may vary significantly depending on the amount and quality of fly ash and unburned carbon. In fact unburned carbon in fly ash absorbs the mercury as the Activated Carbon and they are captured in the downstream filters (ESP / FF).

In addition, considering that the Air Separation Unit produces a significant excess of nitrogen at relatively low temperature (about 20°C or less), which is currently foreseen to be vented to the atmosphere, the possibility of using such cold nitrogen in the Steam Turbine Condenser as coolant might be investigated to obtain a reduction of the required cooling water flowrate.
Based on preliminary information received from an ASU's Licensor, the maximum amount of liquid nitrogen that can be produced in the unit, without significantly penalizing the performance and cost of the plant, is not greater than the amount of oxygen produced, on mass basis. In case of liquid nitrogen production, the expected power requirement of the unit increases by about 0.6 kW/Nm^3 of produced nitrogen.
In order to use the cold liquid nitrogen as cooling medium for the steam turbine condenser, an indirect circuit shall be considered where the liquid nitrogen evaporating cools the cooling water fed in closed circuit to the steam turbine condenser.
The use of nitrogen from ASU as cooling medium is a theoretical possibility that need further detailed investigation in advanced phases of the project if there is the interest of the ASU licensor to cooperate.

1.4.4 Integrated Gasification Combined Cycle (IGCC)

In order to reduce the raw water consumption in the IGCC, all the general technologies mentioned in previous paragraph 1.3.1 can be applied.

In the IGCC fed by Lignite, the drying of the feedstock is necessary for lowering its moisture from 50.7% down to about 5%, making available a significant amount of water. The Shell IGCC needs feedstock drying also when fed with bituminous coal: in this case, moisture content is reduced from 9.5% to about 5% and, as a consequence, the water made available by this process is lower, but it can be easily recovered.

The cooling system of the IGCC Plants analysed in present study is based on once through cooling water or cooling towers, depending on plant location. In order to reduce the water consumption, both alternative solutions described in paragraph 1.3.1.1 can be applied, depending on the degree of raw water that shall be saved and the loss of efficiency accepted.

Finally, recovery of steam in flue gases and collection of rainy water can be applied, if needed.

Generally, the consumption of raw water in IGCC can be significant, especially in the cases where CO_2 capture is considered. Therefore, many of the above mentioned technologies to reduce water consumption are required.
Greater effort shall be focused on cooling water system, where the significant consumption of raw/cooling water can be minimised or completely avoided.
A significant consumption of raw water is also needed for process reasons (mainly in gasification unit and demi plant) and therefore, with the aim of minimising the raw water consumption, the general alternatives described shall be considered.

Moreover, in the following paragraph different process alternatives with the scope of reducing water consumption are described.

1.4.4.1 Water saving in CO shift reaction

In the gasification process, when the CO_2 capture is considered, the CO shift reaction is required for converting carbon monoxide and steam to hydrogen and carbon dioxide (the reaction is: $CO + H_2O \leftrightarrow H_2 + CO_2$, exothermic). As part of a CO_2 capture strategy it's required the previous reaction to move towards hydrogen and CO_2 production.
The process requires an excess of steam in the syngas in order to keep the reaction active. The syngas generated in the Shell Gasification does not have water content enough to satisfy the excess of water required by the CO shift catalyst vendor and

therefore, raw syngas from wet scrubbing in the Gasification Unit is first mixed with a significant amount of MP steam to achieve the required dry gas to steam ratio.
Raw gas is then heated in a feed / effluent heat exchanger by the hot effluent from the First Shift Reactor and successively enters the First Shift Reactor, where CO is shifted to H_2 and CO_2. The exothermic shift reaction brings the syngas temperature up to 450°C. The hot shifted syngas outlet from the shift reactor is cooled in a series of heat exchangers. Process condensate separated in Separator Drums is recycled back to the Sour Water Stripper of the Gasification Island.

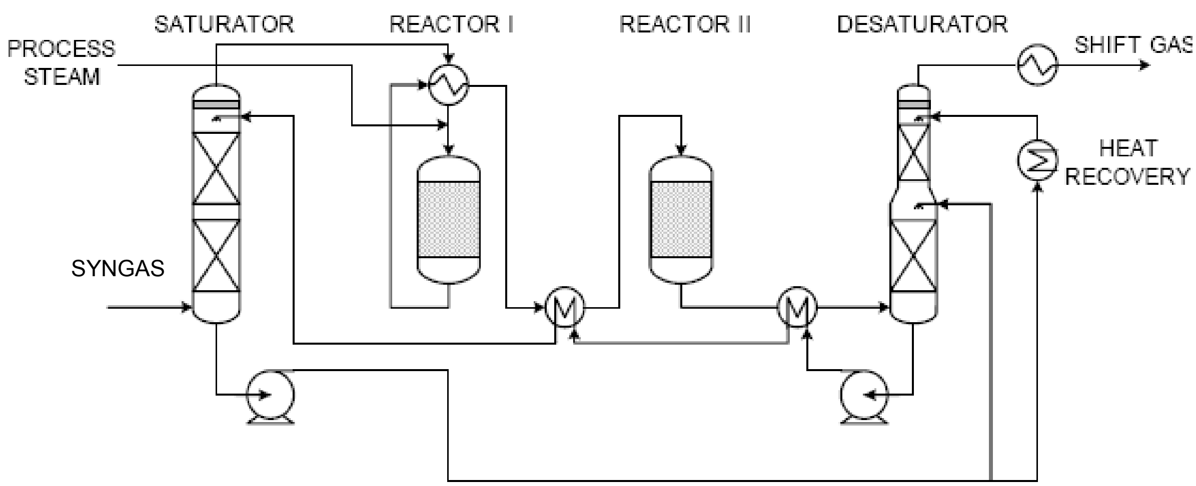
In the IEA GHG Report Number PH4/19 (May 2003) used as reference study for IGCC based on bituminous coal, when CO shift is considered for the cases with CO_2 capture, the amount of steam added to the syngas is controlled in order to ensure a conservative H_2O/CO ratio at the shift reactor inlet. The steam requirement at the catalyst bed inlet is fixed in order to have a minimum steam to CO molar ratio of about 2. This corresponds to a water/dry gas ratio at shift reactor outlet, of about 0.4.
These ratios can be lowered by using different sour shift catalysts that can get the same performance with lower amount of excess water. In this case, the minimum required water/dry gas ratio at shift reactor outlet is 0.3, resulting in approximately 15% of water saved.

In the Lignite IGCC cases with CO_2 capture analyzed in IEA GHG Report Number 2006/1 (January 2006), the water/dry gas ratio at shift reactor outlet is already 0.3 in accordance to the improved performance of the CO sour shift catalysts.

1.4.4.2 Raw syngas saturation

The steam addition for the CO shift reaction can be significantly reduced to about 50% of the typical amount required with the above-described scheme, by the use of a saturator-desaturator system.
In this scheme, syngas from gasification section enters the Saturator, where it is countercurrently contacted with hot water flowing down the column. Syngas leaves the top of the Saturator saturated with water. Syngas is then superheated in a feed / effluent heat exchanger by the First Shift Reactor outlet gas before being mixed with additional process steam. The reaction takes place in two consecutive reactors loaded with shift catalyst with the intermediate cooling by the incoming syngas and the circulating water. The water is thereby heated to about 240°C before entering the saturator. The shifted syngas leaving the second stage still contains all the unconverted steam, which is condensed in the desaturator column, or direct contact cooler. The shifted syngas leaves the top of the desaturator at about 60°C. Water leaving the bottom of the saturator has a temperature of about 140°C. Part of this water is cooled before being used as feed water to the desaturator and the heat

generated in this step is available for boiler feed water or demineralised water preheat.
The following Figure shows a sketch of the system here above described.



Against the cost for the two columns (Saturator and Desaturator) and the pumps, the saturator-desaturator system allows water saving compared to the previously described system, since it only requires the addition of the steam necessary for the reaction, whereas the excess of water (still required for moving the shift reaction towards the products) is provided by the internal water recycle.

1.4.4.3 Use of nitrogen in place of steam for syngas dilution purposes

In general, in the IGCC Power Plants, the Air Separation Unit (ASU) is designed for producing the oxygen required by the Gasification section and by the Sulphur Recovery Unit in the Claus section and eventually a small stream of excess oxygen to fill the Oxygen storage, if present. Nitrogen is obtained as a by-product and can be used in the gas turbines of the combined cycle for NO_x control and power augmentation, as in the GEE technology, or, as in the Shell technology, used mainly in the pneumatic transport and pressurisation of dried pulverized coal to the gasifier with the nitrogen excess routed to the gas turbines for NO_x control and power augmentation.
In the Shell IGCC Power Plant without CO_2 capture, analysed in the present study, the nitrogen production from ASU is enough for coal pneumatic transport, but not enough for satisfying the gas turbines needs. For compensating the lack of inert gas, water is added to the available stream of nitrogen to the gas turbines (in the specific case, more than 110 t/h of Boiler Feed Water are used). Being injected into the process side, this water is to be considered as a net loss (unless a partial condensation of the flue gases is foreseen), with the consequences of increasing the raw water request and requiring an overdesign of the Demiwater Plant. In the case

of lack of nitrogen, the water injection in the gas turbine is necessary in order to meet the NOx emission limits and therefore it is not possible to avoid the water consumption.

It could be theoretically possible designing the ASU for fulfilling the nitrogen requirements. In exchange of reduced plant raw water consumption, the ASU investment and operating costs will significantly increase. Moreover, it should be considered that it is generated an excess of oxygen, which could only be used discontinuously to fill an oxygen storage tank, if present. Due to the significant increase of costs and the presence of an excess of oxygen, this solution is not feasible unless there was the possibility to sell the oxygen to an external user in a profitably manner.

1.4.4.4 Recovery of water from slag from Gasification Island

Both Shell and GE gasification technologies produce slags, i.e. solid effluents containing a certain amount of water. Theoretically, water may be recovered from these slags through evaporation, followed by vapor condensation.
Shell gasification produces slag with low water content (equal to about 10% wt). Considering that the total amount of absorbed water is less than 4 m^3/h (for a 750 MWe nominal power output IGCC) and that only a portion may be easily (from a technical and economical point of view) recovered, it appears difficult that water recovery from slag from Shell gasification may be justified.
On the contrary, water in slag from GE Gasification Island is more concentrated and is present in greater quantity. In particular, fine slag from Filter cake contains 70% wt of water (in absolute values, total absorbed water is about 20 m^3/h for a 750 MWe nominal power output IGCC), whereas coarse slag from Slag Screen contains 50% wt of water (in absolute values, total absorbed water is about 36 m^3/h for a 750 MWe nominal power output IGCC). At current, it is foreseen that both slag product types may be sold to be commercially used as major components in concrete mixtures to make roads, pads or storage bins. From a theoretical point of view it's possible to recover at least a portion of this water through evaporation, followed by vapor condensation. A deeper investigation should be made to evaluate which are the technologies currently available that can cope with the physical properties and the flowrates of these slags.

1.4.5 Natural Gas Combined Cycle

In order to reduce the raw water consumption in the Natural Gas Combined Cycle, all the general technologies mentioned in previous section 1.3.1 can be applied.

The cooling system of the Natural Gas Combined Cycle analysed in present study are all based on once through cooling water system. In order to reduce the water consumption, both solutions described in paragraph 1.3.1.1 can be applied, depending on the degree of raw water that shall be saved.

Finally, recovery of steam in flue gases and collection of rainy water can be applied if needed.

Generally, with the exception of the cooling water system, the consumption of raw water in Natural Gas Combined Cycle is not significant. Therefore not all the above-mentioned technologies to reduce water consumption are needed.
The greater effort shall be focused on cooling water system where the significant consumption of raw/cooling water can be minimised or completely avoided.

1.5 Waste water treatment in different power plants

Purpose of this paragraph is:
- Defining the general basis of design and assumptions for this study;
- Showing the differences concerning pollutants load among power plants based on different technologies;
- Doing an overview on different waste water treatment plant configurations for each power plant technology, whose preliminary mass balances, focused on water discharge, are reported in paragraph 1.3;
- Estimating the percentages of treated water that can be reused in the power plant offsites with the waste water treatment technologies selected;
- Estimating the percentages of water that cannot be reused in the process (e.g. dewatered sludge);
- Estimating the water losses from wastewater treatment plant that could be retrieved with advanced and more expensive technologies when the goal of zero discharge has to be achieved (dry land location).

Detailed Mass balance and schemes are presented in attachment B1, B2…B7 at the end of this volume.

1.5.1 Basis of design and assumptions for waste water treatment plant

The waste water treatment plant for the power plants has to:
- reduce primarily pollutant load in waste water to meet the discharge limits of the surrounding environmental water bodies;
- produce suitable treated water for internal reuse in power plant.

In this study the waste water treatment plant is conceived to produce water that can be discharged to sea or to river, as shown in the Table 1.5-1. The destination of treated water is in accordance with the cooling medium available, i.e. either sea water or river water.

Table 1.5-1 summarizes the treated water receptor surface bodies considered for the different power plants. Reference is made to the power plant cases individuated in paragraph 1.3.

Table 1.5-1: Surface receptor water bodies

Power plant case	Description	Receptor water body
3.24	USC PC, lignite, with CO_2 capture	River
4.13	Oxyfuel, lignite, with CO_2 capture	River
5.01	Shell IGCC, bituminous coal, without CO_2 capture	Sea
5.02	Shell IGCC, bituminous coal, with CO_2 capture	Sea
5.04	Shell IGCC, lignite, with CO_2 capture	River
5.05	GE IGCC, bituminous coal, without CO_2 capture	Sea
5.06	GE IGCC, bituminous coal, with CO_2 capture	Sea

In agreement with IEA GHG, industrial wastewater discharge limits into surface water bodies of Italian law (DLgs 152/2006) are considered.
Discharge limits are recorded in the Table 1.5-2.

Table 1.5-2: Industrial wastewater discharge limits into surface water bodies

Analytical Parameter	Unit	Discharge limit into surface water bodies
Suspended Solids	mg/l	≤ 80 (1)
Petroleum Products (Hydrocarbons)	mg/l	≤ 5
BOD_5 as O_2	mg/l	≤ 40
COD as O_2	mg/l	≤ 160
pH	pH units	5.5-9.5
Chlorides	mg/l	≤ 1200 (10)
Sulphates	mg/l	≤ 1000 (2) (10)
Sulphides	mg/l	≤ 1 (3)
Ammonia Nitrogen	mg/l	≤ 15 (4)
Nitrates	mg/l	≤ 20 (5)
Nitrites	mg/l	≤ 0.6 (6)
Aluminium	mg/l	≤ 1
Iron	mg/l	≤ 2
Copper	mg/l	≤ 0.1
Zinc	mg/l	≤ 0.5
Manganese	mg/l	≤ 2
Nickel	mg/l	≤ 2
Chromium (6+)	mg/l	≤ 0.2
Total Chromium	mg/l	≤ 2
Arsenic	mg/l	≤ 0.5
Barium	mg/l	≤ 20
Boron	mg/l	≤ 2
Cadmium	mg/l	≤ 0.02
Mercury	mg/l	≤ 0.005
Lead	mg/l	≤ 0.2
Selenium	mg/l	≤ 0.03
Tin	mg/l	≤ 10
Total Cyanides	mg/l	≤ 0.5 (7)
Sulphites	mg/l	≤ 1 (8)
Fluorides	mg/l	≤ 6
Phosphorus	mg/l	≤ 10 (9)
NOTES:	1	Total Suspended Solids (TSS)
	2	Sulphates as SO_4^{--}
	3	Sulphides as H_2S
	4	Ammonia Nitrogen as NH_4^+
	5	Nitrate as N
	6	Nitrite as N
	7	Cyanides as CN^-
	8	Sulphites as SO_3^{--}
	9	Phosphorus as P
	10	Not applicable for sea discharge

"Clean" waste streams

In this study the waste water effluents, whose quality is already good enough for being discharged to a water receiver body, are segregated from the other waste waters and not fed to waste water treatment. Segregation can be carried out with a dedicated sewer system (by gravity or pumped lines). "Clean" streams are assumed to be either sent back to demineralization plant or discharged to the water receptor surface body, depending upon the power plant raw water requirements.
These "clean" streams have in some cases a low organic contamination (BOD or biological oxygen demand) and Total Suspended Solids (TSS) content. In case of feeding to demineralization plant, pretreatment should be foreseen (cartridge and activated carbons filters). As this section does not cause a loss of water, it will not affect the results of this study for clean streams.

It has to be highlighted that the temperature of clean streams can be not acceptable for discharge/reuse. In this case it is reasonable to cool the streams in the units where they are generated, before sending to the discharge/reuse.

Polluted waste streams (to be treated)

It is a project goal to utilize the treated waste water for power plant internal uses to the maximum extent. The treated water could be recycled to the demineralization plant in place of raw water, to reduce the fresh water consumption.
However, water for this internal reuse is required to have a higher quality than the treated wastewater, as regards some parameters. In particular, water needs to have low concentration of some pollutants; main parameters affecting demineralization plant operation in this study are as follows:

- COD/BOD: they are an undesirable contaminant, because, in presence of biomass, the growth of bacterial colonies in the circuit and into the ion exchange resins filters could be favoured.
- TSS: in an effluent stream from a wastewater treatment plant they are mainly bacteria flocks and may affect all the circuit and the filters. If the suspended solids concentration is high, it is possible to have deposits with consequent progressive obstruction of resins or membranes.
- Bacteria: they could be present in significant amount in a waste water treatment plant effluent, especially when a biological treatment section is foreseen. They can proliferate and obstruct resins or membranes.

The treated water from waste water treatment of each power plant involved in the study has a very different quality compared to the quality of treated water from other power plant, but they all meet the requirement for discharge into the receiver body.

Only a slip stream of the waste water treatment discharge (depending on the cases) is fed to the demineralized water unit as make up. Therefore, it appears more convenient, from an economical point of view, that the final water polishing is part of the demineralization plant.
Demineralization plant pretreatments are only mentioned here as alternative solutions to be used case by case.
The required pretreatments at demineralization plant for low salinity water coming from water treatment are mainly the following:

- removal of residual TSS with cartridge filters;
- removal of residual BOD/COD with activated carbons filters;
- disinfection, e.g. with UV, but also with chemicals (when not done in the waste water treatment plant).

It has to be highlighted that these technologies do not cause any water loss.
If the treated water has high salinity, reverse osmosis technology is foreseen at demineralization plant instead of the ion exchange resins normally considered, and ultrafiltration pretreatment should be installed instead of activated carbons filters. Reverse osmosis plant produces water reject with high salinity content.
The water loss depends on the salinity concentration reached in the concentrate.

In general, the choice between using the reverse osmosis technology or the ion exchange resins technology depends upon the water flowrate, the salts concentration and the environmental impact of the generated waste water. Detailed technical and economical considerations can be object of more specific studies.

Before discussing wastewater treatment plant for any proposed case of power plant, a brief summary of the main wastewater treatment sections, foreseen in this study, is presented.

Equalization section

The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed with mixer in order to make uniform the physical characteristics of the waste water to be fed to treatment (e.g. pollutants concentration, temperature, etc.).
Equalization section is normally designed in order to guarantee a hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

Chemical – physical treatment

From the equalization section the water is sent to the chemical-physical treatment for the removal of heavy metals, H_2S and cyanides.

This section consists of two basins in series, where chemicals are added for the chemical reactions and particles coagulation, followed by a sedimentation basin for the precipitated flocks separation and removal from water.
In particular, the first basin receiving waste water is a flash mixing treatment. In this basin the following chemicals are dosed:

- Sulfuric acid or caustic soda for pH adjustment. Chemicals dosage is done under pH control in order to maintain the pH at about 9.5. The basic ambient promotes the heavy metals oxidation, and improves the reaction of sulfides.
- Ferrous sulphate for the abatement of sulfides and cyanides. The dosage is done under flow control and promote the oxidation of H_2S to SO_4^{2-} and elementary sulfur. Plant air is insufflated through an air distributor in order to facilite the reaction between ferrous sulphate and sulfides.

From the flash-mixing basin the water flows by gravity into the flocculation basin, where polyelectrolyte is added and mixed to water in order to aggregate the chemical precipitated particles and facilitate the settling in the sedimentation basin.
Finally, in the sedimentation basin the chemical sludge is separated by gravity from water, and sent to the sludge treatment.

In some cases a secondary chemical-physical treatment is foreseen to reduce the high concentration of fluorides.
Calcium hydroxide is dosed under wastewater flow control to precipitate the fluorides as CaF_2, while the pH is maintained at 10.5.
The scheme of the secondary chemical-physical treatment is similar to the previous one. In this case no air insufflation is requested.

In the cases of study no Chromium is present. Nevertheless, being a dangerous pollutant whose the removal process differs from the ones described above depending on the form in water, Cr(VI) or Cr(III), a brief description is carried out.
Cr(III) is removed from water as $Cr(OH)_3$ by raising the pH of the solution to 8.5-9 in a chemical-physical treatment similar to the ones described above. The Cr(VI), instead, needs to be reduced to Cr(III) with bisulphite addition before being removed as $Cr(OH)_3$.

<u>Activated Sludge Process</u>

For industrial wastewater, the objective of the biological treatment is to remove or reduce the concentration of organic compounds. Biological treatment can be used also for ammonia and nitrates reduction in water (respectively nitrification and denitrification process).
The removal of carbonaceous organic matters in wastewater, usually measured as BOD (biological oxygen demand) or COD (chemical oxygen demand), and the stabilization of organic matter are accomplished biologically using a variety of microorganisms, principally bacteria.

The microorganisms are used to convert the dissolved carbonaceous organic matter, and ammonia and nitrates, if necessary, into various gases (CO_2, N_2) and into cell tissue. Since cell tissue has a specific gravity greater than water, the resulting cells can be removed from the treated liquid by gravity settling.

In order to guarantee adequate metabolic conditions, an external dosage of phosphorous, nitrogen or BOD in the correct ratio can be foreseen case by case to avoid the lack of nutrient for biological growth.

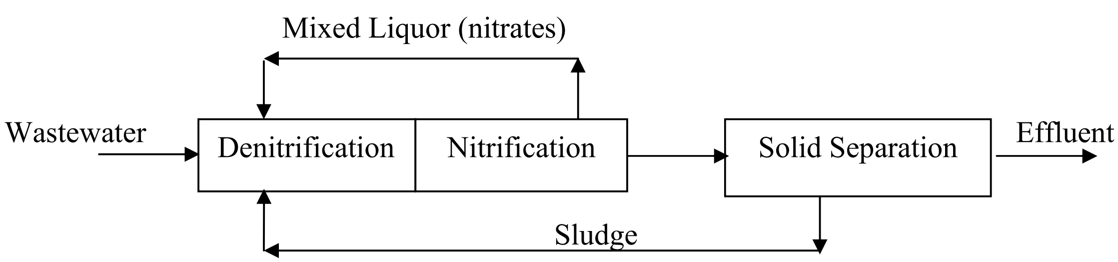
The biological treatments foreseen in this study are presented hereafter.

High load of nitrogen, as ammonia, with respect to the BOD load, requires a specific biological treatment with nitrification and de-nitrification steps. In the nitrification and de-nitrification process (refer to Figure 1.4-1), the removal of nitrogen is accomplished with bacteria in two conversion steps.
In the first step, ammonia is oxidized to nitrates, availing of the established conditions of low organic load (nitrification); in the second step, nitrates are reduced to elemental nitrogen by bacteria which obtain energy for growing-up from the conversion of nitrate to nitrogen using the nitrogen bound oxygen (denitrification), so this last process requires not aerated reactors and anoxic conditions:

First step: $NH_4^+ \rightarrow NO_2^- \rightarrow NO_3^-$

Second Step: $NO_3^- \rightarrow NO_2^- \rightarrow N_2 \uparrow$

Figure 1.5-1: nitro-denitro biological treatment

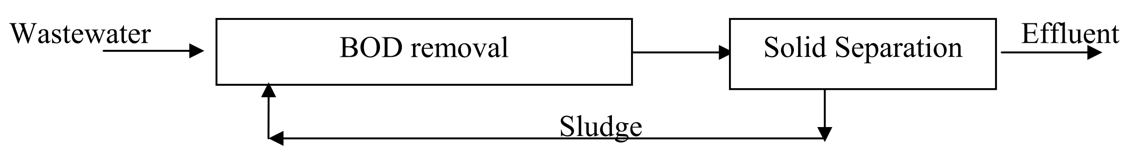


In the suspended-growth process, nitrification is achieved in the same reactors used for the treatment of carbonaceous organic matter (aerated nitrification basin). Autotrophic bacteria (Nitrosomonas and Nitrobacter) are responsible for nitrification, while heterotrophic bacteria remove BOD.
The specific growth rate of autotrophic bacteria is slower than for heterotrophic, so a greater Sludge Retention Time (SRT) is required with respect to the traditional biological reactor for removing BOD only. This implies greater biological reactors volumes.

In order to rise the denitrification process efficiency, and provide to the denitrification step the NO_3^- created in the nitrification basin, the water (mixed liquor) is recycled back, from the nitrification basin to the denitrification basin.
To allow the biological mass permanence into the biological process, settled biomass is recycled from solid separation to the front end of the biological treatment.

In case only the BOD concentration has to be reduced, denitrification and mixed liquor recycle are not needed, and in the aerated basin, where nitrification and BOD reduction took place together in the above description, only the BOD is removed.
The biological section plant for only BOD removal is shown in the Figure 1.4-2.

Figure 1.5-2: biological treatment for only BOD removal



When the load of organic matter (BOD) is low, aerated lagoons can be used. The process is similar to the plant with activated sludge process for BOD removal, without the biological sludge recycle.

When the organic load is very high, it can be opportune reducing a large amount of BOD with an anaerobic biological treatment. In this case the technical and economical advantages, in relation to aerobic treatment, are:
- lower amount of sludge produced to be sent to disposal;
- reactors volumes smaller than the ones requested with aerobic treatment;
- production of biogas (mainly methane, at about 60% concentration) that can be reused for the water heating;
- lower request of power.

Dual media filtration

Purpose of the filtration with sand filter is to remove the TSS concentration in water before sending wastewater to the ammonia stripper, or to the treatments which need a low TSS concentration.
Each sand filter undergoes periodic backwash. Backwash water is discharged where a TSS sedimentation section exists.
To enhance TSS removal, cartridge filters can be used.

Disinfection

The purpose of the disinfection system is to remove microorganisms before the discharge to water body receptor or to membranes treatments.
Many technologies are available: chlorine compounds, ozone and ultraviolet disinfection.

Ammonia stripping

The ammonia stripping is used to remove the ammonia from wastewater by injecting steam stream in a stripping column.
Heating of water is needed before entering the column. Also a pH rising with base addition is foreseen to transform NH_4^+ into NH_3.
After the ammonia stripping a cooling section is requested before feeding water to the following treatments.

Chemical sludge and biological sludge treatment sections

Aim of these sections is to dewater the chemical and biological sludges produced in the relevant physical chemical section and in the biological treatment section.
Sludge from settling has solids content of about 1-3 %wt.
Sludges are thickened, chemically conditioned and sent to the dewatering devices (centrifuge, belt press, etc.) for the separation of solids from water to produce a sludge with a solids content of about 20 %wt; this percentage allows the discharge of sludges to disposal.
As consequence of the dewatering, a large amount of the water contained into the sludge can be recycled to the treatment plant and it is not lost.

Tertiary treatment

To comply with discharge limits into rivers in case of high content of sulphates and chlorides in the treated water, a desalination treatment is needed after the "conventional" wastewater treatment sections described above.
The desalination step can consist of ion exchange resins or reverse osmosis. In general, when the total salinity is high (some thousands of ppmwt), the reverse osmosis is technically and economically preferable. However, it is not possible to make a general decision about the two technologies without considering case by case the flowrates involved, the salts concentrations and the environmental impact of the technology. As the aim of this task is to do a general overview of treatments, the reverse osmosis is chosen as tertiary treatment in relation to high salinity in the cases where it is applied. Detailed technical and economical considerations and evaluations could be object of more specific studies.

The tertiary treatment section of waste water treatment plant includes the following main steps, as summarized in Table 1.5-3:

Table 1.5-3: Main devices and application for reverse osmosis

Devices	Application	Operation
Cartridge filters	TSS removal for membrane protection	TSS removal from water
Ultrafiltration	Pretreatment of Reverse Osmosis	Separation of particles with dimension greater than 0.05 micron (colloids and organic substances – BOD)
Disinfection	Bacteria inhibition	Disinfection
Reverse Osmosis	Removal of salts from water	Separation of ion size particles

The ultrafiltration and the reverse osmosis are membranes technologies, so the products of filtration are:

- Low salinity filtered water;
- Rejected water, with high salts concentration.

In this study the osmosis efficiency in reducing salts from inlet water is considered of 90-95%.
As described, there is a water loss as salts concentrated water. Its amount depends on inlet salinity content and on numbers of stages of the osmosis. However, in this study a flowrate rejection (with respect to the inlet flowrate to the device) of 4% for ultrafiltration and of 30% for reverse osmosis is considered.

To avoid this loss of water, an evaporation step can be added to the tertiary treatment to evaporate the salty water and obtain solid salts and distilled water. This technology is expensive, but it could be justified when it is necessary to minimize water discharge. It is described in the paragraph 1.4.

1.5.2 Power plants without CO_2 capture

In this paragraph the results relevant to the cases of power plants without CO_2 capture, mentioned at paragraph 1.3, are summarized.

Waste water treatments block flow diagrams are shown as attachments to the present document and identified with the code of the relevant power plant cases.
Also preliminary global water mass balances are reported in the abovementioned attachments.
It is highlighted that mass balances do not include the calculated chemicals and utilities streams, so they cannot close exactly.

However these streams are negligible, and the results are good to give an indication of the water loss and recovery for each waste water treatment plant.
Each waste water treatment plant will be schematically described, referring to the paragraph 1.5.1 for information on the treatment sections.

1.5.2.1 Integrated Gasification Combined Cycle

In this paragraph two cases of study are proposed for the IGCC plants without CO_2 capture:

1. Shell IGCC fed with bituminous coal (case 5.01);
2. GE IGCC fed with bituminous coal (case 5.05).

1.5.2.1.1 Shell IGCC, bituminous coal, without CO_2 capture (case 5.01)

Waste water to be treated is polluted by the following substances which exceed the discharge limits reported in Table 1.5-2: H_2S, NH_3, NO_3^-, TSS, COD, BOD, Cyanides, Fluorides, Boron, Selenium and Iron.
For more details refer to table B1-1 in Attachment B1.
As shown in the block flow diagram in Attachment B1, the waste water treatment plant consists of the devices described in Table 1.5-4.

Table 1.5-4: WWTP for Shell IGCC, bituminous coal, without CO_2 capture

Device	Application	Operation
Equalization	Mass loading equalizing	Flow equalization in mixed basins.
Cooling	Reducing the wastewater temperature below 35 °C, to allow especially biological treatments.	Cooling with sea water system
Chemical conditioning 1	pH correction; Chemical oxidation with $FeSO_4$ of H_2S, Se, CN^-, Fe; Precipitation of reaction products.	Flash mixing and flocculation. Filtration through selective media for Boron.
Chemical sludge settling 1	Solid-water separation	Sludge settling
Chemical conditioning 2	pH correction; Dosage of $Ca(OH)_2$ for the precipitation of F^- as CaF_2.	Flash mixing and flocculation.
Chemical sludge settling 2	Solid-water separation	Sludge settling
Neutralization	pH correction before biological treatment	Flash mixing
Activated sludge process	Ammonia, nitrates, BOD and COD reduction (MDEA,	Biological anoxic and aerobic process.

Device	Application	Operation
	organic matter)	
Biological sludge settling	Solid-water separation	Sludge settling
Disinfection	Bacteria inhibition	Disinfection
Chemical and biological sludge treatment: conditioning, thickening and dewatering section	Concentration and dewatering of chemical and biological sludge produced in chemical-physical and biological treatment	Sludge thickening and drying (centrifugation, etc.…)

This plant configuration is a typical physical-chemical and biological treatment plant. The nitrification/denitrification process is the best available technology for reducing BOD, ammonia and nitrates at the same time in the waste water treatment plant. In this case only the supply of few phosphorous as phosphoric acid is requested for the correct nutrient ratio for the biological growth.

Table 1.5-5 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B1-1 and B1-2 in Attachment B1): “clean” stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-5: Shell IGCC, bituminous coal, without CO_2 capture: water balance around waste water treatment plant. Net Electric Power Output = 775.9 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
21.7	58.7	0.27	1.09	0.46	0.34

Table 1.5-6 gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

Table 1.5-6: Shell IGCC, bituminous coal, without CO_2 capture: chemical consumptions

Ferrous sulphate	Calcium hydroxide	Polyelectrolyte	Sulphuric acid	Phosphoric acic
m^3/h	kg/h	m^3/h	m^3/h	m^3/h
0.009 @20%wt.	76.5	0.02 @0.1%wt.	0.06 @98%wt.	0.0002 @85%wt.

1.5.2.1.2 GE IGCC, bituminous coal, without CO_2 capture (case 5.05)

In this case the water to be treated is polluted by the following substances which exceed the discharge limits recorded in the Table 1.5-2: H_2S, NH_3, TSS, COD, BOD, Cyanides.
For more details refer to the table B2-1 in Attachment B2.

As shown in the block flow diagram in Attachment B2, the waste water treatment plant consists of the devices described in Table 1.5-7.

Table 1.5-7: WWTP for GE IGCC, bituminous coal, without CO_2 capture

Device	Application	Operation
Equalization	Mass loading equalizing	Flow equalization in mixed basins
Cooling	Reducing the wastewater temperature to 35 °C, to allow especially biological treatments.	Cooling with sea water system
Chemical conditioning 1	pH correction; Chemical oxidation with $FeSO_4$ of H_2S and CN^-. Precipitation of the reaction products.	Flash mixing and flocculation
Chemical sludge settling 1	Solid-water separation	Sludge settling
Activated sludge process (anaerobic)	BOD and COD reduction (MDEA, Formiates)	Biological anaerobic process for high BOD and COD load
Biological sludge settling	Solid-water separation	Sludge settling
Activated sludge process (aerated lagoon)	BOD and COD final reduction (MDEA, Formiates)	Biological aerobic process for low BOD and COD load
Dual media filtration	TSS separation from water	Sand filter filtration
Heating and chemical conditioning	Increasing of temperature and pH for ammonia stripping	Heating in heat exchanger and chemical dosage in line
Ammonia stripping	Ammonia removal from water	Stripping in column
Cooling	Decreasing of temperature for discharge/reuse	Cooling with sea water system
Neutralization	pH correction before discharge/reuse	Flash mixing

Device	Application	Operation
Disinfection	Bacteria inhibition	Disinfection
Chemical and biological sludge treatment: conditioning, thickening and dewatering section	Concentration and dewatering of chemical and biological sludge produced in chemical-physical and biological treatment	Sludge thickening and drying (centrifugation, etc …)

In this case the high concentration of the BOD (450 mg/l) is significantly reduced with an anaerobic biological treatment for the BOD removal: the advantages, with respect to an aerobic treatment, are here summarized:

- lower amount of produced sludge to be sent to disposal;
- smaller process volumes;
- production of biogas (mainly methane, about the 60%) that can be reused for the water heating;
- lower request of power.

An aerobic treatment is present only as BOD final finishing.

The methane production in the anaerobic treatment results in about 1.2 Nm^3/h.

The low concentration of the ammonia nitrogen in the inlet waste stream (18.2 mg/l) could be removed whit the BOD degradation as nutrient for the bacteria, but the release of nitrogen from the MDEA degradation (12% of the MDEA weight is nitrogen) forces to foresee a dedicated ammonia treatment (stripping) downstream of the biological section for the discharge limit compliance.

Table 1.5-8 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B2-1 and B2-2 in Attachment B2): “clean” stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-8: GE IGCC, bituminous coal, without CO_2 capture: water balance around waste water treatment plant. Net Electric Power Output = 826.5 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
13.82	21.91	0.03	0.51	0.14	0.08

Table 1.5-9 gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

Table 1.5-9: GE IGCC, bituminous coal, without CO_2 capture: chemical consumptions

Ferrous sulphate	**Polyelectrolyte**	**Sulphuric acid**	**Phosphoric acic**
m^3/h	m^3/h	m^3/h	m^3/h
0.006 @20%wt.	0.01 @0.1%wt.	0.0002 @98%wt.	0.0001 @85%wt.

1.5.3 Power plants with CO_2 capture

This paragraph summarizes the main characteristics of waste water treatment units for the power plants with CO_2 capture reported at paragraph 1.3.

Waste water treatments block flow diagrams are shown as attachments to the present document and identified with the code of the relevant power plant cases.
Also preliminary global water mass balances are reported in the abovementioned attachments.
It is highlighted that mass balances do not include the calculated chemicals and utilities streams, so they cannot close exactly. However these streams are negligible, and the results are good to give an indication of the water loss and recovery for each waste water treatment plant.
Each waste water treatment plant will be schematically described, referring to the paragraph 1.5.1 for information on the treatment sections.

1.5.3.1 Ultra Super Critical PC Boiler

In this paragraph two cases of study are proposed for the USCPC Boiler plants:

1. USC PC fired with lignite and CO_2 capture (case 3.24);
2. USC PC fired with lignite and oxyfuel technology (case 4.13).

1.5.3.1.1 USCPC, lignite, with CO_2 capture (case 3.24)

In this case the polluted streams are divided in two groups: the FGD blow down and the others polluted streams.

The Flue gas desulphurisation blow down (or FGD blow down) stream is a chemical sludge with chemical solids (TSS) percentage of about 3 %wt, and very high chlorides concentration (28000 mg/l) which cannot be discharged to river. In this case the salinity has to be reduced with a reverse osmosis even when this stream is mixed with the others.

The remaining polluted water presents concentration of TSS, nitrates and chlorides exceeding the discharge limits for discharge to river recorded in Table 1.5-2.
For more details refer to the table B3-1 in Attachment B3.

As shown in the block flow diagram in Attachment B3, the waste water treatment plant consists of the devices described in the Table 1.5-10.

Table 1.5-10: WWTP for USCPC, lignite, with CO_2 capture

Devices for FGD b.d.	**Application**	**Operation**
Chemical conditioning	Chemical conditioning with polyelectrolyte.	Flocculation.
Chemical sludge settling 2	Solid-water separation	Sludge settling
Devices for other waste streams	**Application**	**Operation**
Equalization	Mass loading equalizing	Flow equalization in mixed basins.
Chemical conditioning	Chemical conditioning with polyelectrolyte.	Flocculation.
Chemical sludge settling 1	Solid-water separation	Sludge settling
Tertiary treatment (Sand filters and cartridge filters)	TSS removal for membrane protection	Filtration
Tertiary treatment (Ultrafiltration)	Separation of particles with dimension greater of 0.05 micron. Pretreatment of Reverse Osmosis	Filtration through membrane
Tertiary treatment (Reverse Osmosis)	Removal of salts from water	Filtration through membrane

Table 1.5-11 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B3-1 and B3-2 in Attachment B3): “clean” stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-11: USC PC, lignite, with CO_2 capture: water balance around waste water treatment plant. Net Electric Power Output = 761.0 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
548.37	73.3	24.4	0.76	33.2	3.9

Table 1.5-14 gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

Table 1.5-12: USC PC, lignite, bituminous coal, with CO_2 capture: chemical consumptions

Polyelectrolyte
m^3/h
0.015 @0.1%wt.

1.5.3.1.2 USCPC oxyfuel post combustion, lignite, with CO_2 capture (case 4.13)

The water to be treated is mainly polluted by a very high concentration of nitric and sulphuric acid (about 1.5 %wt) which generates a solution with pH = 0.

As shown in the block flow diagram in Attachment B4, the waste water treatment plant consists of a neutralization step with caustic soda followed by reverse osmosis to reduce the high salinity, so that the treated water may be discharged to river.

Table 1.5-13 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B4-1 and B4-2 in Attachment B4): “clean” stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-13: USCPC oxyfuel, lignite, with CO2 capture: water balance around waste water treatment plant. Net Electric Power Output = 741.3 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added (Caustic soda @20% wt)	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
606.3	277.4	88.2	16.3	31.8	10.0

In some cases, mercury could be present in the streams discharged to waste water treatment from Flue Gas Desulphurisation unit, but that no data are actually available.
Therefore, a general brief summary of the mercury removal technologies from water is given in the following.
Different technologies are available for the heavy metal removal, whose the effectiveness depends on its concentration and on final discharge limit:

- Precipitation
  Mercury is removed in the solid form by gravity with one of the following alternative precipitation processes:
  - Oxidation at high pH: this treatment consists of the oxidation to mercury oxide at pH 10-11;
  - Addition of Na_2S or FeS at neutral pH: the addition of Na_2S or FeS is effective because the product of the reaction is HgS that is insoluble. Consequently, a solid-liquid separation step (clarification-flocculation followed by filtration) shall follow the precipitation. This treatment allows reaching the 97% of the removal efficiency, but the excess of the dosed Na_2S or FeS could produce high S^{2-} residue in water, which has to be reduced with a dedicated treatment.
  - Addition of Thiourea in alcalyne ambient instead of Na_2S/FeS.

- Ionic exchange
  The majority of these treatments consist of preliminary Cl_2 or ClO^- addition to stream in order to transform the Hg in Cl-Hg- complexes which are easily removed with selective anionic resins filters. The treatment is carried out at neutral pH.

- Activated carbons filtration
  This treatment is especially effective for organic complexes with mercury. For the inorganic ionic mercury removal the performance of the activated carbon can raise if this is pretreated (e.g. with carbon disulphide). Mercury concentration of 0.0002 mg/l can be reached after the filtration.

As for the cost-effectiveness point of view, the best available technology to reduce mercury concentration in water is the precipitation of mercury with sulphites or Thiourea, which allows to achieve residual mercury concentration of some µg/l. Anionic resins or pretreated activated carbons can be used as final polishing to reach metal concentration in water of 0.2-1 µg/l.

1.5.3.2 Integrated Gasification Combined Cycle

In this paragraph three cases are proposed for the IGCC plants with CO_2 capture:

3. Shell IGCC fed with bituminous coal (case 5.02);
4. Shell IGCC fed with lignite (case 5.04);
5. GE IGCC fed with bituminous coal (case 5.06).

1.5.3.2.1 Shell IGCC, bituminous coal, with CO_2 capture (case 5.02)

Wastewater is polluted by the following substances which exceed the discharge limits reported in the Table 1.5-2: H_2S, NH_3, NO_3^-, BOD, Cyanides, Fluorides, Selenium and Iron.
With the exception of the Boron, they are the same pollutants which are above discharge limits in the Shell IGCC case without CO_2 capture.
For more details refer to table B5-1 in Attachment B5.

As shown in the block flow diagram in Attachment B5, the waste water treatment plant is similar to the one for the Shell IGCC effluents without CO_2 capture described at paragraph 1.5.2.1.1.
The most important difference is the dosage of external BOD; in fact, in this case, the ammonia and nitric nitrogen are very high with respect to the BOD concentration and the ratio of nutrients for biological growth is unbalanced. As the nitrification/denitrification biological process is the best technology to reduce together ammonia and nitrates, the external BOD dosage is requested. The cost associated to the external BOD supply depends on the type of organic matter and on its availability: e.g. methanol is qualitatively a good product completely biodegradable, but expensive, while local industrial organic rejects could be bought at low cost.
For the general description of the units operations please refer to Table 1.5-4 (taking into account that Selexol instead of MDEA is to be considered as organic matter)
Table 1.5-14 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B5-1 and B5-2 in Attachment B5): “clean” stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-14: Shell IGCC, bituminous coal, with CO_2 capture: water balance around waste water treatment plant. Net Electric Power Output = 676.2 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
26.44	163.72	0.42	1.15 [(1)]	0.26	0.22

Table 1.5-15 gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

Table 1.5-15: Shell IGCC, bituminous coal, with CO_2 capture: chemical consumptions

Ferrous sulphate	Calcium hydroxide	Polyelectrolyte	Sulphuric acid	Phosphoric acic
m^3/h	kg/h	m^3/h	m^3/h	m^3/h
0.04 @20%wt.	80.5	0.05 @0.1%wt.	0.06 @98%wt.	0.0001 @85%wt.

1.5.3.2.2 Shell IGCC, lignite, with CO_2 capture (case 5.04)

The water to be treated is divided in two main streams:
1. demineralisation plant regeneration water,
2. other polluted streams.

Demineralization plant regeneration water is rich of nitrates and chlorides, and polluted by TSS.
The sum of other polluted streams is contaminated by H_2S, NH_3, COD, BOD, Fluorides, Selenium, Iron and Cyanides, and its Cl^- concentration does not allow the direct discharge to river (for more details refer to the table B6-1 in Attachment B6).
As the BOD is not high enough to carry out a nitrification/denitrification process, considering all polluted streams, the segregation of the demineralisation plant regeneration water allows to:
- remove the nitrates of the regeneration water with the reverse osmosis in the tertiary treatment, to be anyhow foreseen to respect the discharge limits of chlorides.

(1) About 40 kg/h of external BOD are requested to guarantee a correct ratio of nutrients for biological growth; the type is not indicated as it depends on local availability and economical considerations; so its additional flowrate is not computed.

- remove the high concentration of ammonia from others polluted streams by stripping;
- avoid the BOD external dosage that should be necessary to remove biologically ammonia and nitrates, if not reduced as above described.

As shown in the block flow diagram in Attachment B6, the waste water treatment plant scheme consists of the devices described in

Table 1.5-16.

Table 1.5-16: WWTP for Shell IGCC, lignite, with CO_2 capture

Device	Application	Operation
Equalization	Mass loading equalizing	Flow equalization in mixed basins
Chemical conditioning 1	pH correction; Chemical oxidation with $FeSO_4$ of H_2S, Se, CN^-, Fe; Precipitation of reaction products.	Flash mixing and flocculation.
Chemical sludge settling 1	Solid-water separation	Sludge settling
Chemical conditioning 2	pH correction; Dosage of $Ca(OH)_2$ for the precipitation of F^- as CaF_2.	Flash mixing and flocculation.
Chemical sludge settling 2	Solid-water separation	Sludge settling
Dual media filtration	TSS separation from water	Sand filter filtration
Heating and chemical conditioning	Increasing of temperature and pH for ammonia stripping	Heating in heat exchanger and chemical dosage in line
Ammonia stripping	Ammonia removal from water	Stripping in column
Cooling	Reducing the wastewater temperature below 35 °C, to allow especially biological treatments.	Cooling with cooling water
Neutralization	pH correction before biological section	Flash mixing
Activated sludge process (aerated lagoon)	BOD and COD reduction (MDEA)	Biological aerobic process for low BOD and COD load

Device	**Application**	**Operation**
Chemical and biological sludge treatment: conditioning, thickening and dewatering section	Concentration and dewatering of chemical and biological sludge produced in chemical-physical and biological treatment	Sludge thickening and drying (centrifugation, etc…)
Chemical sludge settling 3	TSS reduction in demineralization	Sludge settling after chemical conditioning
Tertiary treatment (dual media filtration + Cartridge filters)	TSS removal for membrane protection	Filtration
Disinfection	Bacteria inhibition	Disinfection
Tertiary treatment (Ultrafiltration)	Separation of particles with dimension greater of 0.05 micron - BOD. Pretreatment of Reverse Osmosis	Filtration through membrane
Tertiary treatment (Reverse Osmosis)	Removal of salts from water	Filtration through membrane

Table 1.5-17 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B6-1 and B6-2 in Attachment B6): "clean" stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-17: Shell IGCC, lignite, with CO_2 capture: water balance after waste around treatment plant. Net Electric Power Output = 628.8 MW

Clean streams	**Polluted streams** (2)	**Loss of water**	**Chemicals/utility water added**	**Loss of water percentage**	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
454.7	207.5	68.9	1.73	33.2	10.4

Table 1.5-18 gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

(2) Included demineralization plant regeneration water.

Table 1.5-18: Shell IGCC, Lignite, with CO_2 capture: chemical consumptions

Ferrous sulphate	Calcium hydroxide	Polyelectrolyte	Sulphuric acid	Phosphoric acic
m^3/h	kg/h	m^3/h	m^3/h	m^3/h
0.08 @20%wt.	98.5	0.07 @0.1%wt.	0.07 @98%wt.	0.0002 @85%wt.

1.5.3.2.3 GE IGCC, bituminous coal combustion, with CO_2 capture (case 5.06)

The water to be treated is polluted by the same substances detected in the GE IGCC case without CO_2 capture: H_2S, NH_3, TSS, COD, BOD, Cyanides.
However there is an important difference: the BOD load in the case with CO_2 capture is significantly lower than the case without CO_2 capture, so that in the present case the anaerobic process is not advantageously feasible. So, only a traditional aerobic BOD removal section is foreseen.
Moreover the selexol solvent, used in this case, does not increase the organic nitrogen of the waste stream (the MDEA, present in the case without CO_2 capture, is constituted by the 12 %wt of nitrogen, and its degradation in the biological treatment releases nitrogen into water). So, in the present case, the ammonia can be stripped before the biological step.
For more details about polluted stream refer to the table B7-1 in the Attachment B7.

As shown in the block flow diagram in Attachment B7, the waste water treatment plant consists of the devices described in Table 1.5-19.

Table 1.5-19: WWTP for GE IGCC, bituminous coal, with CO_2 capture

Device	Application	Operation
Equalization	Mass loading equalizing	Flow equalization in mixed basins
Chemical conditioning 1	pH correction; Chemical oxidation with $FeSO_4$ of H_2S and CN^-; Precipitation of the reaction products.	Flash mixing and flocculation
Chemical sludge settling	Solid-water separation	Sludge settling
Filtration	TSS separation from water	Sand filter filtration
Heating and chemical conditioning	Increasing of temperature and pH for ammonia stripping	Heating in heat exchanger and chemical dosage in line
Ammonia stripping	Ammonia removal from water	Stripping in column

Device	Application	Operation
Cooling	Decreasing of temperature for discharge/reuse	Cooling with once trough sea water system
Neutralization	pH correction before biological treatment	Flash mixing
Activated sludge process (aerobic)	BOD and COD reduction (Formiates, Selexol)	Biological aerobic process
Biological sludge settling	Solid-water separation	Sludge settling
Disinfection	Bacteria inhibition	Disinfection
Chemical and biological sludge treatment: conditioning, thickening and dewatering section	Concentration and dewatering of chemical and biological sludge produced in chemical-physical and biological treatment	Sludge thickening and drying (centrifugation…)

Table 1.5-20 summarizes the water balance for this case of study including the waste water treatment plant (reference Tables B7-1 and B7-2 in Attachment B7): "clean" stream flowrate not fed to waste water treatment plant, polluted stream flowrate to be treated, amount of chemicals/utilities, percentage of loss of water in relation to streams treated into waste water treatment plant and to all the water discharged by power plant.

Table 1.5-20: GE IGCC, bituminous coal, with CO_2 capture: water balance around waste water treatment plant. Net Electric Power Output = 730.3 MW

Clean streams	Polluted streams	Loss of water	Chemicals/utility water added	Loss of water percentage	
m^3/h	m^3/h	m^3/h	m^3/h	% of polluted streams	% of streams from overall plant
15.0	21.7	0.03	0.52	0.14	0.08

Table 1.5-21gives an high-level summary of the chemicals consumed. The amount of chemical shown is indicatively only as it shall be verified during the engineering detailed phase based on the actual water conditions at the inlet of each unit.

Table 1.5-21: GE IGCC, bituminous coal, with CO_2 capture: chemical consumptions

Ferrous sulphate	Calcium hydroxide	Sulphuric acid	Phosphoric acic
m^3/h	kg/h	m^3/h	m^3/h
0.015 @20%wt.	98.5	0.001 @98%wt.	0.0001 @85%wt.

ATTACHMENT B1

Case 5.01: SHELL IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE – IGCC COMPLEX BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B1-1

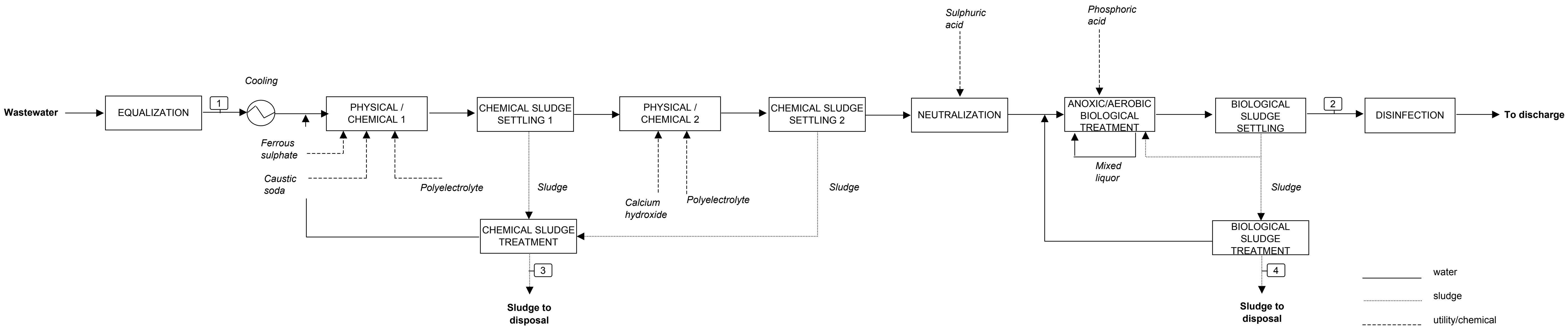
Parameter	Total composition of polluted stream		Total composition of clean stream (2)	
Temperature (°C)	43.54		76.85	
Total Flow (m^3/h)	58.68		21.65	
H_2S mg/l	**8.30**	**Above limit**	**0.00**	**-**
NH_3 mg/l	**66.74**	**Above limit**	**0.28**	**-**
Cl^- mg/l	**4408.12**	**To sea (1)**	**3.70**	**-**
PO_4^{---} mg/l	**2.03**	**-**	**1.01**	**-**
SO_4^{--} mg/l	**267.95**	**-**	**3.70**	**-**
NO_3^- mg/l	**144.26**	**Above limit**	**0.00**	**-**
MDEA mg/l	**93.40**		**0.00**	
TSS mg/l	**97.46**	**Above limit**	**0.55**	**-**
CODmg/l	**441.89**	**Above limit**	**32.41**	**-**
BOD mg/l	**266.26**	**Above limit**	**18.52**	**-**
CN^- tot. mg/l	**29.86**	**Above limit**	**0.00**	**-**
F^- mg/l	**331.73**	**Above limit**	**0.00**	**-**
B mg/l	**3.32**	**Above limit**	**0.00**	**-**
Se mg/l	**19.90**	**Above limit**	**0.00**	**-**
Fe mg/l	**33.17**	**Above limit**	**0.00**	**-**
As mg/l	**0.07**	**-**	**0.00**	**-**
Ba mg/l	**0.27**	**-**	**0.00**	**-**
Cd mg/l	**0.01**	**-**	**0.00**	**-**
Cr mg/l	**0.66**	**-**	**0.00**	**-**
Cu mg/l	**0.01**	**-**	**0.00**	**-**
Hg mg/l	**0.002**	**-**	**0.000**	**-**
Mn mg/l	**0.02**	**-**	**0.00**	**-**
Ni mg/l	**0.33**	**-**	**0.00**	**-**
Pb mg/l	**0.07**	**-**	**0.00**	**-**
Zn mg/l	**0.01**	**-**	**0.00**	**-**

Treated water discharge to: sea.

Notes.
1) There is no limit for discharge to sea.
2) Whit reference to the Attachment A3, clean streams, which do not need any pollution reduction, are:
stream n° 5. BD: steam gen. (HRSG)
stream n° 6. BD: steam gen. (SRU)
stream n° 13. BD steam gen. (gasification)
stream n° 14. BD from coal drying.

ATTACHMENT B1

Case 5.01: SHELL IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B1

Case 5.01: SHELL IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE- WASTE WATER TREATMENT MASS BALANCE

Table B1-2

STREAM	Total composition of polluted stream	Treated water	Chemical sludge to disposal	Biological sludge to disposal
N°	1	2	3	4
Temperature (°C)	43.50	30.00	30.00	30.00
Flowrate (m^3/h)	58.68	59.49	0.24	0.033
H_2S				
H_2S mg/l	**8.30**	**0.50**	**0.50**	**0.50**
H_2S kg/h	0.49	0.03	0.00	0.00
NH_3				
NH_3 mg/l	**66.74**	**10.93**	**65.73**	**10.93**
NH_3 kg/h	3.92	0.65	0.02	0.00
Cl^-				
Cl^- mg/l	**4408.12**	**4328.25**	**4341.84**	**4328.25**
Cl^- kg/h	258.69	257.49	1.06	0.14
PO_4^{---}				
PO_4^{---} mg/l	**2.03**	**0.00**	**2.00**	**0.00**
PO_4^{---} kg/h	0.12	0.00	0.00	0.00
SO_4^{--}				
SO_4^{--} mg/l	**267.95**	**1929.93**	**286.58**	**1929.93**
SO_4^{--} kg/h	15.72	114.81	0.07	0.06
NO_3^-				
NO_3^- mg/l	**144.26**	**79.71**	**142.09**	**79.71**
NO_3^- kg/h	8.47	4.74	0.03	0.00
MDEA				
MDEA mg/l	**93.40**	**0.00**	**92.00**	**0.00**
MDEA kg/h	5.48	0.00	0.02	0.00
TSS				
TSS mg/l	**97.46**	**20.00**	**222826.09**	**207770.27**
TSS kg/h	5.72	1.19	54.38	6.80
COD				
CODmg/l	**441.89**	**30.00**	**435.24**	**30.00**
COD kg/h	25.93	1.78	0.11	0.00
BOD				
BOD mg/l	**266.26**	**20.00**	**262.25**	**20.00**
BOD kg/h	15.63	1.19	0.06	0.00
CN- tot.				
CN^- tot. mg/l	**29.86**	**0.50**	**0.50**	**0.50**
CN^- tot. kg/h	1.75	0.03	0.00	0.00
F^-				
F^- mg/l	**331.73**	**5.99**	**89.19**	**5.99**
F^- kg/h	19.47	0.36	0.02	0.00
B				
B mg/l	**3.32**	**1.98**	**1.99**	**1.98**
kg/h	0.19	0.12	0.00	0.00
Se				
Se mg/l	**19.90**	**0.03**	**0.03**	**0.03**
kg/h	1.17	0.00	0.00	0.00
Fe				
Fe mg/l	**33.17**	**0.00**	**0.00**	**0.00**
Fe kg/h	1.95	0.00	0.00	0.00

ATTACHMENT B2

Case 5.05: GE IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE – IGCC COMPLEX BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B2-1

Parameter	Total composition of polluted stream		Total composition of clean stream (1)	
Temperature (°C)	51.32		100.00	
Total Flow (m^3/h)	21.91		13.82	
H_2S mg/l	**14.20**	**Above limit**	**0.00**	**-**
NH_3 mg/l	**18.21**	**Above limit**	**0.00**	**-**
Cl^- mg/l	**722.70**	**-**	**0.00**	**-**
PO_4^{---} mg/l	**0.00**	**-**	**2.97**	**-**
SO_4^{--} mg/l	**130.24**	**-**	**0.00**	**-**
NO_3^- mg/l	**69.82**	**-**	**0.00**	**-**
MDEA mg/l	**250.13**		**0.00**	
TSS mg/l	**81.52**	**Above limit**	**2.97**	**-**
COD mg/l	**817.55**	**Above limit**	**0.00**	**-**
BOD mg/l	**449.65**	**Above limit**	**0.00**	**-**
CN^- tot. mg/l	**3.32**	**Above limit**	**0.00**	**-**
F^- mg/l	**0.00**	**-**	**0.00**	**-**
B mg/l	**0.00**	**-**	**0.00**	**-**
Se mg/l	**0.00**	**-**	**0.00**	**-**
Fe mg/l	**0.00**	**-**	**0.00**	**-**
As mg/l	**0.00**	**-**	**0.00**	**-**
Ba mg/l	**0.00**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.00**	**-**	**0.00**	**-**
Cu mg/l	**0.00**	**-**	**0.00**	**-**
Hg mg/l	**0.000**	**-**	**0.000**	**-**
Mn mg/l	**0.00**	**-**	**0.00**	**-**
Ni mg/l	**0.00**	**-**	**0.00**	**-**
Pb mg/l	**0.00**	**-**	**0.00**	**-**
Zn mg/l	**0.00**	**-**	**0.00**	**-**
Formiates mg/l	**491.80**		**0.00**	

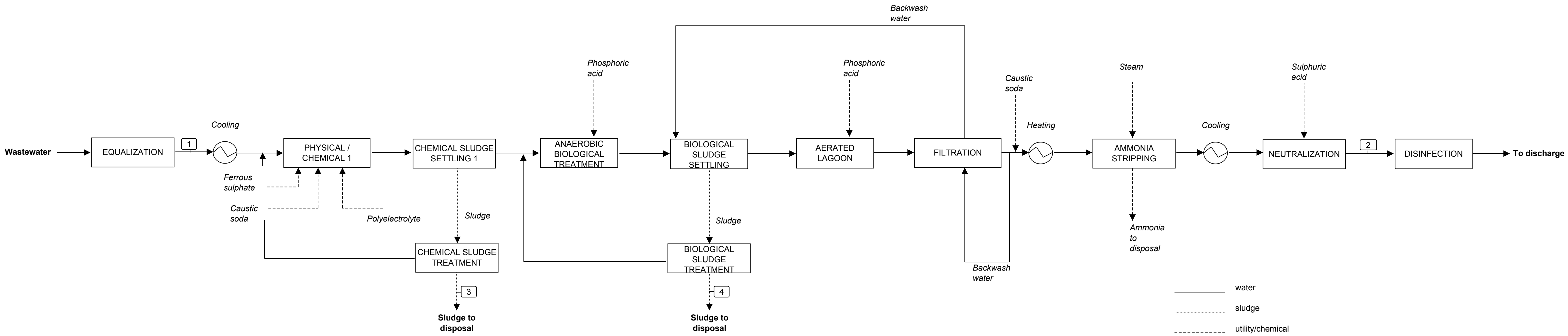
Treated water discharge to: sea.

Notes.

1) Whit reference to the Attachment A6, clean streams, which do not need any pollution reduction, are:
stream n° 4. BD: steam gen. (syngas cool)
stream n° 6. BD: steam gen. (SRU)
stream n° 7. BD: steam gen. (HRSG)

ATTACHMENT B2

Case 5.05: GE IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B2

Case 5.05: GE IGCC, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE – WASTE WATER TREATMENT MASS BALANCE

Table B2-2

STREAM	**Total composition of polluted stream**	**Treated water**	**Chemical sludge to disposal**	**Biological sludge to disposal**
N°	**1**	**2**	**3**	**4**
Temperature (°C)	51.30	30.00	30.00	30.00
Flowrate (m3/h)	21.91	22.39	0.012	0.02
H_2S				
H_2S mg/l	**14.20**	**0.50**	**0.50**	**0.50**
H_2S kg/h	0.31	0.01	0.00	0.00
NH_3				
NH_3 mg/l	**18.21**	**10.00**	**17.80**	**40.14**
NH_3 kg/h	0.40	0.22	0.00	0.00
Cl^-				
Cl^- mg/l	**722.70**	**706.26**	**706.27**	**706.27**
Cl^- kg/h	15.84	15.82	0.01	0.01
PO_4^{---}				
PO_4^{---} mg/l	**0.00**	**0.00**	**0.00**	**0.00**
PO_4^{---} kg/h	0.00	0.00	0.00	0.00
SO_4^{--}				
SO_4^{--} mg/l	**130.24**	**180.35**	**165.17**	**165.17**
SO_4^{--} kg/h	2.85	4.04	0.00	0.00
NO_3^-				
NO_3^- mg/l	**69.82**	**68.23**	**68.23**	**68.23**
NO_3^- kg/h	1.53	1.53	0.00	0.00
MDEA				
MDEA mg/l	**250.13**	**3.00**	**244.44**	**45.04**
MDEA kg/h	5.48	0.07	0.00	0.00
TSS				
TSS mg/l	**81.52**	**5.00**	**222826.09**	**207770.27**
TSS kg/h	1.79	0.11	2.71	3.72
COD				
COD mg/l	**817.55**	**54.27**	**798.96**	**192.62**
COD kg/h	17.92	1.22	0.01	0.00
BOD				
BOD mg/l	**449.65**	**29.85**	**439.43**	**105.94**
BOD kg/h	9.85	0.67	0.01	0.00
CN^- tot.				
CN^- tot. mg/l	**3.32**	**0.50**	**0.50**	**0.50**
CN^- tot. kg/h	0.07	0.01	0.00	0.00
Formiates				
Formiates mg/l	**491.80**	**3.00**	**480.62**	**88.37**
Formiates kg/h	10.78	0.07	0.01	0.00

ATTACHMENT B3

Case 3.24: USCPC, LIGNITE, WITH CO_2 CAPTURE – LIGNITE PF BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B3-1

Parameter	Total composition of polluted stream (without FGD blow down)		FGD Blow Down		Total composition of clean stream [1]	
Temperature (°C)	31.00		50.00		25.90	
Total Flow (m^3/h)	72.70		0.60		548.37	
H_2S mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
NH_3 mg/l	**0.00**	**-**	**0.00**	**-**	**0.22**	**-**
Cl^- mg/l	**2051.06**	**Above limit**	**28130.83**	**Above limit**	**2.94**	**-**
PO_4^{---} mg/l	**0.00**	**-**	**0.00**	**-**	**0.37**	**-**
SO_4^{--} mg/l	**373.33**	**-**	**1319.91**	**Above limit**	**429.30**	**-**
NO_3^- mg/l	**229.39**	**Above limit**	**0.00**	**-**	**3.05**	**-**
MDEA mg/l	**0.00**		**0.00**		**0.00**	
TSS mg/l	**260.76**	**Above limit**	**28468.10**	**Above limit**	**6.09**	**-**
COD mg/l	**0.00**	**-**	**0.00**	**-**	**25.77**	**-**
BOD mg/l	**0.00**	**-**	**0.00**	**-**	**14.72**	**-**
CN^- tot. mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
F^- mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
B mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Se mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Fe mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
As mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Ba mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Cu mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Hg mg/l	**0.000**	**-**	**0.000**	**-**	**0.000**	**-**
Mn mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Ni mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Pb mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Zn mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**

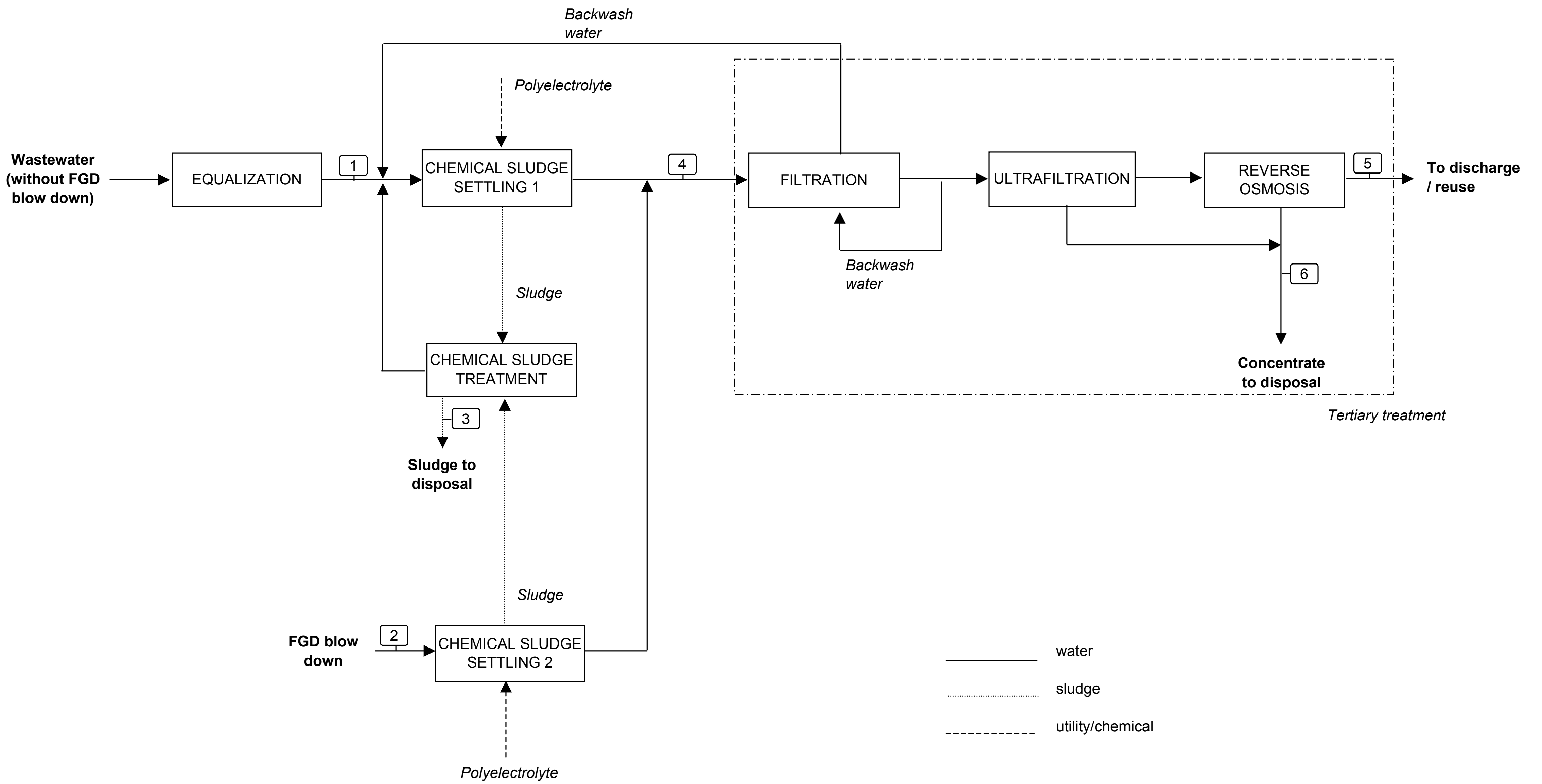
Treated water discharge to: river.

Notes.

1) Whit reference to the Attachment A1, clean streams, which do not need any pollution reduction, are:
stream n° 1. Lignite drying effluent
stream n° 2. CO_2 dryiers/compressor
stream n° 5. Cooling tower system BD

ATTACHMENT B3

Case 3.24: USCPC, LIGNITE, WITH CO_2 CAPTURE - WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B3

Case 3.24: USCPC, LIGNITE, WITH CO_2 CAPTURE – WASTE WATER TREATMENT MASS BALANCE

Table B3-2

STREAM	**Total composition of polluted stream (without FGD blow down)**	**FGD Blow Down**	**Chemical sludge to disposal**	**Pretreated water to tertiary treatment**	**Treated water to discharge / reuse**	**Concentrate from tertiary treatment**
N°	**1**	**2**	**3**	**4**	**5**	**6**
Temperature (°C)	31.00	50.00	31.00	31.00	31.00	31.00
Flowrate (m^3/h)	72.70	0.60	0.160	79.47	49.664	24.241
H_2S						
H_2S mg/l	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
H_2S kg/h	0.00	0.00	0.00	0.00	0.00	0.00
NH_3						
NH_3 mg/l	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
NH_3 kg/h	0.00	0.00	0.00	0.00	0.00	0.00
Cl^-						
Cl^- mg/l	**2051.06**	**28130.83**	**5795.99**	**2233.46**	**319.07**	**6155.63**
Cl^- kg/h	149.11	16.88	0.93	177.49	15.85	149.22
SO_4^{--}						
SO_4^{--} mg/l	**373.33**	**1319.91**	**489.04**	**376.90**	**53.84**	**1038.77**
SO_4^{--} kg/h	27.14	0.79	0.08	29.95	2.67	25.18
NO_3^-						
NO_3^- mg/l	**229.39**	**0.00**	**179.72**	**225.27**	**32.18**	**620.86**
NO_3^- kg/h	16.68	0.00	0.03	17.90	1.60	15.05
TSS						
TSS mg/l	**260.76**	**28468.10**	**222826.09**	**20.00**	**0.00**	**15.24**
TSS kg/h	18.96	17.08	35.67	1.59	0.00	0.37

ATTACHMENT B4

Case 4.13: LIGNITE OXYFUEL PC, WITH CO_2 CAPTURE – USC BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B4-1

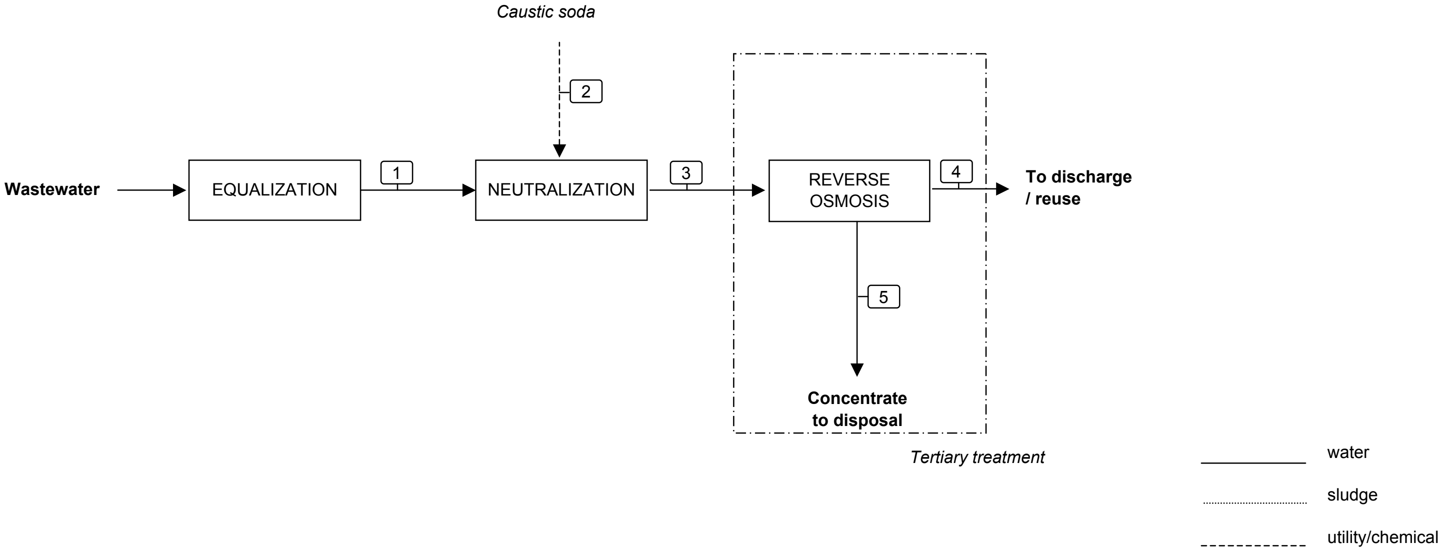
STREAM	Total composition of polluted stream		Total composition of clean stream (1)	
Temperature (°C)	35.00		22.99	
Total Flow (m^3/h)	277.39		606.34	
H_2S mg/l	**0.00**	**-**	**0.00**	**-**
NH_3 mg/l	**0.00**	**-**	**0.18**	**-**
Cl^- mg/l	**1.64**	**-**	**2.46**	**-**
PO_4^{---} mg/l	**0.00**	**-**	**0.31**	**-**
SO_4^{--} mg/l	**16466.18**	**Above limit**	**487.34**	**-**
NO_3^- mg/l	**628.04**	**Above limit**	**3.46**	**-**
MEA mg/l	**0.00**		**0.00**	
TSS mg/l	**0.04**	**-**	**6.93**	**-**
COD mg/l	**0.00**	**-**	**21.51**	**-**
BOD mg/l	**0.00**	**-**	**12.29**	**-**
CN^- tot. mg/l	**0.00**	**-**	**0.00**	**-**
F^- mg/l	**0.00**	**-**	**0.00**	**-**
B mg/l	**0.00**	**-**	**0.00**	**-**
Se mg/l	**0.00**	**-**	**0.00**	**-**
Fe mg/l	**0.00**	**-**	**0.00**	**-**
As mg/l	**0.00**	**-**	**0.00**	**-**
Ba mg/l	**0.00**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.00**	**-**	**0.00**	**-**
Cu mg/l	**0.00**	**-**	**0.00**	**-**
Hg mg/l	**0.000**	**-**	**0.000**	**-**
Mn mg/l	**0.00**	**-**	**0.00**	**-**
Ni mg/l	**0.00**	**-**	**0.00**	**-**
Pb mg/l	**0.00**	**-**	**0.00**	**-**
Zn mg/l	**0.00**	**-**	**0.00**	**-**
H_2SO_4 mg/l	**16808.92**		**0.00**	
HNO_3 mg/l	**637.98**		**0.00**	

Treated water discharge to: river.

Notes. 1) With reference to the Attachment A2, clean streams, which do not need any pollution reduction, are:
stream n° 1. Lignite drying effluent
stream n° 4. Cooling tower system BD

ATTACHMENT B4

Case 4.13: LIGNITE OXYFUEL PC, WITH CO2 CAPTURE - WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B4

Case 4.13: LIGNITE OXYFUEL PC, WITH CO2 CAPTURE- WASTE WATER TREATMENT MASS BALANCE

Table B4-2

STREAM	**Total composition of polluted stream**	**Caustic soda @ 20%**	**Neutralized water**	**Treated water to discharge / reuse**	**Concentrate to disposal**
N°	**1**	**2**	**3**	**4**	**5**
Temperature (°C)	35.00		35.00	35.00	35.00
Total Flow (m^3/h)	277.39	16.33	293.72	205.60	88.12
Na+					
Na+ mg/l	**0.39**	**138000.00**	**7672.78**	**548.06**	**24297.14**
kg/h	0.11	2253.54	2253.65	112.68	2140.97
Cl^-					
Cl^- mg/l	**1.64**		**1.55**	**0.11**	**4.92**
Cl^- kg/h	0.46		0.46	0.02	0.43
SO_4^{--}					
SO_4^{--} mg/l	**16466.18**		**15550.77**	**999.69**	**49503.27**
SO_4^{--} kg/h	4567.57		4567.57	205.54	4362.03
NO_3^-					
NO_3^- mg/l	**628.04**		**593.12**	**42.37**	**1878.23**
NO_3^- kg/h	174.21		174.21	8.71	165.50
TSS					
TSS mg/l	**0.04**		**0.04**	**0.00**	**0.12**
TSS kg/h	0.01		0.01	0.00	0.01
H_2SO_4					
H_2SO_4 mg/l	**16808.92**		**0.00**	**0.00**	**0.00**
H_2SO_4 kg/h	4662.64		0.00	0.00	0.00
HNO_3					
HNO_3 mg/l	**637.98**		**0.00**	**0.00**	**0.00**
HNO_3 kg/h	176.97		0.00	0.00	0.00

Note: water produced during neutralization reaction is not considered.

ATTACHMENT B5

Case 5.02: SHELL IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE – IGCC COMPLEX BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B5-1

Parameter	Total composition of polluted stream		Total composition of clean stream [(2)]	
Temperature (°C)	63.14		77.64	
Total Flow (m^3/h)	163.72		26.44	
H_2S mg/l	**14.05**	**Above limit**	**0.00**	**-**
NH_3 mg/l	**78.42**	**Above limit**	**0.25**	**-**
Cl^- mg/l	**2563.84**	**To sea [(1)]**	**3.31**	**-**
PO_4^{---} mg/l	**0.81**	**-**	**1.58**	**-**
SO_4^{--} mg/l	**253.53**	**-**	**3.31**	**-**
NO_3^- mg/l	**147.65**	**Above limit**	**0.00**	**-**
MDEA mg/l	**0.00**		**0.00**	
TSS mg/l	**58.31**	**-**	**1.16**	**-**
CODmg/l	**98.78**	**-**	**28.93**	**-**
BOD mg/l	**63.59**	**Above limit**	**16.53**	**-**
CN^- tot. mg/l	**11.91**	**Above limit**	**0.00**	**-**
F^- mg/l	**132.30**	**Above limit**	**0.00**	**-**
B mg/l	**1.32**	**-**	**0.00**	**-**
Se mg/l	**7.94**	**Above limit**	**0.00**	**-**
Fe mg/l	**13.23**	**Above limit**	**0.00**	**-**
As mg/l	**0.03**	**-**	**0.00**	**-**
Ba mg/l	**0.11**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.26**	**-**	**0.00**	**-**
Cu mg/l	**0.01**	**-**	**0.00**	**-**
Hg mg/l	**0.001**	**-**	**0.000**	**-**
Mn mg/l	**0.01**	**-**	**0.00**	**-**
Ni mg/l	**0.13**	**-**	**0.00**	**-**
Pb mg/l	**0.03**	**-**	**0.00**	**-**
Zn mg/l	**0.01**	**-**	**0.00**	**-**
Selexol mg/l	**9.85**		**0.00**	

Treated water discharge to: sea.

Notes.

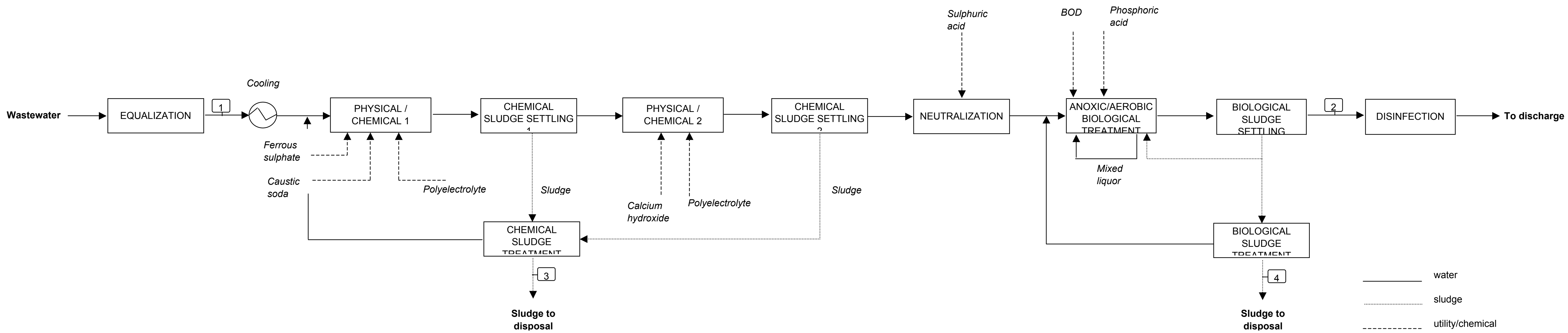
1) There is no limit for discharge to sea.

2) Whit reference to the Attachment A4, clean streams, which do not need any pollution reduction, are:

stream n° 5. BD: steam gen. (HRSG)
stream n° 6. BD: steam gen. (SRU)
stream n° 10. BD: steam gen. (syngas cooling)
stream n° 12. Water from CO_2 compr.
stream n° 13. BD steam gen. (gasification)
stream n° 15. BD from coal drying

ATTACHMENT B5

Case 5.02: SHELL IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B5

Case 5.02: SHELL IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE- WASTE WATER TREATMENT MASS BALANCE

Table B5-2

STREAM	Total composition of polluted stream	Treated water	Chemical sludge to disposal	Biological sludge to disposal
N°	1	2	3	4
Temperature (°C)	63.20	30.00	30.00	30.00
Flowrate (m3/h)	163.72	164.45	0.30	0.12
H_2S				
H_2S mg/l	**14.05**	**0.50**	**0.50**	**0.50**
H_2S kg/h	2.30	0.08	0.00	0.00
NH_3				
NH_3 mg/l	**78.42**	**10.93**	**77.99**	**10.93**
NH_3 kg/h	12.84	1.80	0.02	0.00
Cl^-				
Cl^- mg/l	**2563.84**	**2545.96**	**2549.75**	**2545.96**
Cl^- kg/h	419.76	418.68	0.76	0.32
PO_4^{---}				
PO_4^{---} mg/l	**0.81**	**0.00**	**0.81**	**0.00**
PO_4^{---} kg/h	0.13	0.00	0.00	0.00
SO_4^{--}				
SO_4^{--} mg/l	**253.53**	**921.11**	**290.56**	**921.11**
SO_4^{--} kg/h	41.51	151.48	0.09	0.11
NO_3^-				
NO_3^- mg/l	**147.65**	**66.43**	**146.84**	**66.43**
NO_3^- kg/h	24.17	10.92	0.04	0.01
TSS				
TSS mg/l	**58.31**	**20.00**	**222826.09**	**207770.27**
TSS kg/h	9.55	3.29	66.15	25.78
COD				
COD mg/l	**98.78**	**36.36**	**98.02**	**36.36**
COD kg/h	16.17	5.98	0.03	0.00
BOD				
BOD mg/l	**63.59**	**20.00**	**63.12**	**20.00**
BOD kg/h	10.41	3.29	0.02	0.00
CN^- tot.				
CN^- tot. mg/l	**11.91**	**0.50**	**0.50**	**0.50**
CN^- tot. kg/h	1.95	0.08	0.00	0.00
F^-				
F^- mg/l	**132.30**	**6.00**	**51.26**	**6.00**
F^- kg/h	21.66	0.99	0.02	0.00
Se				
Se mg/l	**7.94**	**0.03**	**0.03**	**0.03**
kg/h	1.30	0.00	0.00	0.00
Fe				
Fe mg/l	**13.23**	**0.00**	**0.00**	**0.00**
Fe kg/h	2.17	0.00	0.00	0.00
Selexol				
Selexol mg/l	**9.85**	**0.00**	**9.79**	**0.00**
Selexol kg/h	1.61	0.00	0.00	0.00

ATTACHMENT B6

Case 5.04: SHELL IGCC, LIGNITE, WITH CO_2 CAPTURE – IGCC CLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B6-1

Parameter	Total composition of polluted stream (without demineralization water plant BD)		Demi plant water BD		Total composition of clean stream [1]	
Temperature (°C)	40.30		20.00		39.58	
Total Flow (m^3/h)	175.12		32.40		454.70	
H_2S mg/l	**24.43**	**Above limit**	**0.00**	**-**	**0.00**	**-**
NH_3 mg/l	**111.81**	**Above limit**	**0.00**	**-**	**0.40**	**-**
Cl^- mg/l	**1415.21**	**Above limit**	**4560.00**	**Above limit**	**5.28**	**-**
PO_4^{---} mg/l	**0.92**	**-**	**0.00**	**-**	**0.75**	**-**
SO_4^{--} mg/l	**15.06**	**-**	**830.00**	**-**	**220.81**	**-**
NO_3^- mg/l	**0.00**	**-**	**510.00**	**Above limit**	**1.54**	**-**
MDEA mg/l	**31.30**		**0.00**		**0.00**	
TSS mg/l	**30.11**	**-**	**110.00**	**Above limit**	**3.17**	**-**
COD mg/l	**171.71**	**Above limit**	**0.00**	**-**	**46.23**	**-**
BOD mg/l	**104.98**	**Above limit**	**0.00**	**-**	**26.42**	**-**
CN^- tot. mg/l	**13.55**	**Above limit**	**0.00**	**-**	**0.00**	**-**
F^- mg/l	**150.55**	**Above limit**	**0.00**	**-**	**0.00**	**-**
B mg/l	**1.51**	**-**	**0.00**	**-**	**0.00**	**-**
Se mg/l	**9.03**	**Above limit**	**0.00**	**-**	**0.00**	**-**
Fe mg/l	**15.06**	**Above limit**	**0.00**	**-**	**0.00**	**-**
As mg/l	**0.03**	**-**	**0.00**	**-**	**0.00**	**-**
Ba mg/l	**0.12**	**-**	**0.00**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.30**	**-**	**0.00**	**-**	**0.00**	**-**
Cu mg/l	**0.01**	**-**	**0.00**	**-**	**0.00**	**-**
Hg mg/l	**0.001**	**-**	**0.000**	**-**	**0.000**	**-**
Mn mg/l	**0.01**	**-**	**0.00**	**-**	**0.00**	**-**
Ni mg/l	**0.15**	**-**	**0.00**	**-**	**0.00**	**-**
Pb mg/l	**0.03**	**-**	**0.00**	**-**	**0.00**	**-**
Zn mg/l	**0.01**	**-**	**0.00**	**-**	**0.00**	**-**

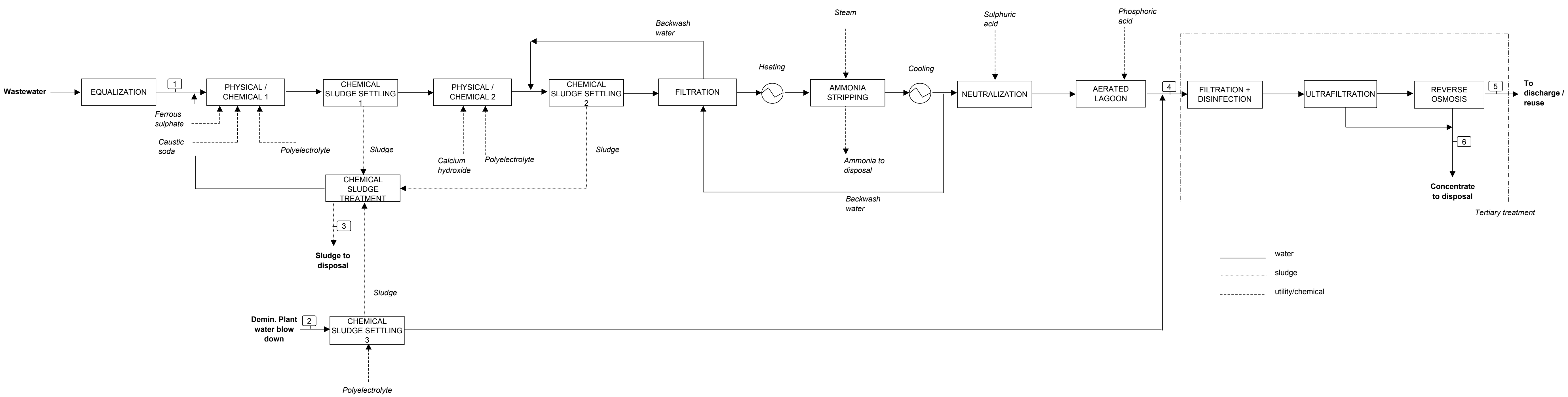
Treated water discharge to: river.

Notes.

1) With reference to the Attachment A5, clean streams, which do not need any pollution reduction, are:
stream n° 5. BD: steam gen. (HRSG)
stream n° 7. Cooling tower system BD
stream n° 8. Lignite drying effluent
stream n° 10. BD: steam gen. (syngas cooling)
stream n° 13. BD steam gen. (gasification)

ATTACHMENT B6

Case 5.04: SHELL IGCC, LIGNITE, WITH CO_2 CAPTURE - WASTE WATER STREAM BLOCK FLOW DIAGRAM



ATTACHMENT B6

Case 5.04: SHELL IGCC, LIGNITE, WITH CO_2 CAPTURE – WASTE WATER TREATMENT MASS BALANCE

Table B6-2

STREAM	Total composition of polluted stream (without demin. Plant water B.D.)	Demin. plant water B.D.	Chemical sludge to disposal	Total water amount to tertiary treatment	Treated water to discharge / reuse	Concentratef rom tertiary treatment
N°	**1**	**2**	**3**	**4**	**5**	**6**
Temperature (°C)	40.30	20.00		34.78	34.77	34.77
Flowrate (m3/h)	175.12	32.40	0.332	208.916	140.392	68.524
H_2S						
H_2S mg/l	**24.43**	**0.00**	**0.48**	**0.42**	**0.06**	**1.16**
H_2S kg/h	4.28	0.00	0.00	0.09	0.01	0.08
NH_3						
NH_3 mg/l	**111.81**	**0.00**	**101.24**	**3.47**	**0.50**	**9.56**
NH_3 kg/h	19.58	0.00	0.03	0.73	0.07	0.66
Cl^-						
Cl^- mg/l	**1415.21**	**4560.00**	**1529.69**	**1891.04**	**270.15**	**5211.88**
Cl^- kg/h	247.83	147.74	0.51	395.07	37.93	357.14
PO_4^{---}						
PO_4^{---} mg/l	**0.92**	**0.00**	**0.88**	**0.00**	**0.00**	**0.00**
PO_4^{---} kg/h	0.16	0.00	0.00	0.00	0.00	0.00
SO_4^{--}						
SO_4^{--} mg/l	**15.06**	**830.00**	**111.82**	**805.70**	**115.10**	**2220.58**
SO_4^{--} kg/h	2.64	26.89	0.04	168.32	16.16	152.16
NO_3^-						
NO_3^- mg/l	**0.00**	**510.00**	**19.99**	**79.06**	**11.29**	**217.90**
NO_3^- kg/h	0.00	16.52	0.01	16.52	1.59	14.93
MDEA						
MDEA mg/l	**31.30**	**0.00**	**29.88**	**4.21**	**0.00**	**0.00**
MDEA kg/h	5.48	0.00	0.01	0.88	0.00	0.00
TSS						
TSS mg/l	**30.11**	**110.00**	**222826.09**	**7.35**	**0.00**	**22.42**
TSS kg/h	5.27	3.56	73.87	1.54	0.00	1.54
COD						
COD mg/l	**171.71**	**0.00**	**163.92**	**36.24**	**0.00**	**0.00**
COD kg/h	30.07	0.00	0.05	7.57	0.00	0.00
BOD						
BOD mg/l	**104.96**	**0.00**	**100.24**	**22.89**	**0.00**	**0.00**
BOD kg/h	18.38	0.00	0.03	4.78	0.00	0.00
CN tot.						
CN tot. mg/l	**13.55**	**0.00**	**0.48**	**0.42**	**0.06**	**1.16**
CN tot. kg/h	2.37	0.00	0.00	0.09	0.01	0.08
F^-						
F^- mg/l	**150.55**	**0.00**	**37.39**	**5.06**	**0.72**	**13.93**
F^- kg/h	26.37	0.00	0.01	1.06	0.10	0.95
Se						
Se mg/l	**9.03**	**0.00**	**0.03**	**0.03**	**0.00**	**0.07**
kg/h	1.58	0.00	0.00	0.01	0.00	0.00
Fe						
Fe pmg/l	**15.06**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Fe kg/h	2.64	0.00	0.00	0.00	0.00	0.00

ATTACHMENT B7

Case 5.06: GE IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE – IGCC COMPLEX BLOCK FLOW DIAGRAM - WASTE STREAMS TO BE TREATED

Table B7-1

Parameter	Total composition of polluted stream		Total composition of clean stream (1)	
Temperature (°C)	48.02		96.31	
Total Flow (m^3/h)	21.71		14.99	
H_2S mg/l	**31.38**	**Above limit**	**0.00**	**-**
NH_3 mg/l	**19.31**	**Above limit**	**0.00**	**-**
Cl^- mg/l	**652.25**	**-**	**0.00**	**-**
PO_4^{---} mg/l	**0.00**	**-**	**3.03**	**-**
SO_4^{--} mg/l	**117.32**	**-**	**0.00**	**-**
NO_3^- mg/l	**61.09**	**-**	**0.00**	**-**
MDEA mg/l	**0.00**		**0.00**	
TSS mg/l	**84.75**	**Above limit**	**3.03**	**-**
COD mg/l	**326.39**	**Above limit**	**0.00**	**-**
BOD mg/l	**179.51**	**Above limit**	**0.00**	**-**
CN^- tot. mg/l	**3.58**	**Above limit**	**0.00**	**-**
F^- mg/l	**0.00**	**-**	**0.00**	**-**
B mg/l	**0.00**	**-**	**0.00**	**-**
Se mg/l	**0.00**	**-**	**0.00**	**-**
Fe mg/l	**0.00**	**-**	**0.00**	**-**
As mg/l	**0.00**	**-**	**0.00**	**-**
Ba mg/l	**0.00**	**-**	**0.00**	**-**
Cd mg/l	**0.00**	**-**	**0.00**	**-**
Cr mg/l	**0.00**	**-**	**0.00**	**-**
Cu mg/l	**0.00**	**-**	**0.00**	**-**
Hg mg/l	**0.000**	**-**	**0.000**	**-**
Mn mg/l	**0.00**	**-**	**0.00**	**-**
Ni mg/l	**0.00**	**-**	**0.00**	**-**
Pb mg/l	**0.00**	**-**	**0.00**	**-**
Zn mg/l	**0.00**	**-**	**0.00**	**-**
Formiates mg/l	**529.64**		**0.00**	
Selexol mg/l	**74.27**		**0.00**	

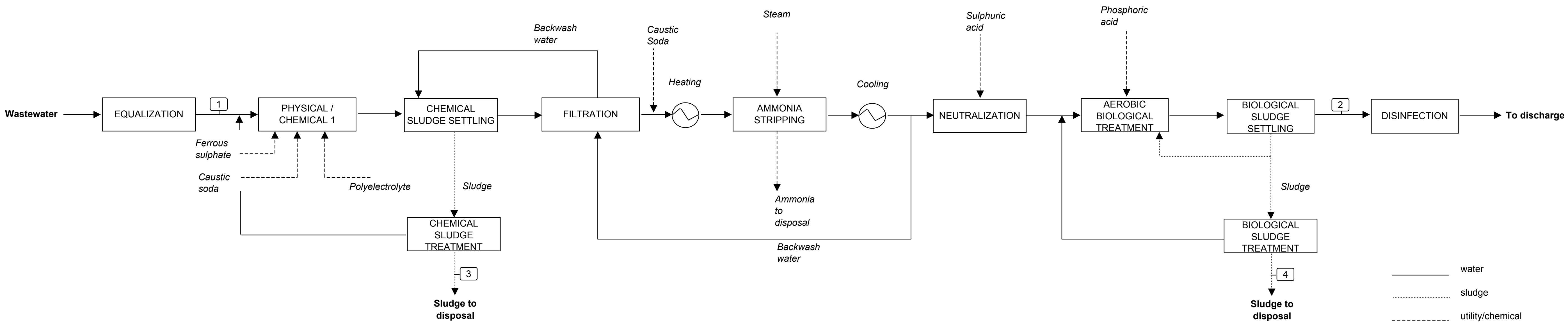
Treated water discharge to: sea.

Notes.

1) With reference to the Attachment A7, clean streams, which do not need any pollution reduction, are:
stream n° 4. BD: steam gen. (syngas cool)
stream n° 6. BD: steam gen. (SRU)
stream n° 7. BD: steam gen. (HRSG)
stream n° 12. Condensate From CO_2 dryers

ATTACHMENT B7

Case 5.06: GE IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



ATTACHMENT B7

Case 5.06: GE IGCC, BITUMINOUS COAL, WITH CO_2 CAPTURE – WASTE WATER TREATMENT MASS BALANCE

Table B7-2

STREAM	Total composition of polluted stream	Treated water	Chemical sludge to disposal	Biological sludge to disposal
N°	1	2	3	4
Temperature (°C)	48.00	30.00	46.75	30.00
Flowrate (m^3/h)	21.71	22.20	0.021	0.01
H_2S				
H_2S mg/l	**31.38**	**0.50**	**0.50**	**0.50**
H_2S kg/h	0.68	0.01	0.00	0.00
NH_3				
NH_3 mg/l	**19.31**	**1.92**	**18.31**	**1.92**
NH_3 kg/h	0.42	0.04	0.00	0.00
Cl^-				
Cl^- mg/l	**652.25**	**637.08**	**637.08**	**637.08**
Cl^- kg/h	14.16	14.14	0.01	0.00
PO_4^{---}				
PO_4^{---} mg/l	**0.00**	**0.00**	**0.00**	**0.00**
PO_4^{---} kg/h	0.00	0.00	0.00	0.00
SO_4^{--}				
SO_4^{--} mg/l	**117.32**	**215.04**	**199.86**	**215.04**
SO_4^{--} kg/h	2.55	4.77	0.00	0.00
NO_3^-				
NO_3^- mg/l	**61.09**	**59.67**	**59.67**	**59.67**
NO_3^- kg/h	1.33	1.32	0.00	0.00
MDEA				
MDEA mg/l	**0.00**	**0.00**	**0.00**	**0.00**
MDEA kg/h	0.00	0.00	0.00	0.00
TSS				
TSS mg/l	**84.75**	**20.00**	**222826.09**	**207770.27**
TSS kg/h	1.84	0.44	4.62	1.19
COD				
COD mg/l	**326.39**	**48.44**	**318.80**	**48.44**
COD kg/h	7.08	1.08	0.01	0.00
BOD				
BOD mg/l	**179.51**	**26.64**	**175.34**	**175.34**
BOD kg/h	3.90	0.59	0.00	0.00
CN tot.				
CN tot. mg/l	**3.58**	**0.50**	**0.50**	**0.50**
CN tot. kg/h	0.08	0.01	0.00	0.00
Formiates				
Formiates mg/l	**529.64**	**3.00**	**517.32**	**3.00**
Formiates kg/h	11.50	0.07	0.01	0.00
Selexol				
Selexol mg/l	**74.27**	**1.00**	**72.54**	**1.00**
Selexol kg/h	1.61	0.02	0.00	0.00

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO_2 CAPTURE
DOCUMENT NAME : USC PC CASES, GENERAL INDEX

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USC PC CASES REPORT

I N D E X

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SECTION A

USC PC CASES, GENEARL INFORMATION

I N D E X

1. Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage and loss of power in power plants with CO_2 capture.

The work is developed thought the establishment of a rigorous accounting of water usage throughout the power plant in order to establish an acceptable methodology that can be used to compare water usage in power plants with and without CO_2 capture. This can provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs.

Cost effective water reduction technologies that could be applied for power plants with CO_2 capture are identified. Finally, an evaluation of the performance of power plants with CO_2 capture and potential impacts on the water usage applicable to areas where water supply could be severely limited is performed.

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
These studies shall be used as a basis for present study.

In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

The purposes of the study, therefore, include:

- A review and assessment of the available information of water usage from power plants such as PC, IGCC and NGCC with or without CO_2 capture from various previous studies done for IEA GHG, based on oxyfuel, pre- or post combustion CO_2 capture technologies.
- A review and assessment of the available technologies that would allow reduction of water usage from power plants;
- An evaluation and assessment of the applicable technologies for power plants with CO_2 capture in areas where water supplies could be severely limited.

The study is based on the current state-of-the-art technologies, evaluating costs and performances of plants which can be presently engineered and built.

Present report #2 analyses the Ultra Super Critical Pulverised Coal (USC PC) cases without and with CO_2 capture and without and with limitation on water usage.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 number PH4/33, November 2004, has been taken as a reference for the configuration and performances of the plant analysed in reference cases of present report. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The following four different alternatives are therefore evaluated:

- Case 3.22: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4/33 – Case 3, dated November 2004.
- Case 3.21: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4/33 – Case 4, dated November 2004.
- Case 3.23: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (dry land case).
- Case 3.25: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

For each of the above mentioned cases the following technical information are provided:

- ✓ Description and process schemes for each section of the plant;

- ✓ Mass and mole flowrates, temperature, pressure, energy content and composition of the main process streams within the plants;
- ✓ Detailed water flow diagram;
- ✓ Detailed water balance of the major section of the plant;
- ✓ Breakdown of the ancillary power consumptions;
- ✓ Breakdown of the major plant equipment;
- ✓ Breakdown of the water consumptions;
- ✓ Specific fuel consumption per MW net produced;
- ✓ Specific emission of CO_2 per MW net produced;
- ✓ Specific water consumption per MW net produced.

2. Project design bases

The Power Plants are designed to process, in an environmentally acceptable manner, a coal from eastern Australia and produce electric energy to be delivered to the local grid.

2.1. Feedstock specification

The feedstock characteristics are listed hereinafter.

2.1.1. Design Feedstock

	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. Back-up Fuel

	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 plant are listed here below with their specifications.

2.2.1. Electric Power

Net Power Output:	750	MWe	nominal capacity
Voltage:	380	kV	
Frequency:	50	Hz	
Fault duty:	50	kA	

2.2.2. Carbon Dioxide

The Carbon Dioxide characteristics at plant B.L., for the post-combutsion CO_2 capture cases only, are the following:

Status:	supercritical
Pressure:	110 bar g
Temperature:	32 °C

Purity:

CO_2:	> 99% mol
Moisture:	<10 ppmv
Oxygen:	<10 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.

Capture rate : 87.5% (as per reference study).

2.2.3. Solid By-products

The plant produces Gypsum and Mill rejects (pyritic) as solid by-products that are potentially saleable to the building industry.

2.3. Environmental Limits

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

2.3.1. Gaseous Emissions

The overall gaseous emissions from the plant referred to dry flue gas with 6% volume O_2 shall not exceed the following limits:

NOx (as NO_2):	≤	200	mg/Nm^3
SOx (as SO_2):	≤	200	mg/Nm^3
Particulate :	≤	30	mg/Nm^3

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 from the plant is the sea cooling water return stream (for wet land cases only).

The 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 plant produces the following solid wastes:

- Bottom ash
- Fly Ash
- Sludges from WWT

2.4. Plant Operation

2.4.1. Capacity

For all the cases the nominal design capacity is 750 MWe.

For both reference cases, fuel input has been selected in order to have 830 MWe gross power output. As a consequence, the net power output of the plants is different due to the different auxiliary consumptions for the cases with and without CO_2 removal.

For the dry land cases, the fuel input has been kept constant as the relevant reference case. Gross power output and auxiliary consumptions are affected by the dry land design and therefore the resulting net power output of each dry land case is significantly lower than the relevant reference case.

In accordance with reference study, a minimum equivalent availability of 90% corresponding to 7,884 hours of operation in one year at 100% capacity is assumed

for the alternatives without CO_2 capture starting from the second year of commercial operation.
For the cases with CO_2 capture a minimum equivalent availability of 88% corresponding to 7,710 hours of operation in one year at 100% capacity is assumed for all the alternatives with CO_2 capture due to the introduction of the CO_2 capture plant.
During the first year of commercial operation, when the plants need final tunings, the equivalent availability will be lower than the normal one (i.e.: 80%, corresponding to 7,000 hours for cases without CO_2 capture, 75%, corresponding to 6,570 h/y for the cases with CO_2 capture).
A lower load factor is considered for the plants with CO_2 capture due to the capture and compression units. The availability of the capture unit shall be confirmed once the first demonstration plant can provide more detailed information on the unit operation.
The units actually operating in the existing plants are designed for applications that are different from the post-combustion CO_2 capture. The characteristics of the flue gases coming from boilers are different from the ones in the existing units, as typically the pressure is lower and the CO_2 is more diluted
In case the solvent cannot tolerate the expected impurity contents, the risk is more related to an higher solvent degradation and therefore to higher operating and maintenance costs associated to the CO_2 capture rather than to lower demonstrated service factor.

It has been assumed that the dry land design does not have any impact on plant load factor.

2.4.2. Unit Arrangement

Based on the configuration shown in the reference studies, the plants have the following 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

2.4.3. Turndown

The plant is designed to operate with a good degree of flexibility in terms of turndown capacity and feedstock characteristics.

The minimum turndown of the boiler is 50% as far as duty is concerned. Such turndown is achieved with a decrease of the steam parameters (i.e. RH temperature).

The minimum turndown 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 turndown of the CO_2 capture plant is between 30% and 40% on the basis of the flue gases inlet flowrate. At low flue gases flowrate will not correspond a proportional reduction of the circulating MEA as the internals of the column need to be properly wetted by the solvent. Therefore the unit consumptions (in terms of MEA circulation and steam consumption for MEA regeneration) will be higher than 30%-40%.

In conclusion, even if the minimum turndown of the Steam Turbine and the CO_2 capture plant is much lower, due to the higher turndown of the boiler, the overall plant turndown is some less than 50%. This is due to the reduced steam characteristics at boiler turndown and the higher specific steam consumption in the CO_2 capture plant that have as a consequence the reduction of the Steam Turbine efficiency and an overall power production lower than 50%.

2.5. Location

Reference cases – wet land
The site for the reference cases, wet land, is a green field located 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 harbor equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

Dry land cases
The site for dry land cases is a green field located in a dry in land region in South Africa.

The plant area is assumed to be close to a river. Coal transport is assumed to be assured by rail connection.

No special civil works implications are assumed.

2.6. 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

Reference cases – wet land			
minimum air temperature:	-10	°C	
maximum air temperature:	30	°C	
average air temperature:	9	°C	(*)
Dry land cases			
minimum air temperature:	2	°C	
maximum air temperature:	30	°C	
average air temperature:	14	°C	(*)

2.7. Software Codes

For the development of the Study, two software codes will be 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 all the units included in the plant to be built on the east coast area of Netherlands for the wet land cases and in an in-land area in South Africa for the dry land cases.

The plant is constituted by the following groups of units:

Process Units:
- 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 services and utility fluids to all the units of the plant; including:
- 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, 380 kV substation).

3.1. Units of Measurement

All calculations are and shall be in SI units, with the exception of piping typical dimensions, which shall be in accordance with ANSI.

3.2. Climatic and Meteorological Information

Reference is made to paragraph 2.6 for main data.

Other data:

Sea water supply temperature and salinity (for reference cases, **wet land**, only)

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:

- Coal;
- Natural gas;
- Sea water supply (for reference cases, **wet land**, only);
- Sea water Return (for reference cases, **wet land**, only);
- Plant/Raw/Potable water;
- CO_2 rich stream.

3.4. Utility and Service fluids characteristics/conditions

In this paragraph are listed the utilities and the service fluids distributed inside the Plant.

3.4.1. Cooling Water

Reference cases – wet land

The plant primary cooling system is sea water 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 and drying exchangers, 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 and drying 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

Dry land cases

No primary cooling water is available at all. Air is used as primary cooling medium.

The temperature difference considered between the inlet condensing steam and the ambient air in the steam condenser is 25 °C.

Machinery Cooling Water (secondary system)

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

Supply temperature:
- max supply temperature: 35 °C
- normal supply temperature: 25 °C
- max allowed temperature increase: 10 °C
- design return temperature for fresh cooling water cooler: 45 °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 and BFW

Steam

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

Table B.3.1 – 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. Natural Gas

Characteristics of Natural Gas are listed in paragraph 2.1.2.

Type : natural gas.
Service : boiler start-up fuel

Operating pressure at Users:	3.5	barg
Operating temperature at Users:	30	°C
Design pressure:	6.0	barg
Design temperature:	60	°C

3.4.6. 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

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

3.4.7. 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	230 ± 1% (from	2	50 ± 0.2%	12.5 kA

supply	UPS)			
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 International and EU Standard Codes.

IEA GHG

Water usage and loss Analysis in Power plants without and with CO_2 capture

Volume #2 - Section B – USC PC reference case, without CCS

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SECTION B

USC PC REFERENCE CASE, WITHOUT CCS
I N D E X

1. Introduction

The present case 3.21 refers to a USC PC plant, fed with bituminous coal and not provided with CO_2 capture unit.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 number PH4/33, November 2004, has been taken as a reference for the configuration and performances of the plant here analysed. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The main features of the Case 3.21 configuration of the USC PC plant are:

- Mitsui-Babcok boiler pulverized fuel ultra supercritical design.
- Flue Gas Desulphurization Plant
- DeNOx Plant
- No CO_2 removal

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%

2. Process Description

2.1. Overview

The IEA GHG study number PH4/33, November 2004, has been taken as a reference for the plant description and configuration.

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

Case 3.21 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. 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 from about 317 ppm @ 6%O_2 v/v (corresponding to approximately 650 mg/Nm^3), dry to less than 100 ppm @ 6% O_2 v/v, dry (corresponding to approximately 200 mg/Nm^3). The catalytic DeNOx reactor is situated in the gas stream between the boiler outlet and the air preheaters. 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 70 ppm @ 6%O_2 v/v, dry 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 Bara/600 Degrees C
HP exhaust	64.5/363 Bara/600 Degrees C
IP Turbine Inlet	60/620 Bara/600 Degrees C
LP Turbine Inlet	8 Bara
Condenser Pressure	0.04 Bara

Recycled vacuum condensate from the condenser hot well is preheated in a bank of preheaters, which are fed with extract steam form the LP turbines. 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. Following the deaerator a further bank of preheaters preheats the feed water 300 Degrees C prior to the boiler. These heaters are heated by IP turbine extract and finally by HP steam extracts from the turbines.

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 9.

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

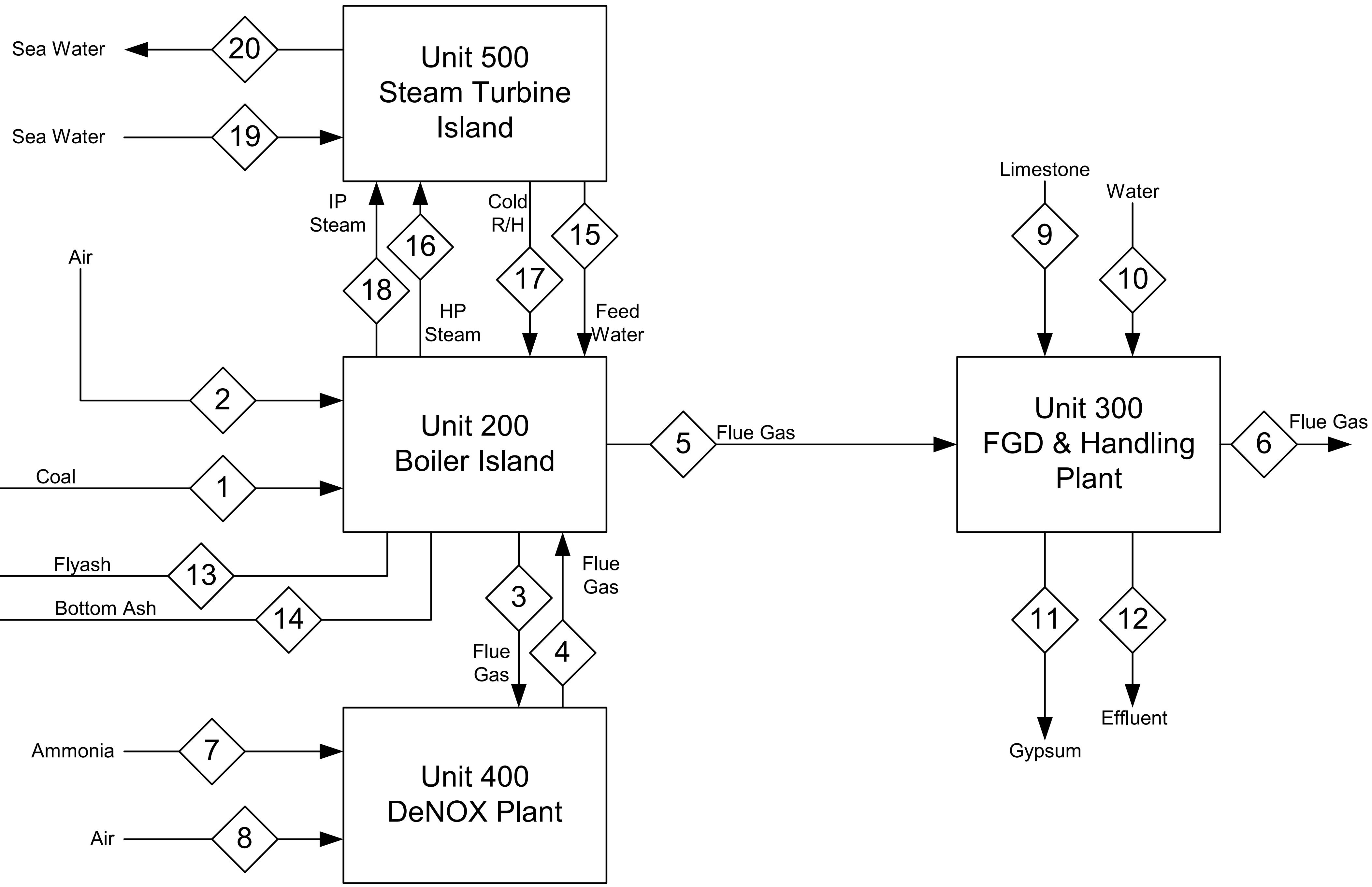
The Block Flow Diagram of the USC PC Plant, Case 3.21, and the schematic Flow Diagrams of Units 300, 400 and 500 are attached hereafter.

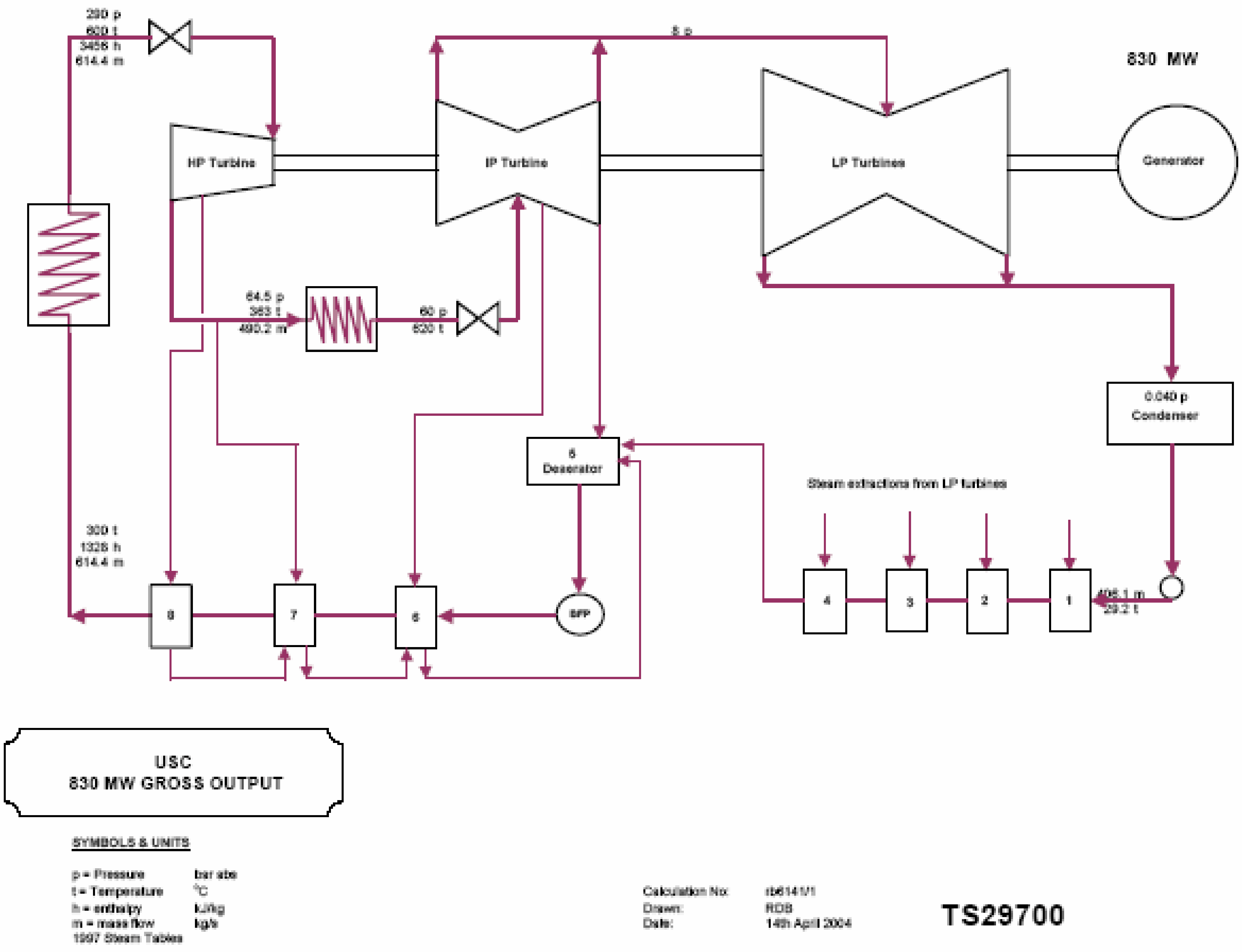
For a schematic representation of the Waste Water Treatment section, reference shall be made to PFD attached to Volume 1 (Attachment B3).

The IEA GHG study number PH4/33, November 2004, has been taken as a reference for the plant Block Flow Diagrams and Process Flow Diagrams attached.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

Case 3.21 830 MWe Gross PF Power Plant Base Case: Block Flow Diagram

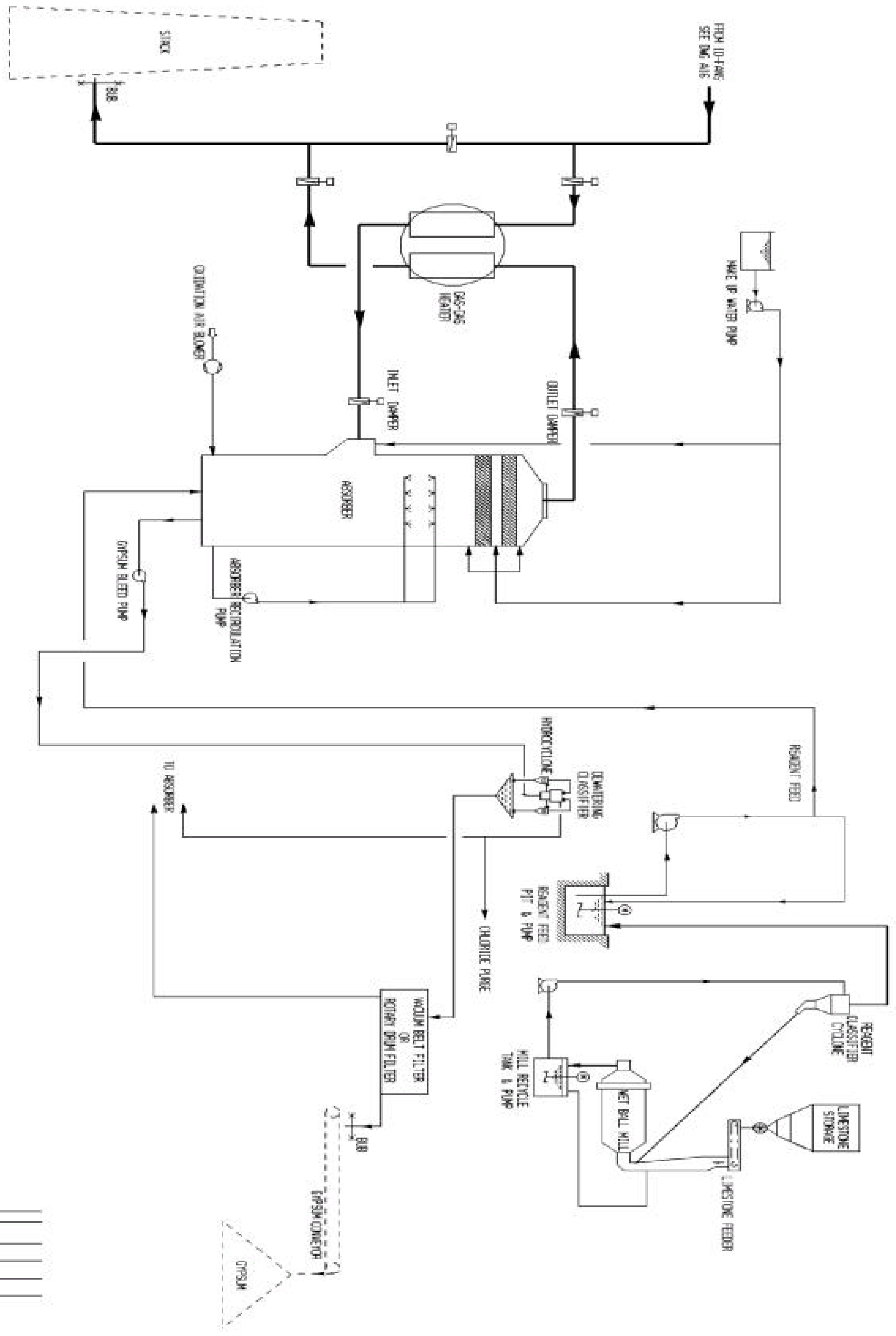




Drawing E7 *USCPF WITHOUT CAPTURE - TURBINE POWER ISLAND*

ALSTOM

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



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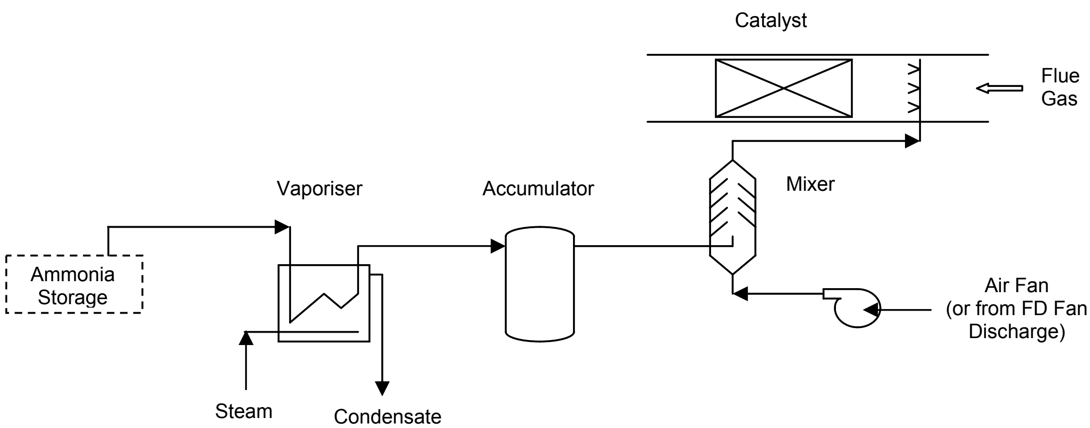
Issue

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		545	545	10,900	10,355	2,122,806
		kg/h		420	420	8,480	8,060	2,794,255
	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



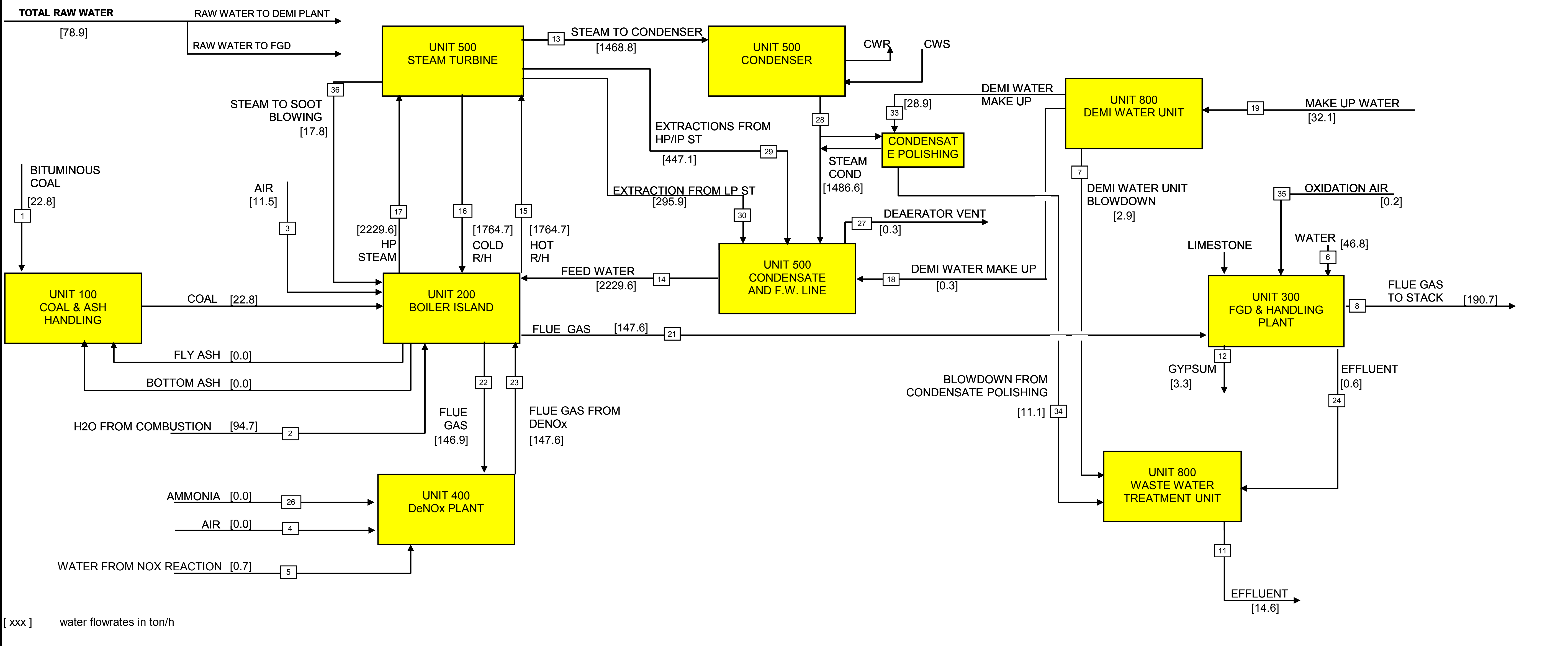
Issue	Date	Reason For Change	By	Chk'd	Rev'd / App'd
D					
C					
B					
A1	08/04/04	Draft Issue	RSP		

4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:
- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

CASE 3.21 - USC PC PLANT, BITUMINOUS COAL, WITHOUT CO2 CAPTURE - BLOCK FLOW DIAGRAM - WATER BALANCE



[xxx] water flowrates in ton/h

IEA GHG R&D PROGRAMME	Revision no.:	1
Water usage and loss Analysis in Power plants without and with CCS	Date:	October2010
Volume #2	Sheet:	

USC CPS fed by bituminous coal, w/o CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	22.8	8	Flue Gas	190.7
2	Water from coal combustion	94.7	11	Effluent from WWT	14.6
3	Moisture in air to Boiler Island	11.5	12	Moisture in Gypsum	3.3
4	Moisture in air to DeNOx Plant	0.0	27	Moisture in deaerator vent	0.3
5	Water from NOx reaction	0.7			
6	Water to FGD & Handling Plant	46.8			
26	Water in ammonia di DeNOx	0.0			
19	Make up to Demi Water Unit	32.1			
35	Water in oxidation air to FGD	0.2			
Total		209.0	Total		209.0

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	22.8	22	Flue Gas to DeNOx Plant	146.9
2	Water from coal combustion	94.7			
3	Moisture in Air to Boiler Island	11.5			
36	Steam for soot blowing	17.8			
Total		146.9	Total		146.9

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	2.9	11	Water Effluent from WWT	14.6
24	Effluent from FGD & Handling Uni	0.6			
34	BD from condensate polishing	11.1			
Total		14.6	Total		14.6

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1764.7	13	Steam to condenser	1468.8
17	HP steam from Boiler	2229.6	16	Cold R/H to Boiler	1764.7
			29	Extractions from HP/IP ST	447.1
			30	Extractions from LP ST	295.9
			36	Steam for soot blowing	17.8
Total		3994.3	Total		3994.3

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around DeNOx unit

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
4	Moisture in air to DeNOx Plant	0.0	23	Flue gas from DeNOx unit	147.6
5	Water from NOx reaction	0.7			
22	Flue gas from Boiler Island	146.9			
26	Water in ammonia to DeNOx	0.0			
Total		147.6	Total		147.6

5. 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.

The IEA GHG study number PH4/33, November 2004, has been taken as a starting reference for the plant H&M balance attached.

Some changes have been made to the H&M balance in order to make consistent the H&M balance of each unit and to close the water balance. The differences with respect to the reference study have been highlighted in the same heat and material balance attached to the appendix 1 of such a volume 2.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in Plants w/o and w CCS

Volume #2 - case 3.21

Revision no.: 1
Date: October 2010
Sheet: 1 of 2

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	66.61	0	0.29	0.29	0	0	0	0	0	0
- Air	kg/s	0	752.3	0	0	0	0	0	2.24	0	0
- Flue Gas	kg/s	0	0	778.7	781.2	817.9	821.8	0	0	0	0
- Ash	kg/s	0	0	5.3	5.3	0.018	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
- Ammonia	kg/s	0	0	0	0	0	0	0.117	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	1.77	0
Volume Flowrate	Am^3/s	-	607.9	1418.1	1416.6	880.0	831.9	-	1.84	-	0.013
	Nm^3/s	-	587.0	592.5	594.5	623.9	634.5	0.151	1.74	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Temperature	°C	9	9	380	380	114	85	9	15	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.24	0.55	0.55	0.93	0.99	-	1.21	-	-
Composition											
O_2	%v/v,wet		20.9	3.27	3.27	4.50	4.36		20.9		
CO_2	%v/v,wet		0.0	13.80	13.80	12.79	12.48		0.0		
SO_2	%v/v,wet		0.0	0.07	0.07	0.06	0.01		0.0		
H_2O	%v/v,wet		0.7	9.77	9.78	9.33	11.51		0.7		
N_2	%v/v,wet		78.4	73.09	73.08	73.32	71.64		78.4		
Emissions @ 6% O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1877	1877	1732	200				
CO	mg/Nm^3			0	0	0	0				
Particulates	mg/Nm^3			8444	8416	30	14				

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in Plants w/o and w CCS

Volume #2 - case 3.21

Revision no.: 1
Date: October 2010
Sheet: 2 of 2

Stream ID		11	12	13	14	15	16	17	18	19	20
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water
Mass Flow Rate											
- Coal	kg/s	0	0	0.34	0.11	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	6.08	2.03	0	0	0	0	0	0
- Water	kg/s	0.31	0.17	0	0	619.3	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	619.3	490.2	490.2	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	2.91	0	0	0	0	0	0	0	0	0
Volume Flowrate	Am^3/s	-	-	-	-	-	-	-	-	28.1	28.1
	Nm^3/s	-	-	-	-	-	-	-	-	-	-
Props											
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid
- Temperature	°C	23	23	114 / 380	1000	300	600	363	620	12	19
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-
- 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										
Particulates	mg/Nm^3										

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter.

					Rev: Draft
FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME			feb-10
	PROJECT:	WATER USAGE AND LOSS OF POWER IN PLANTS WITH CCS			ISSUED BY: L.So.
	LOCATION:	Netherlands			CHECKED BY: PC
	FWI N°:	1- BD 0475A			APPR. BY: SA

CASE 3.21 - WATER CONSUMPTION SUMMARY - USC PC, bituminous coal, without CO2 capture

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			61	
300	Flue Gas Desulphurization (FGD) and Handling Plant	46.8			
400	DeNOx Plant				
200	BOILER ISLAND			80	
500	POWER ISLAND UNIT (Steam Turbine)		29.2	2628	101160
800	UTILITY and OFFSITE UNITS				
	Cooling Water, Demineralized Water Systems, etc	32.1	-29.2	68	4863
	BALANCE	78.9	0	2837	106023

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
		feb-10
PROJECT:	WATER USAGE AND LOSS OF POWER IN PLANTS WITH C	ISSUED BY: L.So.
LOCATION:	Netherlands	CHECKED BY: PC
FWI Nº:	1- BD 0475A	APPR. BY: SA

CASE 3.21 - ELECTRICAL CONSUMPTION SUMMARY - USC PC without CO2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**5000**
300	**FGD**	**6000**
400	**DeNOx**	**300**
	BOILER AND POWER ISLAND UNITS	
200 - 500	**Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)**	**44000**
	Miscellanea utilities	**8000**
	UTILITY and OFFSITE	
800	**Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**10000**
	BALANCE	**73300**

Notes: (1) Minus prior to figure means figure is generated

7. Overall performance

The table summarizing the Overall Performance of the USC PC Plant, case 3.21, is attached hereafter.

USC PC		
bituminous coal, without CO_2 capture		
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	239.8
Coal LHV (air dried basis)	kJ/kg	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1723.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**831.0**

POWER PLANT PERFORMANCES		
FW pumps	MWe	34.0
Draught Plant	MWe	8.0
Coal mills, handling, etc.	MWe	5.0
ESP	MWe	2.0
Miscellanea	MWe	8.0
Utility Units consumption	MWe	10.0
FGD	MWe	6.0
DeNOx	MWe	0.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**73.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**757.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**48.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**44.0**

Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.074**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.743**
Specific water consumption per MW net produced	**t /MWh**	**0.104**

8. Environmental Impact

The USC PC Plant, case 3.21, is designed to process coal, whose characteristic is shown at Section A of present report, and produce electric power.
The gaseous emissions, liquid effluents and solid wastes from the Complex are summarized in the present paragraph.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarises expected flow rate and concentration of the combustion flue gas.

Table 8-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	821.8
Flow, Nm^3/h	2,284,200
Temperature, °C	85
Composition	**(%vol, wet)**
O_2	4.36
CO_2	12.48
SO_2	0.01
H_2O	11.51
N_2+Ar	71.64
Emissions	**mg/Nm^3 (1)**
NOx	200
SOx	203
Particulate	14

(1) Dry gas, O_2 Content 6% vol

8.1.2. 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.

8.2. 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 : 14.6 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 : 106,000 m^3/h
- Temperature : 19 °C

8.3. Solid Effluent

The plant is expected to produce the following solid by-products:

Furnace bottom ash
Flow rate : 7.3 t/h

Fly ash
Flow rate : 22 t/h

Mill rejects (pyritic)
Flow rate : 0.5 t/h

Gypsum
Flow rate : 11.6 t/h

Water content	:	9.5	%wt

<u>Sludges from WWT</u>

Flow rate	:	0.75	t/h
Water content	:	85	%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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

The equipment list in the reference study (IEA GHG study number PH4/33, November 2004) reported the list of the equipment only, without any size or detailed information.
FWI included detailed information for the main equipment and for those equipment that result impacted by the dry land design. In this way, for the investment cost evaluation, it has been possible to highlight the differences between the reference case and the dry land case and make an estimate of such differences only.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: Netherlands	DATE	February 2010	October 2010		
		PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
			DATE	February 2010	October 2010		
			ISSUED BY	L.So.	L.So.		
			CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (22.8 t/h), in combustion air (32.3 t/h) and generated by combustion (94.7 t/h), soot blowing (17.8 t/h)	water outlet as steam in flue gas (167.6 t/h)
		Reheater									
		Superheater									
		Economiser									
		Piping									
		Air handling plant									
		Structures									
		Bunkers									
		Pumps									
		Coal feeders									
		Soot blowers									
		Blow down systems									11.1 t/h water from condensate polishing
		Dosing equipment									
		Mills									
		Auxiliary boiler									
		Miscellaneous equipment									
		Burners									
		ESP									
		Flue gas blower	Axial fan	2.200.000Nm3/h x 700 mmH2O	9.5 MW			CS	1 blower in operation		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
			DATE	February 2010	October 2010		
			ISSUED BY	L.So.	L.So.		
			CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 300 - FGD and Handling Plant - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Ducts									
		GGH (gas to gas reheater)									
		Absorber island								Water inlet as raw water (46.8 t/h) and water in flue gas (150.6 t/h) and in oxidation air (0.2 t/h)	Water is mainly evaporated in flue gas, with some losses in gypsum (3.3 t/h) and blowdown (0.6 t/h).
		Limestone storage									
		Limestone slurry preparation island									
		Gypsum dewatering and storage									Water outlet as chloride purge (0.6 t/h)
		Make up water pumps									
		Oxidation air blower								Water inlet as moisture in ambient air (0.2 t/h)	

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
LOCATION: Netherlands	DATE	February 2010	October 2010		
PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
	APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 400 - DeNOx Plant - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Flue gas ducts									
		Reactor casing									Water generated in DeNOx reaction (0.7 t/h)
		Bypass system									
		Catalyst									
		Ammonia injection equipment									
		Handling equipment									
		Control system									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Steam turbine island package									Water outlet as deaerator vent (0.3 t/h)
		Steam turbine		831 MWe gross							
		Steam turbine condenser		807 MW th				tubes: titanium; shell: CS	Sea water heat exchanger		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 800 - Utility Units - USC PC without CO2 capture, fed with bituminous coal, case 3.21

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Demin water storage tankage								12.5 t/h of make up (raw water)	Water outlet as blowdown (1.1 t/h) and water make up to Steam Turbine Island (11.4 t/h)
		Raw water and firewater storage									
		Plant air compression skid									
		Emergency diesel generator system									
		Closed loop water cooler	plate	40 MW th				plates: titanium frame: SS	sea water heat exchanger		
		Blowdown water sump									
		Condensate return pump									
		Demin water pump									
		Sea water pumps	submerged	18000 m3/h x 20m	1250 kW			casing, shaft: SS; impeller: duplex	6 pumps in operation + 1 spare		
		Close loop CW pumps	centrifugal	2850 m3/h x 30m	335 kW			CS	1 pump 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									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 3, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

CLIENT : IEA GHG

PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO_2 CAPTURE

DOCUMENT NAME : USC PC REFERENCE CASE, WITH CCS – CASE 3.22

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
February 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
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SECTION C

USC PC REFERENCE CASE, WITH CCS
I N D E X

1. Introduction

The present case 3.22 refers to a USC PC plant, fed with bituminous coal, provided with CO_2 capture unit.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 number PH4/33, November 2004, has been taken as a reference for the configuration and performances of the plant here analysed. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The main features of the Case 3.22 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

The IEA GHG study number PH4/33, November 2004, has been taken as a reference for the plant description and configuration.

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

Case 3.22 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 (reference shall be made to paragraph 2.4 of section B of present Volume #2) 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 siutable 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 Bara/600 ° C
HP exhaust	64.5/363 Bara/600 ° C
IP Turbine Inlet	60/620 Bara/600 ° 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.
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 9.

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

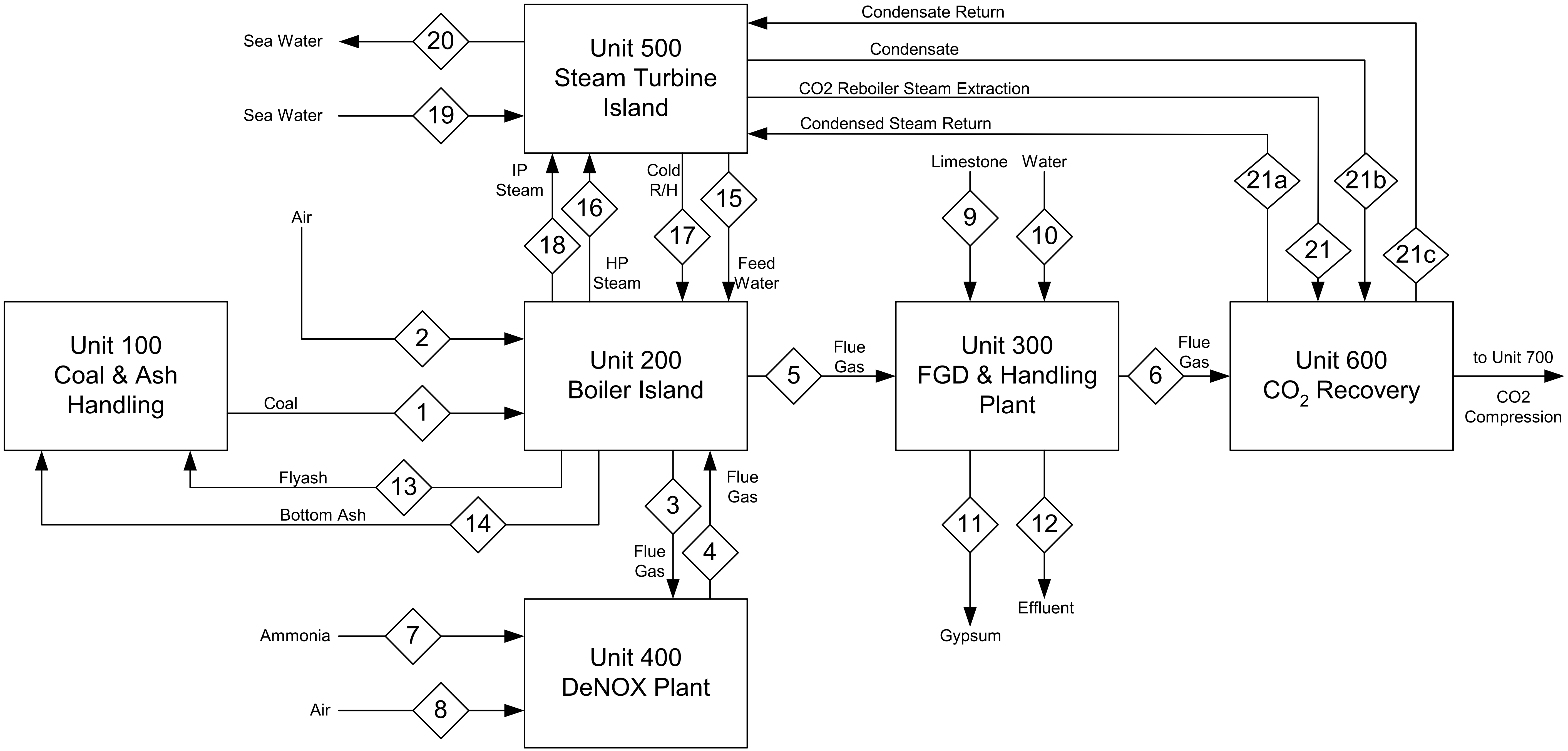
The Block Flow Diagrams of the USC PC Plant, Case 3.22, and the schematic Process Flow diagram of Units 300, 400, 500, 600 and 700 are attached hereafter.

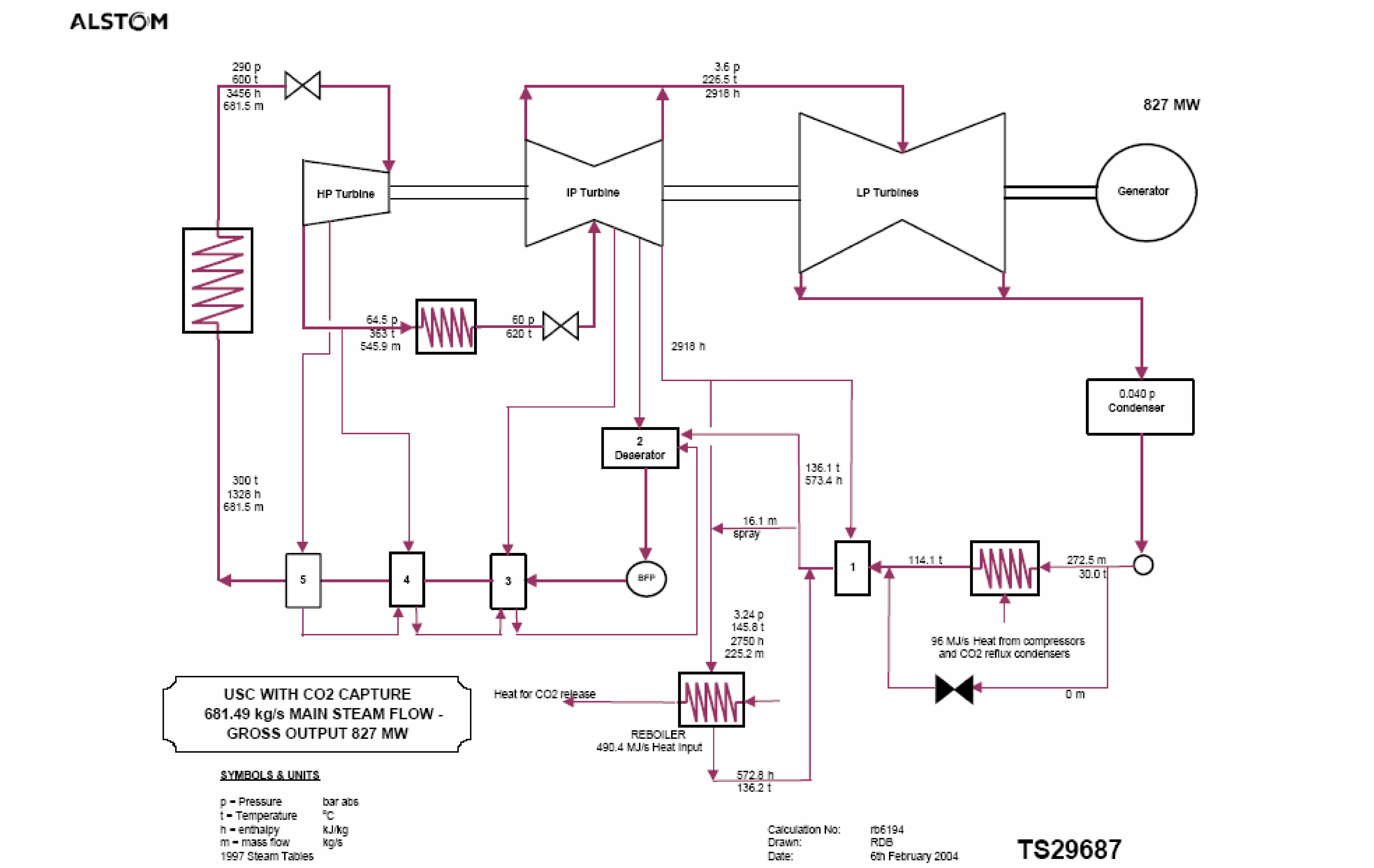
The IEA GHG study number PH4/33, November 2004, has been taken as a reference for the plant Block Flow Diagrams and Process Flow diagram attached.

For a schematic representation of the Waste Water Treatment section, reference shall be made to PFD attached to Volume 1 (Attachment B3).

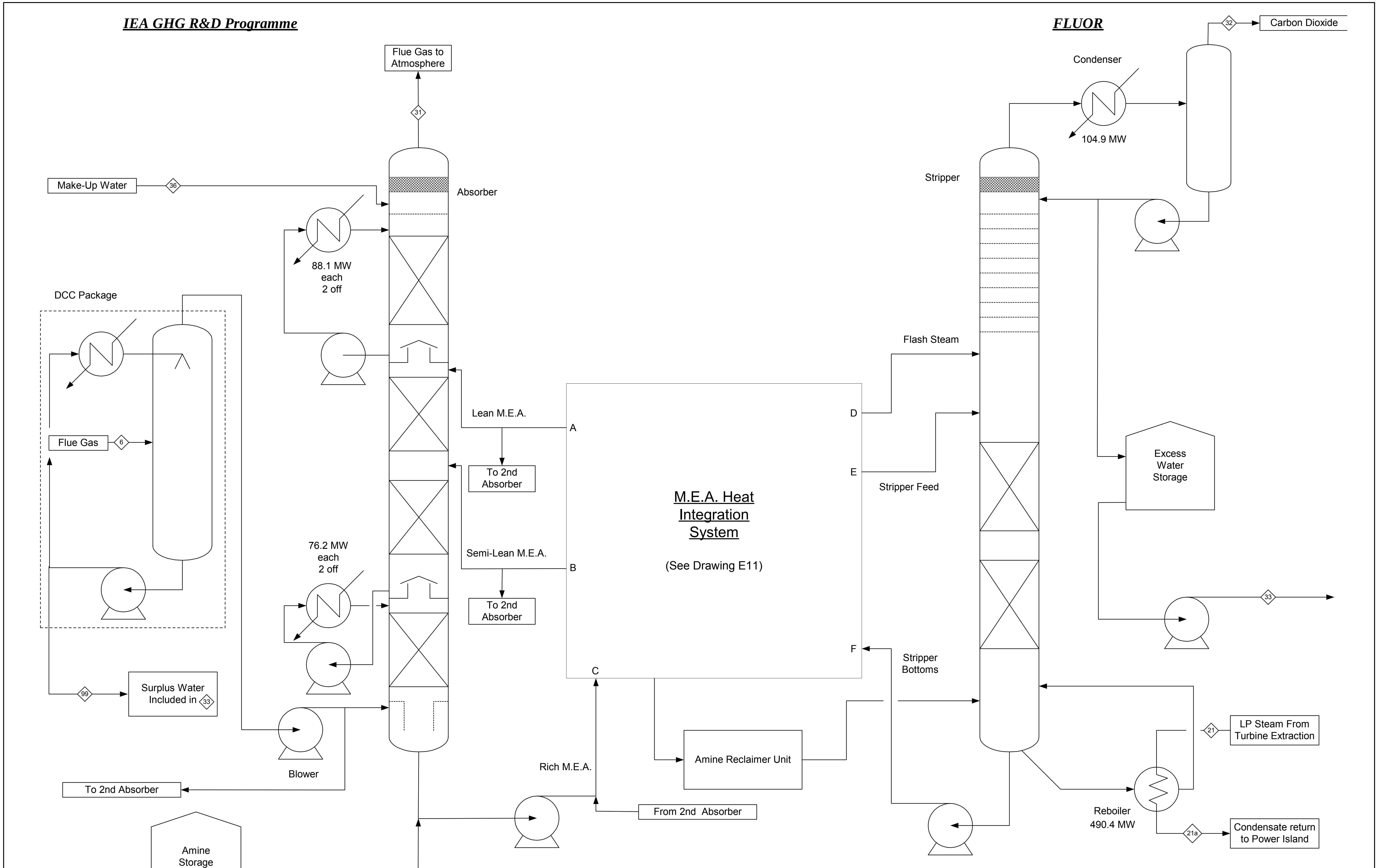
The H&M balances relevant to the scheme attached are shown in paragraph 5.

Case 3.22: 827 MWe Gross PF Power Plant with CO_2 Capture Amine Scrubbing: Block Flow Diagram





Drawing E9 *USCPF WITH CAPTURE - TURBINE POWER ISLAND*



Drawing E10 Case4 Super-Critical Steam Cycle with CO_2 Capture

CO_2 Absorption and Amine Stripping

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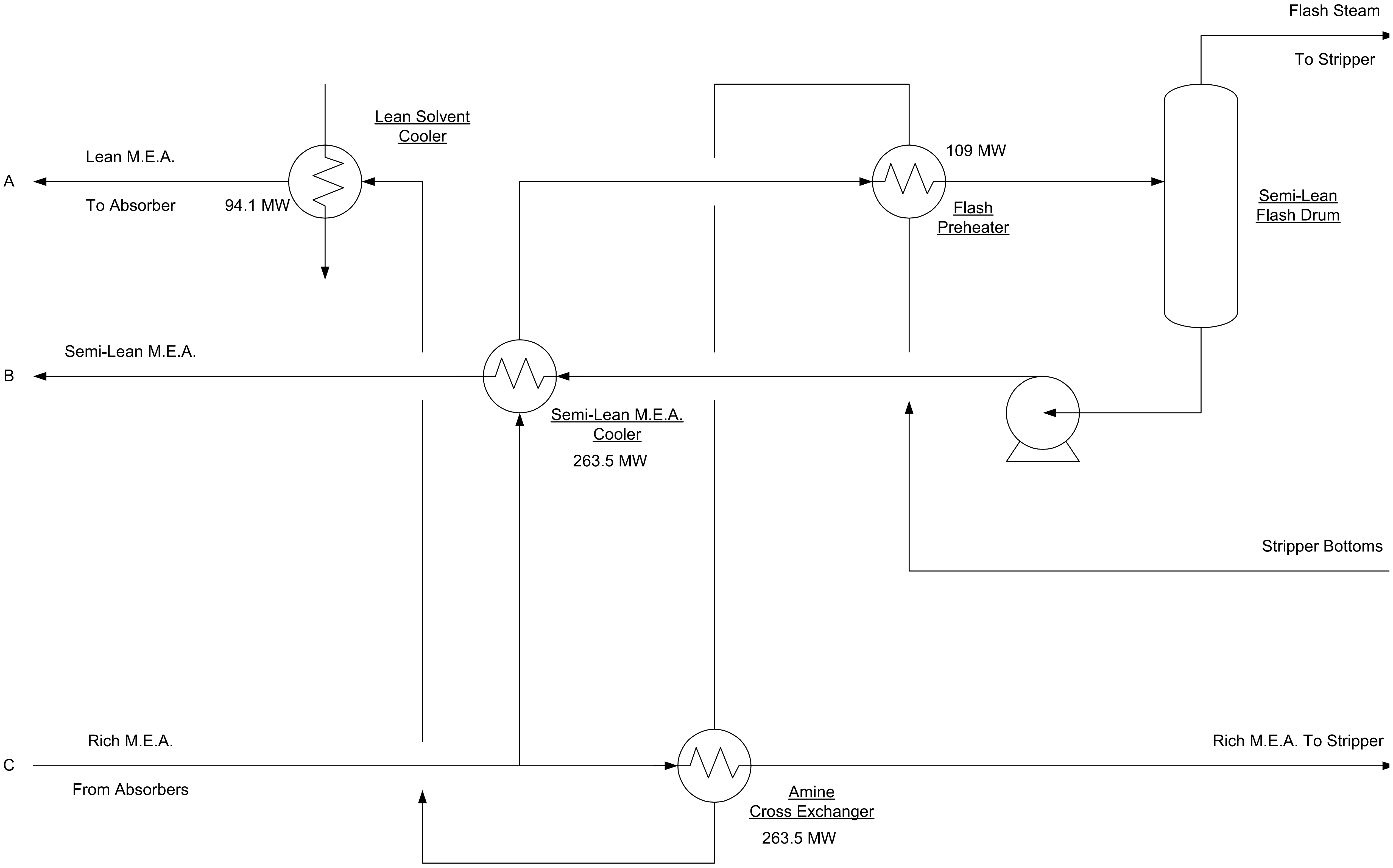
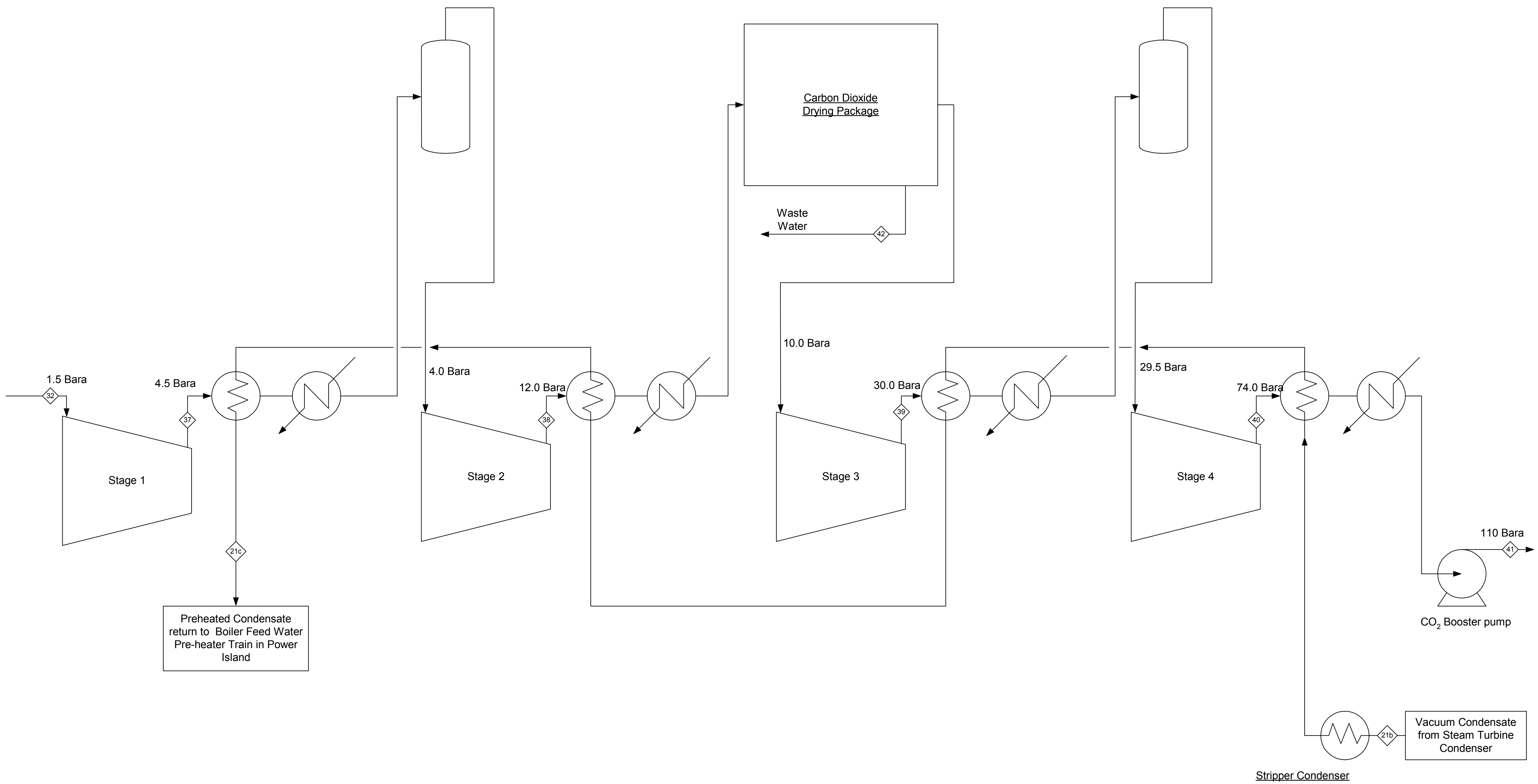
FLUOR



Drawing E11 Case4 Super-Critical Steam Cycle with CO_2 Capture

M.E.A. Heat Integration System

IEA GHG R&D Programme ***FLUOR***

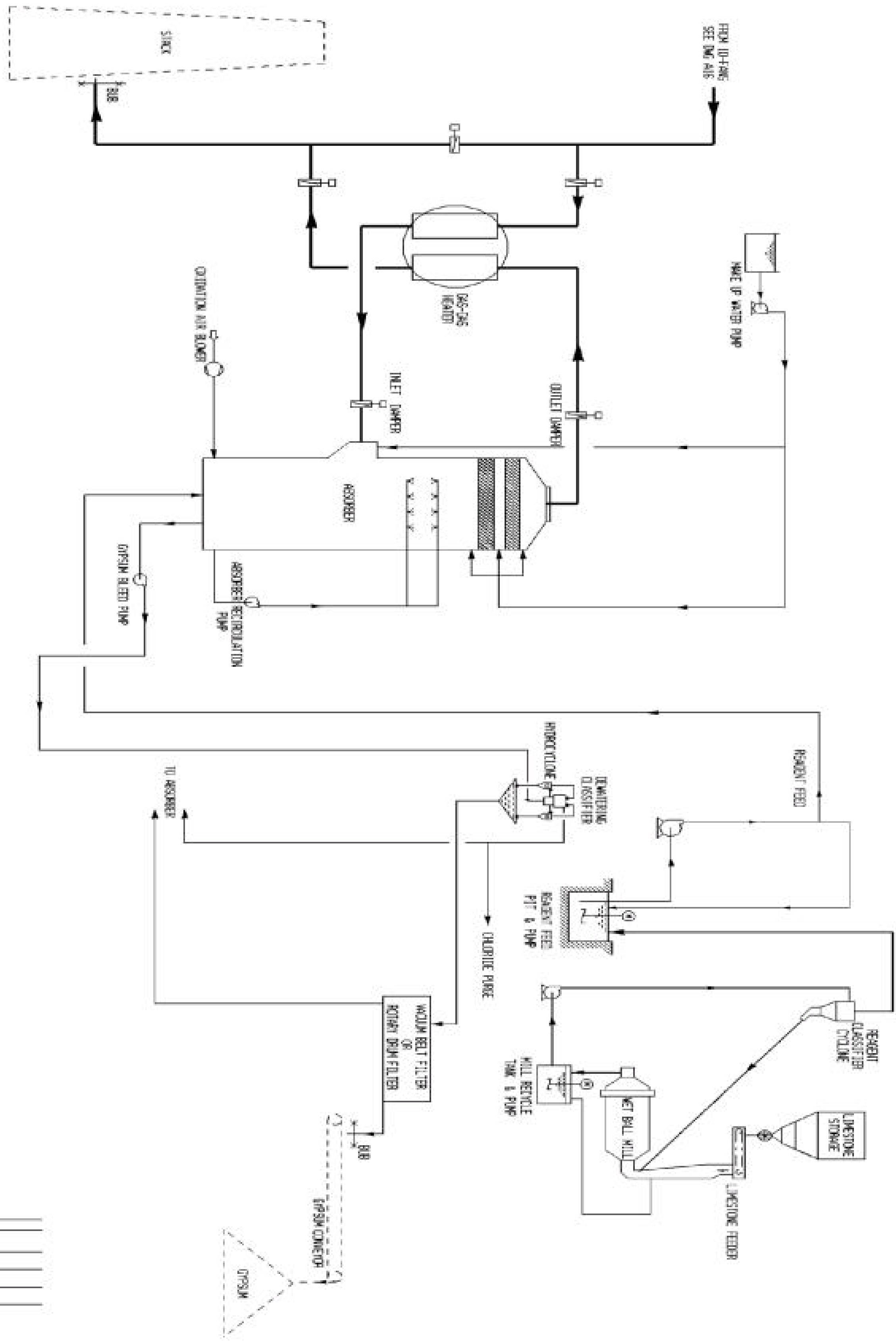


Drawing E12 Case 4 Super-Critical Steam Cycle with CO_2 Capture

CO_2 Compression and Recovery System

ALSTOM

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



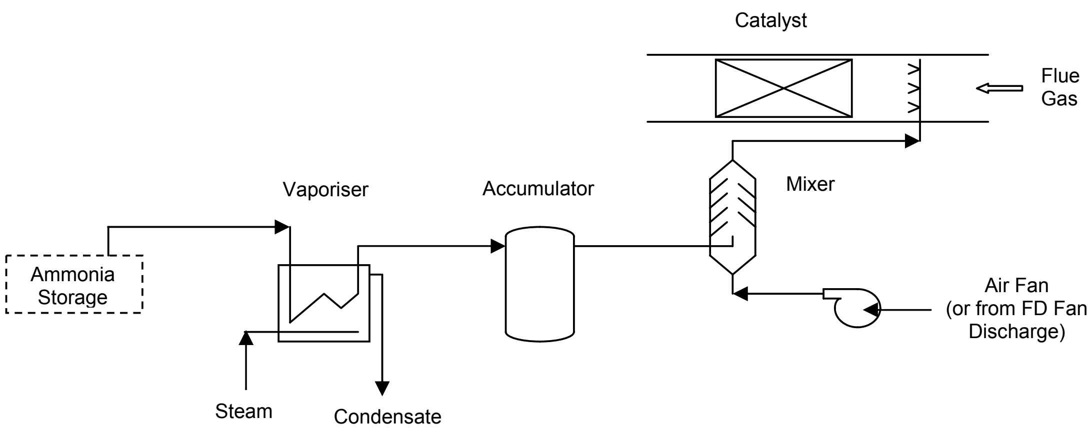
Issue

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. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:
- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units.

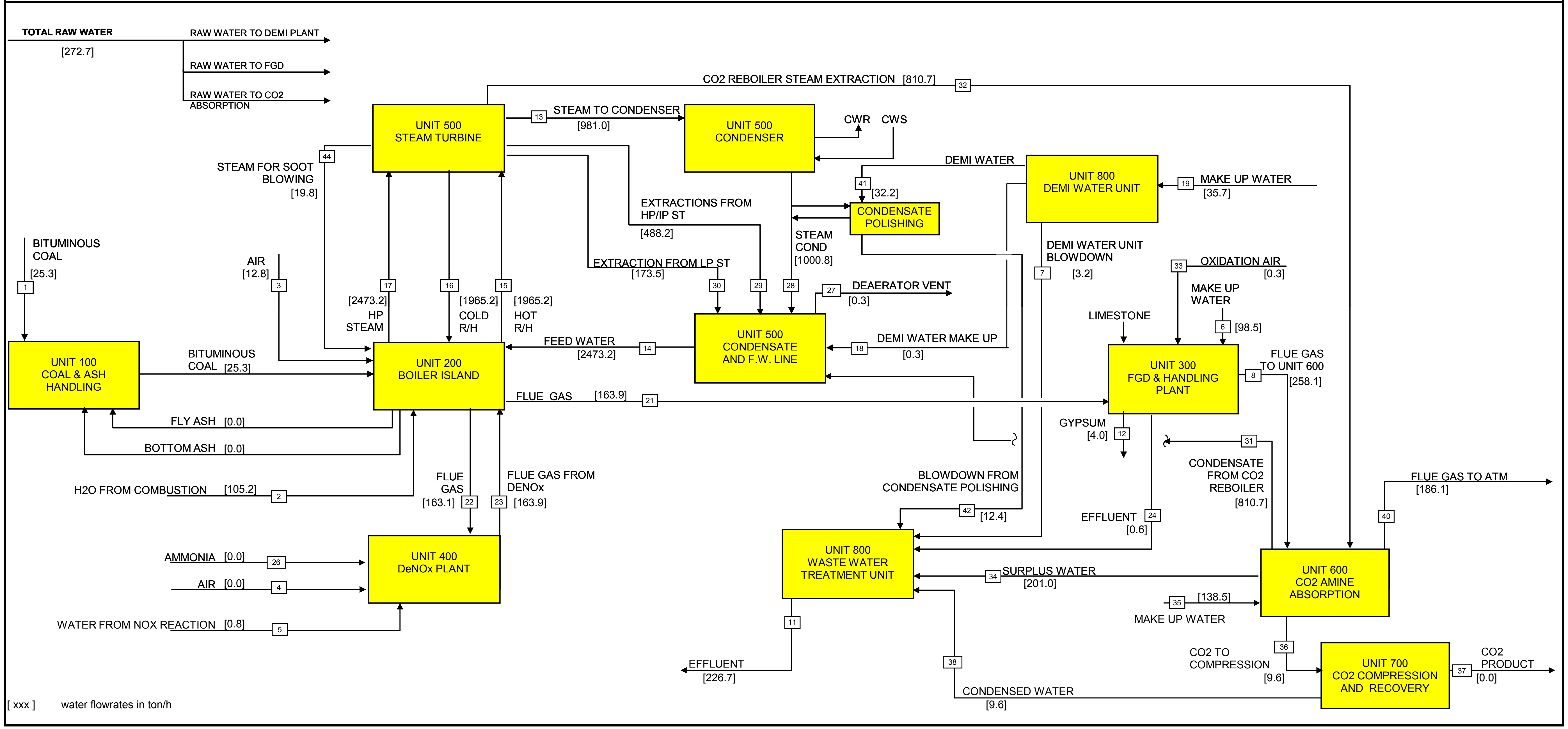
The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in Power plants without and with CCS
Volume #2

Revision no.: 1
Date: October 2010
Sheet:

CASE 3.22 - USC PC PLANT, BITUMINOUS COAL WITH CO2 CAPTURE (NET POWER OUTPUT = 666.0 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



USC CPS, bituminous coal, with CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	25.3	40	Flue Gas to atmosphere	186.1
2	Water from coal combustion	105.2	11	Effluent from WWT	226.7
3	Moisture in air to Boiler Island	12.8	12	Moisture in Gypsum	4.0
4	Moisture in air to DeNOx Plant	0.0	27	Deaerator vent	0.3
5	Water from NOx reaction	0.8	37	CO2 product	0.0
6	Water to FGD & Handling Plant	98.5			
26	Water in ammonia di DeNOx	0.0			
19	Make up to Demi Water Unit	35.7			
33	Oxidation air	0.3			
35	Make up water to Unit 600	138.5			
Total		417.2	Total		417.2

USC CPS, bituminous coal, with CO2 capture - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	3.20	11	Water Effluent from WWT	226.7
24	Effluent from FGD & Handling Uni	0.6			
34	Surplus water from Unit 600	201.0			
38	Condensed water from Unit 700	9.6			
42	BD from condensate polishing	12.4			
Total		226.7	Total		226.7

USC CPS, bituminous coal, with CO2 capture - Water Balance around DeNOx unit

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
4	Moisture in air to DeNOx Plant	0.0	23	Flue gas from DeNOx unit	163.9
5	Water from NOx reaction	0.8			
22	Flue gas from Boiler Island	163.1			
26	Water in ammonia to DeNOx	0.0			
Total		163.9	Total		163.9

USC CPS, bituminous coal, with CO2 capture - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	25.3	22	Flue Gas to DeNOx Plant	163.1
2	Water from coal combustion	105.2			
3	Moisture in Air to Boiler Island	12.8			
44	Steam for soot blowing	19.8			
Total		163.1	Total		163.1

USC CPS, bituminous coal, with CO2 capture - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1965.2	13	Steam to condenser	981.0
17	HP steam from Boiler	2473.2	16	Cold R/H to Boiler	1965.2
			29	Extractions from HP/IP ST	488.2
			30	Extractions from LP ST	173.5
			32	CO2 reboiler steam extraction	810.7
			44	Steam for soot blowing	19.8
Total		4438.4	Total		4438.4

USC CPS, bituminous coal, with CO2 capture - Water Balance around Unit 600

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Make up water to Unit 600	138.5	40	Flue gas to atmosphere	186.1
8	Flue gas to Unit 600	258.1	36	Water in CO2 to compression	9.6
32	CO2 reboiler steam extraction	810.7	31	Condensed steam return	810.7
			34	Surplus water from Unit 600	201.0
Total		1207.4	Total		1207.4

5. 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.

The IEA GHG study number PH4/33, November 2004, has been taken as a starting reference for the plant H&M balance attached.

Some changes have been made to the H&M balance in order to make consistent the H&M balance of each unit and to close the water balance.
The differences with respect to the reference study have been highlighted in the same heat and material balance attached to the appendix 1 of such a volume 2.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o and with CCS

Volume #2 - case 3.22

Revision no.: 1
Date: October 2010
Sheet: 1 of 4

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 Gas	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
- Limestor	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				
Particulat	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
- Limesto	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														
Particulat	mg/Nm^3														

FLUOR

Heat And Material Balance
CASE 3.22: USCPF WITH CAPTURE

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							
	H2O	18.02	15608	10328	533	12435	44990	44990	7688
	CO2	44.01	14330	2125	12181	24			
	MEA	61.08				9			
Note 3	N2	28.02	82278	82277	1				
	O2	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 CO2 recovered is 85% of inlet CO2 in stream 6
4 This stream matches stream 6 on boiler island mass balance table

SEE DWG E10

FLUOR

Heat And Material Balance
CASE 3.22 USCPF WITH CAPTURE

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

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter.

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: 1
FOSTER WHEELER	PROJECT:	Water usage and loss Analysis in plants w/o and with CCS	October 2010
	LOCATION:	Netherlands	ISSUED BY: L.So.
	FWI Nº:	1- BD 0475A	CHECKED BY: PC
			APPR. BY: SA

CASE 3.22 - WATER CONSUMPTION SUMMARY - USC PC with CO2 capture

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

FOSTER WHEELER CLIENT:	IEA GHG R&D PROGRAMME	Rev: 1
PROJECT:	Water usage and loss Analysis in plants w/o and with CCS	October2010
LOCATION:	Netherlands	ISSUED BY: L.So.
FWI Nº:	1- BD 0475A	CHECKED BY: PC
		APPR. BY: SA

CASE 3.22 - ELECTRICAL CONSUMPTION SUMMARY - USC PC with CO2 capture

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

7. Overall performance

The table summarizing the Overall Performance of the USC PC Plant, case 3.22, is attached hereafter.

USC PC		
bituminous coal, with CO_2 capture		
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	266.3
Coal LHV (air dried basis)	kJ/kg	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**827.0**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY		
FW pumps	MWe	37.0
Draught Plant	MWe	9.0
Coal mills, handling, etc.	MWe	5.0
ESP	MWe	2.0
Miscellanea	MWe	9.0
Utility Units consumption	MWe	10.0
FGD	MWe	6.0
DeNOx	MWe	0.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**78.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**748.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**39.1**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY		
Additional consumption		
Unit 600 and 700: CO_2 Absorption, Compression and Drying	MWe	77.0
Additional Utility Units consumptions	MWe	6.1
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**161.4**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**665.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**
Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.875**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.117**
Specific water consumption per MW net produced	**t /MWh**	**0.410**

The Steam Turbine gross power production can be slightly higher (about 4 MWe) as it has been conservatively considered a penalty due to dry land plant location in line with the case without CO_2 capture.

8. Environmental Impact

The USC PC Plant, case 3.22, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarises expected flow rate and concentration of the combustion flue gas.

Table 8-1 - 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

8.1.2. 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.

8.2. 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.

8.3. 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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (25.3 t/h), in combustion air (35.8 t/h) and generated by combustion (105.2 t/h), soot blowing (19.8 t/h)	water outlet as steam in flue gas (186.1 t/h)
		Reheater									
		Superheater									
		Economiser									
		Piping									
		Air handling plant									
		Structures									
		Bunkers									
		Pumps									
		Coal feeders									
		Soot blowers									
		Blow down systems									12.4 t/h water from condenste polishing
		Dosing equipment									
		Mills									
		Auxiliary boiler									
		Miscellaneous equipment									
		Burners									
		ESP									
Δ		**Flue gas blower**	Axial fan	2.500.000Nm3/h x 700 mmH2O	11.0 MW			CS	1 blower in operation		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 300 - FGD and Handling Plant - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Ducts									
		GGH (gas to gas reheater)									
		Absorber island								Water inlet as raw water (98.5 t/h) and water in flue gas.	Water is mainly evaporated in flue gas, with some losses in gypsum (4.0 t/h) and blowdown (0.6 t/h).
		Limestone storage									
		Limestone slurry preparation island									
		Gypsum dewatering and storage									Water outlet as chloride purge (0.6 t/h)
		Make up water pumps									
		Oxidation air blower								Water inlet as moisture in ambient air (0.3 t/h)	

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION:	Netherlands	DATE	Feb 2010	Oct 2010		
		PROJ. NAME:	Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N.	1- BD- 0475 A	CHECKED BY	PC	PC		
				APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 400 - DeNOx Plant - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Flue gas ducts									
		Reactor casing									Water generated in DeNOx reaction (0.8 t/h)
		Bypass system									
		Catalyst									
		Ammonia injection equipment									
		Handling equipment									
		Control system									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Steam turbine island package									Water outlet as deaerator vent (0.3 t/h)
		Steam turbine		827 MWe gross							
		Steam turbine condenser		592 MW th				tubes: titanium; shell: CS	Sea water heat exchanger		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 600 - CO2 Amine Absorption Unit - USC PC with CO_2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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 pump	centrifugal	3200 m3/h x 60 m	750 kW			casing: CS; internals: 12%Cr	two pumps in operation; two spare		
		Absorber column - lower pumparound pump	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									Water outlet as water condensed from flue gas (224 t/h)
		Packing									
		Absorption towers								Water inlet as make up water (138.5 t/h)	
		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 cooler	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 cooler	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		Water outlet is included in the stream from "DCC towers"
		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		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
		DATE	Feb 2010	Oct 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 700 - CO2 compression and inerts removal - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									Water outlet as water condensed from CO2 (9.6 t/h)
		CO2 pumps	centrifugal	750 m3/h x 500m	2.5 MW			SS	1 operating + 1 spare		

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: 0	Rev.: 1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: Netherlands	DATE	Feb 2010	Oct 2010		
		PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 800 - Utility Units - USC PC with CO2 capture, fed with bituminous coal, case 3.22

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Demin water storage tankage								35.7 t/h of make up (raw water)	Water outlet as blowdown (3.2 t/h) and water make up to Steam Turbine Island (32.5 t/h)
		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									

LEGEND:
(1) = reference shall be made to report number PH4/33, case 4, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : USC PC, WITHOUT CCS – DRY LAND – CASE 3.25

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
February 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
August 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti
October 2010	Rev 1	L. Sobacchi	P. Cotone	S. Arienti

SECTION D

USC PC WITHOUT CCS – DRY LAND
I N D E X

1. Introduction

The present case 3.25 refers to the same USC PC plant, fed with bituminous coal, and not provided with a CO_2 capture unit, analysed in Report #2, Section B (case 3.21). The difference with the power plant of case 3.21 is that the power plant analysed here is installed in the reference dry land country (South Africa) and far from the seaside, so that, technologies for saving water and reducing to zero the raw water intake have been applied. The configuration and the performance of the plant so modified are evaluated and the results are discussed in the present Section.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 main features of the Case 3.25 configuration of the USC PC complex are:
- Mitsui-Babcock boiler pulverized fuel ultra supercritical design
- Flue Gas Desulphurization Plant
- DeNOx Plant
- No CO_2 removal
- Dry-land country

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%
800	Utility Units (including flue Gas Direct Contact Cooler)	

2. Process Description

2.1. Overview

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

Case 3.25 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. A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

Due to the installation in a severely limited water supply area and far from the seaside, changes have been made on some process and utilities units, compared with the reference case 3.21. The main peculiarities of the present case 3.25 are the deletion of the seawater cooling system, being the cooling effect provided by aircoolers and by machinery cooling water, and the installation of a Flue Gas Direct Contact Cooler system for condensing and recovering part of the water contained in the flue gas.

2.2. Unit 100 - Coal Handling

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this unit.

Purpose of this system is to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the boiler plant.

2.3. Unit 200 – Boiler Island

2.3.1. Coal Combustion

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this system.
The fuel input has been kept constant as the relevant reference case 3.21.

The coal burners and the firing system used here are designed for minimizing NOx formation. Hot combustion products passing through the radiative and convective heating surfaces provide heat for steam generation and cold steam reheat. Flue gas is then sent to ESP and FGD plant.

2.3.2. Steam Raising

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this system.

Boiler feedwater enters the furnace economizer and then passes to the water wall circuits enclosing the furnace. The HP steam generated here is routed to the HP turbine. Cold reheat steam passes through the reheater and is returned to the IP turbine.

2.3.3. Soot and Ash Handling

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this system.

The ash handling system takes care of collecting and handling the ashes generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers.

2.4. Unit 400 - DeNOx

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this unit.

A catalytic DeNOx reactor is required for reducing NOx content in flue gas, so that the emission limits are satisfied. A schematic Process Flow Diagram is attached in the following paragraph 3.

2.5. Unit 300 - Flue Gas Desulphurization

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this unit.

Flue gas desulphurization is required for reducing SOx content in flue gas, so that the emission limits are satisfied. Gypsum is generated in this unit by the reaction of sulphur oxides with limestone. A schematic Process Flow Diagram is attached in the following paragraph 3.

2.6. Unit 500 - Steam Turbine Generator

Reference shall be made to Report # 2, Section B, paragraph 2 for the process description of this unit.

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 for reheating and then throttled into the double flow IP turbine. Exhaust steam from the IP turbines then flows into the double flow LP turbine system. Exhaust steam from the LP turbine is condensed and then deaerated and preheated for generating recycled boiler feed water to be fed to the Boiler Island.

The major difference with the reference plant, case 3.21, is that the exhaust steam from the LP turbine is condensed in an aircooler and not in a sea water condenser. With respect to the latter condenser, the condensing system with aircooler allows reaching lower steam turbine performances, since the condensing pressure that can be achieved by the air condenser is significantly higher (0.074 bara with aircooler vs 0.040 bara with sea water condenser).

2.7. Unit 800 - Utility Units (including Flue Gas Direct Contact Cooler)

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 9.

The main utility units are the following:
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

2.7.1. Flue Gas Direct Contact Cooler

In the present power plant, case 3.25, in order to reduce the request of raw water from outside the power plant battery limit, the condensation and recovery of part of the steam contained in the exhaust flue gases at stack is carried out. Condensation is performed in the Flue Gas Direct Contact Cooler (FG DCC) system, which is considered included in the Utility Units. FG DCC consists of vertical columns, where the flue gas enters at the bottom and is cooled by contacting a stream of water, which is sprayed at the top. Due to the cooling effect, part of the water contained in the flue gas is condensed and collected at the towers bottom. The water circuit includes pumps for disposing of the excess of condensed water to the waste water treatment unit and recycling part of the water to the spray nozzles at the top of the column, passing through an aircooled heat exchanger.
Due to the additional pressure drop in the direct contact cooler, the head of the ID fan installed in the Boiler Island has to be properly increased.

2.7.2. Waste Water Treatment
The Waste Water Treatment plant includes some specific units necessary for reducing pollutants concentration. Their description follows hereafter.

Sulphites oxidation

The condensate water from flue gas condensate is contaminated with sulphites, differently from the other polluted streams. For this reason this stream is treated separately from the other polluted streams and then rejoined with the others in the equalization tank.
In order to remove HSO_3^-, hydrogen peroxide is added, giving as reaction product sulphuric acid.
The contact time that permit sulphites oxidation is circa 30 minutes and the oxidation basin is normally designed considering this parameter.
The oxidation basin has to be equipped with an adequate number of mixers in order to favourite a close contact between the reagents.

Neutralization

In the neutralization tank the effluent coming from sulphite oxidation basin clarifier is neutralized through the injection of NaOH solution or of H_2SO_4 solution, for pH correction, in order to ensure optimum pH conditions for water reuse.
The neutralization tank is designed for a hydraulic retention time of about 10 min.

Also for the effluent from FGD and handling unit, neutralization process is required (in this case the stream is constituted by a sludge flow but the process doesn't change) and it takes place in an dedicated neutralization basin.

Chemical-Physical treatment

This section consists of two basins in series, where chemicals are added for chemical coagulation, flocculation and for specific ions removal. The purpose of wastewater clariflocculation is to form aggregates or flocs form finely divided particles and from chemical destabilized particles in order to remove them in the following sedimentation step.
In the first basin, coagulation basin, a coagulant as Ferric Chloride is added and a flash-mixing is performed. This basin is designed in order to guarantee a contact time of circa 5 minutes and specific mixing power of some hundreds of watts for cubic meter.
Sodium hydroxide is also added in order to remove specific ions as Mg2+ and Ca2+, responsible to water hardness and connected problems. Adding sodium hydroxide is also possible to increase pH favouring heavy metals precipitations.
In the second basin, flocculation basin, polyelectrolyte is added and slow-mixing is performed. This basin is designed in order to guarantee a contact time of circa 25 minutes and a specific mixing power of some tens of watts for cubic meter.

Chemical sludge settling

Effluent water from chemical-physical coagulation/flocculation section flows into a clarification basin, where solids separation is performed and all setteable compounds are removed. The produced sludge is removed from the bottom of each clarifier by a scraper. The basin is designed in order to guarantee a contact time of about 2 hours.

Reverse osmosis

In order to remove specific ions from clarified water, reverse osmosis process is installed. In general, when the total salinity is high (thousands of ppm), the reverse osmosis is technically and economically preferable rather than other treatments.
In order to guarantee good performance of reverse osmosis process some pre-treatments are recommended in order to remove solids and some substances responsible of fooling phenomena.
The reverse osmosis is a membrane technology, so the products of filtration are:
- Low salinity filtered water;
- Concentrated water, with high salts concentration.

Sludge treatment

The separated sludge from chemical settler and the chemical sludge from neutralization section (effluent from FGD and handling unit) are sent to a mixing basin where are mixed and subjected to a chemical conditioning.
Ferric Chloride (10-30 mgFeCl3/kgSST) and polyelectrolyte (1-3 mgPoly/kgSST) are added in order to favourite solids aggregation and to improve the subsequent dewatering treatment.
The conditioned and mixed sludge is finally sent to a dewatering system (i.e. centrifugal system) in order to achieve a dry solids content of minimum 20%. The separated supernatant, rich in suspended solids, is sent back to chemical treatment while the dewatered sludge is sent to final disposal.

For the Block Flow Diagram of the Waste Water Treatment Unit, see next paragraph.

3. Block Flow Diagrams and Process Flow Diagrams

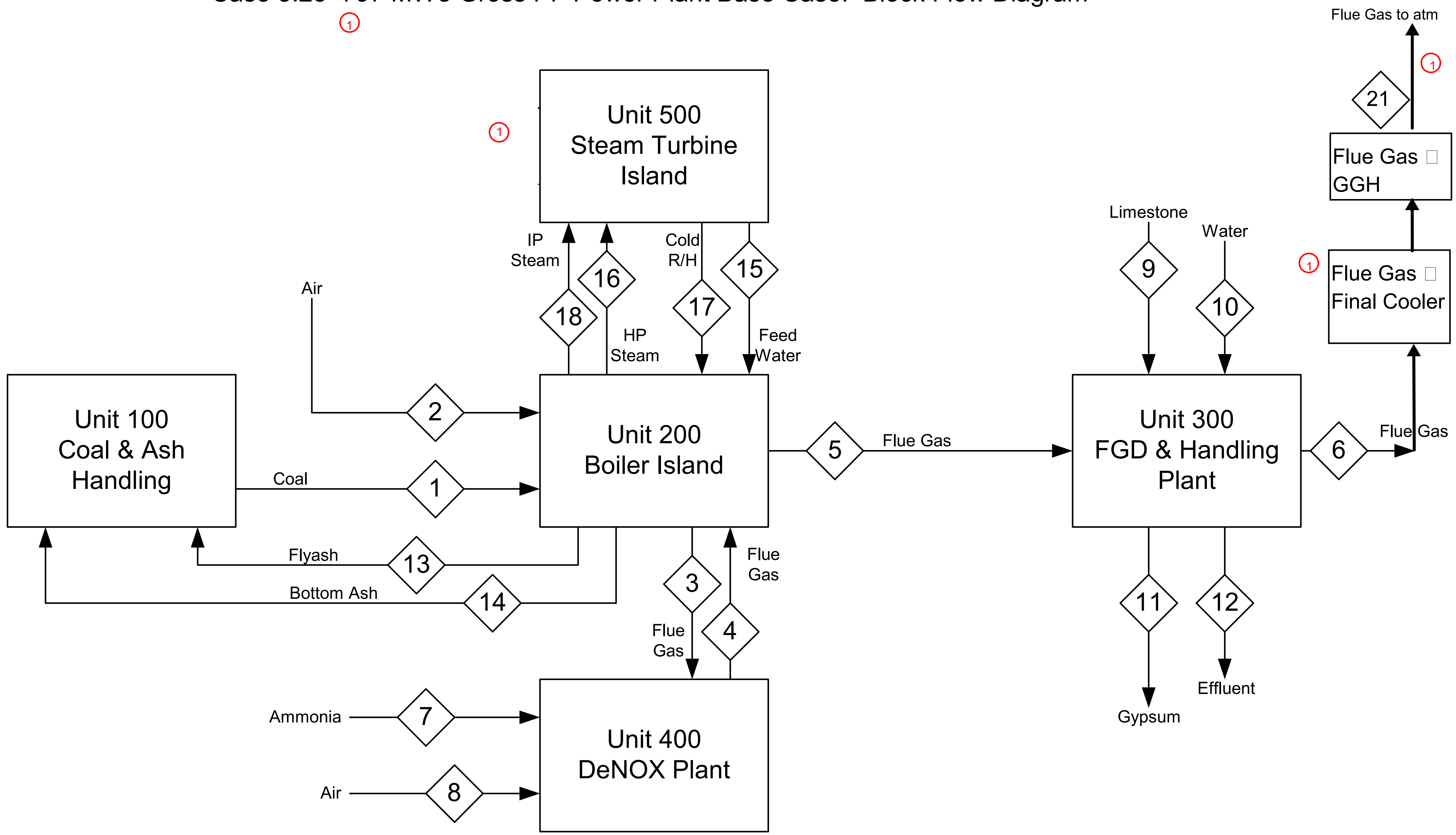
The Block Flow Diagram of the USC PC Complex, case 3.25, and the schematic Process Flow Diagrams of Units 300, 400 and 500 are attached hereafter.

The Block Flow Diagrams and Process Flow Diagrams attached to Report # 2, Section B, paragraph 3 are to be taken as reference: they represent the plant arrangement for case 3.21, i.e. when the plant is installed in a no-dry land country and along the seaside. Modifications required due to installation in a dry land country and far from the seaside have been highlighted in the drawings attached hereafter.

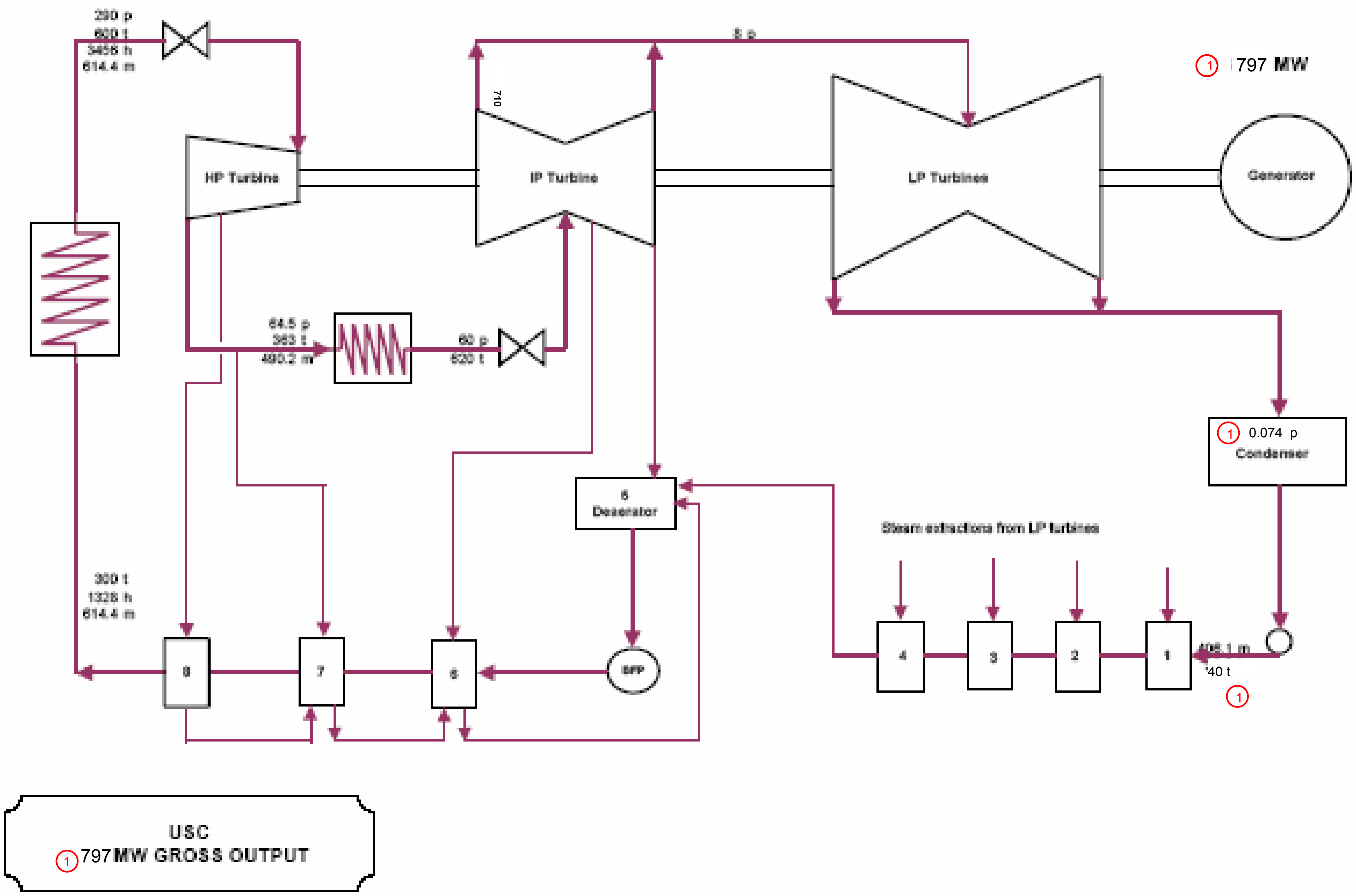
The Block Flow Diagram of the Waste Water Treatment unit, valid for the present case 3.25, is also attached hereafter. The Block Flow Diagram of the Waste Water Treatment unit, valid for the present case 3.23, is also attached hereafter. The relevant Heat&Mass balance is reported in paragraph 5 of this section. The list of the utilities consumption is shown in paragraph 6.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

Case 3.25 797 MWe Gross PF Power Plant Base Case: Block Flow Diagram



1 = revised during the 2009 study for closing the water balance



SYMBOLS & UNITS

p = Pressure	bar abs
t = Temperature	°C
h = enthalpy	kJ/kg
m = mass flow	kg/s
1997 Steam Tables	

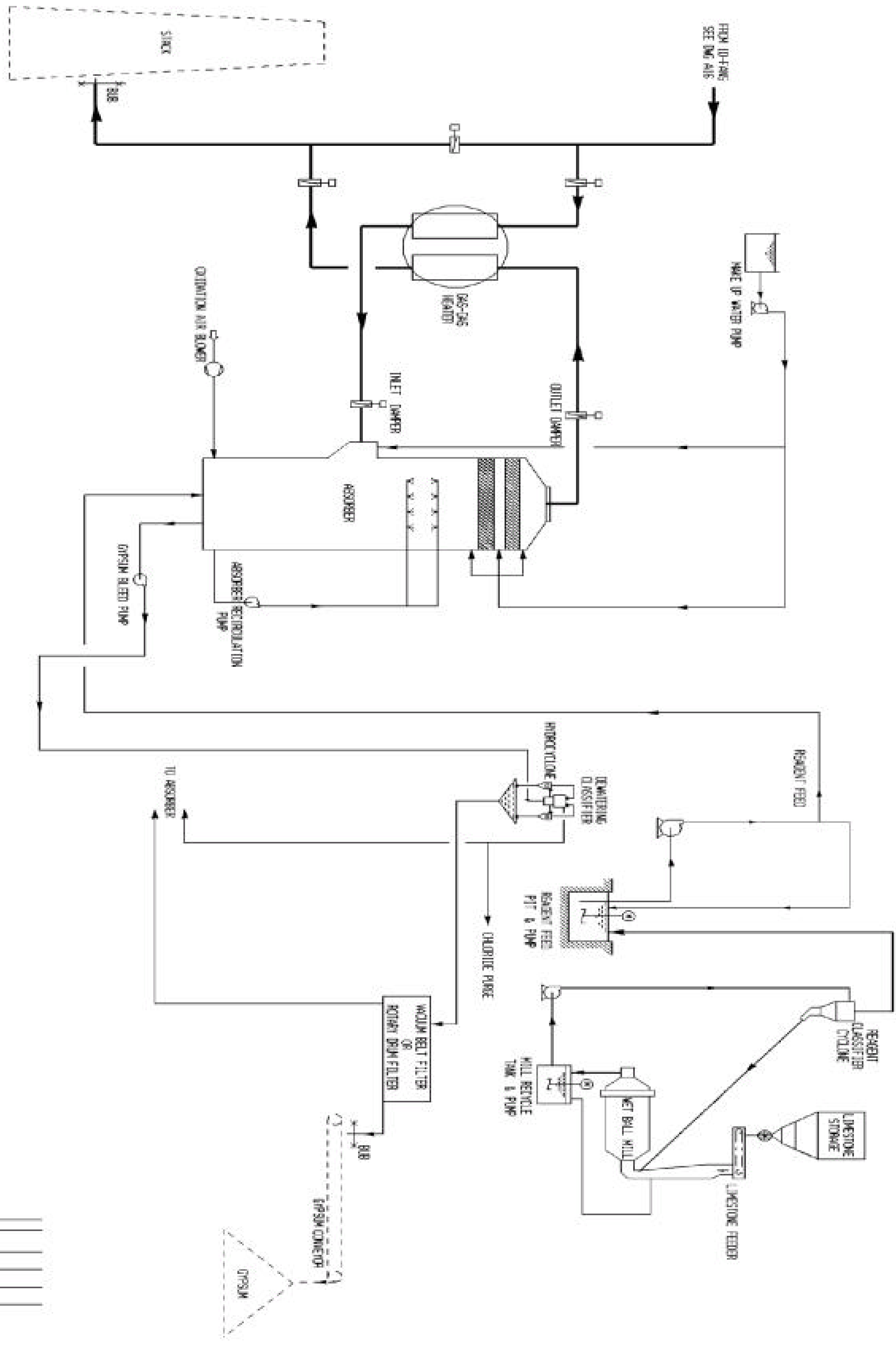
Calculation No:	rb61411/1
Drawn:	RDB
Date:	14th April 2004

TS29700

Drawing E7 *USCPF WITHOUT CAPTURE - TURBINE POWER ISLAND*

ALSTOM

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



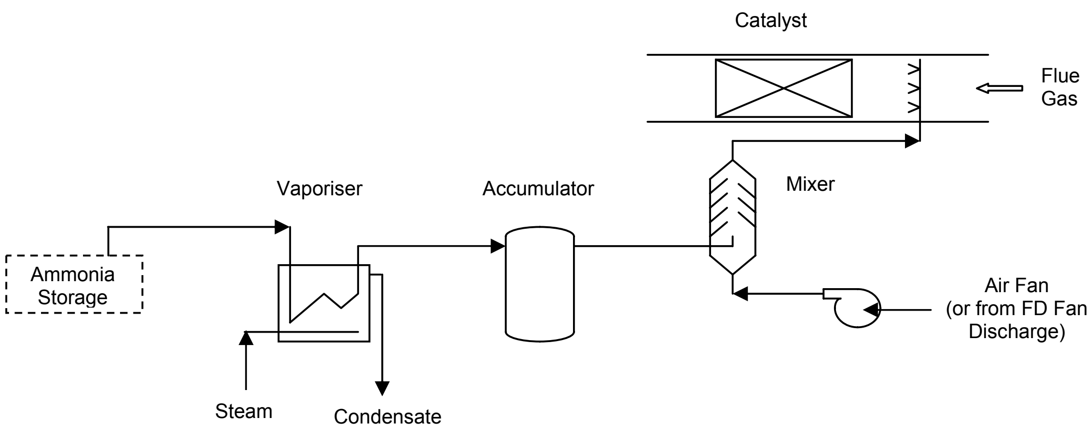
Issue

A1

Ammonia / Air System

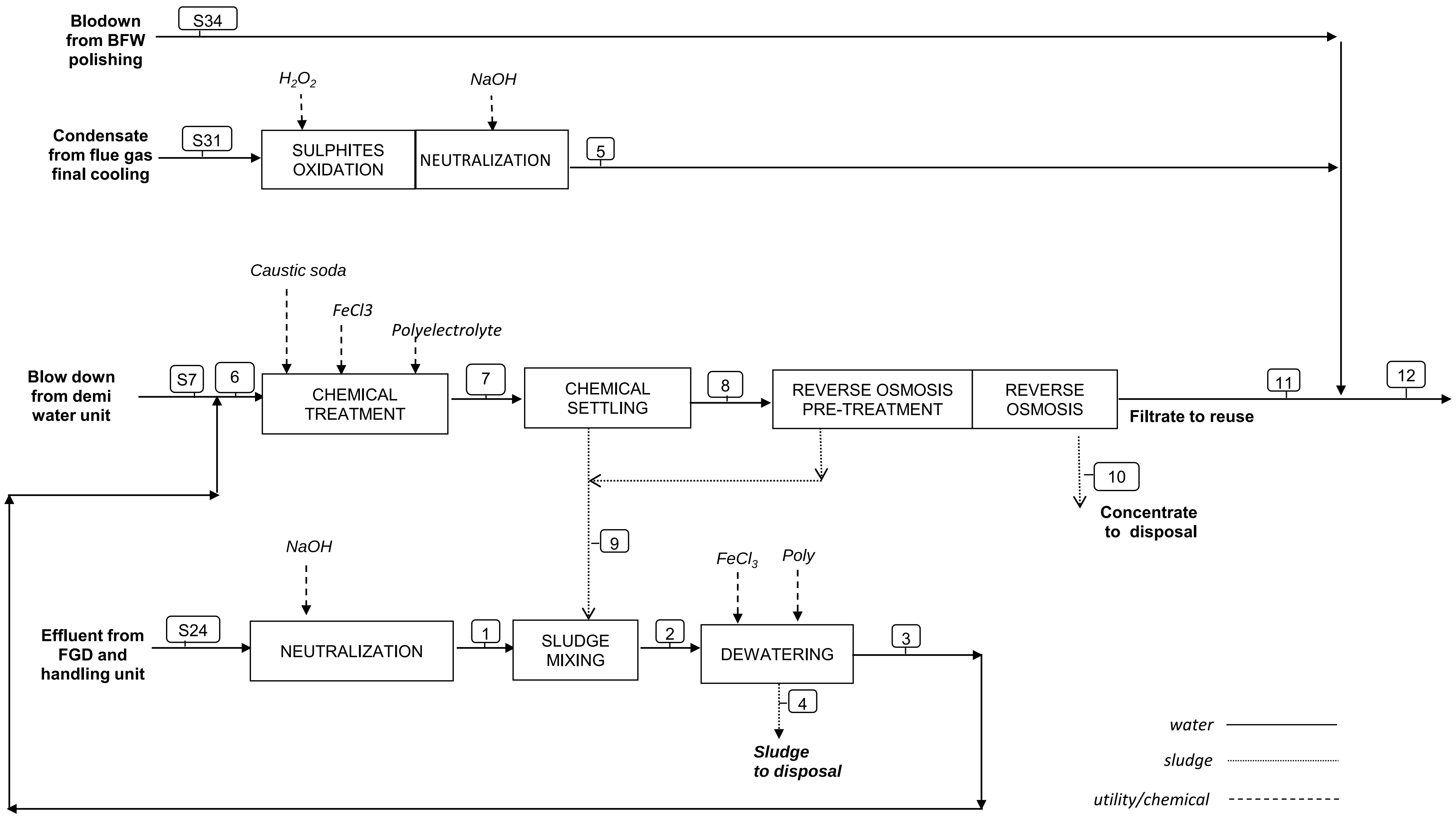
Condition			Vaporiser (H_2O side)	Vaporiser (NH_3 side)	Accumulator	Mixer (after)	Air supply	Grid (gas side)
Operating	Flow	Nm^3/h		545	545	10,900	10,355	2,122,806
		kg/h		420	420	8,480	8,060	2,794,255
	Temperature	°C	~45	~35	~35	~35	~35	380
	Pressure	MPa (g)	see note 1	0.29	0.15			
	Concentration	%				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		

Case 3.25 USC PC COMPLEX, BITUMINOUS COAL, WITHOUT CO_2 CAPTURE - WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



4. Detailed Water Flow Diagram

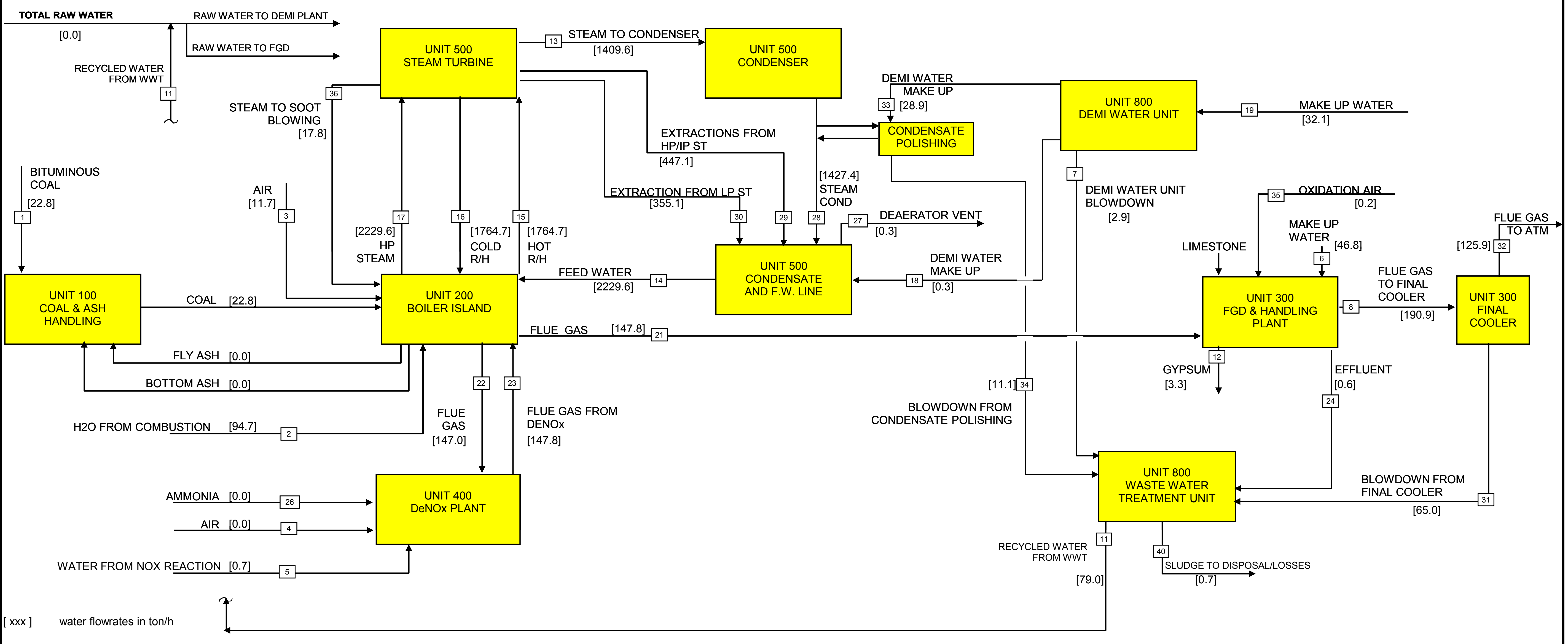
In the present paragraph the following documents are attached:
- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units;
- flowrates and compositions of the streams of water to waster water treatment unit.

It is important to note that the introduction of a final cooler downstream the boiler allows the recovery of a significant amount of water from the boiler flue gases. This water is sent to the WWT together with the polluted streams of the plant.
The treated water is, therefore, sufficient to meet the plant raw water consumption allowing a zero raw water intake.

The ambient temperature affects the minimum temperature that can be achieved in the air cooling systems.
The higher ambient temperature leads to an higher temperature on the process streams downstream the air cooled exchanger. The material balance attached to water diagram is referred to the refence ambient temperature. Therefore, it is to be considered as an average between the cold and the warm season.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

CASE 3.25 - USC PC PLANT, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 725 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



IEA GHG R&D PROGRAMME	Revision no.:	1
Water usage and loss Analysis in Power plants without and with CCS	Date:	October 2010
Volume #2		

USC CPS fed by bituminous coal, w/o CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	22.8	32	Flue Gas to atm	125.9
2	Water from coal combustion	94.7	11	Effluent from WWT to reuse	79.0
3	Moisture in air to Boiler Island	11.7	12	Moisture in Gypsum	3.3
4	Moisture in air to DeNOx Plant	0.0	27	Moisture in deaerator vent	0.3
5	Water from NOx reaction	0.7	40	Sludge to disposal/losses	0.7
6	Water to FGD & Handling Plant	46.8			
26	Water in ammonia di DeNOx	0.0			
19	Make up to Demi Water Unit	32.1			
35	Oxidation air	0.2			
Total		209.2	Total		209.2

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	22.8	22	Flue Gas to DeNOx Plant	147.0
2	Water from coal combustion	94.7			
3	Moisture in Air to Boiler Island	11.7			
36	Steam for soot blowing	17.8			
Total		147.0	Total		147.0

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	2.90	11	Effluent from WWT to reuse	79.0
24	Effluent from FGD & Handling Uni	0.6	40	Sludge to disposal/losses	0.7
31	BD from flue gas final cooler	65.0			
34	Blowdown from BFW polishing	11.1			
Total		79.7	Total		79.7

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1764.7	13	Steam to condenser	1409.6
17	HP steam from Boiler	2229.6	16	Cold R/H to Boiler	1764.7
			29	Extractions from HP/IP ST	447.1
			30	Extractions from LP ST	355.1
			36	Steam for soot blowing	17.8
Total		3994.3	Total		3994.3

USC CPS fed by bituminous coal, w/o CO2 capture - Water Balance around DeNOx unit

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
4	Moisture in air to DeNOx Plant	0.0	23	Flue gas from DeNOx unit	147.8
5	Water from NOx reaction	0.7			
22	Flue gas from Boiler Island	147.0			
26	Water in ammonia to DeNOx	0.0			
Total		147.8	Total		147.8

CASE 3.25 - USC PC PLANT, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (DRY LAND) - WATER STREAMS SENT TO WWT

STREAM	7	24	31	34			
SERVICE	Blowdown from Demi Water Unit	Effluent from FGD & Handling Unit	BD from flue gas final cooler	Blowdown from BFW polishing			
Temperature (°C):	amb	50	39	30			
Total flowrate (t/h):	2.9	0.6	65.0	11.1			
Composition (ppm wt)		FOR THE COMPOSITION, REFER TO TABLE AT THE SIDE					
SO2			5				
HSO3-			74				
CO2			140				
NH3							
Na+	1090						
Cl-	4560						
PO4---				5			
SiO2	110			5			
CaCO3	406			100			
SO4--	830						
NO3-	510						
Ca AAS	1410						
Mg AAS	420						
MEA							
Suspended solids			100 (**)				
K	30						
HCO3-	250		1				
H2O (% wt)	99.0384		99.9680	99.9890			
TOTAL (%wt)	100		100	100			
NOTES:	*						

(*) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate
(**) = solids consist of coal fines

24	
Effluent from FGD & Handling Unit	
Components	ppm wt
CaSO4 * 2 H2O solid	7300
CaCO3 solid	110
MgCO3 solid	200
CaF2 solid	3870
Inerts from limestone	15720
Fly ash, solid	1260
Total Solids	**28460**
Cl -	28130
SO4 --	1320
Ca ++	2180
Mg ++	6790
Total Ions	**38420**
CaSO4 dissolved	**1860**
H2O (% wt)	**93.13**
TOTAL (% wt)	100

5. Heat and Material Balance

The Heat and Material Balances, referring to the Block Flow Diagrams attached in the previous paragraph, are attached hereafter.
The H&M balance makes reference to the schemes attached to paragraph 3.

Reference shall be made to Report # 2, Section B, paragraph 5 for the H&M balance attached. The information relevant to WWT has been included. Modifications due to dry land have been highlighted in the H&M balance attached in the appendix 1 of this Volume 2.

IEA GHG R&D PROGRAMME

Water Usage and Loss Analysis in Plants w & w/o CCS

Volume #2 - Case 3.25 USCPC without CCS (dry land)

Revision no.: 1
Date: October 2010
Sheet: 1 of 2

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	66.61	0	0.29	0.29	0	0	0	0	0	0
- Air	kg/s	0	752.3	0	0	0	0	0	2.24	0	0
- Flue Gas	kg/s	0	0	778.7	781.2	817.9	821.8	0	0	0	0
- Ash	kg/s	0	0	5.3	5.3	0.018	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
- Ammonia	kg/s	0	0	0	0	0	0	0.117	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	1.77	0
Volume Flowrate	Am^3/s	-	621.7	1418.1	1416.6	880.0	831.9	-	1.84	-	0.013
	Nm^3/s	-	587.0	592.5	594.5	623.9	634.5	0.151	1.74	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Temperature	°C	14	14	380	380	114	85	14	15	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.21	0.55	0.55	0.93	0.99	-	1.21	-	-
Composition											
O_2	%v/v,wet		20.9	3.27	3.27	4.50	4.36		20.9		
CO_2	%v/v,wet		0.0	13.80	13.80	12.79	12.48		0.0		
SO_2	%v/v,wet		0.0	0.07	0.07	0.06	0.01		0.0		
H_2O	%v/v,wet		0.7	9.77	9.78	9.33	11.51		0.7		
N_2	%v/v,wet		78.4	73.09	73.08	73.32	71.64		78.4		
Emissions @ 6% O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1877	1877	1732	200				
CO	mg/Nm^3			0	0	0	0				
Particulates	mg/Nm^3			8444	8416	30	14				

IEA GHG R&D PROGRAMME

Water Usage and Loss Analysis in Plants w & w/o CCS

Volume #2 - Case 3.25 USCPC without CCS (dry land)

Revision no.: 1
Date: October 2010

Stream ID		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Gas
Mass Flow Rate												
- Coal	kg/s	0	0	0.34	0.11	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	803.7
- Ash	kg/s	0	0	6.08	2.03	0	0	0	0	0	0	0
- Water	kg/s	0.31	0.17	0	0	619.3	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	619.3	490.2	490.2	0	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0	0	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	2.91	0	0	0	0	0	0	0	0	0	0
Volume Flowrate	Am^3/s	-	-	-	-	-	-	-	-	-	-	
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	
Props												
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas
- Temperature	°C	23	23	114 / 380	1000	300	600	363	620	-	-	75
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	0
- 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											
Particulates	mg/Nm^3											

Case 3.25 USC PC COMPLEX, BITUMINOUS CAOL, WITHOUT CO_2 CAPTURE - WASTE WATER TREATMENT MASS BALANCE

Stream		N°	S34	S7	S31	S24	1	2	3	4	5	6	7	8	9	10	11	12
Parameter	**Note**	**unit**	**BD from BFW polishing**	**BD from demi water unit**	**BD from fluee gas final cooler**	**effluent from FGD**	**Neutralized effluent form FGD**	**Mixed sludge**	**supernatant**	**Sludge to disposal**	**condensate from oxidation pretreat.**	**water to chemical pretreatment**	**water from chemical pretreatment**	**Clarifield BD. To R.O.**	**Sludge to sludge treatment**	**Concetrate to disposal**	**Filtrate to reuse**	**treated water to reuse**
Temperature		°C	30,00	20,00	39,00	50,00												
		ton/h	11,10	2,90	65,00	0,66	0,78	1,99	1,74	0,25	65,01	4,64	4,83	3,63	1,20	0,54	3,08	79,19
NO2--		mg/l		-	-								-	-	-			
CO2		mg/l		-	140,00						139,94		-	-	-			114,88
NH3		mg/l		-	-								-	-	-			
Na+		mg/l		1090,00			98356,51	37087,40	37087,40	37087,40	269,06	14301,87	1090,00	1090,00	1090,00	10682,00	24,22	221,83
Cl-		mg/l		4560,00		28130,00	24120,19	11782,11	24120,19	24120,19			4560,00	4560,00	4560,00	44688,00	101,33	3,94
PO4--		mg/l	5,00	-	-								-	-	-			0,70
SiO2		mg/l	5,00	110,00	-			AS TSS					AS TSS	-	AS TSS			0,70
TSS	(1)	mg/l			50,00	28460,00	24403,15	23111,73	1453,68	222222,22	49,98	533,53	5776,99	777,36	22492,13	7618,13	17,27	41,70
CaCO3		mg/l	100,00	406,00	-			21,91	1,10	1,04			35,00	35,00	35,00			14,01
SO4--	(2)	mg/l		830,00	0,00	1320,00	1131,84	938,48	938,48	938,48	93,59	869,82	830,00	830,00	830,00	8134,00		77,55
NO3-	(3)	mg/l		510,00	-	-		319,24	319,24	319,24		439,99	510,00	510,00	510,00	4998,00	11,33	0,44
Ca2+		mg/l		1410,00	-	2180,00	1869,25	1574,48	1574,48	1574,48		1470,37	AS TSS	1410,00	1410,00	13818,00		1,22
Mg2+		mg/l		420,00	-	6790,00	5822,11	2417,87	2417,87	2417,87		1153,26	AS TSS	420,00	420,00	4116,00	9,33	0,36
MEA		mg/l		-	-													
K+		mg/l		30,00	-			18,78	18,78	18,78			30,00	30,00	30,00	294,00		0,03
HCO3-		mg/l		250,00	1,00			156,49	156,49	156,49	1,00	215,68	250,00	250,00	250,00	2450,00	5,56	1,04
CaSO4	(4)	mg/l		-	-	1860,00	1594,87	590,31	590,31	590,31			-					0,00
HNO3	(5)	mg/l		-	-	-							-					
HSO3-		mg/l		-	79,00	-					-		-					
H2O		%	100	99	100	94	86	93	93	75	100	98	99	99	97	94	100	100

General notes
Present mass balance is indicative only and related to the prosecc treatment selected

Notes

1. $CaCO_3$ and SiO_2 contribution has been considered
2. Sulphuric acid contribution has been considered
3. Nitric acid contribution has been considered
4. Sulphuric acid contribution has been considered as SO_4^{2-}
5. Nitric acid contribution has been considered as NO_3^-

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. Details for WWT utility consumptions are also attached.

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	WATER USAGE AND LOSS OF POWER PLANTS WITH CCS
LOCATION:	JOHANNESBURG - SOUTH AFRICA
FWI N°:	1- BD 0475A

Rev: Draft
Oct 09
ISSUED BY: L.So.
CHECKED BY: PC
APPR. BY: SA

WATER CONSUMPTION SUMMARY - CASE 3.25 - USC PC, bituminous coal, without CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				SEA WATER IS NOT AVAILABLE IN POWER PLANTS INSTALLED IN DRY LAND
100	Coal and Ash Handling			73	
300	Flue Gas Desulphurization (FGD) and Handling Plant	46.8			
400	DeNOx Plant				
200	**BOILER ISLAND**			96	
500	**POWER ISLAND UNIT (Steam Turbine)**		29.2	3154	
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water. Demineralized Water Systems. etc	32.1	-29.2	82	
	BALANCE	78.9	0	3404	0

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
		Oct 09
PROJECT:	WATER USAGE AND LOSS OF POWER PLANTS WITH (	ISSUED BY: L.So.
LOCATION:	JOHANNESBURG - SOUTH AFRICA	CHECKED BY: PC
FWI Nº:	1- BD 0475A	APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - CASE 3.25 - USC PC without CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	Coal and Ash Handling	5000
300	FGD	6000
400	DeNOx	300
	BOILER AND POWER ISLAND UNITS	
200 - 500	Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)	52040
	Miscellanea utilities	8000
	UTILITY and OFFSITE	
800	Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems	5643
	BALANCE	76983

Notes: (1) Minus prior to figure means figure is generated

		CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1
FOSTER WHEELER		LOCATION:	Dry land	DATE	February '10	
		PROJ. NAME:	Water usage and loss Analysis	ISSUED BY	M.P.	
		CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.	
				APPROVED BY		

Utilities consumption

Unit 800 - BoP, Electrical, I&C - USC PC oxycomb, bituminous coal, without CO2 capture, case 3.25 - DRY LAND

	ITEM	DESCRIPTION	Absorbed Electical power	NaOH	H_2O_2	$FeCl_3$	Poly	Remarks
			[kW]	[kg/h]	[kg/h]	[kg/h]	[kg/h]	
	UNIT 4600	WWT - waste water treament complex	~50	~230	~5	~5	~1	

Table below summarize specific consumpltion for each treatment section- reported values are indicative only

	ITEM	DESCRIPTION	Absorbed Electical power [kW]		NaOH (1)	H_2O_2 (1)	$FeCl_3$ (1)	Poly (1)	Remarks
			total	specific	[kg/h]	[kg/h]	[kg/h]	[kg/h]	
		Sulphides oxidation and Neutralization Section			30	4			
		Softening treatment Section			74				
		Sludge Dewatering			120		5	0.1	
		Reverse osmosis section							

Notes:
1. As pure products.

7. Overall performance

The following table shows the overall performance of the USC PC power plant, case 3.25.

USC PC		
bituminous coal, without CO_2 capture - DRY LAND		
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	239.8
Coal LHV (air dried basis)	kJ/kg	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1723.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**802.0**

POWER PLANT PERFORMANCES		
FW pumps	MWe	34.0
Draught Plant and other consumptions in Power Island	MWe	9.2
Coal mills, handling, etc.	MWe	5.0
ESP	MWe	2.0
Steam Turbine Condenser	MWe	6.8
Utility Units consumption and Miscellanea	MWe	13.6
FGD	MWe	6.0
DeNOx	MWe	0.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**77.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**725.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**46.5**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**42.1**

Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.149**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.777**
Specific water consumption per MW net produced	**t /MWh**	**0.000**

8. Environmental Impact

The USC PC Plant, case 3.21, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarises expected flow rate and concentration of the combustion flue gas.

Table 8-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	803.7
Flow, Nm^3/h	2,284,200
Temperature, °C	75
Composition	**(%vol, wet)**
O_2	4.52
CO_2	12.94
SO_2	0.01
H_2O	8.26
N_2+Ar	74.27
Emissions	**mg/Nm^3 (1)**
NOx	200
SOx	200
Particulate	5

(1) Dry gas, O_2 Content 6% vol

8.1.2. 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.

8.2. Liquid Effluent

Waste Water Treatment (included in Unit 800)

The expected flow rate of treated water from Waste Water Treatment to be discharged outside Plant battery limit is in practice reduced to zero: in fact, apart from a negligible amount of water present in the minor streams sent to disposal (concentrate from reverse osmosis section and sludge from sludge dewatering section), all the water received by Waste Water Treatment is treated and recycled back to the power plant.

8.3. Solid Effluent

The plant is expected to produce the following solid by-products:

Furnace bottom ash
Flow rate : 7.3 t/h

Fly ash
Flow rate : 22 t/h

Mill rejects (pyritic)
Flow rate : 0.5 t/h

Gypsum
Flow rate : 11.6 t/h
Water content : 9.5 %wt

Sludges from WWT
Flow rate : 0.75 t/h
Water content : 85 %wt

Some of solids effluent could be theoretically dispatched to cement industries and therefore they could be treated as revenue for the plant economics. They 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 revenue nor as disposal cost.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3		
		DATE	February 2010	October 2010				
		ISSUED BY	L.So.	L.So.				
		CHECKED BY	PC	PC				
		APPROVED BY	SA	SA				

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:

(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (22.8 t/h), in combustion air (32.3 t/h) and generated by combustion (94.7 t/h), soot blowing (17.8 t/h)	water outlet as steam in flue gas (167.6 t/h)
		Reheater									
		Superheater									
		Economiser									
		Piping									
		Air handling plant									
		Structures									
		Bunkers									
		Pumps									
		Coal feeders									
		Soot blowers									
		Blow down systems									11.1 t/h water from condensate polishing
		Dosing equipment									
		Mills									
		Auxiliary boiler									
		Miscellaneous equipment									
		Burners									
		ESP									
Δ		**Flue gas blower**	Axial fan	2.200.000Nm3/h x 800 mmH2O	11 MW			CS	1 blower in operation		

LEGEND:
(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 300 - FGD and Handling Plant - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Ducts									
		GGH (gas to gas reheater)									
		Absorber island								Water inlet as raw water (46.8 t/h) and water in flue gas (150.6 t/h) and in oxidation air (0.2 t/h)	Water is mainly evaporated in flue gas, with some losses in gypsum (3.3 t/h) and blowdown (0.6 t/h).
		Limestone storage									
		Limestone slurry preparation island									
		Gypsum dewatering and storage									Water outlet as chloride purge (0.6 t/h)
		Make up water pumps									
		Oxidation air blower								Water inlet as moisture in ambient air (0.2 t/h)	

LEGEND:
(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: SOUTH AFRICA	DATE	February 2010	October 2010		
		PROJ. NAME: Water usage and loss analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 400 - DeNOx Plant - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Flue gas ducts									
		Reactor casing									Water generated in DeNOx reaction (0.7 t/h)
		Bypass system									
		Catalyst									
		Ammonia injection equipment									
		Handling equipment									
		Control system									

LEGEND:
(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: SOUTH AFRICA	DATE	February 2010	October 2010		
		PROJ. NAME: Water usage and loss analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Steam turbine island package									Water outlet as deaerator vent (0.3 t/h)
Δ		**Steam turbine**		802 MWe gross							
Δ		**Steam turbine condenser**	aircooler	822 MW th	80 x 95 kWe			CS	80 modules, 12x12 m2 each		

LEGEND:
(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 800 - Utility Units - USC PC without CO2 capture, fed with bituminous coal, case 3.25 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Demin water storage tankage								12.5 t/h of make up (raw water)	Water outlet as blowdown (1.1 t/h) and water make up to Steam Turbine Island (11.4 t/h)
		Raw water and firewater storage									
		Plant air compression skid									
		Emergency diesel generator system									
Δ		Closed loop water cooler	aircooler	40 MW th	990 kWe			CS			
		Blowdown water sump									
		Condensate return pump									
		Demin water pump									
Δ		Close loop CW pumps	centrifugal	3500 m3/h x 30m	425 kW			CS	1 pump in operation + 1 spare		
		Oily water sump pump									
		Fire pumps (diesel)									
		Fire pumps (electric)									
		FW jockey pump									
Δ		Waste water treatment plant									
		OWS									
-		~~Sea water pumps~~							DELETED		
-		~~Seawater chemical injection~~							DELETED		
-		~~Sea water inlet/outlet works~~							DELETED		
+		Flue gas final cooler (aircooler)	aircooler	50 MW th	40 x 27 kWe			CS+2 mm 304L clad			
+		Flue gas final DCC		D=8m; H=16m				KCS+6 mm 304L clad	4 separators		65 t/h cond'd water to WWT
+		Flue gas final water pump	centrifugal	3100 m3/h x 40 m	520 kW			casing: CS; internals: 12%Cr	1 pump operating; 1 pump spare		
		Buildings									
		Electrical equipment									

LEGEND:
(1) = reference shall be made to CASE 3.21: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION:	Dry land	DATE	January '09			
PROJ. NAME:	Water usage and loss Analysis	ISSUED BY	M.P.			
CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.			
		APPROVED BY				

EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel without CO_2 capture, fed with bituminous coal, case 3.25 - DRY LAND

	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Sulphides oxidation and Neutralization Section									
	0800-Y1001	Oxidation Reactor		S=21 m^2 ; H 3 m					1X100% (1op)		
	0800-MX1001 A/B	Mixer			1,5				2X50% (2op)		
	0800-PK1001	H_2O_2 dosage system		Φ=1,3 m; H=1,2 m	0,43				1X100%(about 15 day storage)		
	0800-PK1002 A/B	Caustic soda dosage system		Φ=1,6 m; H=2,3 m	0,74				2X50% (about 15 day storage)		
	0800-P1001 A/B	treated water pump	Centrifugal	72 mc/h; 1,8 bar	9				2X100% (1op + 1 spare)		
		Chemical treatment Section									
	0800-Y1002	Chemical Reactor and sedimentation		L=5 m W= 1,5; H =3 m					1X100 (1op)		
	0800-MX1002 A/B/C	Mixer			0.18				3X33% (3op)		
	0800-PK1002	Caustic soda dosage system		Φ=1,6 m; H=2 m	0,36				1X100 (1op)		
	0800-PK1003	FeCl3 dosage system		5 dm^3	0,18				1X100 (1op)		
	0800-PK1004	polyelectrolite dosage system		5 dm^3	0,18				1X100 (1op)		
	0800-P1002 A/B	reverse osmosis feed pump	Centrifugal	2,5 mc/h; 2 bar	0,37				2X100% (1op + 1 spare)		
	0800-P1003 A/B	Chemical sludge pump	Centrifugal	1 mc/h; 1,8 bar	0,18				2X100% (1op + 1 spare)		
		Sludge Dewatering									
	0800-Y1003	sludge pit		L=1 m W= 1; H =1,5 m	0,18				1X100		
	0800-PK1005	Caustic soda dosage system		Φ=2,3 m; H=3 m	0,36				1X100 (about 15 gg storage)		
	0800-PK1006	FeCl3 dosage system		1 mc					1X100 (about 10 gg storage)		
	0800-PK1007	polyelectrolite dosage system		20 dm^3					1X100 (about 10 gg storage)		
	0800-P1004 A/B	dewatering sludge pump		2 mc/h; 1,3 bar	0,25				2X100% (1op + 1 spare)		
	0800-P1005 A/B	centrifugal		Q= 2 mc/h	1,5				2X100% (1op + 1 spare)		
	0800-P1006 A/B	supernatant feed pump		2 mc/h; 1,8 bar	0,25				2X100% (1op + 1 spare)		
	0800-X1001	Reverse osmosis section									
	include in 0800-X1001	Membrane unit		Qin~4 mc/h					1X100		
		high pressure pump		4 mc/h; 12 bar	3				1X100		

Notes:

Present equipment list is indicateve only and related to the WWT layout selected.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : USC PC, WITH CCS – DRY LAND – CASE 3.23

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
February 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
August 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti
October 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti

SECTION E
USC PC, WITH CCS – DRY LAND
I N D E X

1. Introduction

The present case 3.23 refers to the same USC PC plant, fed with bituminous coal, provided with CO_2 capture unit, analysed in Report #2, Section C (case 3.22). The difference with the power plant of case 3.22 is that the power plant analysed here is installed in the reference dry land country (South Africa) and far from the seaside, so that, technologies for saving water and reducing to zero the raw water intake have been applied. The configuration and the performance of the plant so modified are evaluated and the results are discussed in the present Section.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 main features of the Case 3.23 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
- Dry-land country

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%

The Flue Gas Direct Contact Cooler is considered included in Unit 600.

2. Process Description

2.1. Overview

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

Case 3.23 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.

Due to the installation in a severely limited water supply area and far from the seaside, changes have been made on some process and utilities units, compared with the reference case 3.22. The main peculiarities of the present case 3.23 are the deletion of the seawater cooling system, being the cooling effect provided by aircoolers and by machinery cooling water, and the installation of a Flue Gas Direct Contact Cooler system for condensing and recovering part of the water contained in the flue gas.

2.2. Unit 100 - Coal Handling

Please refer to Report # 2, Section C, paragraph 2 for the process description of this unit.

Purpose of this system is to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the boiler plant.

2.3. Unit 200 – Boiler Island

2.3.1. Coal Combustion

Please refer to Report # 2, Section C, paragraph 2 for the process description of this system.
The fuel input has been kept constant as the relevant reference case 3.22.

The coal burners and the firing system used here are designed for minimizing NOx formation. Hot combustion products passing through the radiative and convective heating surfaces provide heat for steam generation and cold steam reheat. Flue gas is then sent to ESP and FGD plant.

2.3.2. Steam Raising

Please refer to Report # 2, Section B, paragraph 2 for the process description of this system.

Boiler feedwater enters the furnace economizer and then passes to the water wall circuits enclosing the furnace. The HP steam generated here is routed to the HP turbine. Cold reheat steam passes through the reheater and is returned to the IP turbine.

2.3.3. Soot and Ash Handling

Please refer to Report # 2, Section C, paragraph 2 for the process description of this system.

The ash handling system takes care of collecting and handling the ashes generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers.

2.4. Unit 400 - DeNOx

Please refer to Report # 2, Section C, paragraph 2 for the process description of this unit.

A catalytic DeNOx reactor is required for reducing NOx content in flue gas, so that the emission limits and the inlet requirement of the carbon dioxide absorption plant are satisfied. A schematic Process Flow Diagram is attached in the following paragraph 3.

2.5. Unit 300 - Flue Gas Desulphurization

Please refer to Report # 2, Section B, paragraph 2 for the process description of this unit.

Flue gas desulphurization is required for reducing SOx content in flue gas, so that the emission limits and the inlet requirement of the carbon dioxide absorption plant are satisfied. Gypsum is generated in this unit by the reaction of sulphur oxides with limestone. A schematic Process Flow Diagram is attached in the following paragraph 3.

2.6. Unit 500 - Steam Turbine Generator

Please refer to Report # 2, Section C, paragraph 2 for the process description of this unit.

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 for reheating and then throttled into the double flow IP turbine. Exhaust steam from the IP turbines then flows into the double flow LP turbine system. Exhaust steam from the LP turbine is condensed and then deaerated and preheated for generating recycled boiler feed water to be fed to the Boiler Island.

The major difference with the reference plant, case 3.22, is that the exhaust steam from the LP turbine is condensed in an aircooler and not in a sea water condenser. With respect to the latter condenser, the condensing system with aircooler allows reaching lower steam turbine performances, since the condensing pressure that can be achieved by the air condenser is significantly higher (0.074 bara with aircooler vs 0.040 bara with sea water condenser).

2.7. Unit 600 - CO_2 Amine Absorption

Please refer to Report # 2, Section B, paragraph 2 for the process description of this unit.

The major difference with the reference plant, case 3.22, is that all the sea water coolers (absorber column DCC cooler, absorber column pumparounds coolers, lean MEA cooler and stripper trim condenser) have been replaced by aircoolers. From the point of view of the operating conditions, such change leads to slightly higher temperatures in the columns. For this reason, in order to maintain the CO_2 absorption performance constant, the MEA circulation has to be increased.

Furthermore, in the present power plant, case 3.23, in order to reduce the request of raw water from outside the power plant battery limit, the condensation and recovery of part of the steam contained in the exhaust flue gases at stack is carried out. Condensation is performed in the Flue Gas Direct Contact Cooler (FG DCC) system, which is considered included in Unit 600. FG DCC consists of vertical columns, where the flue gas enters at the bottom and is cooled by contacting a stream of water, which is sprayed at the top. Due to the cooling effect, part of the water contained in the flue gas is condensed and collected at the towers bottom. The water circuit includes pumps for disposing of the excess of condensed water to the waste water treatment unit and recycling part of the water to the spray nozzles at the top of the column, passing through an aircooled heat exchanger.

Due to the additional pressure drop in the direct contact cooler, the head of the ID fan installed in the Boiler Island has to be properly increased.

2.8. Unit 700 - CO_2 compression

Please refer to Report # 2, Section B, paragraph 2 for the process description of this unit.

The major differences with the reference plant, case 3.22, are:

- all the sea water coolers (compressor intercoolers) have been replaced by aircoolers
- since the aircooler installed downstream of the fourth compression stage doesn't allow condensing the compressed CO_2, the booster pump, used in case 3.22 for the final compression to deliver CO_2 at the plant battery limit at 110 bara, is replaced with a further compressor stage. Thus, the compression train results composed by a five stages compressor and no more in a four stage compressor followed by a pump.

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 9.

The main utility units are the following:
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

2.9.1. Waste Water Treatment

The Waste Water Treatment plant includes some specific units necessary for reducing pollutants concentration. Their description follows hereafter.

Sulphites oxidation

Surplus water from Unit 600 and the water from FG DCC are contaminated with sulphites. These two streams are treated separately in two different oxidation basin because of their different composition. In order to remove HSO_3-, hydrogen peroxide is added, giving as reaction product sulphuric acid. The contact time that permit sulphites oxidation is circa 30 minutes and the oxidation basin is normally designed considering this parameter. The oxidation basin can be equipped with an adequate number of mixers in order to favourite a close contact between the reagents. After oxidation, surplus water from Unit 600 is rejoined with the others polluted stream in the equalization tank, while treated water from FG DCC is sent directly to reuse because no other pollutants are present in addition to sulphites.

Equalization

The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed in order to make uniform the physical characteristics of the waste water to be fed to treatment (e.g. pollutants concentration, temperature, etc.). Surplus water from unit 600 and blow down water from demineralization unit are sent to the equalization basin in order to make uniform the wastewater characteristic and to optimise the following treatment units. Equalization basin is normally designed in order to guarantee an hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

Anaerobic treatment

Considering the presence of a high organic load (deriving from a high concentration of MEA in the main polluted stream) in the equalized polluted flow, an anaerobic

treatment is recommended and, particularly, an anaerobic sludge blanket process (UASB) is selected.
In this kind of process, influent wastewater is distributed at the bottom of the UASB reactor and travel in an up-flow mode through the sludge blanket. Critical elements of UASB reactor design are the influent distribution system, the gas solid separators and the effluent withdrawal design. The key feature of the UASB process that allow the use of high volumetric COD loads (max 25 kgCODSOL/m3/d for a temperature of 40°C) is the development of a dense granulated sludge with decreasing concentration from the bottom to the top of reactor.
Removal efficiencies of 90 to 95% for COD are achieved at COD loadings ranging from 12 to 20 kgCOD/m3/d on a variety of wastes at 30-35°C.
For UASB design typical up-flow velocity ranges between 2 and 6 m/h with a hydraulic retention time of circa 6 - 8 hours, function of temperature values.
The pH should be maintained near 7.0 and a recommended COD:N:P ratio during start-up is 300:5:1, while a ratio 600:5:1 can be used during steady-state operation.

<u>Aerobic biological treatment and denitrification</u>

Effluent water from UASB reactor presents a residual concentration of COD and an high concentration of ammonia that have to be removed.
For this reason the wastewater is sent to a Nitrification-Denitrification section. In the nitrification section aerobic bacteria oxidize the pollutants and BOD is converted to carbon dioxide (CO_2), while ammonia (NH_3) is converted to nitrate (NO_3). In order to allow this reaction oxygen has to be provided with dedicated air blowers and air distribution system.
Duty of the denitrification section, operating under anoxic conditions, is the removal of nitrates converted to gaseous nitrogen (N_2). In order to remove a high nitrate concentration, an adequate amount of external COD (i.e. CH_3OH) has to be added (circa 4 kg COD / kg NO_3). An adequate mixing has to be provided in order to avoid solid sedimentation.
A final aerobic section may be necessary in order to remove the residual COD eventually present.
In order to maintain the request biomass concentration (i.e. 4-5 kg SST / m3) in the biological basins, a settling system is necessary in order to separate biological solids produced. Then, part of the solids are recirculated to biological basins by means of a recirculation pumps (generally the recirculation flowrate is at least equal to the inlet flowrate to biological system), while the excess sludge is sent to sludge treatment section by a dedicated pump.
Biological settler is designed considered a hydraulic load of 0.6-0.9 m/h and a maximum solid rate of 5 kgSST/m2/h.

Sand Filtration

The clarified water from biological basin is applied to the top of the sand filter bed in order to remove the remaining unsetteable solids.
As the water passes through the filter bed, the suspended matter in the wastewater is intercepted and removed. With the passage of time, as material accumulates within the interstices of the granular medium, the head loss through the filter start to build up beyond the initial value. After some period of time, the operating head loss through the filter reaches a predetermined head loss value and the filter must be cleaned.
The filters are designed in function of different parameters:
- Influent wastewater flowrate and characteristics;
- Granular medium geometric and dimensional characteristics;
- Admissible head loss and admissible filtration velocity;
- Flow control type.

Sludge Treatment

The separated sludge from biological settler and the chemical sludge from Flue Gas Desulphurization unit are sent to a mixing basin, where they are subjected to a chemical conditioning.
Ferric Chloride (10-30 mg $FeCl_3$ / kg SST) and polyelectrolyte (1-3 mg Poly / kg SST) are added in order to favourite solids aggregation and to improve the subsequent dewatering treatment.
The conditioned and mixed sludge is finally sent to a dewatering system (i.e. centrifugal system) in order to achieve a dry solids content of minimum 20%. The separated polluted water (supernatant) is recirculated to the equalization tank while the dewatered sludge is sent to final disposal.

3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagram of the USC PC Plant, Case 3.23, and the schematic Process Flow diagram of Units 300, 400, 500, 600 and 700 are attached hereafter.

The Block Flow Diagrams and Process Flow Diagrams attached to Report # 2, Section C, paragraph 3 are to be taken as reference: they represent the plant arrangement for case 3.22, i.e. when the plant is installed in a no-dry land country and along the seaside. Modifications required due to installation in a dry land country and far from the seaside have been highlighted in the drawings attached hereafter.

The Block Flow Diagram of the Waste Water Treatment unit, valid for the present case 3.23, is also attached hereafter. The relevant Heat&Mass balance is reported in paragraph 5 of this section. The list of the utilities consumption is shown in paragraph 6.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

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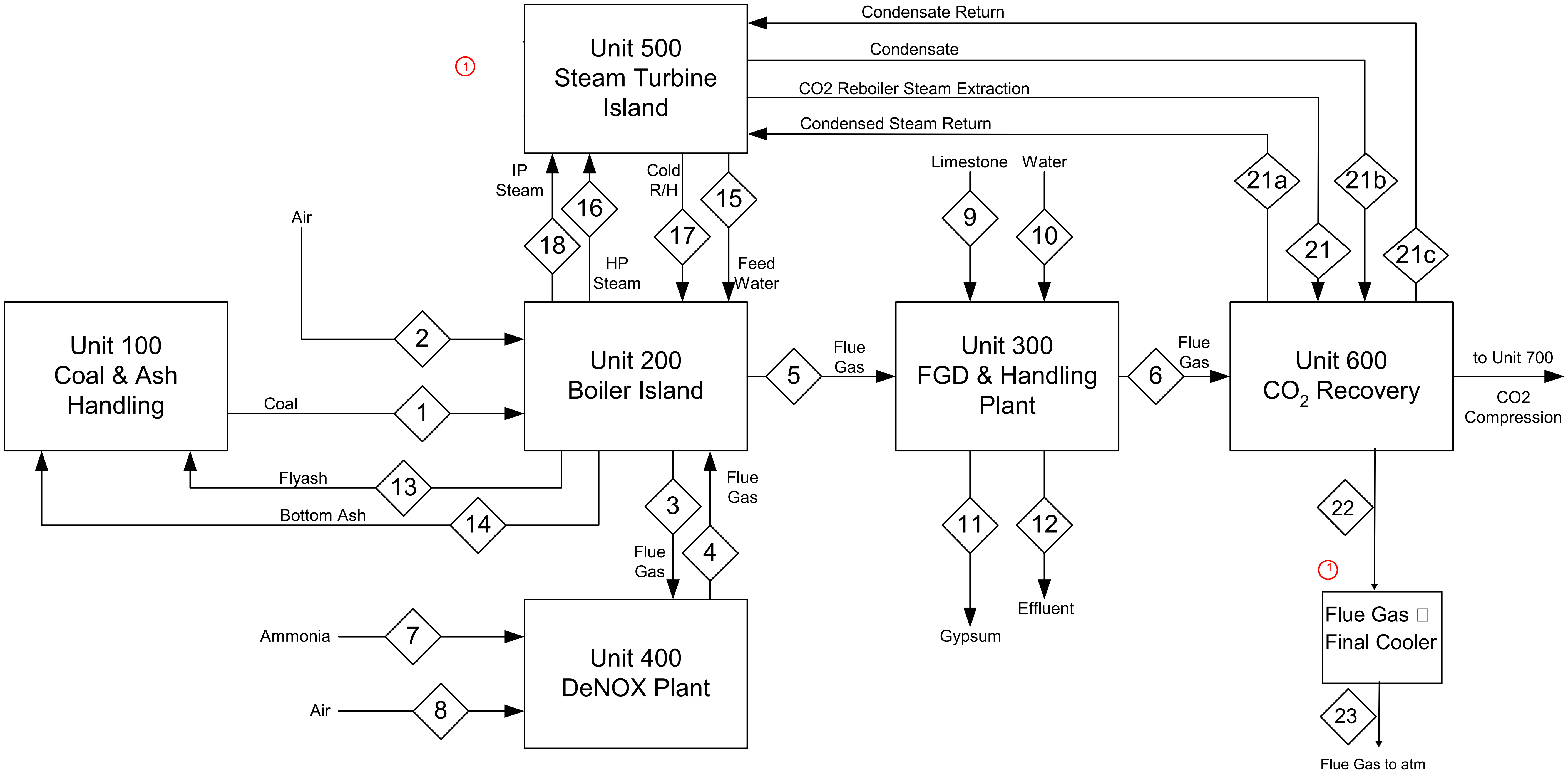
MITSUI BABCOCK

Case 3.23 799 MWe Gross PF Power Plant with CO_2 Capture Amine Scrubbing: Block Flow Diagram

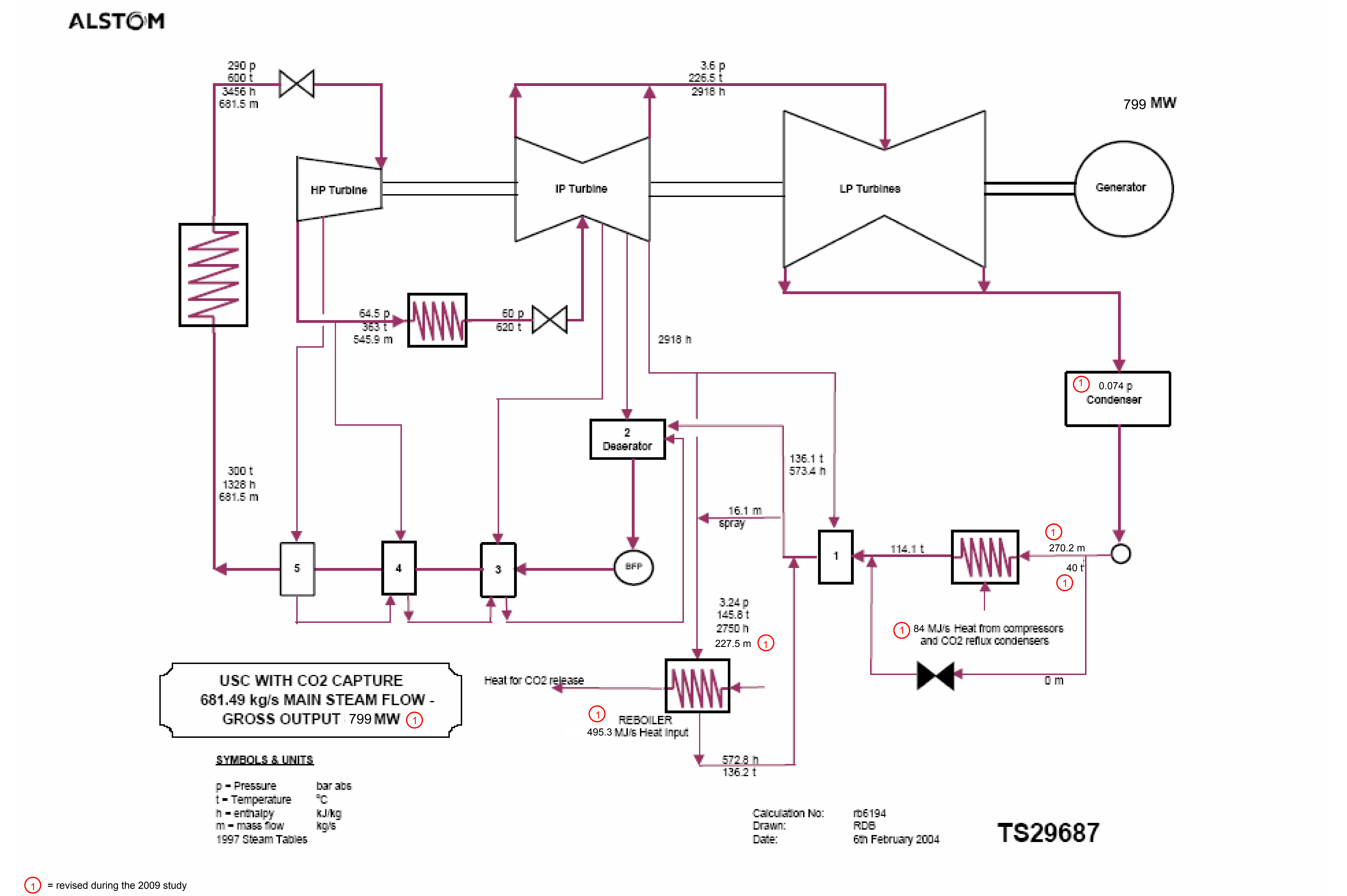


1 = revised during the 2009 study for closing the water balance

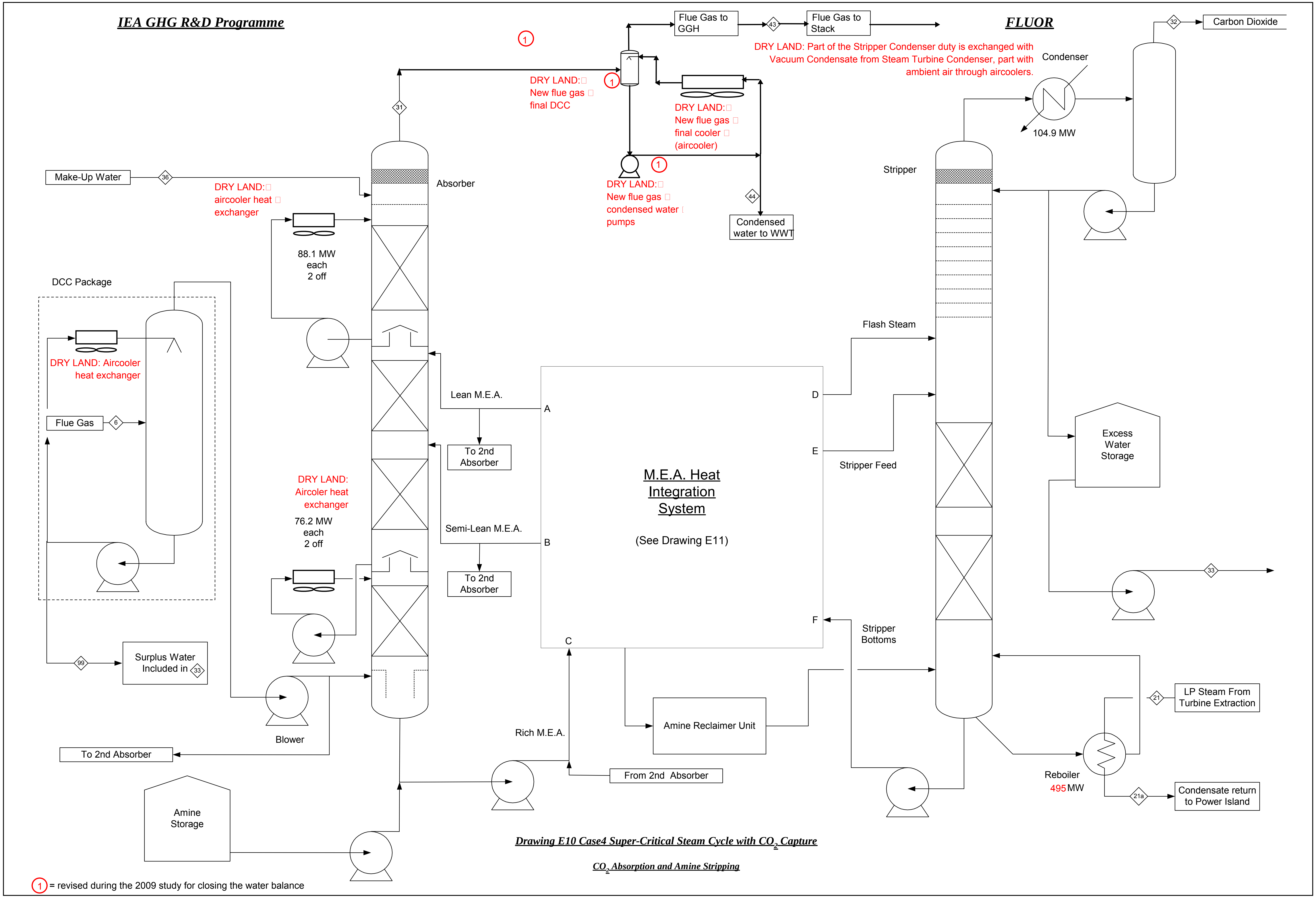
Drawing E8

Case 3.23 SCPF With Capture

FLUOR

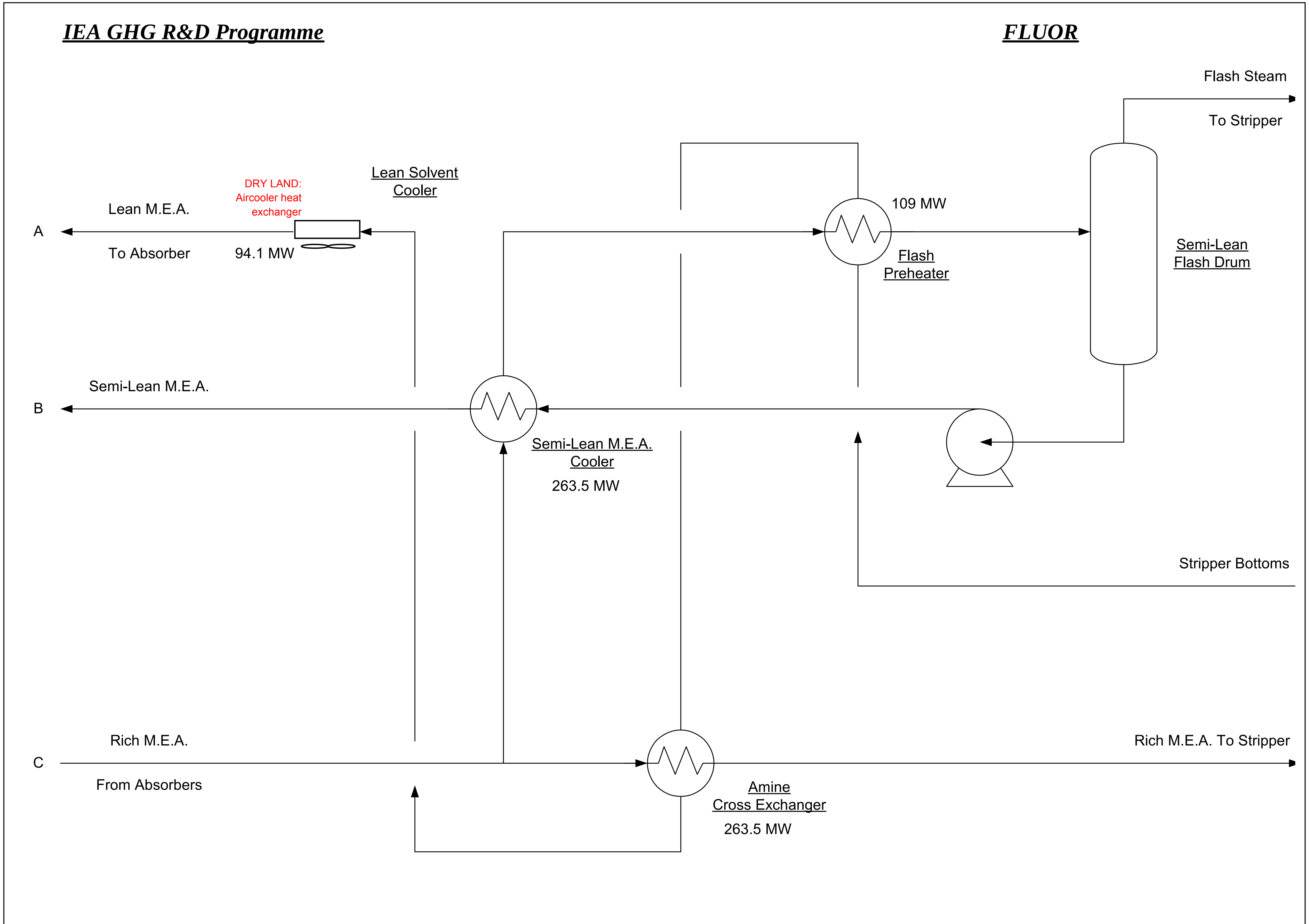


Drawing E9 *CASE_3.23_USCPF WITH CAPTURE - TURBINE POWER ISLAND*



Drawing E10 Case4 Super-Critical Steam Cycle with CO_2 Capture

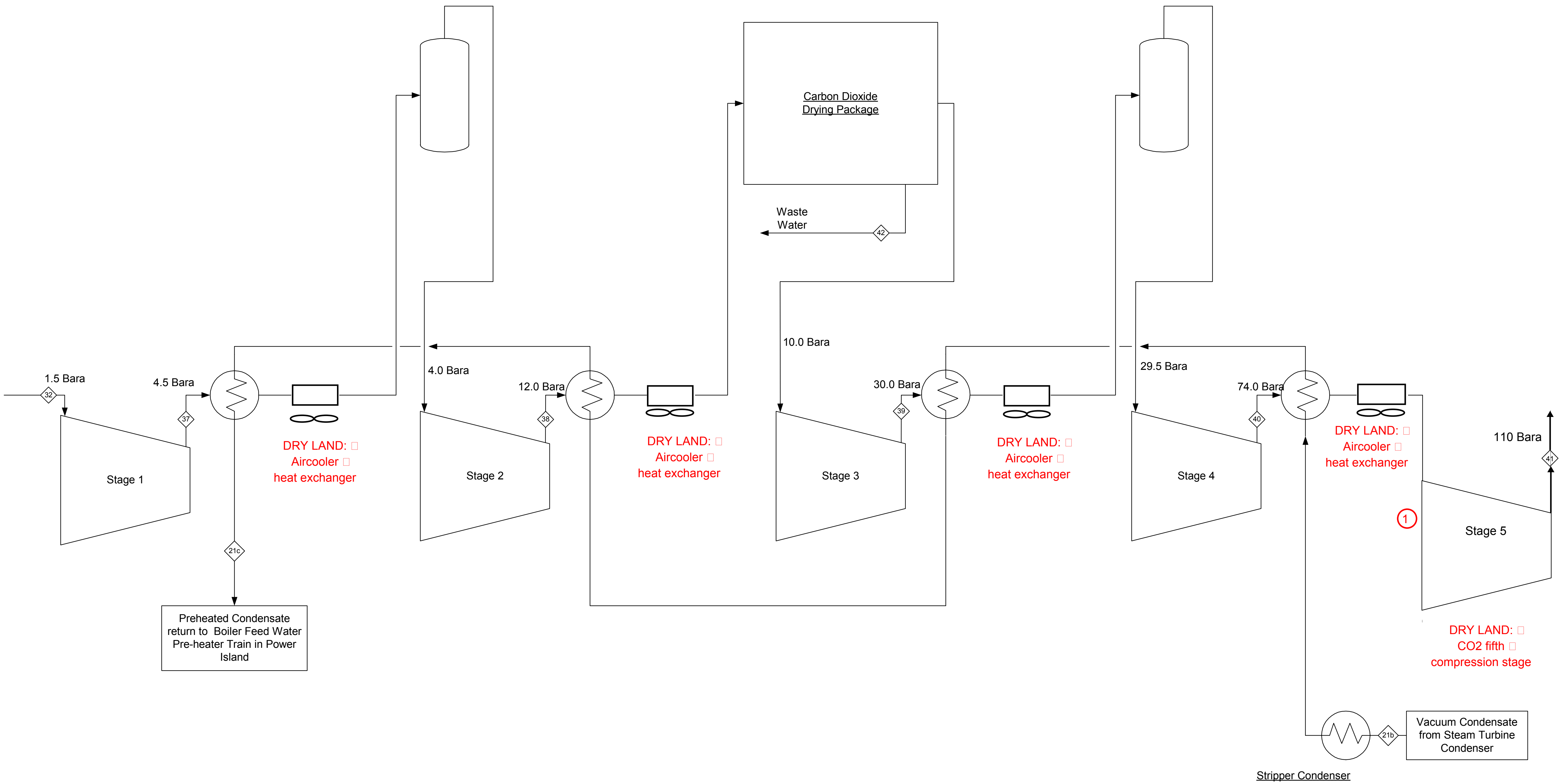
CO_2 Absorption and Amine Stripping



Drawing E11 Case4 Super-Critical Steam Cycle with CO_2 Capture

M.E.A. Heat Integration System

IEA GHG R&D Programme *FLUOR*



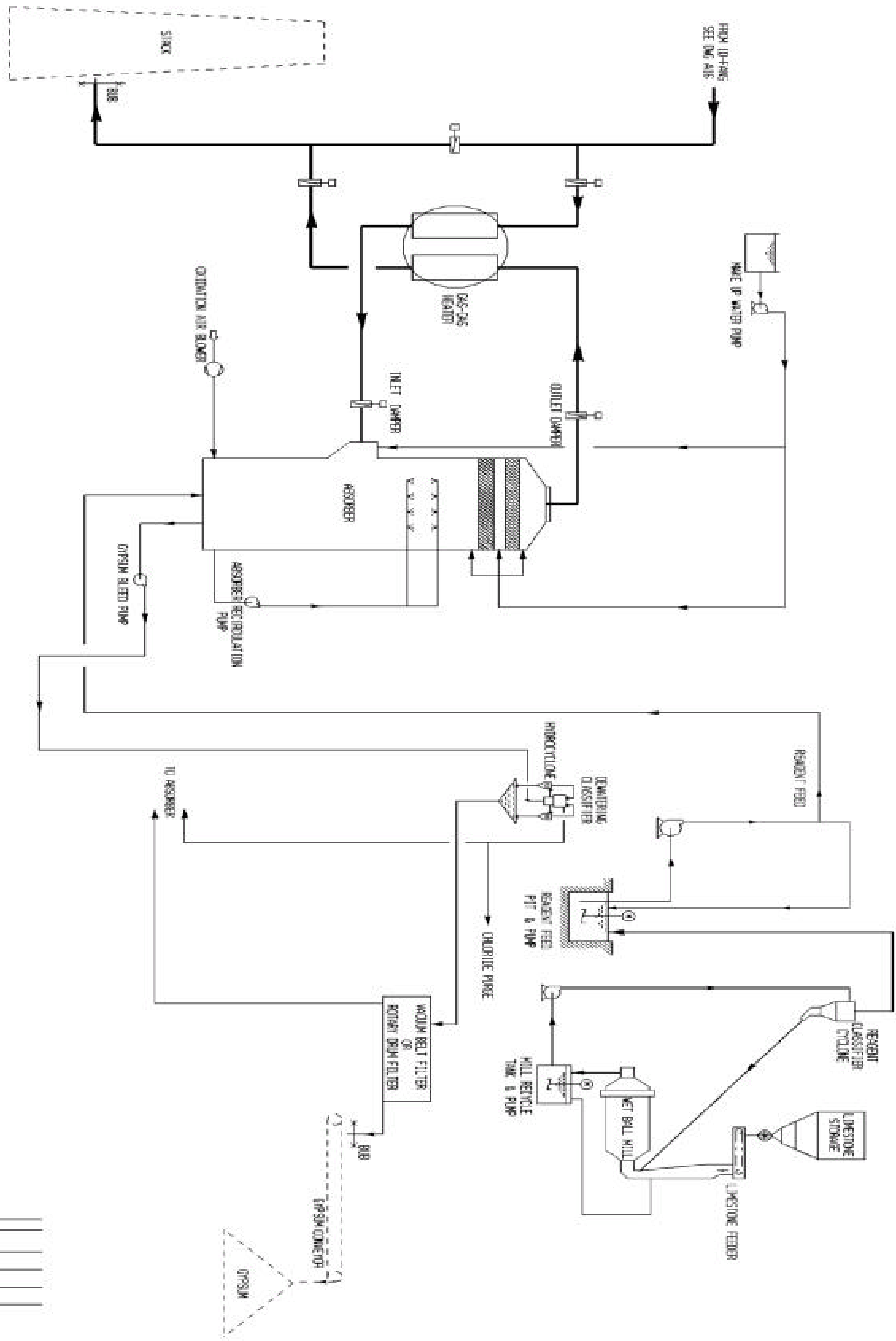
Drawing E12 Case 4 Super-Critical Steam Cycle with CO_2 Capture

CO_2 Compression and Recovery System

1 = revised during the 2009 study for closing the water balance

ALSTOM

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



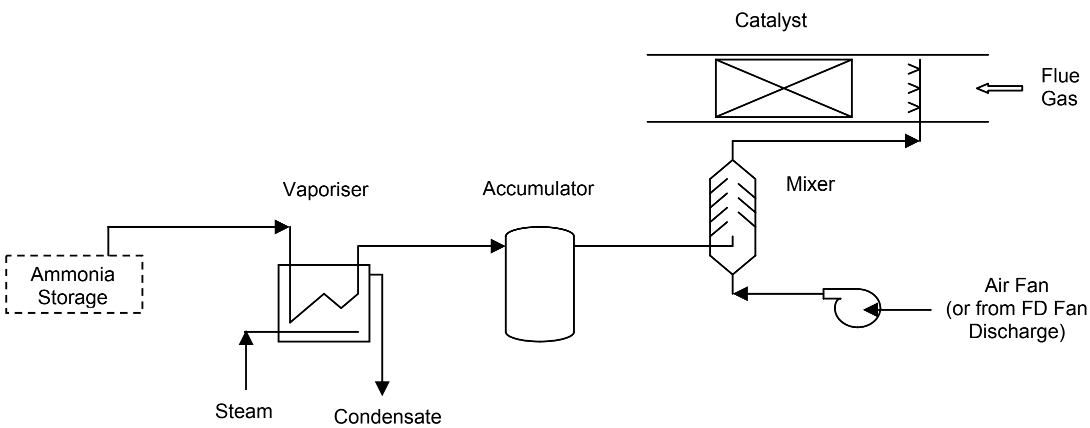
Issue

A1

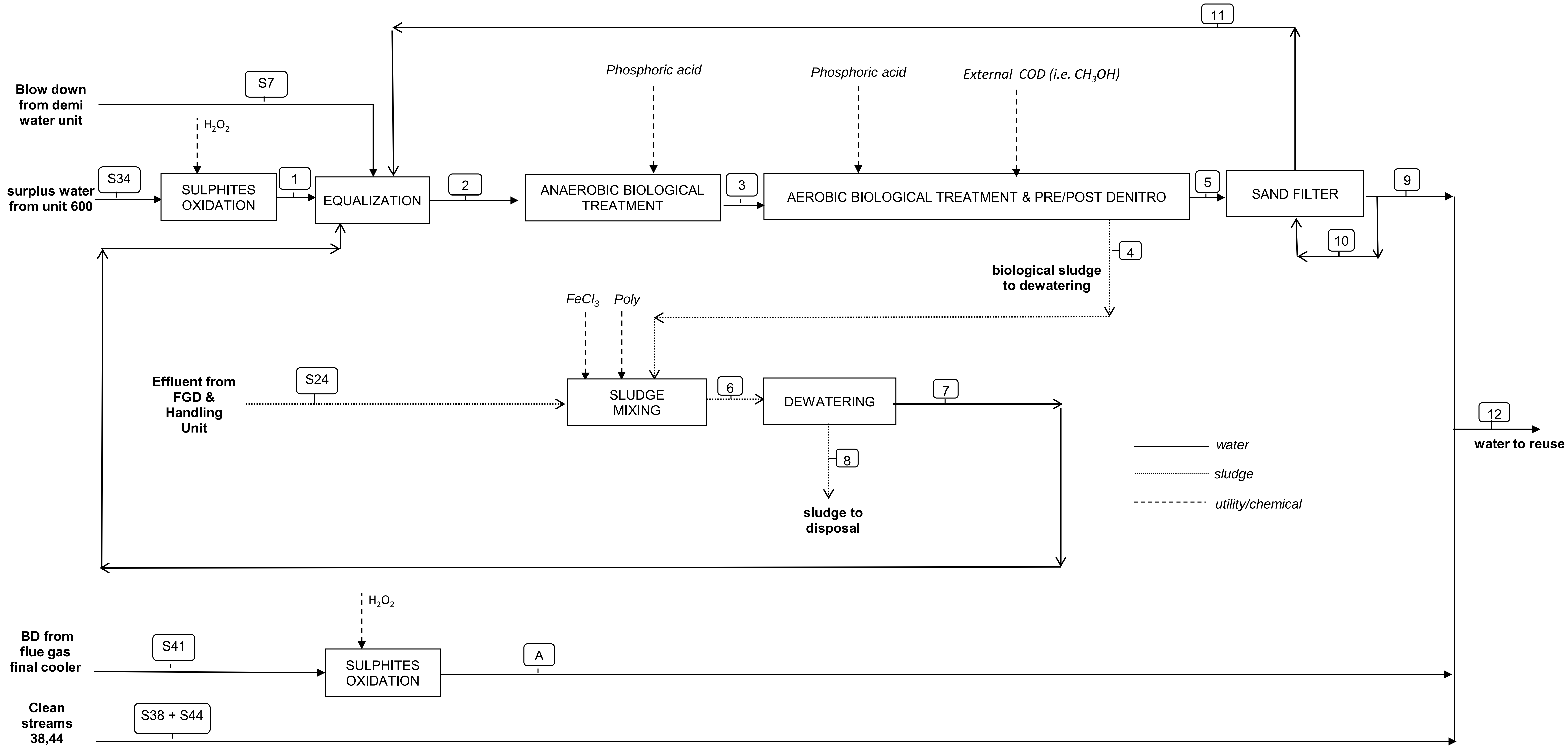
Ammonia / Air System

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



Case 3.23 USC PC COMPLEX, BITOMINOUS COAL WITH CO_2 CAPTURE (DRY LAND)



4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units;
- flowrates and compositions of the streams of water to waster water treatment unit.

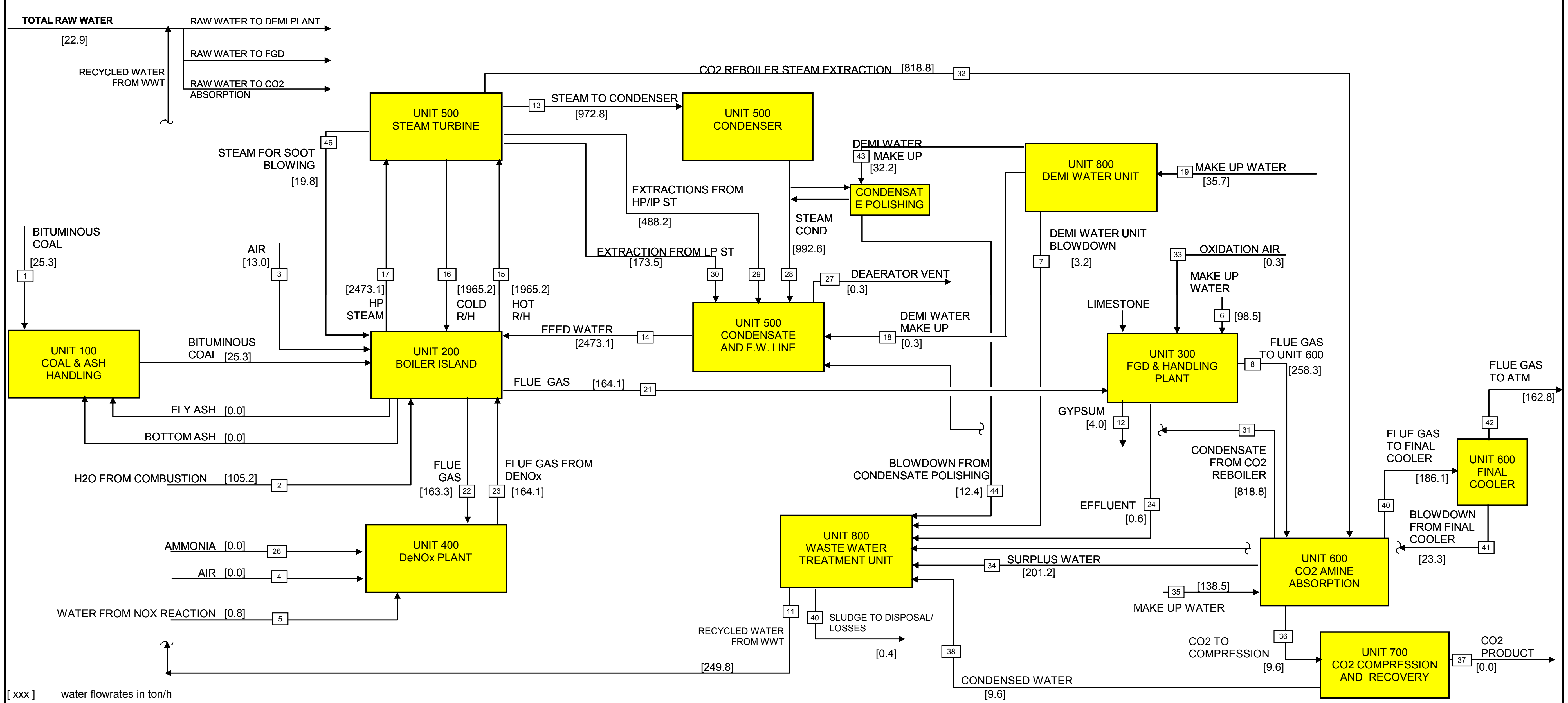
It is important to note that the introduction of a final cooler downstream the boiler allows the recovery of a significant amount of water from the boiler flue gases. This water is sent to the WWT together with the polluted streams of the plant.
The treated water is, therefore, sufficient to meet the plant raw water consumption allowing a zero raw water intake.

The ambient temperature affects the minimum temperature that can be achieved in the air cooling systems.
The higher ambient temperature leads to an higher temperature on the process streams downstream the air cooled exchanger. The material balance attached to water diagram is referred to the refence ambient temperature. Therefore, it is to be considered as an average between the cold and the warm season.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

In the CO_2 capture unit, raw water is required to scrub the gases leaving the column and remove any entrained MEA. This consumption of water can be avoided in some CO_2 capture processes where part of the water discharged into the flue gas cooling upstream the column can be reused. For the purposes of this paper, the need of such a makeup is considered.

CASE 3.23 - USC PC PLANT, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 622.5 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



USC CPS, bituminous coal, with CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	25.3	42	Flue Gas to atmosphere	162.8
2	Water from coal combustion	105.2	11	Effluent from WWT to reuse	249.8
3	Moisture in air to Boiler Island	13.0	12	Moisture in Gypsum	4.0
4	Moisture in air to DeNOx Plant	0.0	27	Deaerator vent	0.3
5	Water from NOx reaction	0.8	37	CO2 product	0.0
6	Water to FGD & Handling Plant	98.5	40	Sludge to disposal/losses	0.4
26	Water in ammonia di DeNOx	0.0			
19	Make up to Demi Water Unit	35.7			
33	Oxidation air	0.3			
35	Make up water to Unit 600	138.5			
Total		417.4	Total		417.4

USC CPS, bituminous coal, with CO2 capture - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	3.2	11	Effluent from WWT to reuse	249.8
24	Effluent from FGD & Handling Uni	0.6	40	Sludge to disposal/losses	0.4
34	Surplus water from Unit 600	201.2			
38	Condensed water from unit 700	9.6			
41	BD from flue gas final cooler	23.3			
44	Blowdown from BFW polishing	12.4			
Total		250.2	Total		250.2

USC CPS, bituminous coal, with CO2 capture - Water Balance around DeNOx unit

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
4	Moisture in air to DeNOx Plant	0.0	23	Flue gas from DeNOx unit	164.1
5	Water from NOx reaction	0.8			
22	Flue gas from Boiler Island	163.3			
26	Water in ammonia di DeNOx	0.0			
Total		164.1	Total		164.1

USC CPS, bituminous coal, with CO2 capture - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	25.3	22	Flue Gas to DeNOx Plant	163.3
2	Water from coal combustion	105.2			
3	Moisture in Air to Boiler Island	13.0			
46	Steam for soot blowing	19.8			
Total		163.3	Total		163.3

USC CPS, bituminous coal, with CO2 capture - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1965.2	13	Steam to condenser	972.8
17	HP steam from Boiler	2473.1	16	Cold R/H to Boiler	1965.2
			29	Extractions from HP/IP ST	488.2
			30	Extractions from LP ST	173.5
			32	CO2 reboiler steam extraction	818.8
			46	Steam for soot blowing	19.8
Total		4438.3	Total		4438.3

USC CPS, bituminous coal, with CO2 capture - Water Balance around Unit 600

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Make up water to Unit 600	138.5	42	Flue gas to atmosphere	162.8
8	Flue gas to Unit 600	258.3	36	Water in CO2 to compression	9.6
32	CO2 reboiler steam extraction	818.8	31	Condensed steam return	818.8
			34	Surplus water from Unit 600	201.2
			41	Blowdown to WWT	23.3
Total		1215.7	Total		1215.7

CASE 3.23 - USC PC PLANT, BITUMINOUS COAL, WITH CO2 CAPTURE (DRY LAND) - WATER STREAMS SENT TO WWT

STREAM	7	24	34	38	41	44	
SERVICE	Blowdown from Demi Water Unit	Effluent from FGD & Handling Unit	Surplus water from Unit 600	Condensed water from unit 700	BD from flue gas final cooler	Blowdown from BFW polishing	
Temperature (°C):	amb	50	40	35	39	30	
Total flowrate (t/h):	3.2	0.6	201.2	9.6	23.3	12.4	
Composition (ppm wt)		FOR THE COMPOSITION, REFER TO TABLE AT THE SIDE					
SO2			} 250		1		
HSO3-					25		
CO2			4616	150	20		
NH3							
Na+	1090						
Cl-	4560						
PO4---						5	
SiO2	110					5	
CaCO3	406					100	
SO4--	830						
NO3-	510						
Ca AAS	1410						
Mg AAS	420						
MEA			4807				
Suspended solids			67 (**)		170(**)		
K	30						
HCO3-	250				0.1		
H2O (% wt)	99.0384		99.0133	99.9850	99.9758	99.9890	
TOTAL (%wt)	100		100	100	100	100	

24	
Effluent from FGD & Handling Unit	
Components	ppm wt
CaSO4 * 2 H2O solid	7300
CaCO3 solid	110
MgCO3 solid	200
CaF2 solid	3870
Inerts from limestone	15720
Fly ash, solid	1260
Total Solids	**28460**
Cl -	28130
SO4 --	1320
Ca ++	2180
Mg ++	6790
Total Ions	**38420**
CaSO4 dissolved	**1860**
H2O (% wt)	**93.13**
TOTAL (% wt)	100

NOTES: *

(*) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate
(**) = solids consist of coal fines

5. 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.

Reference shall be made to Report # 2, Section C, paragraph 5 for the H&M balance attached. The information relevant to WWT has been included. Modifications due to dry land have been highlighted in the H&M balance attached in the apendix 1 of present Volume 2.

IEA GHG R&D PROGRAMME

Water usage and loss of power in plants with CCS

Volume #2 - Case 3.23 USCPC with CCS (dry land)

Revision no.: 0
Date: February 2010

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 Gas	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
- Limestor	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	-	684.6	1568.4	1573.1	977.2	866.1	-	2.04	-	0.028
	Nm^3/s	-	653.1	658.0	660.0	692.8	729.8	0.168	1.93	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Tempera	°C	14	14	380	380	114	51	14	14	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.22	0.55	0.55	0.93	1.09	-	1.22	-	-
Composition											
O_2	%v/v,wet		20.90	3.27	3.27	4.50	4.28		20.90		
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	9.78	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				
Particulat	mg/Nm^3			8444	8416	30	14				

IEA GHG R&D PROGRAMME

Water usage and loss of power in plants with CCS

Volume #2 - Case 3.23 USCPC with CCS (dry land)

Revision no.: 0
Date: February 2010

Stream ID		11	12	13	14	15	16	17	18	19	20	21	21a	21b	21c	22	23
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Steam	Sat. Water	Condensate	Condensate	Gas	Gas
Mass Flow Rate																	
- Coal	kg/s	0	0	0.37	0.12	0	0	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	0	0
- Flue Ga	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	763.0	
- Ash	kg/s	0	0	6.75	2.26	0	0	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	0	0
- Steam	kg/s	0	0	0	0	0	687.0	545.9	545.9	0	0	227.5	227.5	270.2	270.2	0	0
- Ammoni	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Limesto	kg/s	0	0	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	0	0
Volume Flo	Am^3/s	-	-	-	-	-	-	-	-	0	0	-	-	-	-		
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Props																	
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas	Liquid	Liquid	Liquid	Gas	Gas
- Tempera	°C	-	-	114 / 380	1000	300	600	363	620	---	---	146	136	40	114	46.8	39
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	2.24	2.24	-	-	0.01	0
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Composition																as stream 31 on next page	as stream 43 on next page
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																
Particulat	mg/Nm^3																

FLUOR

Heat And Material Balance
CASE 3.23: USCPF WITH CAPTURE

Stream Description			Flue Gas to DCC	Flue Gas to DCC..	CO2 From Stripper	Surplus Water	LP Steam to Reboiler	Cond Return to Power Island	Make Up Water	Flue gas to stack	DCC cond to WWT
Stream Number			6	31	32	33	21	21a	36	43	44
Temperature Deg C			52	49.3	37.8	37.8	136	136	37.8	46.8	46.8
Pressure,Bara			1.01	1.15	1.6	2.76	3.24	3.24	1.38	1.02	1.02
Component Flows		MW									
	H2O	18.02	15608	10328	533	12435	44990	44990	7688	8997	1331
	CO2	44.01	14330	2125	12181	24				2125	
	MEA	61.08				9					
Note 3	N2	28.02	82278	82277	1					82277	
	O2	32	5012	5012						5012	
Note2	Nat Gas	19.35									
Note 4	AIR	28.89									
Total kgmol/hr			117228	99742	12715	12468	44990	44990	7688	98411	1331
Total Tonnes/hr			3376.8	2745.7	545.72	225.7	810.72	810.72	138.5	2710.7	24
Molecular weight			28.80	27.53	42.92	18.10	18.02	18.02	18.02	27.54	18.02
Density,Kg/m3			1.083	1.05	2.71	990		929	990	1.05	990
			Note 4	**Note 2**	**Note 3**				**Note1**	Note 1	Note 1

NOTES

component flows in Kgmol/Hr

1 Flows for a total of two streams
2 Flows for two absorbers discharging to atmosphere
3 CO2 recovered is 85% of inlet CO2 in stream 6
4 This stream matches is a match stream for stream 6 on boiler island mass balance table

SEE DWG E10

FLUOR

Heat And Material Balance
CASE 3.23 USCPF WITH CAPTURE

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	40	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	12425						12425	
	MEA	61.08								
Note 3	N2	28.02	1							
	O2	32								
Note2	Nat Gas	19.35								
Note 4	AIR	28.89								
Total kgmol/hr			12959						12425	533
Total Tonnes/hr			556.426				972	972	546.8	9.59
Molecular weight			42.94						44.01	18.02
Density,Kg/m3							1000	1000		
									13123TPD	**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 preheat train in power plant. See Alstom Dwg TS 29687 (DWG E9)

SEE DWG E12

Case 3.23 USC PC COMPLEX, BITOMINOUS COAL WITH CO2 CAPTURE (DRY LAND)

Stream		N°	S24	S7	S34	S41	S38	S44	A	1	2	3	4	5	6	7	8	9	10	11	12
Parameter	**Note**	**unit**	**Effluent from FDG & Handling Unit**	**Blowdown from Demi water unit**	**Surplus water from unit 600**	**BD from flue gas final cooler**	**Condensate water from unit 700**	**Blowdown from BFW polishing**	**Flue water from HSO3- oxidation**	**Water from HSO3- oxidation**	**Equalized water**	**Water from anaerobic treatment**	**Biological sludge**	**Water from biological settler**	**Sludge to dewatering**	**supernatant to equalization**	**Sludge to disposal**	**Filtered water**	**Clean S.F. backwash water**	**Polluted S.F. Backwash water**	**Water to reuse**
Temperature	(1)	°C	50,00	20,00	40,00	39,00	35,00	30,00													
Flow rate		ton/h	0,72	3,20	224,10	23,30	9,60	12,40	23,45	224,15	259,23	259,38	20,53	238,85	21,30	20,51	0,79	227,48	11,37	11,37	272,93
CO2		mg/l	0,00	0,00	4616,00	20,00	150,00	0,00	20,00	4615,03	4562,49	4562,49	4562,49	4562,49	4421,95	4573,83	4421,95	4790,61	4790,61	4790,61	4001,83
NH3		mg/l	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	0,00	0,00	0,00	0,00	0,00	0,00
Na+		mg/l	0,00	1090,00	0,00	0,00	0,00	0,00	0,00	0,00	15,38	15,38	15,38	15,38	14,91	15,42	14,91	16,15	16,15	16,15	13,47
Cl-		mg/l	28130,82557	4560	0,00	0,00	0,00	0,00	0,00	0,00	138,80	138,80	138,80	138,80	943,42	975,83	943,42	145,74	145,74	145,74	121,53
PO4--		mg/l	0,00	0,00	0,00	0,00	0,00	5,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,23
SiO2		mg/l	0,00	110,00	0,00	0,00	0,00	5,00	0,00	0,00	1,55	1,55	1,55	1,55	1,50	1,56	1,50	1,63	1,63	1,63	1,59
TSS		mg/l	28460	110	60,00	0,00	0,00	0,00	0,00	59,99	184,56	200,00	10000,00	60,00	10510,33	1087,13	284861,64	10,00	10,00	1060,00	8,34
COD		mg/l	0,00	0,00	6249,10	0,00	0,00	0,00	0,00	6247,79	5531,37	442,51	29,24	110,00	28,34	1543,73	28,34	40,00	40,00	40,00	33,36
BOD		mg/l	0,00	0,00	4566,65	0,00	0,00	0,00	0,00	4565,69	4020,00	321,60	16,08	60,00	15,58	849,05	15,58	20,00	20,00	20,00	16,68
CaCO3		mg/l	110,00	406,00	0,00	0,00	0,00	100,00	0,00	0,00	6,02	6,02	6,02	6,02	9,00	9,31	9,00	6,32	6,32	6,32	9,82
SO4--		mg/l	1319,91	830,00	0,00	0,00	0,00	0,00	0,00	0,00	13,49	1,35	1,35	1,35	39,26	40,61	39,26	1,42	1,42	1,42	1,18
NO3-		mg/l	0,00	510,00	0,00	0,00	0,00	0,00	0,00	0,00	7,55	7,55	10,00	10,00	9,69	10,02	9,69	10,50	10,50	10,50	8,76
Ca2+		mg/l	2180,43	1410,00	0,00	0,00	0,00	0,00	0,00	0,00	25,67	25,67	25,67	25,67	87,58	90,59	87,58	26,95	26,95	26,95	22,48
Mg2+		mg/l	6790,40	420,00	0,00	0,00	0,00	0,00	0,00	0,00	23,90	23,90	23,90	23,90	218,42	225,92	218,42	25,09	25,09	25,09	20,92
MEA		mg/l	0,00	0,00	4807,00	0,00	0,00	0,00	0,00	4805,99	4188,35	335,07	335,07	25,2	324,75	335,90	324,75	26,43	26,43	26,43	22,04
K+		mg/l	0,00	30,00	0,00	0,00	0,00	0,00	0,00	0,00	0,42	0,42	0,42	0,42	0,41	0,42	0,41	0,44	0,44	0,44	0,37
HCO3-		mg/l	0,00	250,00	0,00	0,10	0,00	0,00	0,10	0,00	3,53	3,53	3,53	3,53	3,42	3,54	3,42	3,70	3,70	3,70	3,10
HSO3-		mg/l	0,00	0,00	250,00	26,00	0,00	0,00	0,50	0,50	0,49	0,49	0,49	0,49	0,48	0,50	0,50	0,52	0,52	0,52	0,48
Norg		mg/l	0,00	0,00	1105,61	0,00	0,00	0,00	0,00	1105,38	958,28	885,19	10,00	10,00	9,69	10,02	10,02	10,50	10,50	10,50	8,76
H2O		%	94	99	97	100	100	100	100	97	98	99	98	99	98	99	74	99	99	99	99

General notes

Present mass balance is indicative only and related to the prosecc treatment selected

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. Details for WWT utility consumptions are also attached.

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: WATER USAGE AND LOSS OF POWER IN POWER PLANTS WITH CCS
LOCATION: SOUTH AFRICA
FWI N°: 1- BD 0475A

Rev: Draft
Feb 10
ISSUED BY: L.So.
CHECKED BY: PC
APPR. BY: SA

WATER CONSUMPTION SUMMARY - CASE 3.23 - USC PC with CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water (note 2) [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				SEA WATER IS NOT AVAILABLE IN POWER PLANTS INSTALLED IN DRY LAND
100	Coal and Ash Handling			82	
300	Flue Gas Desulphurization (FGD) and Handling Plant	98.5			
400	DeNOx Plant				
600	CO2 Absorption and Amine Stripping	138.5		250	
700	CO2 Compression and Recovery System				
200	BOILER ISLAND			107	
500	POWER ISLAND (Steam Turbine)		32.5	3502	
800	UTILITY and OFFSITE UNITS				
	Cooling Water, Demineralized Water Systems, etc	35.7	-32.5	90	
	BALANCE excluding CO_2 compression	134.2	0	3780	0
	BALANCE including CO_2 compression	272.7	0	4030	0

Note: (1) Minus prior to figure means figure is generated
(2) Machinery water max delta T is 10°C.

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	WATER USAGE AND LOSS OF POWER IN POWER PLANTS WITH (	Feb 10
LOCATION:	SOUTH AFRICA	ISSUED BY: L.So.
FWI Nº:	1- BD 0475A	CHECKED BY: PC
		APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - CASE 3.23 - USC PC with CO2 capture - DRY LAND

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 and aircoolers	20939
	CO2 Absorption and Amine Stripping - pumps	5190
700	CO2 Compression and Recovery System	70620
	POWER AND BOILER ISLAND UNITS	
200 - 500	Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)	54630
	Miscellanea utilities	6300
	UTILITY and OFFSITE	
800	Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems	830
	Additional consumption including CO_2 Compression and Drying	5000
	BALANCE excluding CO_2 compression	74160
	BALANCE including CO_2 compression	175909

Notes: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2
	LOCATION:	Dry land	DATE	February '10		
	PROJ. NAME:	Water usage and loss Analysis	ISSUED BY	M.P.		
	CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.		
			APPROVED BY			

Utilities consumption

Unit 800 - BoP, Electrical, I&C - USC PC oxycomb, bituminous coal, with CO2 capture, case 3.23 - DRY LAND

	ITEM	DESCRIPTION	Absorbed Electical power	CH_3OH	H_3PO_4	H_2O_2	$FeCl_3$	Poly	Remarks
			[kW]	[kg/h]	[kg/h]	[kg/h]	[kg/h]	[kg/h]	
	UNIT 4600	WWT - waste water treament complex	~860	~450	~80	~15	~7	~1	

Table below summarize specific consumpltion for each treatment section- reported values are indicative only

	ITEM	DESCRIPTION	Absorbed Electical power [kW]		CH_3OH (1)	H_3PO_4 (1)	H_2O_2 (1)	$FeCl_3$ (1)	Poly (1)	Remarks
			total	specific	[kg/h]	[kg/h]	[kg/h]	[kg/h]	[kg/h]	
		Sulphides oxidation Section (S34)	2.14				14.1			
		Sulphides oxidation Section (S41)	1.07				0.4			
		Equalization Section								
		Anaerobic Treatment section	45.44			68.0				
		Aerobic Treatment section	713.44			11.0				
		Anoxic Treatment section	22		445					
		Final Aerobic Treatment section	13.2							
		Sedimentation section	4.9							
		Sludge treatment section	18.26					6.6	0.7	
		Media filtration section								

Notes:
1. As pure products.
2. The biogas production deriving form anaerobic degradation is not included in the consumption list and it's estimated to be equal to about 19.000 n^3/d

7. Overall performance

The following table shows the overall performance of the USC PC power plant, case 3.23.

USC PC		
bituminous coal, with CO_2 capture - DRY LAND SCENARIO		
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	266.3
Coal LHV (air dried basis)	kJ/kg	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1913.7**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**799.0**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY		
FW pumps	MWe	37.0
Draught Plant and other consumptions in Power Island	MWe	10.5
Coal mills, handling, etc.	MWe	5.0
ESP	MWe	2.0
Steam Turbine Condenser	MWe	5.1
Utility Units consumption and Miscellanea	MWe	12.1
FGD	MWe	7.0
DeNOx	MWe	0.4
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**79.2**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**719.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**37.6**
POWER PLANT PERFORMANCES INCLUDING CO_2 RECOVERY		
Additional consumption		
Unit 600 and 700: CO_2 Absorption, Compression and Drying	MWe	96.7
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**175.9**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**623.1**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.6**
Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**3.071**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.125**
Specific water consumption per MW net produced	**t /MWh**	**0.000**

8. Environmental Impact

The USC PC Plant, case 3.23, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarises expected flow rate and concentration of the combustion flue gas.

Table 8-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	753.0
Flow, Nm^3/h	2,205,784
Temperature, °C	80
Composition	**(%vol, wet)**
O_2	5.09
CO_2	2.16
H_2O	9.14
N_2+Ar	83.61
Emissions	**mg/Nm^3 (1)**
NOx	10
SOx	<20
MEA	1
Particulate	Nil

(1) Dry gas, O_2 Content 6% vol

8.1.2. 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.

8.2. Liquid Effluent

Waste Water Treatment (included in Unit 800)

The expected flow rate of treated water from Waste Water Treatment to be discharged outside Plant battery limit is in practice reduced to zero: in fact, apart from a negligible amount of water present in the sludge from sludge dewatering section, all the water received by Waste Water Treatment is treated and recycled back to the power plant.

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.

8.3. Solid Effluent

The plant is expected to produce the following solid by-products:

Furnace bottom ash
Flow rate : 8.1 t/h

<u>Fly ash</u>

Flow rate	:	24.4	t/h

<u>Mill rejects (pyritic)</u>

Flow rate	:	0.5	t/h

<u>Gypsum</u>

Flow rate	:	14.1	t/h
Water content	:	9.5	%wt

<u>Sludges from WWT</u>

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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: SOUTH AFRICA	DATE	February 2010	October 2010		
		PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (25.3 t/h), in combustion air (35.8 t/h) and generated by combustion (105.2 t/h), soot blowing (19.8 t/h)	water outlet as steam in flue gas (186.1 t/h)
		Reheater									
		Superheater									
		Economiser									
		Piping									
		Air handling plant									
		Structures									
		Bunkers									
		Pumps									
		Coal feeders									
		Soot blowers									
		Blow down systems									12.4 t/h water from condensate polishing
		Dosing equipment									
		Mills									
		Auxiliary boiler									
		Miscellaneous equipment									
		Miscellaneous equipment									
		Burners									
		ESP									
Δ		Flue gas blower	Axial fan	2.500.000Nm3/h x 800 mmH2O	12.6 MW			CS	1 blower in operation		

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 300 - FGD and Handling Plant - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Ducts									
		GGH (gas to gas reheater)									
		Absorber island								Water inlet as raw water (98.5 t/h) and water in flue gas.	Water is mainly evaporated in flue gas, with some losses in gypsum (4.0 t/h) and blowdown (0.6 t/h).
		Limestone storage									
		Limestone slurry preparation island									
		Gypsum dewatering and storage									Water outlet as chloride purge (0.6 t/h)
		Make up water pumps									
		Oxidation air blower								Water inlet as moisture in ambient air (0.3 t/h)	

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 400 - DeNOx Plant - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Flue gas ducts									
		Reactor casing									Water generated in DeNOx reaction (0.8 t/h)
		Bypass system									
		Catalyst									
		Ammonia injection equipment									
		Handling equipment									
		Control system									

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Steam turbine island package									Water outlet as deaerator vent (0.3 t/h)
Δ		**Steam turbine**		799 MWe gross							
Δ		**Steam turbine condenser**	aircooler	603 MW th	60 x 95 kWe			CS	60 modules, 12x12 m2 each		

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
LOCATION: SOUTH AFRICA	DATE	February 2010	October 2010		
PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
	APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 600 - CO2 Amine Absorption Unit - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
Δ		DCC circulation pumps	centrifugal	11625 m3/h x 50 m	2000 kW			casing: CS; internals: 12%Cr	two pumps in operation; one spare		
		Wash water pumps									
		Rich amine pumps									
		Reflux pump									
		Stripper bottoms pump									
Δ		Absorber column - upper pumparound pump	centrifugal	4200 m3/h x 60 m	950 kW			casing: CS; internals: 12%Cr	two pumps in operation; two spare		
Δ		Absorber column - lower pumparound pump	centrifugal	3600 m3/h x 50 m	710 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									Water outlet as water condensed from flue gas (204 t/h)
		Packing									
		Absorption towers								Water inlet as make up water (138.5 t/h)	
		Stripper									
		Packing for stripper									
		Semi lean flash drum									
		Ohd accumulator									
		MEA storage									
		Surplus water tankage									
Δ		DCC cooler	aircooler	108 MW th	1400 kWe			CS			
		Water wash cooler									
Δ		Absorber column - upper pumparound cooler	aircooler	88.1 MW th	1140 kWe			tubes: 316L header: CS	2 aircoolers (88.1 MW th each)		
Δ		Absorber column - lower pumparound cooler	aircooler	76.2 MW th	985 kWe			tubes: 316L header: CS	2 aircoolers (76.2 MW th each)		
		Cross exchangers									
		Flash preheater									
Δ		Overhead stripper condenser	aircooler	75 MW th	20 x 30 kWe						Water outlet is included in the stream from "DCC towers"
Δ		Stripper reboiler	kettle	496 MWth; 8100 m2				shell/tubesheet: KCS; tubes: SS 304L	S&T reboiler with steam		
Δ		Lean solvent cooler	aircooler	94.1 MW th	1200 kWe			tubes: 316L header: CS			
+		Flue gas final cooler (aircooler)	aircooler	20 MW th	20 x 20 kWe			CS+2 mm 304L clad			
+		Flue gas final DCC		D=8m; H=16m				KCS+6 mm 304L clad	4 separators		24 t/h cond'd water to WWT
+		Flue gas final water pump	centrifugal	1030 m3/h x 40 m	190 kW			casing: CS; internals: 12%Cr	1 pump operating; 1 pump spare		

LEGEND:
(1) = reference shall be made to CASE 3.22; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	October 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 700 - CO2 compression and inerts removal - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Compression package									
Δ		**Compressor**	5 stage compressor	145000 Nm3/h x overall β = 73; β per stage = 2.5	motor = 38 MW each machine			SS	2 x 50% machines (145000 Nm3/h each)		
		Intercoolers	Shell & tube						steam condensate heat exchanger		
Δ		**Intercoolers**	aircooler	5 MWth	100 kWe			tubes: SS header: CS	8 aircoolers, 5 MWth (100 kWe) each		
		Dryer									Water outlet as water condensed from CO2 (9.6 t/h)
-		~~**CO2 pumps**~~									

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: SOUTH AFRICA
PROJ. NAME: Water usage and loss Analysis
CONTRACT N. 1- BD- 0475 A

REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
DATE	February 2010	October 2010		
ISSUED BY	L.So.	L.So.		
CHECKED BY	PC	PC		
APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 800 - Utility Units - USC PC with CO2 capture, fed with bituminous coal, case 3.23 DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Demin water storage tankage								35.7 t/h of make up (raw water)	Water outlet as blowdown (3.2 t/h) and water make up to Steam Turbine Island (32.5 t/h)
		Raw water and firewater storage									
		Plant air compression skid									
		Emergency diesel generator system									
Δ		**Closed loop water cooler**	aircooler	47 MW th	32 x 37 kWe			CS			
		Blowdown water sump									
		Condensate return pump									
		Demin water pump									
Δ		**Close loop CW pumps**	centrifugal	4030 m3/h x 30m	600 kW			CS	1 pump in operation + 1 spare		
		Oily water sump pump									
		Fire pumps (diesel)									
		Fire pumps (electric)									
		FW jockey pump									
Δ		**Waste water treatment plant**									
		OWS									
–		**~~Sea water pumps~~**							DELETED		
–		**~~Seawater chemical injection~~**							DELETED		
–		**~~Sea water inlet/outlet works~~**							DELETED		
		Buildings									
		Electrical equipment									

LEGEND:
(1) = reference shall be made to CASE 3.22: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION: Dry land	DATE	Janunary '09			
PROJ. NAME: Water usage and loss Analysis	ISSUED BY	M.P.			
CONTRACT N. 1- BD- 0475 A	CHECKED BY	A.S.			
	APPROVED BY				

EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC oxycomb, bituminous coal, with CO_2 capture, case 3.23 - DRY LAND

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
	Sulphides oxidation Section (S34)									
800-Y1001	Oxidation Reactor		S= 65 m^2 ; H 2.5 m					1X100% (1op)		
800-MX1001 A/B	Mixer			0,35				2X50% (2op)		
800-PK1001 A/B	H_2O_2 dosage system		Φ=2 m; H=2.7 m	0,72				2X50% (about 15 day storage)		
	Sulphides oxidation Section (S41)									
800-Y1002	Oxidation Reactor		S= 18 m^2 ; H 2.5 m					1X100% (1op)		
800-MX1002 A/B	Mixer			0,35				2X50% (2op)		
800-PK1002 A/B	H_2O_2 dosage system		Φ=0.8 m; H=1 m	0,36				2X50% (about 15 day storage)		
	Equalization Section									
800-Y1003	Equalization basin		S=600 m^2 ; H= 5 m					1X100 (underground basin)		
	Anaerobic Treatment section									
800-Y1004 A/B/C/D	UASB Anaerobic reactor		Φ=8 m; H=12.5 m					4X25% (4op)		
800-P1001 A/B/C/D/E	anaerobic treatment feed pump		70 mc/h; 2.5 bar	11,00				5X25% (4op)		
800-PK1003 A/B	H_3PO_4 dosage system		Φ=2 m; H=2.5 m	0,72				2X50% (about 15 day storage)		
	Aerobic Treatment section									
800-Y1005	Aerobic basin		L= 38 m; W= 20 m; H= 5 m					2X50% (2op)		
800-MX1003 A/B	Aerobic basin mixer			3,00				2X50% (2op)		
800-P1002 A/B/C	Aerobic Treatment feed pump		140 mc/h; 2 bar	18,50				3X50% (2op)		
800-P1003 A/B/C	Aerobic Treatment recirculation pump		140 mc/h; 1.3 bar	11,00				3X50% (2op)		
800-PK1004 A/B	H_3PO_4 dosage system		Φ=2.2 m; H=2.7 m	0,72				2X50% (about 15 day storage)		
800-C1001 A/B/C	Aerobic basin compressor			160				5X25% (4op)		
	Anoxic Treatment section									
800-Y1006	Anoxic basin		L= 22 m; W= 20 m; H= 5 m					2X50% (2op)		
800-MX1004 A/B	Anoxic basin mixer			4,00				4X25% (4op)		
800-PK1005 A/B	CH_3OH dosage system		Φ=5.4 m; H=5.8 m	1,50				4X50% (about 15 day storage)		
	Final Aerobic Treatment section									
800-Y1007	Final aerobic basin		L= 20 m; W= 4 m; H= 5 m					2X50% (2op)		
800-MX1005 A/B	Final aerobic basin mixer			1,10				2X50% (2op)		
800-C1002 A/B	Final aerobic basin compressor			11,00				2X100%		
	Sedimentation section									
800-Y1008 A/B	Biological sludge settling Basin		Φ=18 m; H=4 m					2 op		
800-K1001 A/B	Sludge scraper			0,25				2 op		
800-P1004 A/B/C	Biological sludge settling feed pump	centrifugal	7.5 mc/h; 1.5 bar	2,20				3X50% (2op + 1 spare)		
	Sludge treatment section									
800-Y1009	sludge mixing basin		S=1 m^2 ; H=1.5 m							
800-MX1004	sludge basin mixer			0,35				1X100%		
800-P1005 A/B	mixed sludge feed pump		7.5 mc/h; 1.5 bar	0,75				2X100% (1op + 1spare)		
800-PK1007 A/B	$FeCl_3$ dosage system		Φ=2.6 m; H=2.9 m	0,72				2X50% (about 15 day storage)		
800-PK1008 A/B	Poly dosage system		Φ=0.5 m; H=1.0 m	0,36				2X50% (about 15 day storage)		
800-C1001	sludge dewatering system	centrifugal		15,00				1X100%		
	Media filtration section									
800-F1001 A/…/F	Sand filter		Φ=3.0 m; H=2.25 m	7,50				6 op		
800-P1006 A/B/C	sand filter water feed pump		135 mc/h; 2 bar	17,50				3X50% (2op + 1 spare)		
800-Y1010	Filtered water basin		S=18 m^2 ; H= 3.5 m							
800-P1007 A/B	sand filters backwash pump	centrifugal	230 mc/h; 2 bar	22,00				2X100% (1op + 1 spare)		

General Note:
Present equipment list is indicateve only and related to the WWT layout selected.

APPENDIX

1. H&M Balance case 3.21

The H&M Balance highlighting the differences with respect to the reference study is attached here below.

MASSBAL.xls

FOSTER WHEELER

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - case 3.21

Revision no.: 1
Date: October 2010
Sheet: 1 of 2

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	66.61	0	0.29	0.29	0	0	0	0	0	0
- Air	kg/s	0	752.3	0	0	0	0	0	2.24	0	0
- Flue Gas	kg/s	0	0	778.7	781.2	817.9	821.8	0	0	0	0
- Ash	kg/s	0	0	5.3	5.3	0.018	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
- Ammonia	kg/s	0	0	0	0	0	0	0.117	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	1.77	0
Volume Flowrate	Am^3/s	-	607.9	1418.1	1416.6	880.0	831.9	-	1.84	-	0.013
	Nm^3/s	-	587.0	592.5	594.5	623.9	634.5	0.151	1.74	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Temperature	°C	9	9	380	380	114	85	9	15	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.24	0.55	0.55	0.93	0.99	-	1.21	-	-
Composition											
O_2	%v/v,wet		20.9	3.27	3.27	4.50	4.36		20.9		
CO_2	%v/v,wet		0.0	13.80	13.80	12.79	12.48		0.0		
SO_2	%v/v,wet		0.0	0.07	0.07	0.06	0.01		0.0		
H_2O	%v/v,wet		0.7	9.77	9.78	9.33	11.51		0.7		
N_2	%v/v,wet		78.4	73.09	73.08	73.32	71.64		78.4		
Emissions @ 6%O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1877	1877	1732	200				
CO	mg/Nm^3			0	0	0	0				
Particulates	mg/Nm^3			8444	8416	30	14				

= figure revised during the 2009 study for closing the water balance

Mitsui Babcock 2004

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - case 3.21

Revision no.: 1
Date: October 2010
Sheet: 2 of 2

Stream ID		11	12	13	14	15	16	17	18	19	20
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water
Mass Flow Rate											
- Coal	kg/s	0	0	0.34	0.11	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	6.08	2.03	0	0	0	0	0	0
- Water	kg/s	0.31	0.17	0	0	619.3	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	619.3	490.2	490.2	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	2.91	0	0	0	0	0	0	0	0	0
Volume Flowrate	Am^3/s	-	-	-	-	-	-	-	-	28.1	28.1
	Nm^3/s	-	-	-	-	-	-	-	-	-	-
Props											
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid
- Temperature	°C	23	23	114 / 380	1000	300	600	363	620	12	19
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-
- 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										
Particulates	mg/Nm^3										

= figure revised during the 2009 study

2. H&M Balance case 3.22

The H&M Balance highlighting the differences with respect to the reference study is attached here below.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - case 3.22

Revision no.: 1
Date: October 2010
Sheet: 1 of 4

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 Gas	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
- Limestor	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		20.9		
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		0.7		
N_2	%v/v,wet		78.40	73.09	73.08	73.32	70.19		78.4		
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				
Particulat	mg/Nm^3			8444	8416	30	14				

● = figure revised during the 2009 study for closing the water balance

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														
Particulat	mg/Nm^3														

● = figure revised during the 2009 study for closing the water balance

FLUOR

Heat And Material Balance
CASE 3.22: USCPF WITH CAPTURE

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							
	H2O	18.02	15608	10328	533	12435	44990	44990	7688
	CO2	44.01	14330	2125	12181	24			
	MEA	61.08				9			
Note 3	N2	28.02	82278	82277	1				
	O2	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 CO2 recovered is 85% of inlet CO2 in stream 6
4 This stream matches stream 6 on boiler island mass balance table

SEE DWG E10

= figure revised during the 2009 study for closing the material balance

FLUOR

Heat And Material Balance
CASE 3.22 USCPF WITH CAPTURE

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

● = figure revised during the 2009 study for closing the material balance

3. H&M Balance case 3.25

The H&M Balance highlighting the differences due to the dry land design is attached here below.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - Case 3.25 USCPC without CCS (dry land)

Revision no.: 1
Date: October 2010
Sheet: 1 of 2

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	66.61	0	0.29	0.29	0	0	0	0	0	0
- Air	kg/s	0	752.3	0	0	0	0	0	2.24	0	0
- Flue Gas	kg/s	0	0	778.7	781.2	817.9	821.8	0	0	0	0
- Ash	kg/s	0	0	5.3	5.3	0.018	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
- Ammonia	kg/s	0	0	0	0	0	0	0.117	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	1.77	0
Volume Flowrate	Am^3/s	-	621.7	1418.1	1416.6	880.0	831.9	-	1.84	-	0.013
	Nm^3/s	-	587.0	592.5	594.5	623.9	634.5	0.151	1.74	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Temperature	°C	14	14	380	380	114	85	14	15	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.21	0.55	0.55	0.93	0.99	-	1.21	-	-
Composition											
O_2	%v/v,wet		20.9	3.27	3.27	4.50	4.36		20.9		
CO_2	%v/v,wet		0.0	13.80	13.80	12.79	12.48		0.0		
SO_2	%v/v,wet		0.0	0.07	0.07	0.06	0.01		0.0		
H_2O	%v/v,wet		0.7	9.77	9.78	9.33	11.51		0.7		
N_2	%v/v,wet		78.4	73.09	73.08	73.32	71.64		78.4		
Emissions @ 6% O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1877	1877	1732	200				
CO	mg/Nm^3			0	0	0	0				
Particulates	mg/Nm^3			8444	8416	30	14				

highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - Case 3.25 USCPC without CCS (dry land)

Revision no.: 1
Date: October 2010

Stream ID		11	12	13	14	15	16	17	18	19	20	21
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Gas
Mass Flow Rate												
- Coal	kg/s	0	0	0.34	0.11	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	803.7
- Ash	kg/s	0	0	6.08	2.03	0	0	0	0	0	0	0
- Water	kg/s	0.31	0.17	0	0	619.3	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	619.3	490.2	490.2	0	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0	0	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	2.91	0	0	0	0	0	0	0	0	0	0
Volume Flowrate	Am^3/s	-	-	-	-	-	-	-	-	-	-	
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	
Props												
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas
- Temperature	°C	23	23	114 / 380	1000	300	600	363	620	-	-	75
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	0
- 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											
Particulates	mg/Nm^3											

highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

4. H&M Balance case 3.23

The H&M Balance highlighting the differences due to the dry land design is attached here below.

IEA GHG R&D PROGRAMME

Water usage and loss Analysis in plants w/o & w CCS

Volume #2 - Case 3.23 USCPC with CCS (dry land)

Revision no.: 1
Date: October 2010

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 Gas	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
- Limestor	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	-	● 684.6	1568.4	1573.1	977.2	866.1	-	2.04	-	0.028
	Nm^3/s	-	653.1	658.0	660.0	692.8	729.8	0.168	1.93	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Tempera	°C	● 14	● 14	380	380	114	51	● 14	14	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	● 1.22	0.55	0.55	0.93	1.09	-	1.22	-	-
Composition											
O_2	%v/v,wet		20.56	3.27	3.27	4.50	4.28		20.56		
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		1.89	9.77	9.78	9.33	13.31		● 1.89		
N_2	%v/v,wet		77.52	73.09	73.08	73.32	70.19		77.52		
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				
Particulat	mg/Nm^3			8444	8416	30	14				

● highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

Stream ID		11	12	13	14	15	16	17	18	19	20	21	21a	21b	21c	22	23
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Steam	Sat. Water	Condensate	Condensate	Gas	Gas
Mass Flow Rate																	
- Coal	kg/s	0	0	0.37	0.12	0	0	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	0	0
- Flue Ga	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	763.0	
- Ash	kg/s	0	0	6.75	2.26	0	0	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	0	0
- Steam	kg/s	0	0	0	0	0	687.0	545.9	545.9	0	0	227.5	227.5	270.2	270.2	0	0
- Ammoni	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Limesto	kg/s	0	0	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	0	0
Volume Flo	Am^3/s	-	-	-	-	-	-	-	-	0	0	-	-	-	-		
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Props																	
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas	Liquid	Liquid	Liquid	Gas	Gas
- Tempera	°C	-	-	114 / 380	1000	300	600	363	620	---	---	146	136	40	114	46.8	39
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	2.24	2.24	-	-	0.01	0
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Composition																as stream 31 on next page	as stream 43 on next page
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																
Particulat	mg/Nm^3																

highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

FLUOR

Heat And Material Balance
CASE 3.23: USCPF WITH CAPTURE

Stream Description			Flue Gas to DCC	Flue Gas to DCC..	CO2 From Stripper	Surplus Water	LP Steam to Reboiler	Cond Return to Power Island	Make Up Water	Flue gas to stack	DCC cond to WWT
Stream Number			6	31	32	33	21	21a	36	43	44
Temperature Deg C			52	49.3	37.8	37.8	136	136	37.8	46.8	46.8
Pressure,Bara			1.01	1.15	1.6	2.76	3.24	3.24	1.38	1.02	1.02
Component Flows		MW									
	H2O	18.02	15608	10328	533	12435	44990	44990	7688	8997	1331
	CO2	44.01	14330	2125	12181	24				2125	
	MEA	61.08				9					
Note 3	N2	28.02	82278	82277	1					82277	
	O2	32	5012	5012						5012	
Note2	Nat Gas	19.35									
Note 4	AIR	28.89									
Total kgmol/hr			117228	99742	12715	12468	44990	44990	7688	98411	1331
Total Tonnes/hr			3376.8	2745.7	545.72	225.7	810.72	810.72	138.5	2710.7	24
Molecular weight			28.80	27.53	42.92	18.10	18.02	18.02	18.02	27.54	18.02
Density,Kg/m3			1.083	1.05	2.71	990		929	990	1.05	990
			Note 4	**Note 2**	**Note 3**				**Note1**	Note 1	Note 1

NOTES

component flows in Kgmol/Hr

1 Flows for a total of two streams
2 Flows for two absorbers discharging to atmosphere
3 CO2 recovered is 85% of inlet CO2 in stream 6
4 This stream matches is a match stream for stream 6 on boiler island mass balance table

SEE DWG E10

highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

FLUOR

Heat And Material Balance
CASE 3.23 USCPF WITH CAPTURE

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	● 40	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	12425						12425	
	MEA	61.08								
Note 3	N2	28.02	1							
	O2	32								
Note2	Nat Gas	19.35								
Note 4	AIR	28.89								
Total kgmol/hr			12959						12425	533
Total Tonnes/hr			556.426				● 972	● 972	546.8	9.59
Molecular weight			42.94						44.01	18.02
Density,Kg/m3							1000	1000		
									13123TPD	**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 preheat train in power plant. See Alstom Dwg TS 29687 (DWG E9)

SEE DWG E12

● highligths the differences between the present case (DRY land) and the case where the Power Plant is installed in WET land.

IEA GHG

Water usage and loss Analysis in Power plants without and with CO2 capture
Volume #3 – Oxycombustion cases - General index

Revision no.: 1
Date: November 2010
Sheet: 1 of 2

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : OXYCOMBUSTION CASES, GENERAL INDEX

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
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OXYCOMBUSTION CASES REPORT

I N D E X

CLIENT : IEA GHG
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DOCUMENT NAME : OXYCOMBUSTION CASES, GENERAL INFORMATION

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SECTION A

OXYCOMBUSTION CASES, GENEARL INFORMATION

I N D E X

1. Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage and loss of power in power plants with CO_2 capture.

The work is developed thought the establishment of a rigorous accounting of water usage throughout the power plant in order to establish an acceptable methodology that can be used to compare water usage in power plants with and without CO_2 capture. This can provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs.

Cost effective water reduction technologies that could be applied for power plants with CO_2 capture are identified. Finally, an evaluation of the performance of power plants with CO_2 capture and potential impacts on the water usage applicable to areas where water supply could be severely limited is performed.

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
These studies shall be used as a basis for present study.

In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

The purposes of the study, therefore, include:

- A review and assessment of the available information of water usage from power plants such as PC, IGCC and NGCC with or without CO_2 capture from various previous studies done for IEA GHG, based on oxyfuel, pre- or post combustion CO_2 capture technologies.
- A review and assessment of the available technologies that would allow reduction of water usage from power plants;
- An evaluation and assessment of the applicable technologies for power plants with CO_2 capture in areas where water supplies could be severely limited.

The study is based on the current state-of-the-art technologies, evaluating costs and performances of plants which can be presently engineered and built.

Present report #3 analyses the Ultra Super Critical Pulverised Coal (USC PC) oxyfired cases with CO_2 capture and without and with limitation on water usage.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 number 2005/9, July 2005, has been taken as a reference for the configuration and performances of the plant analysed in reference case of present report. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The following two different alternatives are therefore evaluated:

- Case 4.11: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number 2005/9 – Case 2, dated July 2005.

- Case 4.12: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

For each of the above mentioned cases the following technical information are provided:

- ✓ Description and process schemes for each section of the plant;
- ✓ Mass and mole flowrates, temperature, pressure, energy content and composition of the main process streams within the plants;
- ✓ Detailed water flow diagram;
- ✓ Detailed water balance of the major section of the plant;
- ✓ Breakdown of the ancillary power consumptions;
- ✓ Breakdown of the major plant equipment;
- ✓ Breakdown of the water consumptions;
- ✓ Specific fuel consumption per MW net produced;
- ✓ Specific emission of CO_2 per MW net produced;
- ✓ Specific water consumption per MW net produced.

2. Project design bases

The Power Plants are designed to process, in an environmentally acceptable manner, a coal from eastern Australia and produce electric energy to be delivered to the local grid.

2.1. Feedstock specification

The feedstock characteristics are listed hereinafter.

2.1.1. Design Feedstock

	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. Back-up Fuel

	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 plant are listed here below with their specifications.

2.2.1. Electric Power

Net Power Output:	750	MWe	nominal capacity
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: 32 °C
Purity:
CO_2: > 95% mol
Oxygen: <10 ppmv

Capture rate : 90% (as per reference study).

2.2.3. Solid By-products

The plant does not produce any solid by-product.

2.3. Environmental Limits

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

2.3.1. Gaseous Emissions

The overall gaseous emissions from the plant referred to dry flue gas with 6% volume O_2 shall not exceed the following limits:

NOx (as NO_2):	≤	200	mg/Nm^3
SOx (as SO_2):	≤	200	mg/Nm^3
Particulate :	≤	30	mg/Nm^3

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 from the plant is the sea cooling water return stream (for wet land cases only).

The 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.

In agreement with IEA GHG, industrial wastewater discharge limits into surface water bodies of Italian law (DLgs 152/2006) are considered. Discharge limits are listed in Volume 1 – para 1.5.

2.3.3. Solid Wastes

The plant produces the following solid wastes:
- Bottom ash
- Fly Ash
- Sludges from WWT

2.4. Plant Operation

2.4.1. Capacity

For all the cases the nominal design capacity is 750 MWe.

For reference case, fuel input has been selected in order to have 740 MWe gross power output.

For the dry land cases, the fuel input has been kept constant as the reference case. Gross power output and auxiliary consumptions are affected by the dry land design and therefore the resulting net power output of the dry land case is significantly lower than the reference case.

In accordance with reference study, a minimum equivalent availability of 85% corresponding to 7,446 hours of operation in one year at 100% capacity is assumed starting from the second year of commercial operation.
During the first year of commercial operation, when the plant needs final tunings, the equivalent availability will be much lower than the normal one (around 45%).

It has been assumed that the dry land design does not have any impact on plant load factor.

2.4.2. Unit Arrangement

Based on the configuration shown in the reference studies, the plants have the following arrangement:

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

2.4.3. Turndown

The plant is designed to operate with a good degree of flexibility in terms of turndown capacity and feedstock characteristics.

The minimum turndown of the boiler is expected to be around 50% as far as duty is concerned. Such turndown is achieved with a decrease of the steam parameters.

The minimum turndown 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 turndown of the CO_2 compression and purification section is expected to be lower than 50% on the basis of the flue gases inlet flowrate.

Therefore, even if the minimum turndown of the Steam Turbine and the CO_2 purification section can be lower, due to the higher turndown of the boiler, the overall plant turndown is expected to be some less than 50%. This is due to the reduced steam characteristics at boiler turndown that have as a consequence the reduction of the Steam Turbine efficiency and an overall power production lower than 50%.

2.5. Location

Reference case – wet land
The site for the reference case, wet land, is a green field located 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 harbor equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

Dry land case
The site for dry land case is a green field located in a dry in land region in South Africa.

The plant area is assumed to be close to a river. Coal transport is assumed to be assured by rail connection.

No special civil works implications are assumed.

2.6. 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
  - **Reference cases – wet land**
  - minimum air temperature: -10 °C
  - maximum air temperature: 30 °C
  - average air temperature: 9 °C (*)

Dry land case

minimum air temperature:	2	°C	
maximum air temperature:	30	°C	
average air temperature:	14	°C	(*)

2.7. Software Codes

For the development of the Study, two software codes will be mainly used:

- 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 all the units included in the plant to be built on the east coast area of Netherlands for the wet land case and in an in-land area in South Africa for the dry land case.

The plant is constituted by the following groups of units:

Process Units:
- 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 services and utility fluids to all the units of the plant; including:
- 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, 380 kV substation).

3.1. Units of Measurement

All calculations are and shall be in SI units, with the exception of piping typical dimensions, which shall be in accordance with ANSI.

3.2. Climatic and Meteorological Information

Reference is made to paragraph 2.6 for main data.

Other data:

Sea water supply temperature and salinity (for reference case, **wet land**, only)

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:

- Coal;
- Natural gas;
- Sea water supply (for reference case, **wet land**, only);
- Sea water Return (for reference case, **wet land**, only);
- Plant/Raw/Potable water;

- CO_2 rich stream.

3.4. Utility and Service fluids characteristics/conditions

In this paragraph are listed the utilities and the service fluids distributed inside the Plant.

3.4.1. Cooling Water

Reference case – wet land

The plant primary cooling system is sea water 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 and drying exchangers, 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 and drying 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

Dry land case

No primary cooling water is available at all. Air is used as primary cooling medium. The temperature difference considered between the inlet condensing steam and the ambient air in the steam condenser is 25 °C.

Machinery Cooling Water (secondary system)

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

Supply temperature:

- max supply temperature: 35 °C
- normal supply temperature: 25 °C
- max allowed temperature increase: 10 °C
- design return temperature for fresh cooling water cooler: 45 °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 and BFW

Steam

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

Table B.3.1 – steam conditions.

HP SH		Cold RH	Hot RH	
P, bar	T, °C	T, °C	P, bar	T, °C
290	600	360	60	620

Boiler Feed Water

The Boiler Feed Water is available at Boiler B.L. at 270°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. Natural Gas

Characteristics of Natural Gas are listed in paragraph 2.1.2.

Type : natural gas.
Service : boiler start-up fuel

Operating pressure at Users:	3.5	barg
Operating temperature at Users:	30	°C
Design pressure:	6.0	barg
Design temperature:	60	°C

3.4.6. 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
$FeCl_3$	40% wt
Polyelectrolyte	0.1% wt

3.4.7. 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 International and EU Standard Codes.

CLIENT	:	IEA GHG
PROJECT NAME	:	WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME	:	USC PC OXYCOMBUSTION REFERENCE CASE – CASE 4.11

ISSUED BY	:	L. SOBACCHI
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SECTION B

USC PC OXYCOMBUSTION REFERENCE CASE
I N D E X

1. Introduction

The present case 4.11 refers to a USC PC Oxyfuel plant, fed with bituminous coal and provided with CO_2 capture unit.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 number 2005/9, July 2005, has been taken as a reference for the configuration and performances of the plant here analysed: in general, plant description, process schemes and performance have been taken from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.
The only significant difference with the reference study is in unit 700 (CO_2 cooling and compression to 30 bara): as agreed with IEA GHG, the original equipment arrangement has been partially modified to introduce the process scheme reported in the Air Products patent N° US 7,416,716 B2 for CO_2 purification. More details about this system are given in the relevant paragraph 2.6.

The main features of the present USC PC Oxyfuel plant configuration are:

- Mitsui-Babcock 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 4.11 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.

The IEA GHG study number 2005/9, July 2005, has been taken as a reference for the plant description and configuration, with the exception of the unit 700 (CO_2 compression and inerts removal), which has been partially modified to include the Air Products CO_2 purification treatment. In such treatment the NOx (produced in the coal combustion) and the SOx (produced in stoichiometrical quantity with the sulphur present in coal) contaminating the flue gas are removed, making them reacting with water and oxygen to give nitric acid and sulphuric acid, respectively.

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 Volume 2, Section B, 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 simlar heat tranfer in the radiant and convection sectoins 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 4.11 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.

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.

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.

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.

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.

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.

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 O_2 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 O_2 product being available at approximately 0.6 barg.

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 mantained 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 9.

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

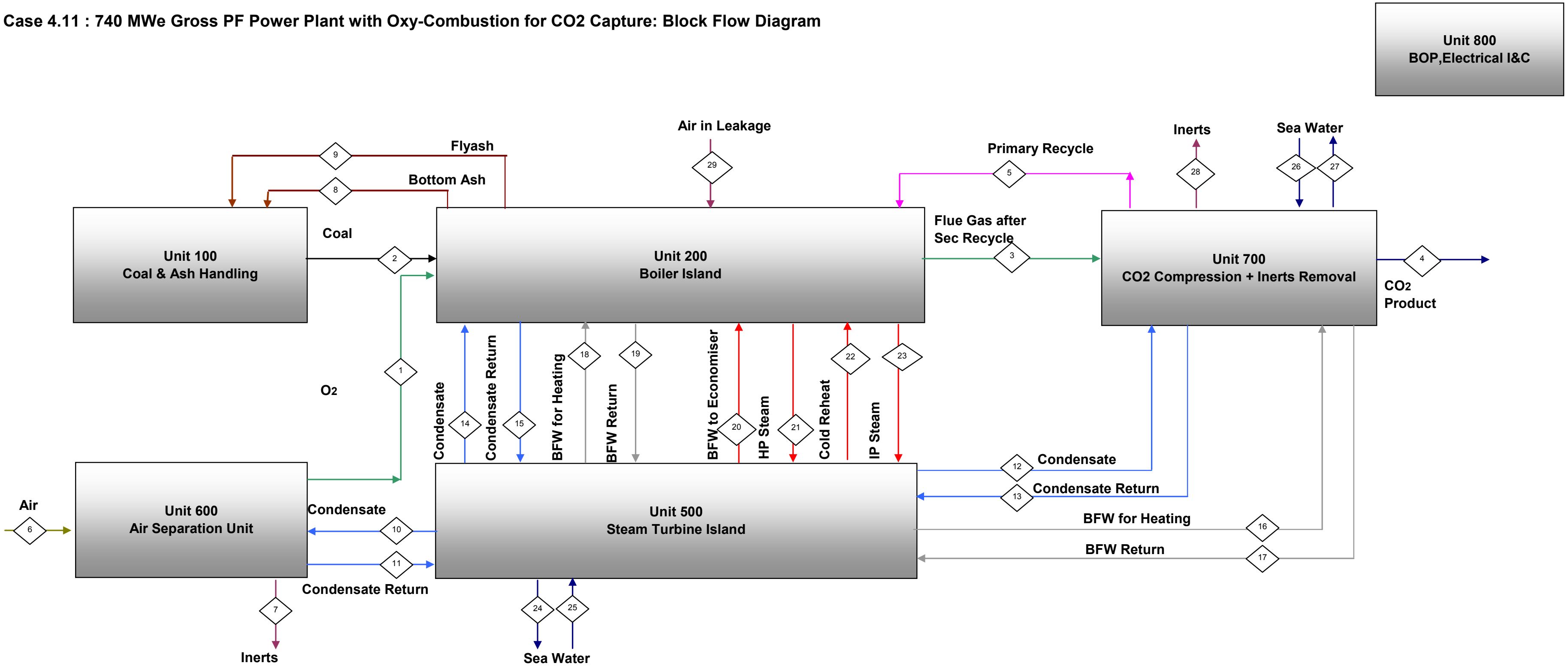
The Block Flow Diagrams of the USC PC Oxyfuel plant, Case 4.11, and the schematic Process Flow Diagram of Units 500, 600 and 700 are attached hereafter.

The IEA GHG study number 2005/9, July 2005, has been taken as a reference for the plant Block Flow Diagrams and Process Flow diagram attached. The schematic Process Flow Diagram of unit 700 has been partially modified by including the Air Products patented CO_2 purification package. Modifications are shown on PFD tagged 5A and 5B.

For a schematic representation of the Waste Water Treatment section, reference shall be made to PFD attached to Volume 1 (Attachment B4).

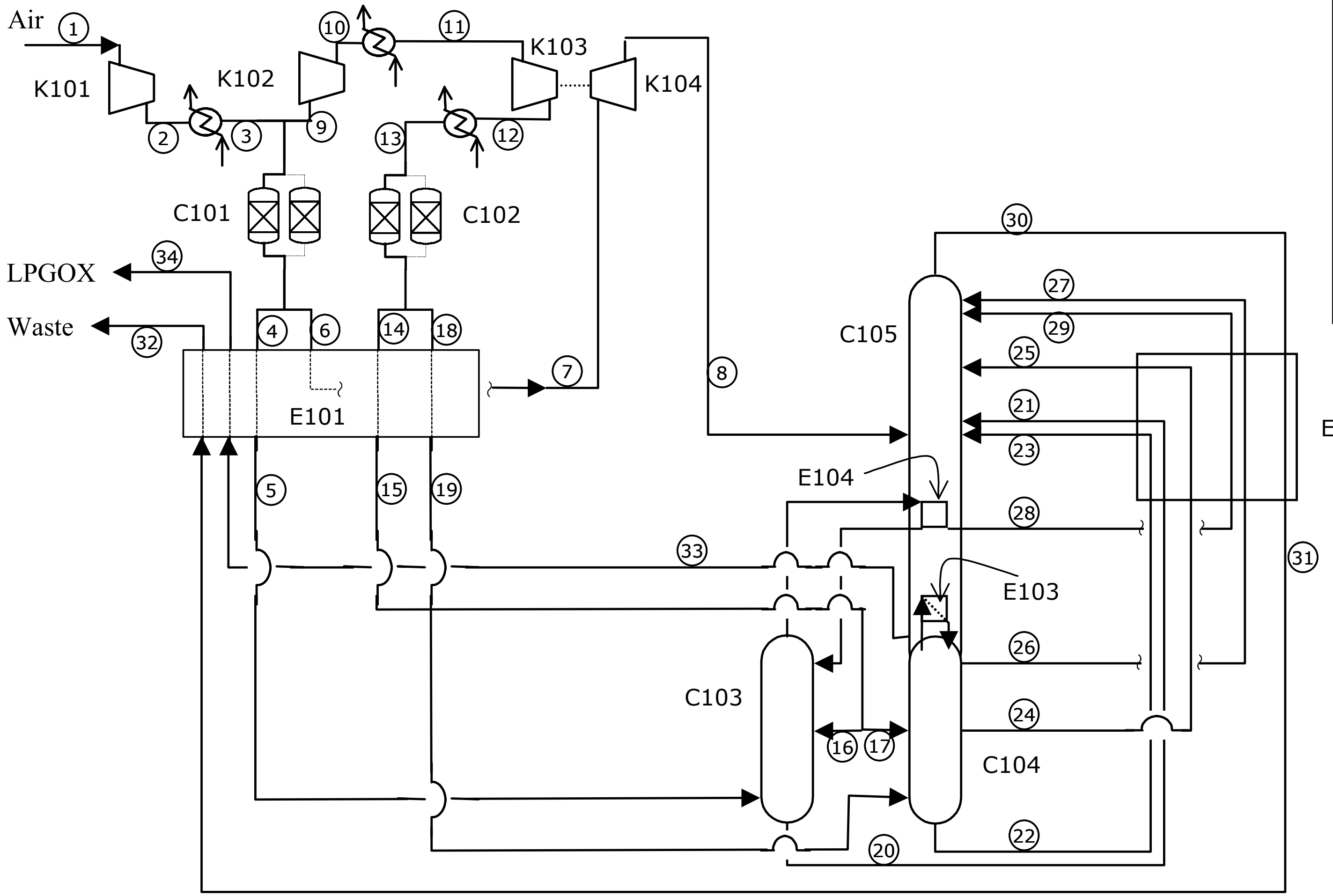
The H&M balances relevant to the scheme attached are shown in paragraph 5.

Case 4.11 : 740 MWe Gross PF Power Plant with Oxy-Combustion for CO2 Capture: Block Flow Diagram



CASE 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM

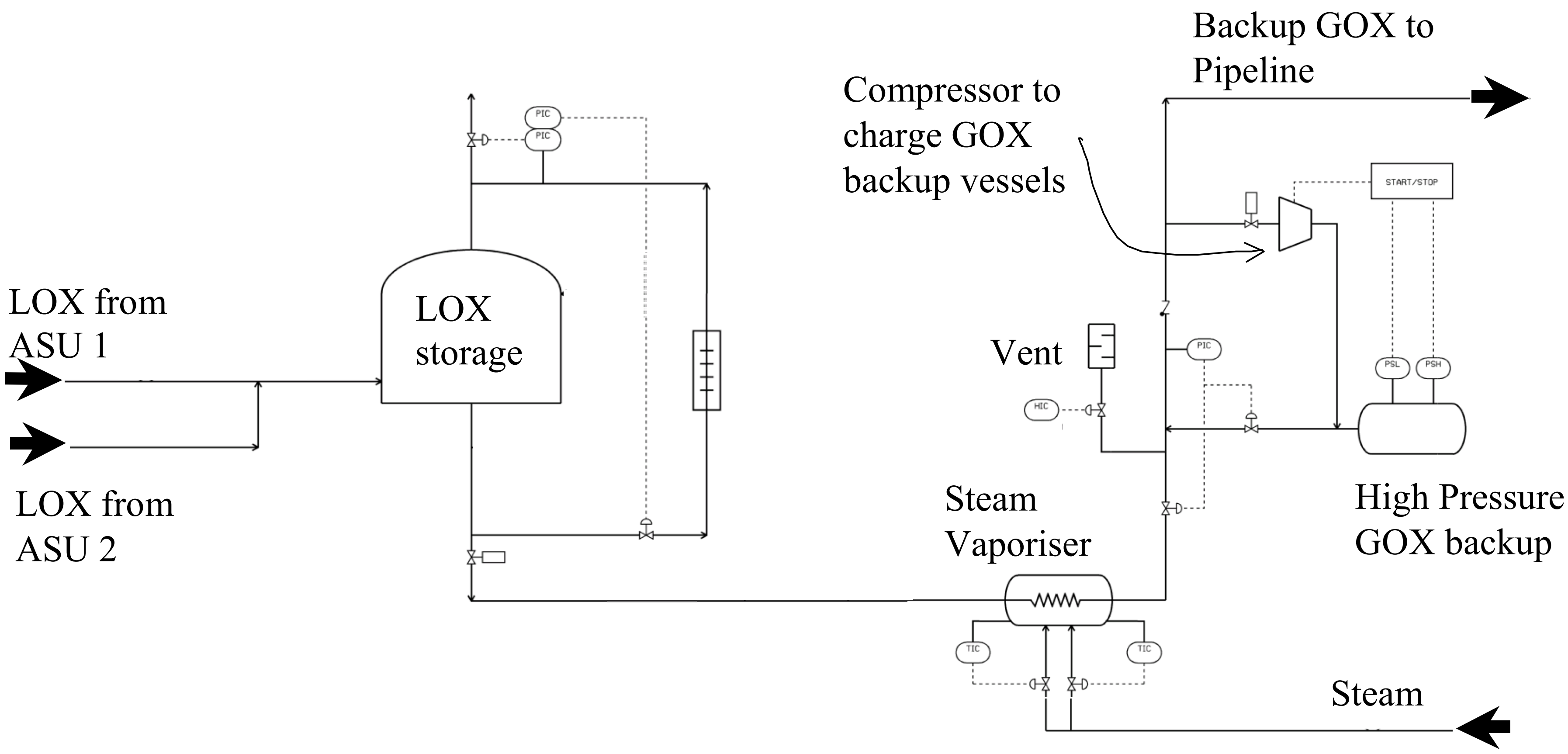
PFD 2



C101	Dual Bed Absorber
C102	Dual Bed Absorber
C103	IP Column
C104	HP Column
C105	LP Column
E101	Main Heat Exchanger
E102	Subcooler
E103	Reboiler
E104	Condensor
K101	Main Air Compressor
K103	Centrifugal Compressor
K104	Expansion Turbine

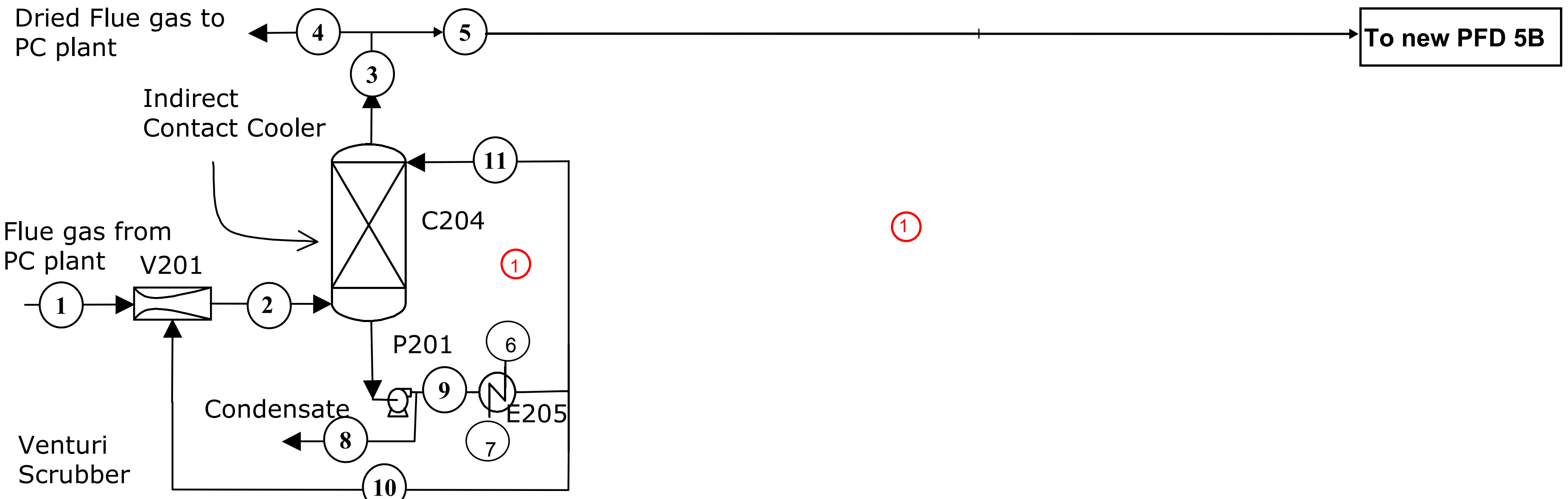
CASE 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : ASU PROCESS FLOW DIAGRAM

PFD 3



CASE 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : OXYGEN BACK UP SYSTEM

PFD 4

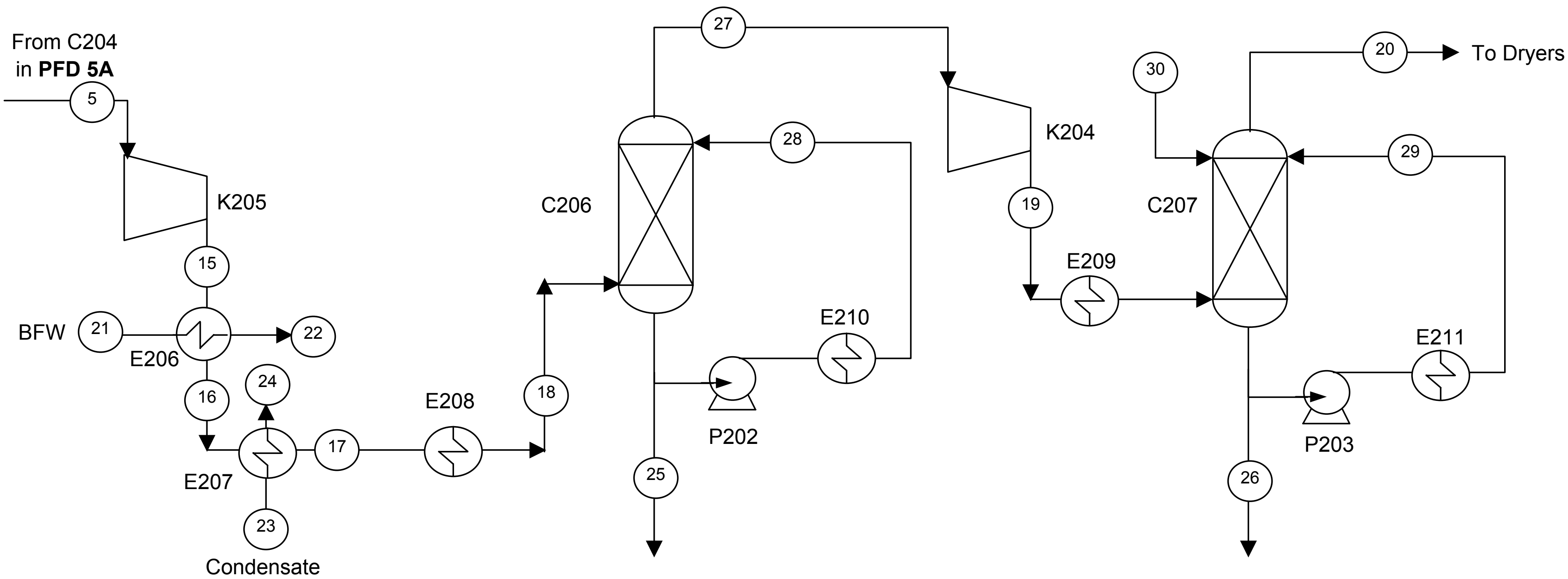


C204	Indirect Contact Cooler
E205	Plate Frame Heat Exchanger
P201	Contact water pump
V201	Venturi Scrubber

Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 COOLING AND COMPRESSION TO 30 BAR (a)

PFD 5A

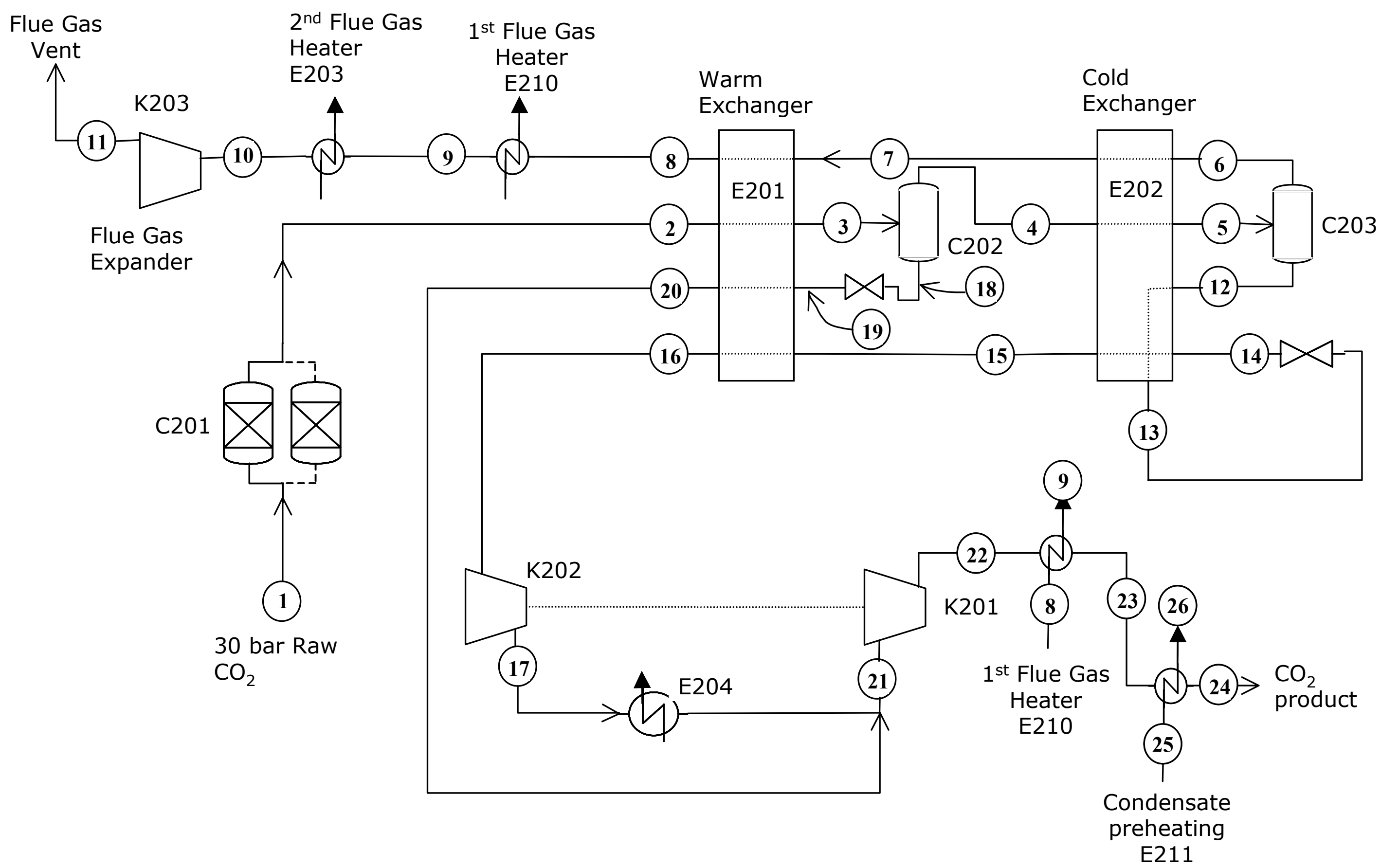
1 = revised during the 2009 study



Case 4.11: 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	

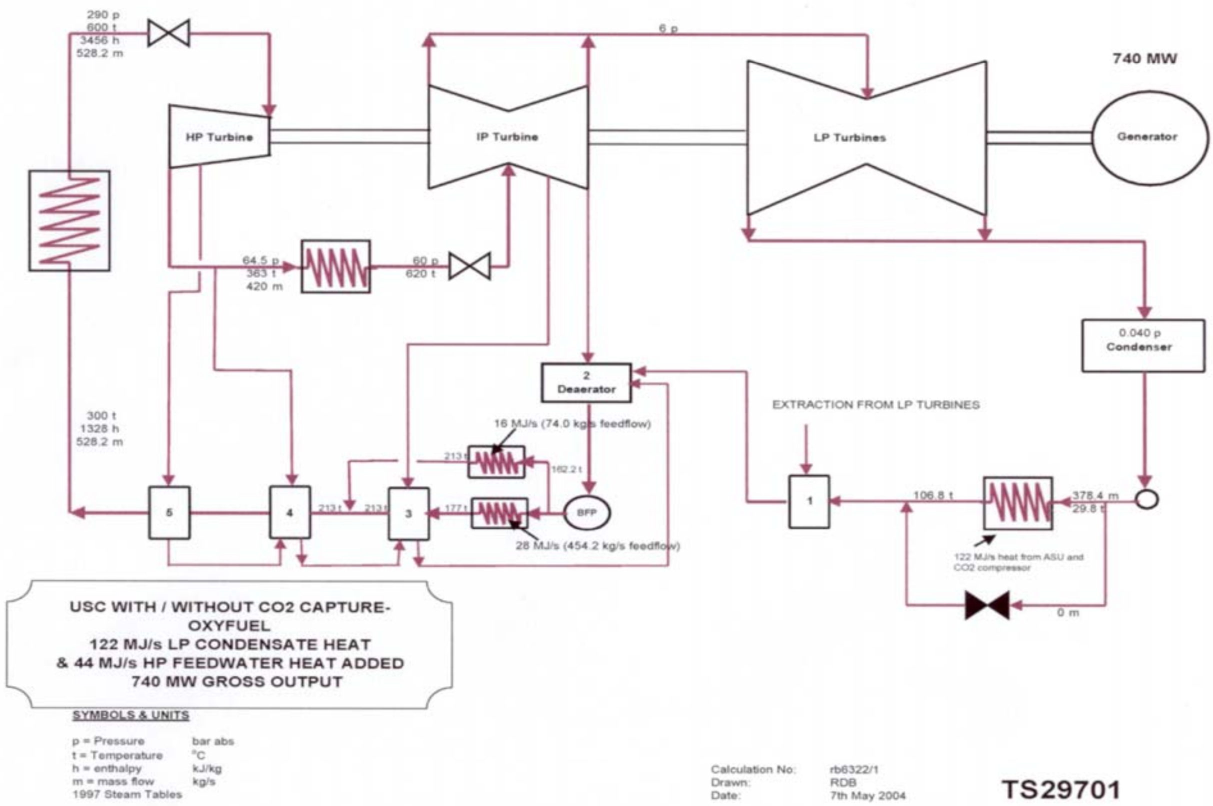


C201	Dual Bed Dryer
C202	Separator Pot
C203	Separator Pot
E201	Warm Heat Exhanger
E202	Cold Heat Exchanger
E203	2nd Flue Gas Heater
E210	1st Flue Gas Heater
E211	Condensate Preheater
K201	Adiabatic Compressor
K202	Compressor
K203	Flue Gas Expander

CASE 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR (a)

PFD 6

ALSTOM



OXY-COMBUSTION ASC PF POWER PLANT WITH CO_2 CAPTURE PLANT FEED HEATING ARRANGEMENT

FIGURE 10

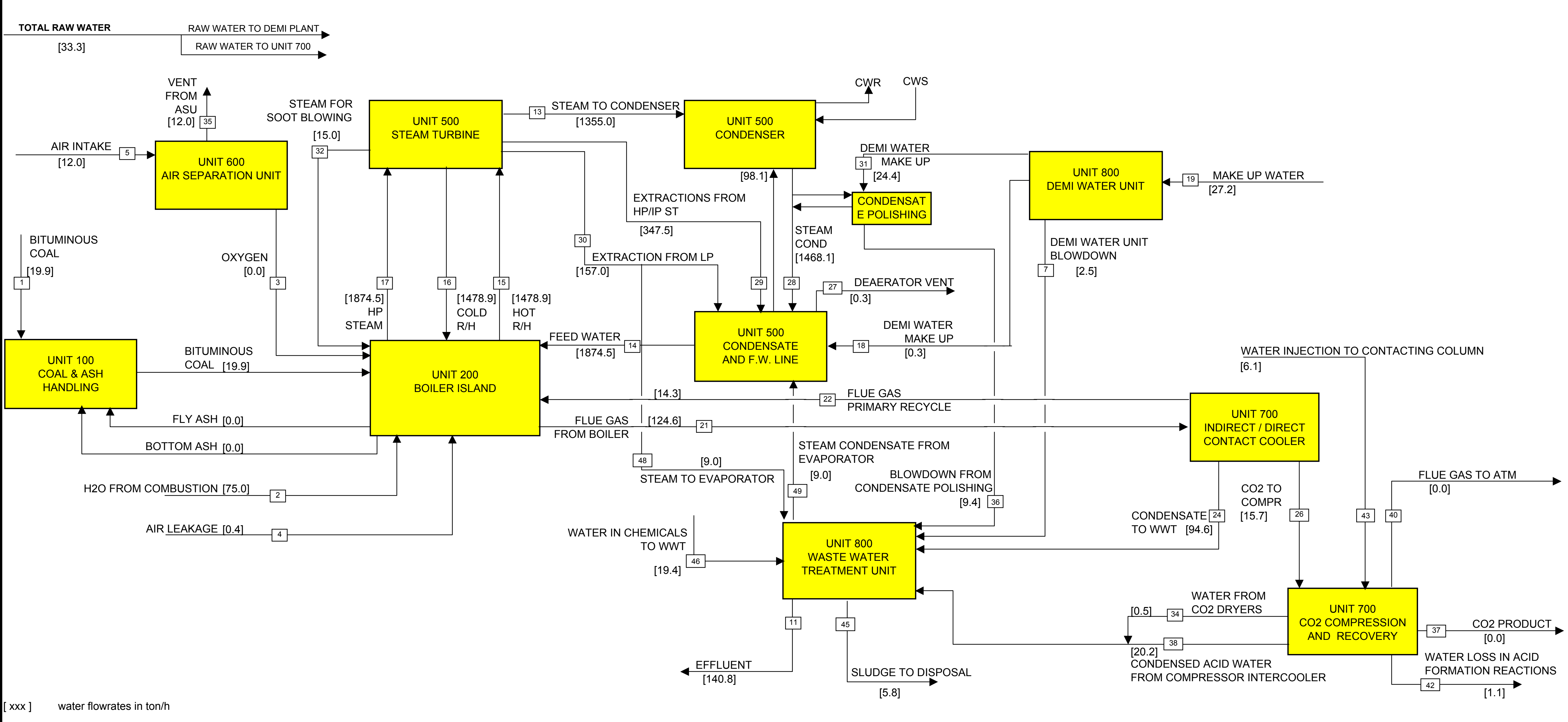
4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units;

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

CASE 4.11 - USC PC PLANT, WITH OXYCOMBUSTION, BITUMINOUS COAL AND CO2 CAPTURE (NET POWER OUTPUT = 532.0 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



IEA GHG R&D PROGRAMME	Revision no.:	1
Water usage and loss Analysis in Power plants w/o & w CCS	Date:	November 2010
Volume #3	Sheet:	

USC PC with Oxycombustion, bituminous coal and CCS - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.9	40	Flue Gas to atmosphere	0.0
2	Water from coal combustion	75.0	11	Effluent from WWT	140.8
3	Moisture in Oxygen to Boiler Islan	0.0	35	Moisture in vent from ASU	12.0
4	Air leakage to boiler	0.4	27	Moisture in deaerator vent	0.3
19	Make up to Demi Water Unit	27.2	37	CO2 product	0.0
5	Moisture in air to ASU	12.0	42	Loss in acid formation reaction	1.1
43	Water injection to contacting column	6.1	45	Sludge to disposal/losses	5.8
46	Water in chemicals to WWT	19.4			
Total		160.0	Total		160.0

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	2.5	11	Water Effluent from WWT	140.8
24	Condensate from Unit 700	94.6	45	Sludge to disposal/losses	5.8
38	Condensed acid water from unit 7	20.2	49	Steam condensate from evaporator	9.0
36	Blowdown from BFW polishing	9.4			
34	Water from CO2 dryers	0.5			
48	Steam to evaporator	9.0			
46	Water in chemicals to WWT	19.4			
Total		155.6	Total		155.6

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.90	21	Flue gas from boiler	124.6
2	Water from coal combustion	75.0			
4	Air leakage to boiler	0.4			
32	Steam for soot blowing	15.0			
22	Flue Gas primary recycle	14.3			
Total		124.6	Total		124.6

USC PC with Oxycombustion, bituminous coal and CCS - Balance around Units 200 and 700

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.9	42	Loss in acid formation reaction	1.1
2	Water from coal combustion	75.0	24	Condensate from Unit 700	94.6
3	Moisture in Oxygen to boiler	0.0	38	Condensed acid water from unit 700	20.2
4	Air leakage to boiler	0.4	34	Water from CO2 dryers	0.5
32	Steam for soot blowing	15.0	37	CO2 product	0.0
43	Water injection to contacting column	6.1	40	Flue Gas to atmosphere	0.0
Total		116.4	Total		116.4

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1478.9	13	Steam to condenser	1355.0
17	HP steam from Boiler	1874.5	16	Cold R/H to Boiler	1478.9
			29	Extractions from HP/IP ST	347.5
			30	Extractions from LP ST	157.0
			32	Steam for soot blowing	15.0
Total		3353.4	Total		3353.4

5. 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.

The IEA GHG study number 2005/9, July 2005, has been taken as a starting reference for preparing the H&M balance of the present case.

Some changes have been made to the H&M balance in order to make consistent the H&M balance of each unit and to close the water balance. Moreover, a different pollutant treatment section has been considered in order to include an alternative scheme for the removal of the NOx and SOx as explained in paragraph 2.6. The differences with respect to the reference study have been highlighted in the same heat and material balance attached to the appendix 1 of such a volume 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 4.11: 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 4.11 : 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 out	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	7.143	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 4.11 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 4.11: 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
Composition - (mol%)													DELETED
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	14	15	16	17	18	19	20	21	22	23	24
Composition - (mol%)		DELETED	DELETED										
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 4.11: 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 4.11: 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 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR(a)
STREAMS 1 – 26

PFD 6

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter.

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft	
PROJECT:	WATER USAGE AND LOSS OF POWER PLANTS WITH CCS	feb-11	ISSUED BY: NF
LOCATION:	NETHERLANDS	CHECKED BY: PC	
FWI Nº:	1- BD 0475 A	APPR. BY: LM	

CASE 4.11 - WATER CONSUMPTION SUMMARY - USC PC Oxyfuel with CO_2 capture

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	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

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
		Feb 2010
PROJECT:	WATER USAGE AND LOSS OF POWER IN PLANTS WITH C(	ISSUED BY: L.So.
LOCATION:	NETHERLANDS	CHECKED BY: PC
FWI Nº:	1- BD 0475A	APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - CASE 4.11 - USC PC Oxyfuel with CO2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	**Coal and Ash Handling**	**4000**
600	**Air Separation Unit**	**86740**
700	**CO2 Compression and Recovery System (including Air Products package)**	**64900**
	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**	**6000**
	BALANCE excluding CO_2 compression	**140740**
	BALANCE including CO_2 compression	**205640**

Notes: (1) Minus prior to figure means figure is generated

7. Overall performance

The table summarizing the Overall Performance of the USC PC Oxyfuel Plant, case 4.11, is attached hereafter.

USC PC, Oxyfuel

bituminous coal, with CO_2 capture

OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	209.1
Coal LHV (air dried basis)	kJ/kg	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**737.0**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY		
ASU	MWe	86.7
FW pumps	MWe	35.0
Draught Plant	MWe	5.0
Coal mills, handling, etc.	MWe	4.0
ESP	MWe	2.0
Miscellanea	MWe	8.0
Unit 700 (CO_2 compr and inerts removal + Air Products package)	MWe	64.9
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**205.6**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**531.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.1**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.4**

Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.827**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.085**
Specific water consumption per MW net produced	**t /MWh**	**0.063**

8. Environmental Impact

The USC PC Oxyfuel plant, case 4.11, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarizes expected flow rate and concentration of the combustion flue gas.

Table 8-1 - 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

8.1.2. 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.

8.2. 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

8.3. 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

<u>Sludges from WWT</u>

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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER	LOCATION: Netherlands	DATE	February 2010	Nov 2010		
	PROJ. NAME: Water usage &loss analysis in plants w/o & w CC	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
(1) = reference shall be made to report number 2005/9, by IEA; "+" means that the item shall be added; "-" means that the item shall be deleted.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
	LOCATION: Netherlands	DATE	February 2010	Nov 2010		
	PROJ. NAME: Water usage &loss analysis in plants w/o & w C(	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (19.9 t/h), generated by combustion (75.0 t/h), steam injection for soot blowing (15.0 t/h) and from primary recycle (14.3 t/h)	water outlet as steam in flue gas (124.6 t/h)
		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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The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3		
	LOCATION: Netherlands	DATE	February 2010	Nov 2010				
	PROJ. NAME: Water usage &loss analysis in plants w/o & w CC	ISSUED BY	L.So.	L.So.				
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC				
		APPROVED BY	SA	SA				

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HP, IP & LP Turbines		740 MWe gross							
		Associated Pipework									
		Feedwater heaters									
		Deaerator									0.3 t/h steam vented to atm
		Condenser		631 MW th				tubes: titanium; shell: CS	sea water heat exchanger		
		Condensate polishing									9.4 t/h blowdown to WWT
		LP Pump									
		HP Pump									
		Sea water Circulation Pumps	submerged	18600 m3/h x 20m	1250 kW			casing, shaft: SS; impeller: duplex	5 pump in operation + 1 spare		
		Waste water treatment plant									
		Sea water inlet /outlet works									
		Demiwater plant								27.2 t/h raw water	24.7 t/h demi water production; 2.5 t/h blowdown to WWT
		Machinery cooling water cooler	plate heat exchange	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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The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: Netherlands	DATE	February 2010	Nov 2010		
		PROJ. NAME: Water usage &loss analysis in plants w/o & w CCS	ISSUED BY	L.So.	L.So.		
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 600 - Air Separation Unit - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Main air compressors	centrifugal	75.6 MW							
		Air purification system									
		Main heat exchanger									
		ASU compander									
		ASU Column System									12 t/h water vapor vented to atm
		Pumps	centrifugal	0.74 MW							
		Backup storage vessel									
		ASU chiller		26 MW th							

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The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
	LOCATION: Netherlands	DATE	February 2010	Nov 2010		
	PROJ. NAME: Water usage &loss analysis in plants w/o & w CCS	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 700 - CO2 compression and inerts removal - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Venturi scrubber									
		Indirect contact cooler									94.6 t/h condensate from flue gas to WWT
	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		
-		~~**Direct contact seawater cooler**~~							DELETED with respect to configuration selected in the original report		
		Compressors	centrifugal	1 64.0 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									0.5 t/h water to WWT
+	C-206	**First contacting column**		D=3.5 m; H=10.5 m				Shell: Alloy 20 CLAD	ADDED with respect to configuration selected in the original report		14 t/h water to WWT
+	C-207	**Second contacting column**		D=2.7 m; H=8.1 m				Shell: SS 304L CLAD	ADDED with respect to configuration selected in the original report	6.1 t/h water in for scrubbing	6.1 t/h water to WWT
+	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 - ADDED with respect to configuration selected in the original report		
+	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 - ADDED with respect to configuration selected in the original report		
+	P-202	**First contacting column circulation pumps**	centrifugal	600 m3/h x 50 m	110 kW			Alloy 20	one pump in operation, one spare - ADDED with respect to configuration selected in the original report		
+	P-203	**Second contacting column circulation pumps**	centrifugal	500 m3/h x 45 m	90 kW			SS 304L	one pump in operation, one spare - ADDED with respect to configuration selected in the original report		

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The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage &loss analysis in plants w/o & w CCS CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010	Nov 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.11

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Balance of Power Plant									
		Controls									
		Instruments									
		Electrics									

LEGEND:
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The water consumer equipment is highlighted in the present equipment list.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : USC PC OXYCOMBUSTION – DRY LAND – CASE 4.12

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
February 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
August 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti
November 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti

SECTION C

USC PC OXYCOMBUSTION - DRY LAND
I N D E X

1. Introduction

The present case 4.12 refers to the same USC PC Oxyfuel plant, fed with bituminous coal and provided with CO_2 capture unit, analysed in Report #3, Section B (case 4.11). The difference with the power plant of case 4.11 is that the power plant analysed here is installed in the reference dry land country (South Africa) and far from the seaside, so that, technologies for saving water and reducing to zero the raw water intake have been applied. The configuration and the performance of the plant so modified are evaluated and the results are discussed in the present Section.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 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

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

Case 4.12 is a pulverized coal, oxyfuel fired, ultra supercritical steam plant. The design is based on a USC PC plant market based design, converted to oxyfuel fired operation.

Unit 700 (CO_2 compression and inerts removal) includes the Air Products CO_2 purification treatment, where the NOx (produced in the coal combustion) and the SOx (produced in stoichiometrical quantity with the sulphur present in coal) contaminating the flue gas are removed, making them reacting with water and oxygen to give nitric acid and sulphuric acid, respectively.

A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

Due to the installation in a severely limited water supply area and far from the seaside, changes have been made on some process and utilities units, compared with the reference case 4.11. The main peculiarity of the present case 4.12 is the deletion of the seawater cooling system, being the cooling effect provided by aircoolers and by machinery cooling water. No other technology for reducing water consumption or saving water is required in this typology of power plants, since the plant design already allows recovering completely the water present in the flue gases, so that water effluent from Waste Water Treatment exceeds by far the plant needs.

2.2. Unit 100 - Coal Handling

Reference shall be made to Report # 3, Section B, paragraph 2 for the process description of this unit.

Purpose of this system is to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the boiler plant.

2.3. Unit 200 – Boiler Island

Reference shall be made to Report # 3, Section B, paragraph 2 for the process description of this unit.
The fuel input has been kept constant as the relevant reference case 4.11.

A standard designed USC PC boiler is operated without nitrogen being present in the combustion air, resulting in a substantial reduction in the quantity of flue gas that must be treated in downstream processing equipment to capture the CO_2.
Flue gas is recycled to the burners to maintain temperatures within the furnace at similar levels to air firing.

2.4. Unit 500 - Steam Turbine Generator

Reference shall be made to Report # 3, Section B, paragraph 2 for the process description of this unit.

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 for reheating and then throttled into the double flow IP turbine. Exhaust steam from the IP turbines then flows into the double flow LP turbine system. Exhaust steam from the LP turbine is condensed and then deaerated and preheated for generating recycled boiler feed water to be fed to the Boiler Island.

The major difference with the reference plant, case 4.11, is that the exhaust steam from the LP turbine is condensed in an aircooler and not in a sea water condenser. With respect to the latter condenser, the condensing system with aircooler allows reaching lower steam turbine performances, since the condensing pressure that can be achieved by the air condenser is significantly higher (0.074 bara with aircooler vs 0.040 bara with sea water condenser).

2.5. Unit 600 - Air Separation Unit

Reference shall be made to Report # 3, Section B, paragraph 2 for the process description of this unit.

As regards the equipment arrangement of unit 600, Case 4.12 differs from case 4.11 only for the type of coolers: in case 4.12 compressor intercoolers are aircoolers instead of sea water coolers, as used in case 4.11.
The use of air cooled exchanger in compressor intercoolers strongly affects the power consumption of the overall compressor train. The temperature at the inlet of

each compressor, in fact, is higher than the same one in the wet land cases and therefore a penalisation of about 8 MWe is expected.

2.6. Unit 700 – CO_2 compression and inerts removal

Reference shall be made to Report # 3, Section B, paragraph 2 for the process description of this unit.

As regards the equipment arrangement of unit 700, case 4.12 differs from case 4.11 only for the type of coolers: all the sea water coolers present in case 4.11 are replaced with aircoolers.

As in ASU, the temperature at the inlet of each compressor is higher than the same one in the wet land cases and therefore a penalisation of about 8.5 MWe is expected.

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 9.

The main utility units are the following:
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

2.7.1. Waste Water Treatment (WWT)

WWT includes some specific units necessary for reducing pollutants concentration. Their description follows hereafter.

Sulphites oxidation

The condensate water from flue gas condensate is contaminated with sulphites. For this reason this stream is treated separately from the other polluted streams and then rejoined with the others in the equalization tank.
In order to remove HSO3- hydrogen peroxide is added, giving as reaction product sulphuric acid.

The contact time permitting sulphites oxidation is about 30 minutes and the oxidation basin is normally designed considering this parameter.
The oxidation basin has to be equipped with an adequate number of mixers in order to favourite a close contact between the reagents.

Softening

Sodium hydroxide is added to the polluted water coming from demi water unit in order to remove specific ions as Mg^{2+} and Ca^{2+}, responsible for water hardness and connected problems (deposits and incrustations). This operation is made necessary by the presence of an evaporation unit downstream, where an increasing in temperature can cause phenomena of incrustation.
The softening reactor is designed considering a hydraulic retention time of circa 30 minutes.

Equalization

Condensate acid water from unit 700, water from softening section and condensate water from sulphite oxidation section are sent to equalization section.
The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed in order to make uniform the physical characteristics (pollutants concentration, temperature, etc.) of the waste water to be fed to the following treatment.
Equalization basin is normally designed in order to guarantee a hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

Neutralization

In the neutralization section the effluent coming from equalization basin is neutralized through the injection of a caustic soda solution (or of a sulphuric acid solution), for pH correction, in order to ensure optimum pH conditions for water reuse.
The neutralization tank is designed for a hydraulic retention time of about 10 minutes.

Physical-Chemical treatment

This section consists of two basins in series, where chemicals are added for chemical coagulation, flocculation and for specific pollutants removal. The purpose of waste water clariflocculation is to form aggregates or flocs from finely divided particles

and from chemical destabilized particles in order to remove them in the following sedimentation step.
In the first basin, coagulation basin, a coagulant as Ferric Chloride is added and a flash-mixing is performed. This basin is designed in order to guarantee a contact time of about 5 minutes and mixers are foreseen.
In the second basin (flocculation basin) polyelectrolyte is added and slow-mixing is performed. This basin is designed in order to guarantee a contact time of about 25 minutes and mixers are foreseen.

Chemical sludge settling

Effluent water from coagulation/flocculation section flows into a clarification basin, where solids separation is performed and all setteable compounds are removed.
The produced sludge, consisting of settled solids, is removed from the bottom of each clarifier by a scraper and pumped to an evaporator/crystallization section.
The basin is designed in order to guarantee a contact time of about 2 hours and a surface loading rate of about 1.5 m3/m2/h.

Sand Filtration

The clarified water from clarification basin is delivered to the top of the sand filter bed in order to remove the remaining unsetteable solids.
As the water passes through the filter bed, the suspended matter in the wastewater is intercepted and removed. With the passage of time, as material accumulates within the interstices of the granular medium, the headloss through the filter starts to build up beyond the initial value. After some period of time, the operating headloss through the filter reaches a predetermined value and the filter must be cleaned.
The filters are designed in function of different parameters:
- Wastewater flowrate and characteristics;
- Granular medium geometric and dimensional characteristics;
- Admissible headloss and admissible filtration velocity;
- Flow control type.

Reverse Osmosis

In order to remove specific ions from clarified water, reverse osmosis process can be considered an adequate solution. In general, when the total salinity is high (some thousands of ppm), the reverse osmosis is technically and economically preferable rather than other treatments.
In order to guarantee good performance of reverse osmosis process some pre-treatments are recommended in order to remove solids and some substances responsible of fooling phenomena.

The reverse osmosis is a membrane technology, so the products of filtration are:

- Low salinity filtered water;
- Concentrated water, with high salts concentration.

Finally, the concentrated water is sent to an evaporation system, while the filtered water is sent to WWT section battery limit.

Evaporation/Crystallization

The concentrated water coming from reverse osmosis and the sludge from chemical settling is sent to an evaporation system, where water is evaporated using steam.
For providing a consumption estimate, the steam flowrate is evaluated as about 1.1 kg (steam) / kg (condensate).
The evaporated water is finally condensed and rejoined to the water streams destined to reuse. The solid residues with high dry content (up to about 80%) are sent to final disposal.

3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagrams of the USC PC Oxyfuel plant, case 4.12, and the schematic Process Flow Diagram of Units 500, 600 and 700 are attached hereafter.

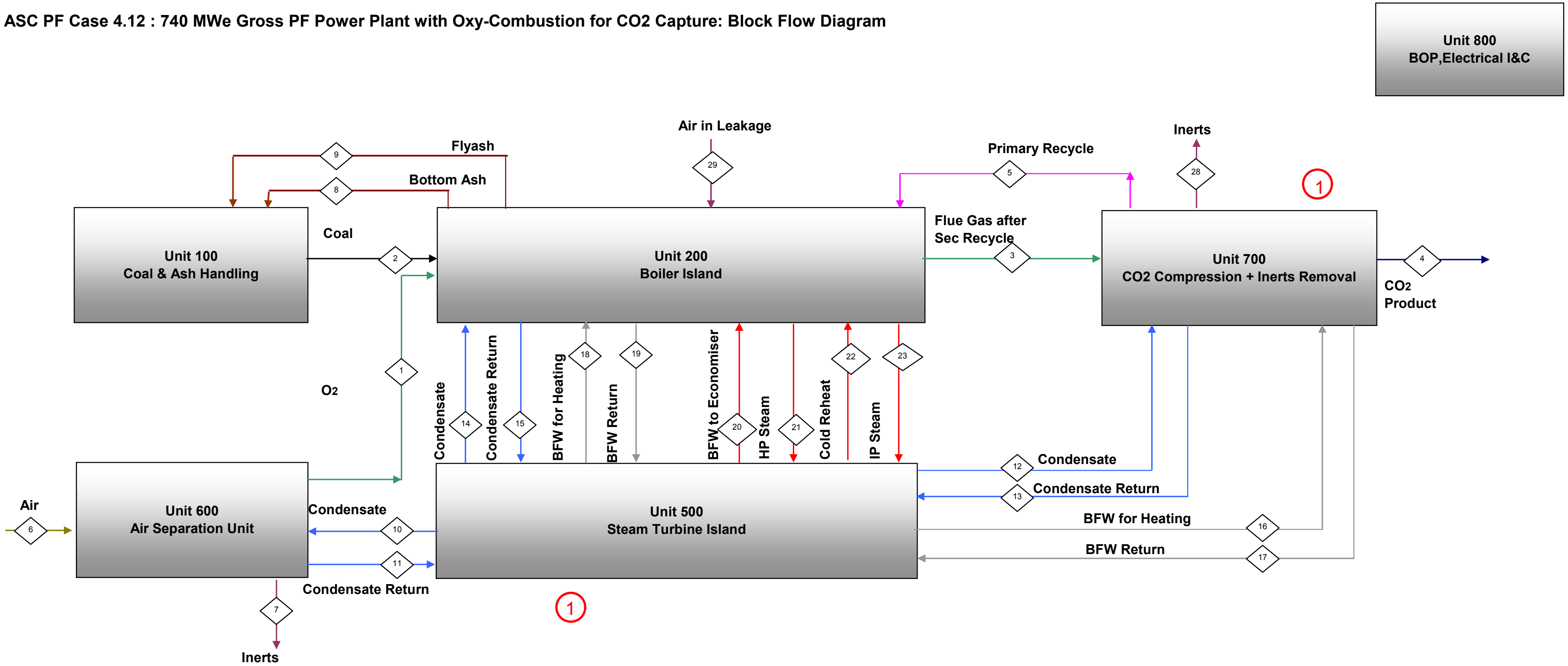
The Block Flow Diagrams and Process Flow Diagrams attached to Report # 3, Section B, paragraph 3 are to be taken as reference: they represent the plant arrangement for case 4.11, i.e. when the plant is installed in a no-dry land country, along the seaside. Modifications required due to installation in a dry land country and far from the seaside have been highlighted in the drawings attached hereafter.

The Block Flow Diagram of the Waste Water Treatment unit, valid for the present case 4.12, is also attached hereafter. The relevant Heat&Mass balance is reported in paragraph 5 of this section. The list of the utilities consumption is shown in paragraph 6.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

It's important to notice that the original design of the USC PC Oxyfuel power plant already allows a complete recovery of the water present in the boiler flue gases. Such water (together with the other polluted streams of water produced by the plant) is sent to Waste Water Treatment unit and it is evaluated that the effluent of treated water from WWT exceeds by far the raw water needs of the plant. Thus, it results that the only equipment modifications required to case 4.12 compared with case 4.11 are the replacement of the sea water heat exchangers with aircoolers, in accordance with the requirement of installing the power plant far from the seaside.

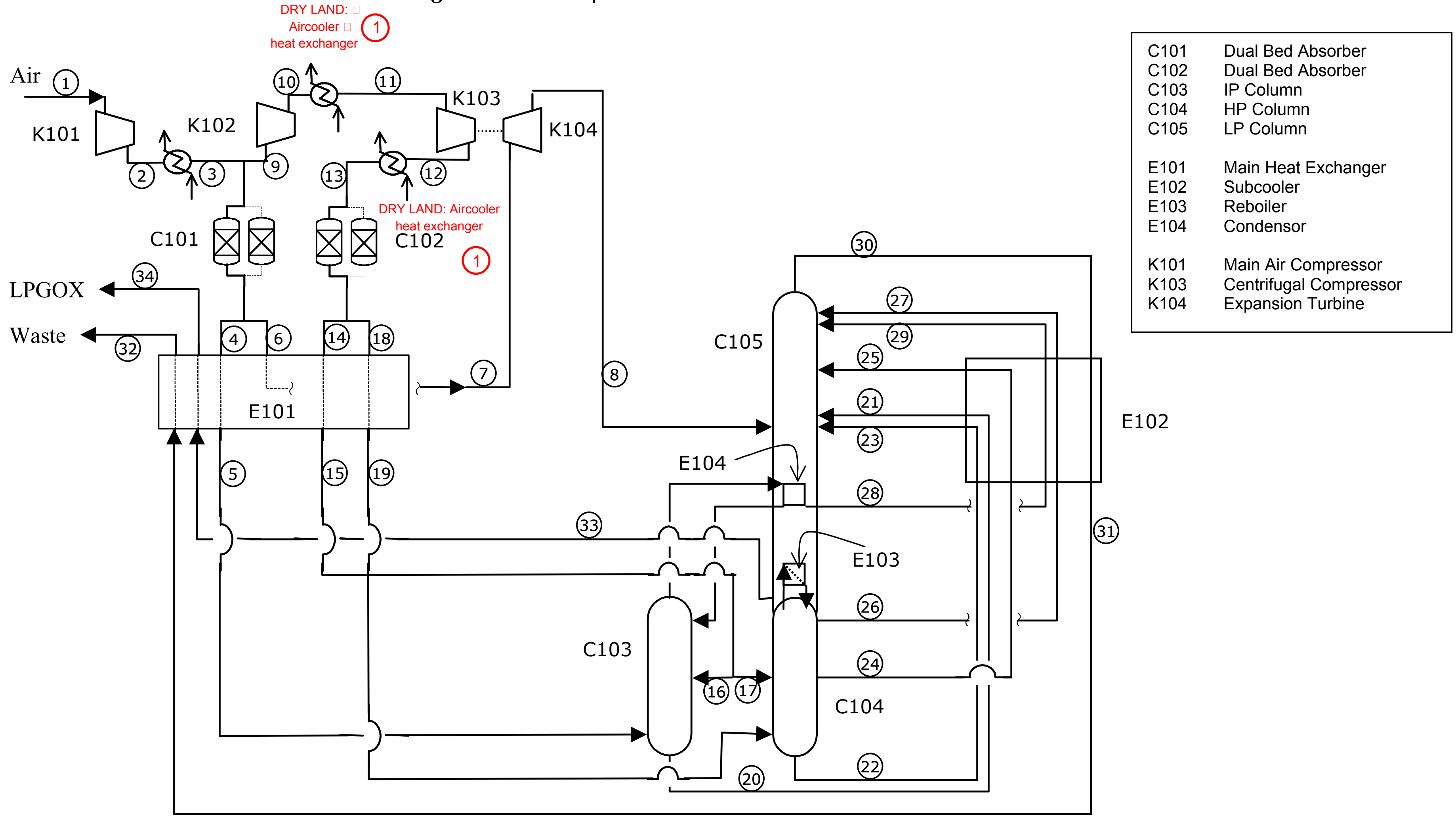
ASC PF Case 4.12 : 740 MWe Gross PF Power Plant with Oxy-Combustion for CO2 Capture: Block Flow Diagram



Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM

PFD 2

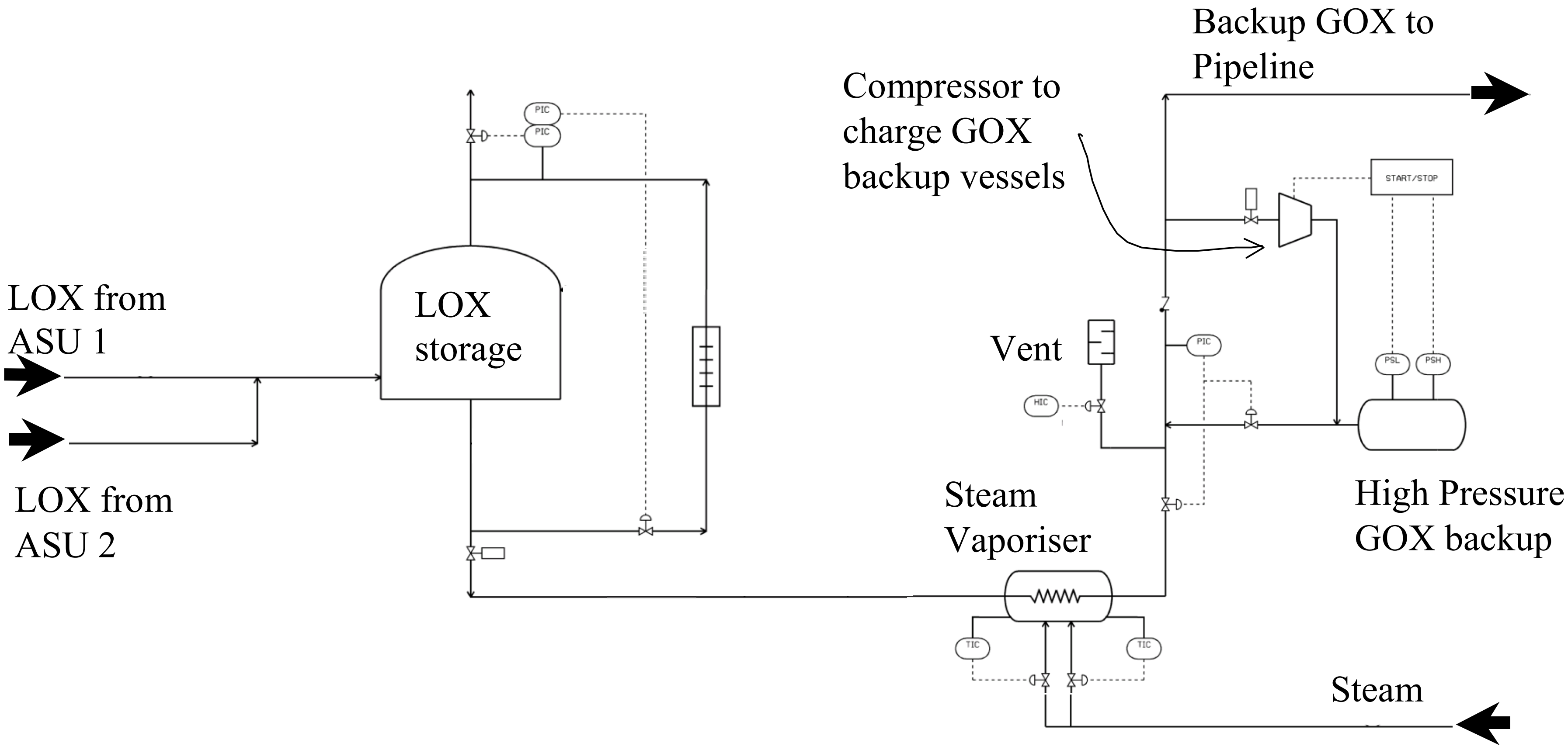
1 = revised during the 2009 study



Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : ASU PROCESS FLOW DIAGRAM

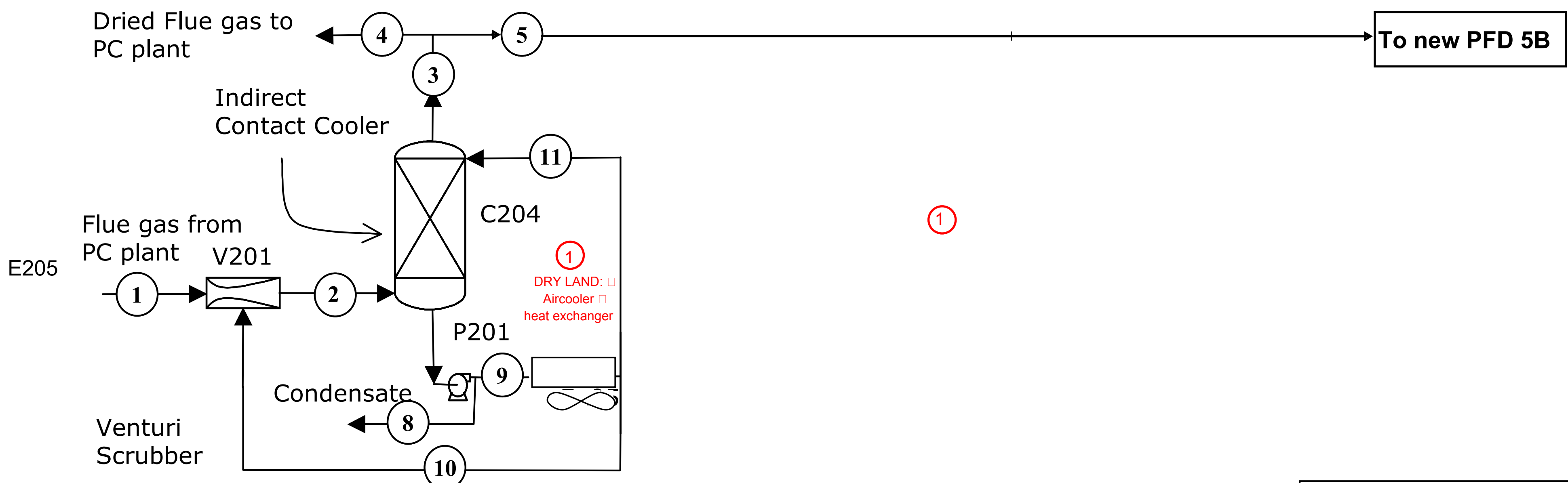
1 = revised during the 2009 study

PFD 3



Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : OXYGEN BACK UP SYSTEM

PFD 4

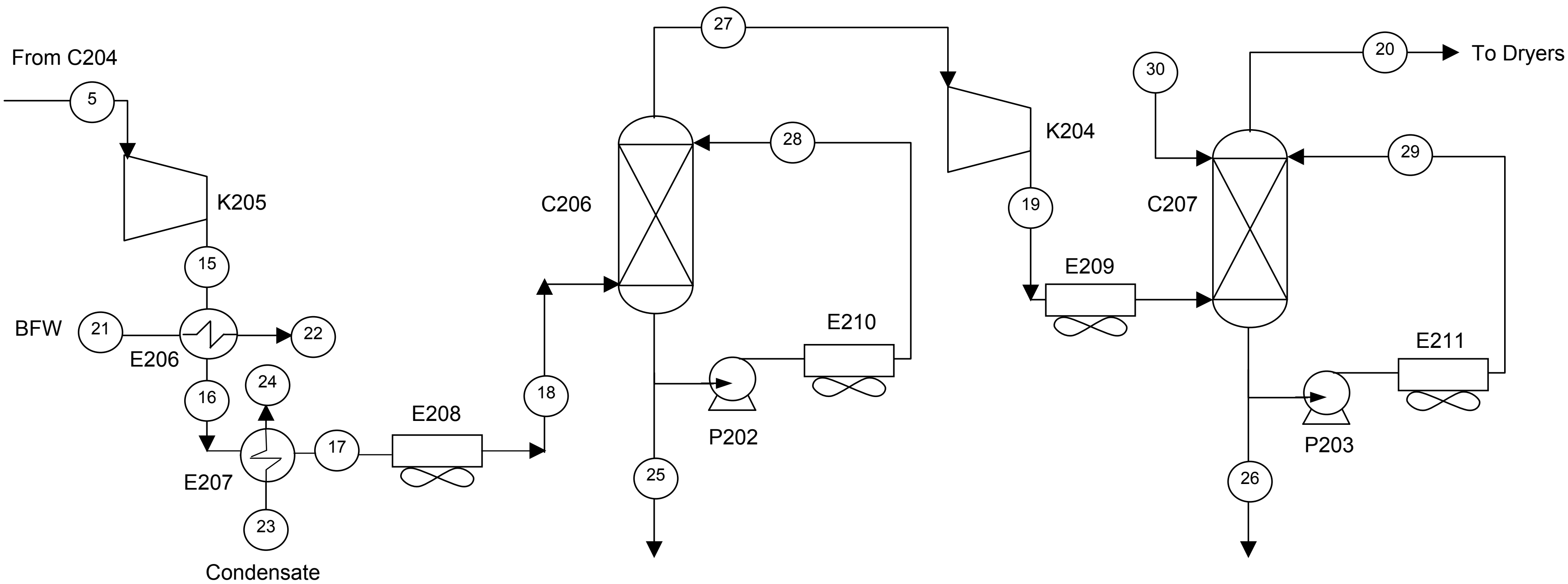


C204	Indirect Contact Cooler	1
E205	Contact Cooler Aircooler	
P201	Contact water pump	
V201	Venturi Scrubber	

Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 COOLING AND COMPRESSION TO 30 BAR (a)

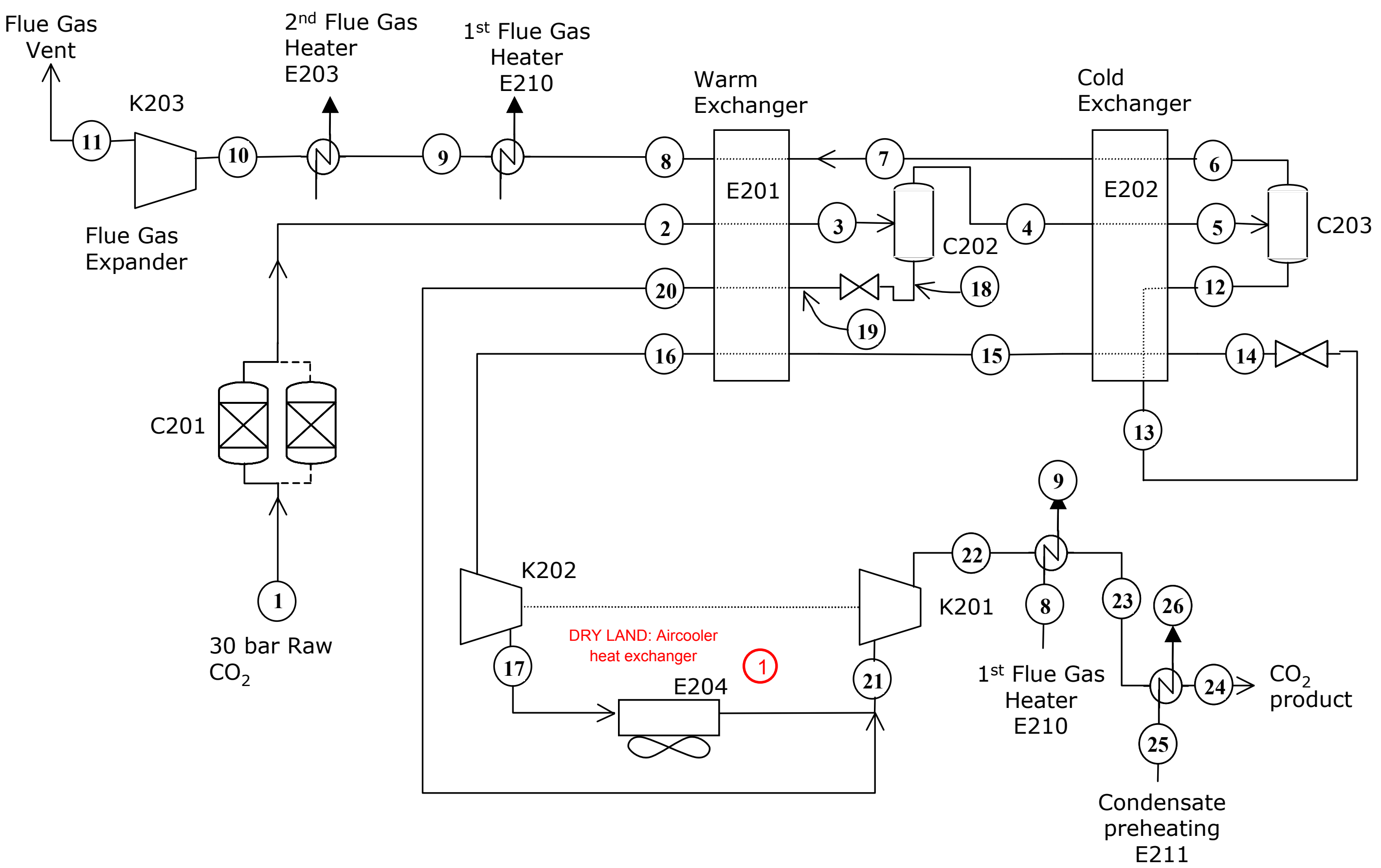
PFD 5A

1 = revised during the 2009 study



Case 4.12: ASC PF POWER PLANT WITH CO2 CAPTURE : CO2 COOLING AND COMPRESSION TO 30 BAR (a) **PFD 5B**

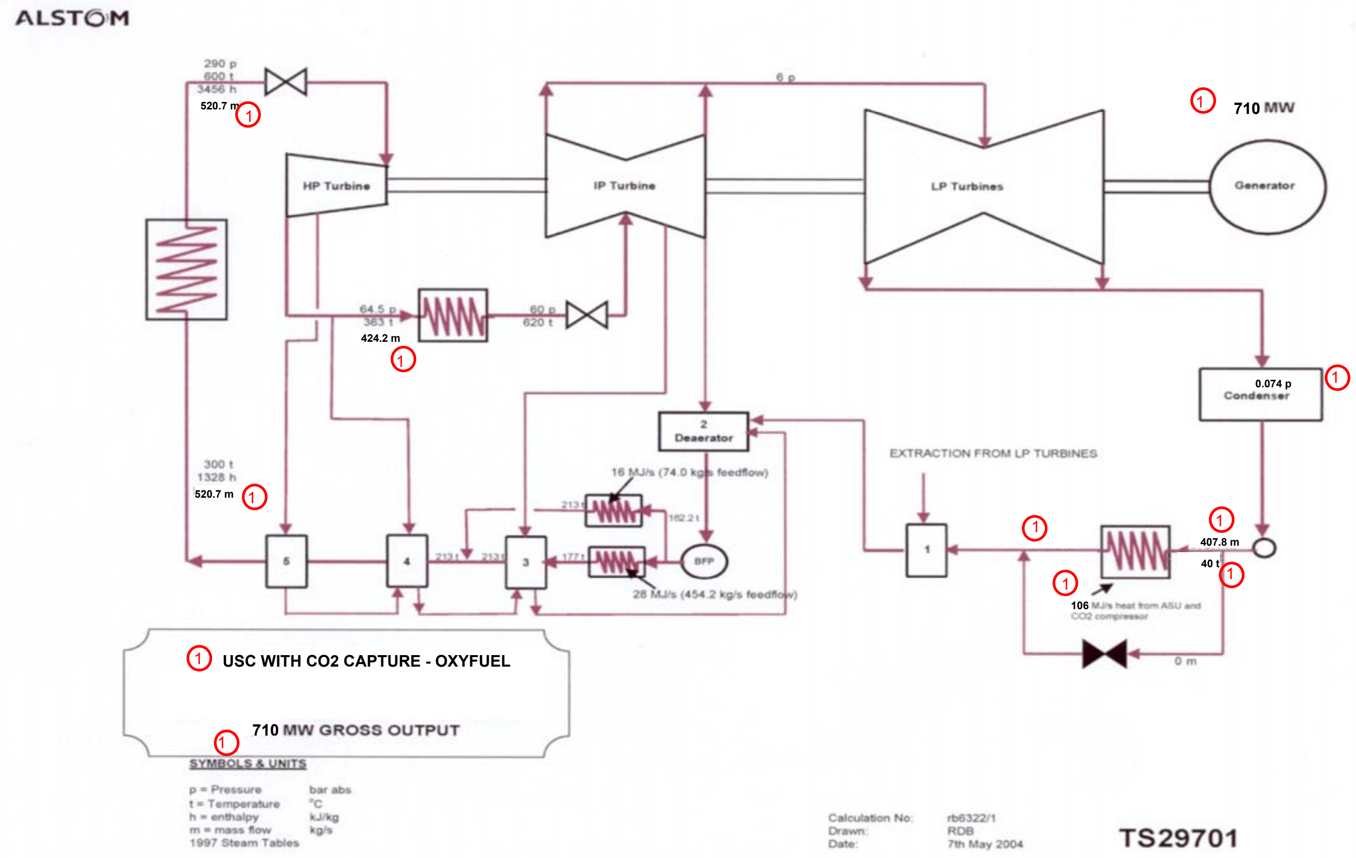
C206	First contacting column	E206	BFW preheater
C207	Second contacting column	E207	Condensate preheater
		E208	CO2 aircooler
K205	CO2 compression to 15 bara	E209	CO2 aftercooler (aircooler)
K204	CO2 compression to 30 bara	E210	First contacting column aircooler
		E211	Second contacting column aircooler
P202	First contacting column circulation pump		
P203	Second contacting column circulation pump		



C201	Dual Bed Dryer
C202	Separator Pot
C203	Separator Pot
E201	Warm Heat Exhanger
E202	Cold Heat Exchanger
E203	2nd Flue Gas Heater
E210	1st Flue Gas Heater
E211	Condensate Preheater
K201	Adiabatic Compressor
K202	Compressor
K203	Flue Gas Expander

Case 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR (a)

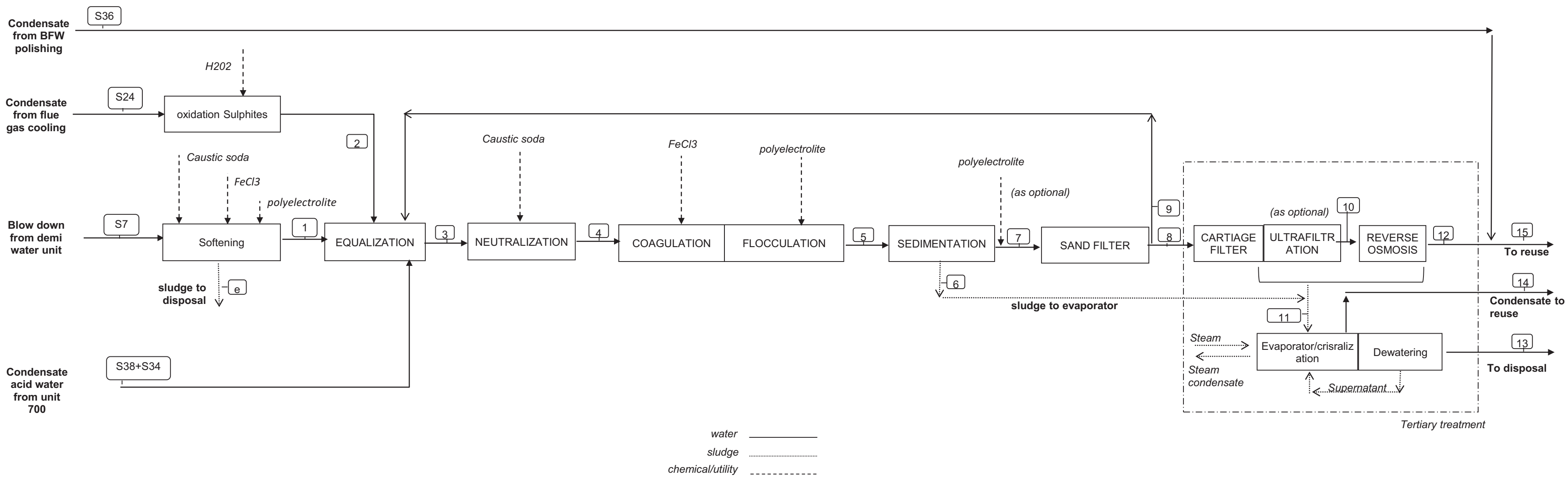
PFD 6



OXY-COMBUSTION ASC PF POWER PLANT WITH CO_2 CAPTURE PLANT
FEED HEATING ARRANGEMENT

FIGURE 10

Case 4.12 USC PC WITH OXYCOMBUSTION COMPLEX, BITUMINOUS CAOL, WITH CO2 CAPTURE - WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



Notes:
1. Chemical conditioning of concentrate water from reverse osmosis section has to be evaluate in order to prevent nitrates volatilization in the evaporation section.
2. For stream 36 a chemical treatment for hardness removal can be evaluate in order to reduce deposite formation.

4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units;
- flowrates and compositions of the streams of water to waster water treatment unit.

As explained in the previous paragraph 3, even considering the original design of the USC PC Oxyfuel power plant without implementing any modification, it results that the treated water recovered from the waste water treatment unit exceeds by far the plant raw water needs, allowing a zero raw water intake and generating a treated water excess to be disposed at unit battery limit.

The ambient temperature affects the minimum temperature that can be achieved in the air cooling systems.
The higher ambient temperature leads to an higher temperature on the process streams downstream the air cooled exchanger. The material balance attached to water diagram is referred to the refence ambient temperature. Therefore, it is to be considered as an average between the cold and the warm season.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

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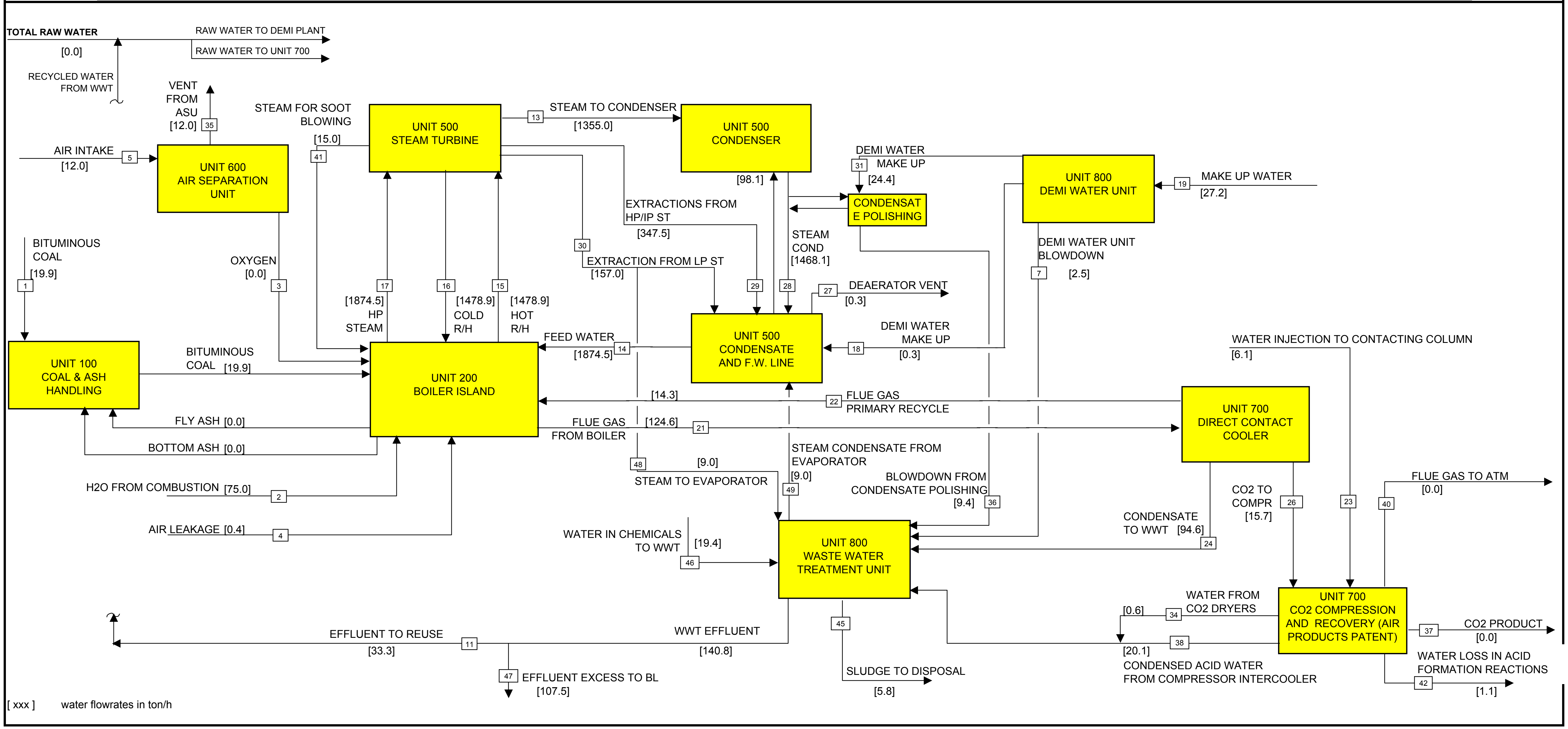
CASE 4.12 - USC PC WITH OXYCOMBUSTION PLANT, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 487 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



FOSTER WHEELER

IEA GHG R&D PROGRAMME		Revision no.:	Draft
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Volume #3		Sheet:	

USC PC with Oxycombustion, bituminous coal and CCS - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.9	40	Flue Gas to atmosphere	0.0
2	Water from coal combustion	75.0	11	Effluent from WWT to reuse	33.3
3	Moisture in Oxygen to Boiler Islan	0.0	27	Moisture in deaerator vent	0.3
4	Air leakage to boiler	0.4	37	CO2 product	0.0
19	Make up to Demi Water Unit	27.2	35	Vent from ASU	12.0
5	Moisture in air to ASU	12.0	42	Loss in acid formation reactions	1.1
23	Water injection to contacting column	6.1	47	Excess effluent from WWT to BL	107.5
46	Water in chemicals to WWT	19.4	45	Sludge to disposal/losses	5.8
Total		159.9	Total		160.0

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around WWT

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
7	Blowdown from Demi Water Unit	2.5	11	Water Effluent to reuse	33.3
24	Condensate from Unit 700	94.6	45	Sludge to disposal/losses	5.8
38	Condensed acid water from unit 700	20.1	47	Excess effluent from WWT to BL	107.5
36	Blowdown from BFW polishing	9.4	49	Steam condensate from evaporator	9.0
34	Water from CO2 dryers	0.6			
48	Steam to evaporator	9.0			
46	Water in chemicals to WWT	19.4			
Total		155.6	Total		155.6

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around Boiler Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.90	21	Flue gas from boiler	124.6
2	Water from coal combustion	75.0			
4	Air leakage to boiler	0.4			
41	Steam for soot blowing	15.0			
22	Flue Gas primary recycle	14.3			
Total		124.6	Total		124.6

USC PC with Oxycombustion, bituminous coal and CCS - Balance around Units 200 and 700

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	19.9	42	Loss in acid formation reactions	1.1
2	Water from coal combustion	75.0	24	Condensate from Unit 700	94.6
3	Moisture in Oxygen to boiler	0.0	38	Condensed acid water from unit 700	20.1
4	Air leakage to boiler	0.4	37	CO2 product	0.0
23	Water injection to contacting column	6.1	40	Flue Gas to atmosphere	0.0
41	Steam for soot blowing	15.0	34	Water from CO2 dryers	0.6
Total		116.4	Total		116.4

USC PC with Oxycomb., bituminous coal and CCS - Water Balance around Steam Turbine

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
15	Hot R/H from Boiler	1478.9	13	Steam to condenser	1355.0
17	HP steam from Boiler	1874.5	16	Cold R/H to Boiler	1478.9
			29	Extractions from HP/IP ST	347.5
			30	Extractions from LP ST	157.0
			41	Steam for soot blowing	15.0
Total		3353.4	Total		3353.4

USC PC with Oxycombustion, bituminous coal and CCS - Water Balance around Unit 700

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
21	Flue gas from boiler	124.6	24	Condensate from Unit 700	94.6
23	Water injection to contacting column	6.1	38	Condensed acid water from unit 70	20.1
			34	Water from CO2 dryers	0.6
			22	Flue gas primary recycle	14.3
			42	Loss in acid formation reactions	1.1
Total		130.7	Total		130.7

CASE 4.12 - USC PC PLANT, BITUMINOUS COAL, WITH OXYCOMBUSTION AND CCS (DRY LAND) - WATER STREAMS SENT TO WWT

STREAM	7	24	36	34+38
SERVICE	Blowdown from Demi Water Unit	Condensate from Unit 700	Blowdown from BFW polishing	Condensed acid water from unit 700
Temperature (°C)	amb	35	30	35
Total flowrate (t/h)	2.5	94.6	9.4	26.7
Composition (ppm wt)				
H2				
NO2		43		
CO2		822		6300
NH3				
Na+	1090			
Cl-	4560	999		
PO4---			5	
SiO2	110		5	
CaCO3	406		100	
SO4--	830			
NO3-	510			
Ca AAS	1410			
Mg AAS	420			
MEA				
Suspended solids		343		
K	30			
HCO3-	250			
H2SO4		525		204458
HNO3				15017
SO2 / HSO3-		299		
H2O (% wt)	99.0384	99.6969	99.9890	77.4224
TOTAL (%wt)	100	100	100	100

NOTES:

5. 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.

The H&MB attached to Report # 2, Section C, paragraph 5 has been taken as a reference for preparing the H&MB of the present case. The material balance relevant to WWT is also provided. Modifications due to dry land and inland installation have been highlighted in the same heat and material balance attached to the appendix 1 of such a volume 3.

In the IEA GHG study number 2005/9, July 2005 taken as reference study, the temperature profile dowstream some water cooled exchangers has not been optimized. A cold temperature ranging from 30°C to 35°C dowstream sea water cooled exchanger, in fact, could still be lowered just increasing the water circulation. In the dry land case, in some exchanger, therefore, it has been possible to achieve the same temperature as in reference case althought the use of air as cooling medium. The result is that a lower penalisation is obtained in the oxyfuel cases comparign wet and dry land design with respect to the other technologies, where an optimized temperature profile has been considered both in dry land and in wet land design.

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	14	16	1102	264	40
- 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 4.12: 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	40	155	40	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 4.12 : 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	7.143	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 4.12 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	14.0	149.39	12.00	20.00	-178.54	20.00	-171.44	-188.16	12.00	46.19	30.00	39.92	30.00

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	30.00	-176.75	-176.75	-176.75	30.00	-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	20.00	-180.05	20.00					

CASE 4.12: 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
Composition - (mol%)							DELETED	DELETED					DELETED
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	9,407,225	9,407,225	94,570	11,900,000	30,321	11,869,679	1,303,688
	Nm3/hr	782,400	820,080	664,217	316,035	348,183	11,697,021	11,697,021	117,550	14,793,500	37,700	14,755,800	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	29.00	29.00	12.00

STREAM No.		13	14	15	16	17	18	19	20	21	22	23	24
Composition - (mol%)		DELETED	DELETED										
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	40.0	93.20

CASE 4.12: 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 4.12: 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	40.0	93.20

CASE 4.12: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR(a)
STREAMS 1 – 26

PFD 6

Case 4.12 USC PC WITH OXYCOMBUSTION COMPLEX, BITUMINOUS CAOL, WITH CO2 CAPTURE - WASTE WATER TREATMENT MATERIAL BALANCE

Stream		N°	S36	S7	S24	S38+S34	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Parameter	**Note**	**unit**	**Blowdown from BFW polishing**	**Blowdown from demi water unit**	**conden.from flue gas cool.**	**Condensate acid water from unit 700**	**BD from softening**	**condensate from oxidation pretreat.**	**Equalized water**	**Neutralized water**	**Water to sedimentation**	**Sludge to evaporator**	**clarifield water**	**Filtered water**	**Sand filter backwash**	**Water to reverse osmosis**	**Concetrate to evaporator**	**Treated Water**	**Sludge to disposal**	**Condensate to reuse**	**Water to reuse**
Temperature		°C	30,00	20,00	35,00	35,00															
Flow rate		ton/h	9,40	2,50	94,60	26,70	2,27	94,62	131,17	152,68	152,68	1,14	151,54	151,54	7,58	143,97	22,64	122,47	13,72	8,92	131,87
NO2--		mg/l		-	43,00		-	42,99	33,85	29,65	29,65	29,65	29,65	29,65	29,65	29,65	270,75	0,66	639,45		0,61
CO2		mg/l		-	822,00	6300,00	-	821,79	1820,09	1594,14	1594,10	1594,10	1594,10	1594,10	1594,10	1594,10	14556,14	35,42	34378,94		32,90
NH3		mg/l		-	-		-		-												
Na+		mg/l		1090,00			4400,24		1211,33	19987,80	19987,35	19987,35	19987,35	19987,35	19987,35	19987,35	182509,45	444,16	431053,91		412,50
Cl-		mg/l		4560,00	999,00		5014,01	998,75	881,39	771,97	771,95	771,95	771,95	771,95	771,95	771,95	7048,89	17,15	16648,20		15,93
PO4--		mg/l	5,00	-	-		-		-												0,36
SiO2		mg/l	5,00	110,00	-		-														0,36
TSS	(1)	mg/l			343,00		1353,95	342,91	385,24	337,41	338,07	30549,90	102,01	10,00	1840,25	28,40	2578,80	0,63	6090,65		0,59
CaCO3		mg/l	100,00	406,00	-		35,00		0,73	0,64	0,64	0,64	0,64	0,64	0,64	0,64	5,82	0,01	13,75		7,14
SO4--	(2)	mg/l		830,00	514,29	200285,39	912,64	868,44	37990,13	33273,90	33273,16	33273,16	33273,16	33273,16	33273,16	33273,16	303825,45	739,40	717580,10		686,70
NO3-	(3)	mg/l		510,00	-	14778,63	560,78		2762,08	2419,19	2419,14	2419,14	2419,14	2419,14	2419,14	2419,14	22089,73	53,76	52171,90		49,93
Ca2+		mg/l		1410,00	-		-														
Mg2+		mg/l		420,00	-		-														
MEA		mg/l		-	-		-		-												
K+		mg/l		30,00	-		32,99		0,62	0,55	0,55	0,55	0,55	0,55	0,55	0,55	4,99	0,01	11,79		0,01
HCO3-		mg/l		250,00	-		274,89		5,20	4,56	4,56	4,56	4,56	4,56	4,56	4,56	41,60	0,10	98,25		0,09
H2SO4	(4)	mg/l		-	as (SO42-)	as (SO42-)	-		as (SO42-)												
HNO3	(5)	mg/l		-	-	as (NO3-)	-		as (NO3-)												
HSO3-		mg/l		-	299,00	-	-	-	-												
H2O		%	100	99	100	81	99	100	95	94	94	91	94	94	94	94	65	100	42	100	100

Notes:

1 Dissolved solid consist in fine coal.Considered as TSS

2 Sulphuric acid contribution has been considered

3 Nitric acid contribution has been considered

4 Sulphuric acid contribution has been considered as SO_4^{2-}

5 Nitric acid contribution has been considered as NO_3^-

General notes: Present mass balance is indicative only and related to the prosecc treatment selected

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter.

FOSTER WHEELER

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	WATER USAGE AND LOSS OF POWER IN PLANTS WITH CCS
LOCATION:	SOUTH AFRICA
FWI N°:	1- BD 0475A

Rev: Draft
Feb 10
ISSUED BY: L.So.
CHECKED BY: PC
APPR. BY: SA

WATER CONSUMPTION SUMMARY - CASE 4.12 - USC PC Oxyfuel with CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				SEA WATER IS NOT AVAILABLE IN POWER PLANTS INSTALLED IN DRY LAND
100	Coal and Ash Handling	-	-	64.8	
600	Air Separation Unit	-	-	1000.8	
700	CO2 Compression and Inerts Removal (including Air Products package)	6.1	-	1302.0	
200 - 500	POWER ISLAND UNITS (Boiler and Steam Turbine)	-	24.7	2834.4	
800	**UTILITY and OFFSITE UNITS**				
	Cooling Water, Demineralized Water Systems, etc	27.2	-24.7	70.8	
	BALANCE excluding CO_2 compression	33.3	0.0	3970.8	0.0
	BALANCE including CO_2 compression	33.3	0.0	5272.8	0.0

Note: (1) Minus prior to figure means figure is generated

CLIENT:	IEA GHG R&D PROGRAMME
PROJECT:	WATER USAGE AND LOSS OF POWER IN PLANTS WITH CCS
LOCATION:	SOUTH AFRICA
FWI N°:	1- BD 0475A

Rev: Draft
Feb 10
ISSUED BY: L.So.
CHECKED BY: PC
APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - CASE 4.12 - USC PC Oxyfuel with CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
100	Coal and Ash Handling	4000
600	Air Separation Unit	93008
700	CO2 Compression and Recovery System (including Air Products package)	70580
	POWER ISLANDS UNITS	
200 - 500	Boiler Island and Steam Turbine Island (including BFW pumps, Draught Plant, ESP)	47310
	Miscellanea utilities	2000
	UTILITY and OFFSITE	
800	Cooling/Demineralized/Condensate Recovery/Plant and Potable Water Systems	1725
	BALANCE excluding CO_2 compression	148043
	BALANCE including CO_2 compression	218623

Notes: (1) Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GREENHOUSE R&D	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
	LOCATION:	Dry land	DATE	February '10			
	PROJ. NAME:	Water usage and loss of P	ISSUED BY	M.P.			
	CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.			
			APPROVED BY				

Utilities consumption

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

	ITEM	DESCRIPTION	Absorbed Electical power	LP- Steam	$NaOH^{(1)}$	$H_2O_2^{(1)}$	$FeCl_3^{(1)}$	$Poly^{(1)}$	Remarks
			[kW]	[t/h]	[t/h]	[kg/h]	[kg/h]	[kg/h]	
	0800-Y1001 A/B	WWT - waste water treament complex	~200	~ 9	~5	~6	~0,5	~0,5	

Table below summarize specific consumpltion for each treatment section- value indicated are indicative only

	ITEM	DESCRIPTION	Absorbed Electical power [kW]		LP- Steam	$NaOH^{(1)}$	$H_2O_2^{(1)}$	$FeCl_3^{(1)}$	$Poly^{(1)}$	Remarks
			total	specific	[t/h]	[t/h]	[kg/h]	[kg/h]	[kg/h]	
		Sulphides oxidation Section	2.2				6			
		Softening Section	1.62			0.01				
		Equalization Section	22							
		Neutralization section	5.36			4.5				
		Clari/flocculation section	2.16					0.5	0.5	
		Sedimentation section	1.6							
		Media filtrration section	89.5							
		membrane filtration section	22							
		eluate cristallization section	47		9					

Notes:
1. As pure products

7. Overall performance

The table summarizing the Overall Performance of the USC PC Oxyfuel Plant, case 4.12, is attached hereafter.

USC PC, Oxyfuel		
bituminous coal, with CO_2 capture - DRY LAND SCENARIO		
OVERALL PERFORMANCES OF THE POWER PLANT COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	209.1
Coal LHV (air dried basis)	kJ/kg	25860.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1502.2**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**710.0**

POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY		
ASU	MWe	93.0
FW pumps	MWe	35.0
Draught Plant	MWe	5.0
Coal mills, handling, etc.	MWe	4.0
ESP	MWe	2.0
Steam Turbine Condenser aircooler	MWe	5.3
Miscellanea and utilities	MWe	3.7
Unit 700 (CO2 compr and inerts removal + Air Products package)	MWe	70.6
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**218.6**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**491.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**47.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.7**

Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**3.057**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.092**
Specific water consumption per MW net produced	**t /MWh**	**0.000**

8. Environmental Impact

The USC PC Oxyfuel plant, case 4.11, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8-1 summarizes expected flow rate and concentration of the combustion flue gas.

Table 8-1 - Expected gaseous emissions from the plant

	Normal Operation
Wet gas flow rate, kg/s	38.5
Flow, Nm^3/h	92531
Temperature, °C	20.2
Composition	**(%vol, wet)**
O_2	19.44
CO_2	24.65
SO_2	0
H_2O	0
N_2+Ar	55.91
Emissions	**mg/Nm^3 (1)**
NO	180
SOx	0
Particulate	0

(1) Dry gas, O_2 Content 6% vol

8.1.2. 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.

8.2. Liquid Effluent

Waste Water Treatment

After recycling enough treated water for covering the power plant raw water needs, the excess of treated water to be discharged outside Plant battery limit is as follows:

- Flow rate : 107.5 m3/h

8.3. 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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss of Power in Plants with CCS CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	February 2010			
		ISSUED BY	L.So.			
		CHECKED BY	PC			
		APPROVED BY	SA			

EQUIPMENT LIST

Unit 100 - Coal and Ash Handling - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER		LOCATION: SOUTH AFRICA	DATE	February 2010			
		PROJ. NAME: Water usage and loss of Power in Plants with CC	ISSUED BY	L.So.			
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC			
			APPROVED BY	SA			

EQUIPMENT LIST

Unit 200 - Boiler Island - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Furnace								water inlet as moisture in coal (19.9 t/h), generated by combustion (75.0 t/h), steam injection for soot blowing (15.0 t/h) and from primary recycle (14.3 t/h)	water outlet as steam in flue gas (124.6 t/h)
		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									

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3	
LOCATION: SOUTH AFRICA	DATE	February 2010				
PROJ. NAME: Water usage and loss of Power in Plants with CCS	ISSUED BY	L.So.				
CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC				
	APPROVED BY	SA				

EQUIPMENT LIST

Unit 500 - Steam Turbine Unit - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
Δ		HP, IP & LP Turbines		710 MWe gross							
		Associated Pipework									
		Feedwater heaters									
		Deaerator									0.3 t/h steam vented to atm
Δ		Condenser		634 MW th	62x95 kWe			CS	aircooler type, 62 modules, 12x12m2 each		
		Condensate polishing									9.4 t/h blowdown to WWT
		LP Pump									
		HP Pump									
-		~~Sea water Circulation Pumps~~							DELETED		
		Waste water treatment plant									
-		~~Sea water inlet /outlet works~~							DELETED		
		Demiwater plant								27.2 t/h raw water	24.7 t/h demi water production; 2.5 t/h blowdown to WWT
Δ		Machinery cooling water cooler	aircooler	62 MW th;	1500 kW			CS			
Δ		Machinery cooling water pumps	centrifugal	5300 m3/h x 30 m	600 kW			CS	1 pump in operation + 1 spare		

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3		
		LOCATION: SOUTH AFRICA	DATE	February 2010					
		PROJ. NAME: Water usage and loss of Power in Plants with CCS	ISSUED BY	L.So.					
		CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC					
			APPROVED BY	SA					

EQUIPMENT LIST

Unit 600 - Air Separation Unit - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
Δ		**Main air compressors**		77.9 MW					including intercoolers (aircoolers)		
		Air purification system									
		Main heat exchanger									
		ASU compander									
		ASU Column System									12 t/h water vapor vented to atm
		Pumps		0.74 MW							
		Backup storage vessel									
Δ		**ASU chiller**		36 MW th					40% bigger than in case 4.11		

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss of Power in Plants with CCS CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER			DATE	February 2010			
			ISSUED BY	L.So.			
			CHECKED BY	PC			
			APPROVED BY	SA			

EQUIPMENT LIST

Unit 700 - CO2 compression and inerts removal - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Venturi scrubber									
		Indirect contact cooler									94.6 t/h condensate from flue gas to WWT
Δ	**P-201**	**Indirect contact cooler circulation pump**		6000 m3/h x 40 m	800 kWe			casing: CS; internals: 12%Cr	two pumps in operation, one spare		
Δ		**Compressors**	centrifugal type	67.0 MWe				SS	4 stage compressor		
		Heat exchangers							heat exchanged with BFW and steam condensate		
Δ	**E-205**	**Heat exchanger**	aircooler	90 MW th	1140 kWe			tubes: SS header: CS			
Δ	**E-208**	**Heat exchanger**	aircooler	21.3 MW th	520 kWe			tubes: SS header: CS			
Δ	**E-209**	**Heat exchanger**	aircooler	11.2 MW th	296 kWe			tubes: SS header: CS			
Δ	**E-204**	**Heat exchanger**	aircooler	2.6 MW th	70 kWe			tubes: SS header: CS			
		Flue gas expander									
		Dual bed dryers									0.5 t/h water to WWT
	C-206	**First contacting column**		D=3.5 m; H=10.5 m				Shell: Alloy 20 CLAD			14 t/h water to WWT
	C-207	**Second contacting column**		D=2.7 m; H=8.1 m				Shell: SS 304L CLAD		6.1 t/h water in for scrubbing	6.1 t/h water to WWT
Δ	**E-210**	**First contacting column cooler**	aircooler	10.5 MW th	260 kWe			Tubes: Alloy 20 clad header: CS			
Δ	**E-211**	**Second contacting column cooler**	aircooler	3.5 MW th	86 kWe			Tubes: SS 304L clad header: CS			
	P-202	**First contacting column circulation pumps**		600 m3/h x 50 m	110 kW			Alloy 20	one pump in operation, one spare		
	P-203	**Second contacting column circulation pumps**		500 m3/h x 45 m	90 kW			SS 304L	one pump in operation, one spare		

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
	LOCATION: SOUTH AFRICA	DATE	February 2010			
	PROJ. NAME: Water usage and loss of Power in Plants with CCS	ISSUED BY	L.So.			
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC			
		APPROVED BY	SA			

EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Balance of Power Plant									
		Controls									
		Instruments									
		Electrics									

LEGEND:
(1) = reference shall be made to CASE 4.11; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION:	Dry land	DATE	January '09			
PROJ. NAME:	Water usage and loss of Power Plants with CCS	ISSUED BY	M.P.			
CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.			
		APPROVED BY				

EQUIPMENT LIST

Unit 800 - BoP, Electrical, I&C - USC PC Oxyfuel with CO2 capture, fed with bituminous coal, case 4.12 - DRY LAND

	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Sulphides oxidation Section									
	0800-Y1001 A/B	**Oxidation Reactor**		$S=13\ m^2$; H 2,5 m					2X50% (2op)		
	0800-MX1001 A/B/C/D	**Mixer**			0,45				4X25% (4op)		
	0800-PK1001 A/B	**H_2O_2 dosage system**		Φ=1,6 m; H=2,3 m	0,74				2X50% (about 15 day storage)		
		Softening Section									
	0800-Y1002	**Softening Reactor**		$S=1,5\ m^2$; H 2 m					1X100 (1op)		
	0800-MX1002	**Mixer**			0,18				1X100 (1op)		
	0800-PK1002 A/B	**Caustic soda dosage system**		Φ=1,5 m; H=1 m	0,36				2X50% (2op)		
	0800-PK1003	**FeCl3 dosage system**		$2\ dm^3$	0,18				1X100 (1op)		
	0800-PK1004	**polyelectrolite dosage system**		$5\ dm^3$	0,18				1X100 (1op)		
	0800-P1001 A/B	**Chemical sludge pump**	Centrifugal	0,5 mc; 0,8 bar	0,18				2X100% (1op + 1 spare)		
		Equalization Section									
	0800-Y1003	**Equalization basin**		$S=327\ m^2$; H= 5 m					1X100 (underground basin)		
	0800-P1002 A/B/C	**equalized water pump**	Centrifugal	80 mc; 2,5 bar	11				3X50% (2op + 1 spare)		
		Neutralization section									
	0800-Y1004	**Neutralization basin**		$S=4\ m^2$; H 4 m					1X100 (1op)		
	0800-MX1003 A/B	**Mixer**			0,18				2X50% (2op)		
	0800-PK1005 A/…/J	**Caustic soda dosage system**		Φ=7 m; H=9 m	0,5				10X10% (about 7 day storage		
		Clari/flocculation section									
	0800-Y1005 A/B	**Clariflocculation basin**		$S=13,3m^2$; H =4 m					2X50 % coagulation+flocculation		
	0800-MX1003 A/B/C/D	**mixer**			0,18				4X25% (4op)		
	0800-PK1006 A/B	**FeCl3 dosage system**		$60\ dm^3$	0,36				2X50% (about 15 day storage)		
	0800-PK1007 A/B	**polyelectrolite dosage system**		$120\ dm^3$	0,36				2X50% (about 15 day storage)		
		Sedimentation section									
	0800-Y1006 A/B	**Sedimentation Basin**		L=13,2 m W= 4,7; H =4 m					2 op		
	0800-K1006 A/B	**Sludge scraper**			1,1				2 op		
	0800-P1003 A/B/C	**Sludge pump**	Centrifugal	1 mc; 2 bar	0,25				3X50% (2op + 1 spare)		
		Media filtrration section									
	0800-P1004 A/B/C	**sand filter feed pump**	centrifugal	85 mc; 2 bar	11				3X50% (2op + 1 spare)		
	0800-F1001 A/…/F	**Sand filter**		Φ=2,3 m; H=2,25 m					6 op		
	0800-Y1006	**Filtered water basin**		$S=4,8\ m^2$; H= 4 m							
	0800-P1005 A/B	**backwash pump**	centrifugal	60 mc; 1,6 bar	7,5				2X100% (1op + 1 spare)		
	0800-P1006 A/B/C	**Reverse osmosis feed pump**	centrifugal	85 mc; 1,7 bar	30				3X50% (2op + 1 spare)		
	0800-X1001	**membrane filtration section**									
	include in 0800-X1001	**reverse osmosis pretreatment**		Qin=170 mc					1X100 (1op)		
		Reverse osmosis		Qin=85 mc					2X50% (2op)		
		Chemical washing packadge							2X50% (2op)		
		Reverse osmosis extraction pump	mohno	Qin=80 mc; 6 bar	11				3X50% (2op + 1 spare)		
	0800-X1002	**eluate cristallization section**									
	include in 0800-X1002	**Evaporator**		Qin~10 mc					2X50% (2op)		
		Cristalizator							2X50% (2op)		
		Fluidification pump	mohno	Qin=30 mc; 0,3 bar	18,5				2X50% (2op)		
		Dewatering		90% ss out (after cristall.)	5				2X50% (2op)		

Notes:
Present equipment list is indicateve only and related to the WWT layout selected.

APPENDIX

1. H&M Balance case 4.11

The H&M Balance highlighting the differences with respect to the reference study is attached here below.

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 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM STREAMS 1 - 10

= figure revised during the 2009 study

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 4.11 : ASC PF POWER PLANT WITH CO_2 CAPTURE : PROCESS FLOW BLOCK DIAGRAM STREAMS 11 - 20

PFD 2

= figure revised during the 2009 study

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 out	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	7.143	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 4.11 ASC PF POWER PLANT WITH CO2 CAPTURE: PROCESS FLOW BLOCK DIAGRAM STREAMS 21 - 29

PFD 2

● = figure revised during the 2009 study

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 4.11: 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
Composition - (mol%)													DELETED
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	14	15	16	17	18	19	20	21	22	23	24
Composition - (mol%)		DELETED	DELETED										
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 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 COOLING AND COMPRESSION TO 30 BAR (a) STREAMS 1 - 24

PFD 5A

● = figure revised during the 2009 study

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 4.11: 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 4.11: ASC PF POWER PLANT WITH CO_2 CAPTURE : CO_2 INERTS REMOVAL AND COMPRESSION TO 110 BAR(a)
STREAMS 1 – 26

PFD 6

● = figure revised during the 2009 study

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO_2 CAPTURE
DOCUMENT NAME : IGCC CASES, GENERAL INDEX

ISSUED BY : L. SOBACCHI
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APPROVED BY : S. ARIENTI

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IGCC CASES REPORT

I N D E X

CLIENT : IEA GHG
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SECTION A

IGCC CASES, GENEARL INFORMATION

I N D E X

1. Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage and loss of power in power plants with CO_2 capture.

The work is developed thought the establishment of a rigorous accounting of water usage throughout the power plant in order to establish an acceptable methodology that can be used to compare water usage in power plants with and without CO_2 capture. This can provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs.

Cost effective water reduction technologies that could be applied for power plants with CO_2 capture are identified. Finally, an evaluation of the performance of power plants with CO_2 capture and potential impacts on the water usage applicable to areas where water supply could be severely limited is performed.

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
These studies shall be used as a basis for present study.

In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

The purposes of the study, therefore, include:

- A review and assessment of the available information of water usage from power plants such as PC, IGCC and NGCC with or without CO_2 capture from various previous studies done for IEA GHG, based on oxyfuel, pre- or post combustion CO_2 capture technologies.
- A review and assessment of the available technologies that would allow reduction of water usage from power plants;
- An evaluation and assessment of the applicable technologies for power plants with CO_2 capture in areas where water supplies could be severely limited.

The study is based on the current state-of-the-art technologies, evaluating costs and performances of plants which can be presently engineered and built.

Present report #4 analyses the Integrated Gasification Combined Cycle (IGCC) cases without and with CO_2 capture and without and with limitation on water usage.

The following four different alternatives are therefore evaluated:

- Case 5.05: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4-19 – Case C1, dated May 2003.
- Case 5.06: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (wet land case). This case is based on IEA GHG study number PH4-19 – Case D1, dated May 2003.
- Case 5.07: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (dry land case).
- Case 5.03: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (dry land case).

For each of the above mentioned cases the following technical information are provided:

- ✓ Description and process schemes for each section of the plant;
- ✓ Mass and mole flowrates, temperature, pressure, energy content and composition of the main process streams within the plants;
- ✓ Detailed water flow diagram;
- ✓ Detailed water balance of the major section of the plant;
- ✓ Breakdown of the ancillary power consumptions;
- ✓ Breakdown of the major plant equipment;
- ✓ Breakdown of the water consumptions;
- ✓ Specific fuel consumption per MW net produced;
- ✓ Specific emission of CO_2 per MW net produced;
- ✓ Specific water consumption per MW net produced.

2. Project design bases

The Power Plants are designed to process, in an environmentally acceptable manner, a coal from eastern Australia and produce electric energy to be delivered to the local grid.

2.1. Feedstock specification

The feedstock characteristics are listed hereinafter.

2.1.1. Design Feedstock

	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. Back-up Fuel

	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 plant are listed here below with their specifications.

2.2.1. Electric Power

Net Power Output:	750	MWe	nominal capacity
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:	32 °C

Purity:

CO_2:	> 99% mol
Moisture:	<10 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.

Capture rate : 85% (as per reference study).

2.2.3. Sulphur

The Sulphur characteristics at 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. Solid By-products

The plant produces slag as solid by-products that is potentially saleable to the building industry.

2.3. Environmental Limits

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

2.3.1. Gaseous Emissions

The overall gaseous emissions from the plant referred to dry flue gas with 6% volume O_2 shall not exceed the following limits:

NOx (as NO_2):	≤	80	mg/Nm^3
SOx (as SO_2):	≤	10	mg/Nm^3
CO:	≤	50	mg/Nm^3
Particulate :	≤	10	mg/Nm^3

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 from the plant is the sea cooling water return stream (for wet land cases only).

The 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 plant produces as solid waste a filter cake that contains toxic compounds and shall be disposed.
Other potential solid waste are typical industrial plant waste e.g. (sludge from WasteWater Treatment etc.). However the wastewater sludge is recovered and recycled back to the Gasification Island to be processed by the Gasifiers

2.4. Plant Operation

2.4.1. Capacity

For all the cases the nominal design capacity is 750 MWe.

The gasification capacity, i.e. the coal flow rate of the IGCC Complex has been fixed to match the appetite of the selected gas turbines which are two General Electric Frame 9FA. As a consequence, the net power output of the plants is different due to the different auxiliary consumptions for the cases with and without CO_2 removal.

For the dry land cases, the fuel input has been kept constant as the relevant reference case. Plant gross power output and auxiliary consumptions are affected by the dry land design and therefore the resulting net power output of each dry land case is significantly lower than the relevant reference case.

Looking at the Gas Turbine, the slightly higher ambient temperature of dry land cases with respect to the wet land cases should impact on machine performance.
GT gross power output should result slightly reduced as well as the GT appetite that should be reduced by approximately 2%.
Nevertheless, the appetite of GT and consequently the gasification capacity has been kept constant in order to see clearly the impact of the dry land design on performance and costs of the IGCC without the additional impact of the ambient temperature. The results of this study can be used, therefore, to evaluate the penalties on plant performance and the investment cost increase due to the limitations on water usage. These limitations can derive from ambient reasons (dry land design) or from political reasons that can force to the limitation on water consumption.
For the same reasons, also the overall GT performance, gross power output and flue gas characteristics in the dry land cases have been kept constant to the wet land figures.

In accordance with reference study, a minimum equivalent availability of 85% corresponding to 7,446 hours of operation in one year at 100% capacity is assumed for the alternatives without and with CO_2 capture starting from the second year of commercial operation.
During the first year of commercial operation, when the plants need final tunings, the equivalent availability will be lower than the normal one (i.e.: 45%, corresponding to 3,940 hours).
Same load factor is considered for the plants without and with CO_2 capture as the capture unit is conceptually the same in the cases with and without CO_2 capture and no significant more complexity is added.

It has been assumed that the dry land design does not have any impact on plant load factor.

2.4.2. Unit Arrangement

Based on the configuration shown in the reference studies, the plants have the following 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

2.4.3. Turndown

The IGCC Complex is designed to operate with a large degree of flexibility in terms of turndown capacity and feedstock characteristics.

The Gasification Unit is composed of four gasifiers, thus allowing to operate at low loads with respect to the IGCC design capacity, the 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. This ensures a large availability of syngas production, at least at reduced load, which ensures a high power production by co firing syngas and natural gas in the gas turbines and a high hydrogen production.

The minimum turndown of each Gas Turbine on syngas is 20% as far as electrical generation is concerned, this corresponding to 10% of the IGCC capacity. The minimum turndown of the Power Island when all the machines are in operation (two Gas Turbines and one Steam Turbine) is about 25% of the IGCC capacity. This figure should be verified with GT emissions at reduced load.

In conclusion, even if the IGCC complex operation at 25% load is a necessary step of the start-up procedure, its duration has to be limited. In fact, during the prolonged continuous operation, the load is expected to be 35%.

2.5. Location

Reference cases – wet land
The site for the reference cases, wet land, is a green field located 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 harbor equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

Dry land cases
The site for dry land cases is a green field located in a dry in land region in South Africa.

The plant area is assumed to be close to a river. Coal transport is assumed to be assured by rail connection.

No special civil works implications are assumed.

2.6. 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
  Reference cases – wet land
  minimum air temperature: -10 °C

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

Dry land cases

minimum air temperature:	2	°C	
maximum air temperature:	30	°C	
average air temperature:	14	°C	(*)

2.7. Software Codes

For the development of the Study, two software codes will be mainly used:

- 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 all the units included in the plant to be built on the east coast area of Netherlands for the wet land cases and in an in-land area in South Africa for the dry land cases.

The plant is constituted by the following groups of units:

Process Units:
- 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 services and utility fluids to all the units of the plant; including:
- 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;
- Solid (Slag & Filtercake) Handling;
- Sulphur Storage and Handling;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical, 380 kV substation).

3.1. Units of Measurement

All calculations are and shall be in SI units, with the exception of piping typical dimensions, which shall be in accordance with ANSI.

3.2. Climatic and Meteorological Information

Reference is made to paragraph 2.6 for main data.

Other data:

<u>Sea water supply temperature and salinity</u> (for reference cases, **wet land**, only)

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:

- Coal;
- Natural gas;
- Sea water supply (for reference cases, **wet land**, only);
- Sea water Return (for reference cases, **wet land**, only);
- Plant/Raw/Potable water;
- Sulphur product;
- CO_2 rich stream.

3.4. Utility and Service fluids characteristics/conditions

In this paragraph are listed the utilities and the service fluids distributed inside the Plant.

3.4.1. Cooling Water

Reference cases – wet land

The plant primary cooling system is sea water 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 and drying exchangers, 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 and drying 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

Dry land cases

No primary cooling water is available at all. Air is used as primary cooling medium. The temperature difference considered between the inlet condensing steam and the ambient air in the steam condenser is 25 °C.

Machinery Cooling Water (secondary system)

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

Supply temperature:

- max supply temperature: 35 °C
- normal supply temperature: 25 °C
- max allowed temperature increase: 10 °C
- design return temperature for fresh cooling water cooler: 45 °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

Steam

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

Table B.3.1 – 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:	(*)	
Design pressure:	22.8	barg
Design temperature:	130	°C
Fouling Factor:	0.0002	h °C m2/kcal

(*) Depending on the process alternative.

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 B.3.2 – 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

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

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

The Oxygen for the gasification unit has the following characteristics:

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

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 International and EU Standard Codes.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : GEE IGCC WITHOUT CCS, REFERENCE CASE – CASE 5.05

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

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March 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
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SECTION B

GEE IGCC WITHOUT CCS, REFERENCE CASE
I N D E X

1. Introduction

The present case 5.05 refers to a GEE IGCC power plant, fed with bituminous coal and not provided with CO_2 capture unit.

The IEA GHG study number PH4-19, May 2003, has been taken as a reference for the configuration and performances of the plant here analysed. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The main features of the GEE IGCC plant, case 5.05, are:

- High pressure (65 bar g) GEE Gasification (Texaco in reference study);
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- No CO Shift and CO_2 removal.

The removal of acid gas (AGR) 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	
	Gasifiers	4 x 33%
	Other sections	2 x 66%
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
	Syngas Expansion	1 x 100%
2300	AGR	1 x 100%

2400	SRU	2 x 100%
	TGT	1 x 100%
3000	Gas Turbine (PG – 9351 - FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

2. Process Description

2.1. Overview

The IEA GHG study number PH4-19, May 2003, has been taken as a reference for the plant description and configuration.

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

Case 5.05 is an IGCC power plant, based on GEE gasification technology, fed with bituminous coal and not 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, which are described briefly hereinafter:

- Coal Grinding/Slurry Preparation
- Gasification
- Slag Handling
- Black Water Flash
- Black Water Filtration

The following description refers to a single train.

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.

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 oC) 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.

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.

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.

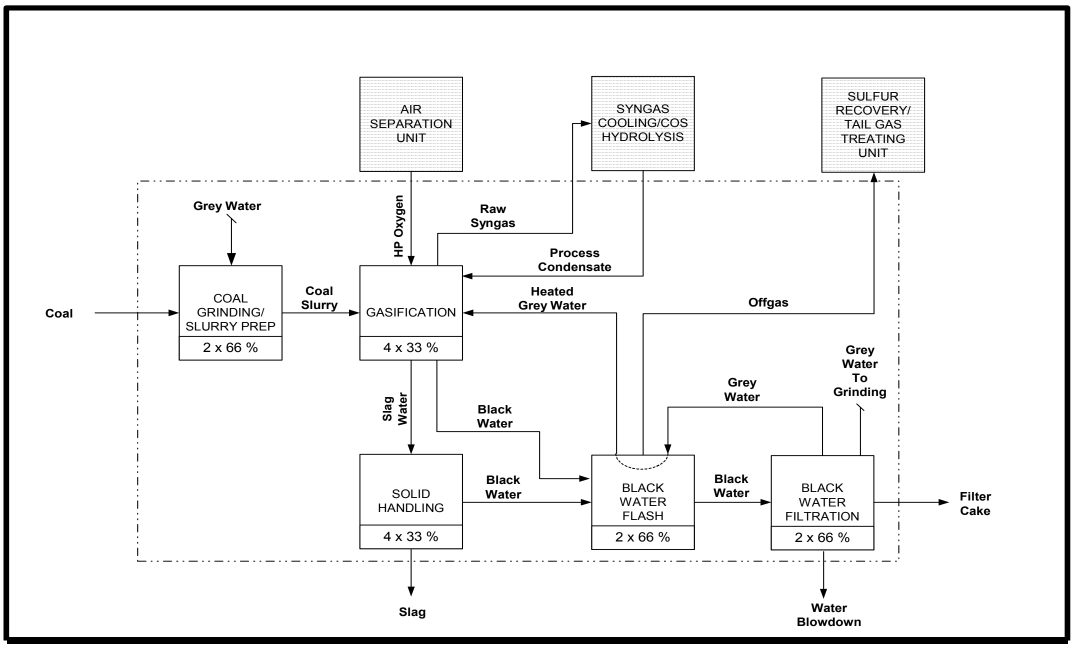
Black Water from the Gasifier quench chamber and the Syngas Scrubber is first routed to the LP Flash Drum. The overhead vapor is first used to heat the grey water return from the Black Water Filtration Section before it is condensed by the LP Flash Condenser. Then, both of the vapor and condensate are 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.

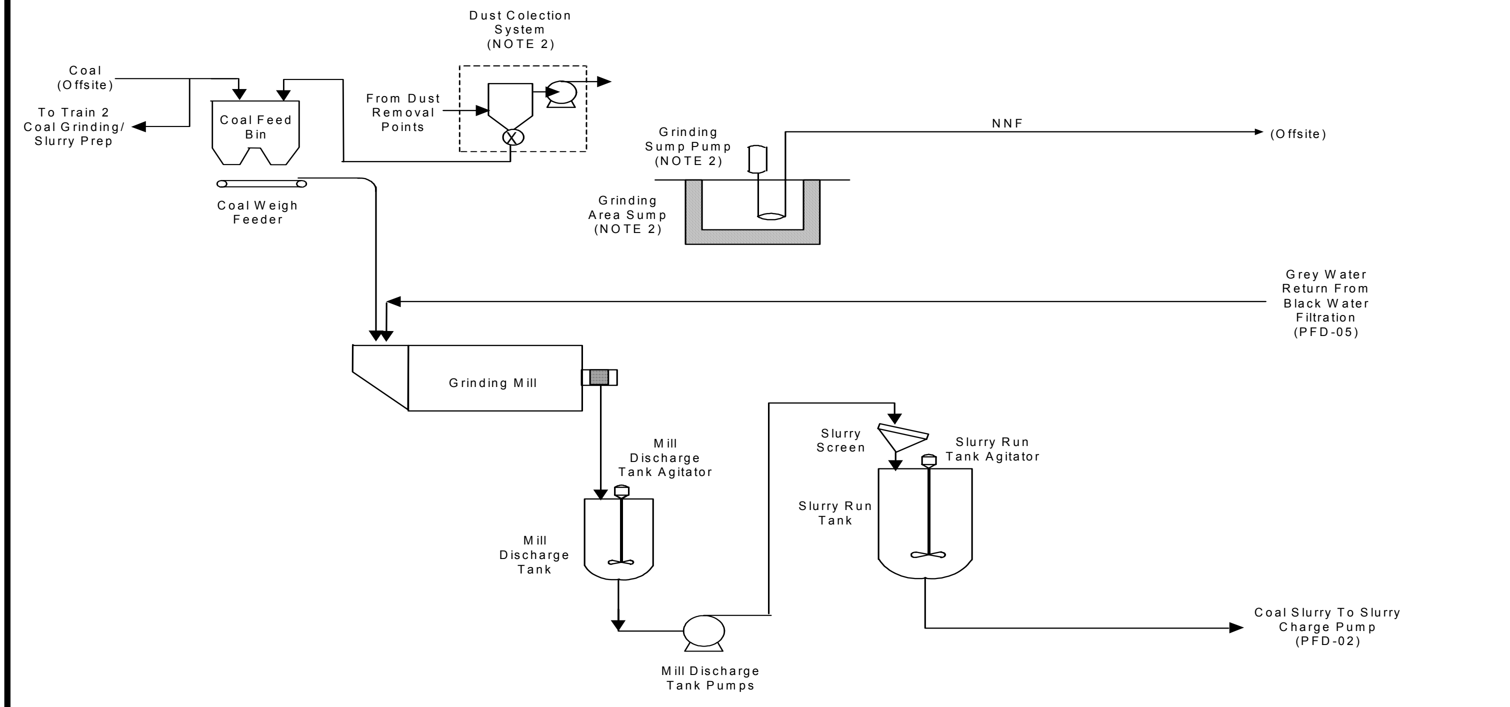
Black Water Filtration

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.

FIGURE 1
PROCESS SCHEME FOR GEE IGCC CASES w/o CO_2 CAPTURE





TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

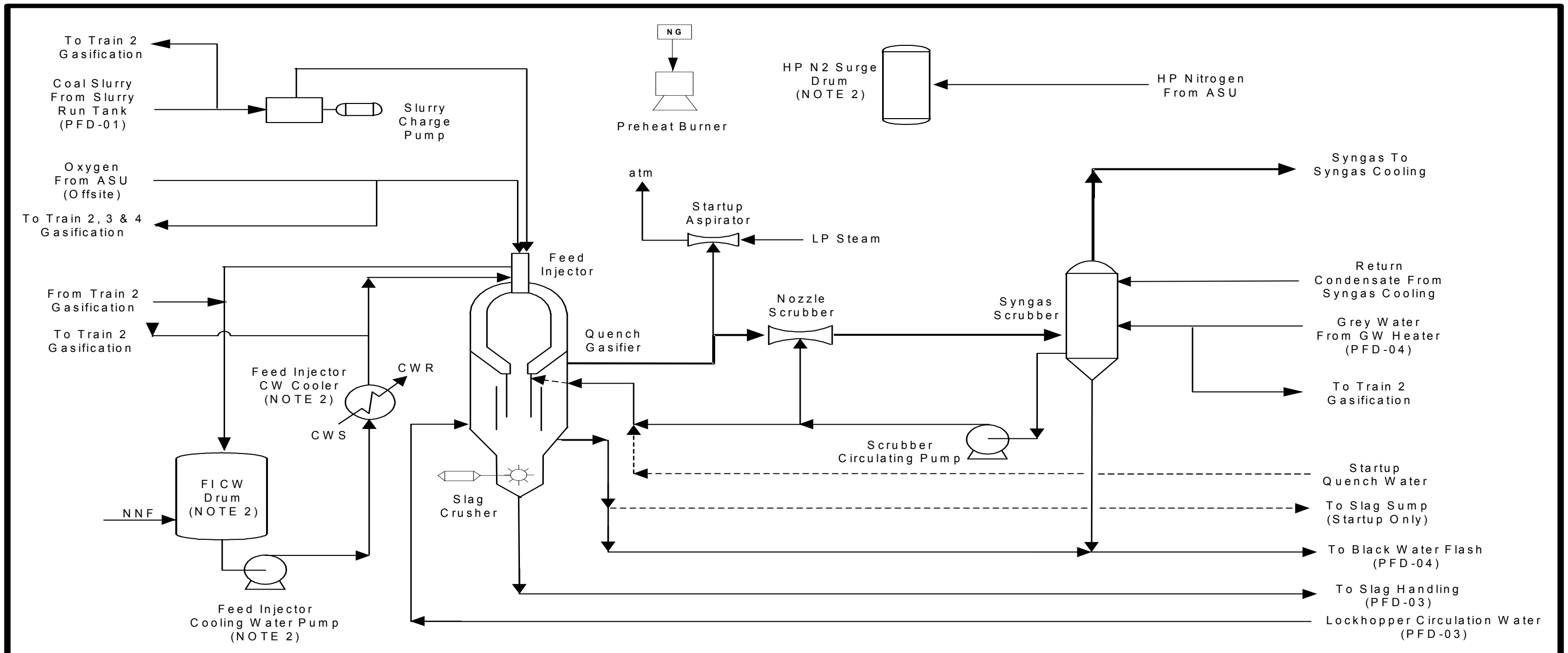
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

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:

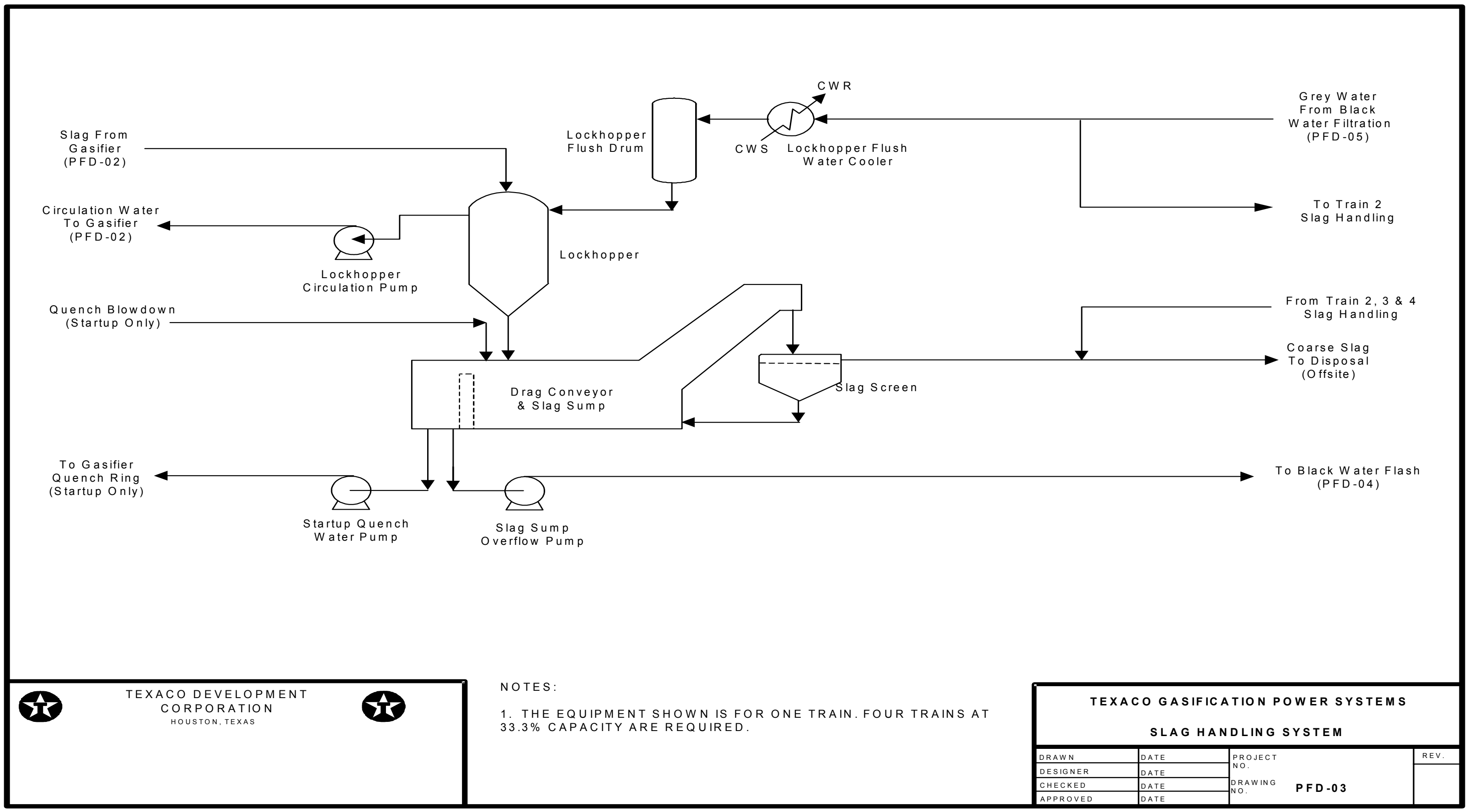
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. FOUR TRAINS AT 33.3% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

2. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED FOR HP N2 SURGE DRUM, FICW DRUM, FICW PUMP, AND FICW COOLER.

TEXACO GASIFICATION POWER SYSTEMS

GASIFICATION SECTION

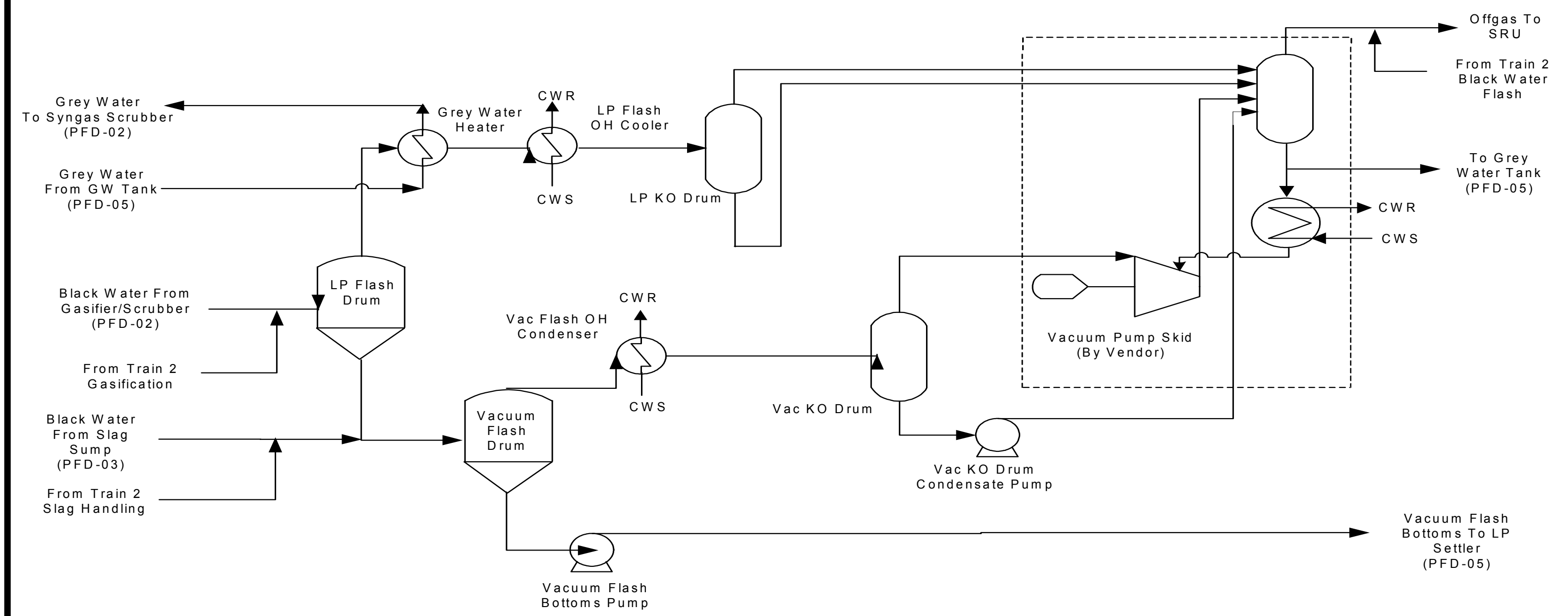
DRAWN	DATE	PROJECT NO.		REV.
DESIGNER	DATE			
CHECKED	DATE	DRAWING NO.	PFD-02	
APPROVED	DATE			


CWR
Grey Water
From Black
Water Filtration
(PFD-05)
Slag From
Gasifier
(PFD-02)
Lockhopper
Flush Drum
CWS
Lockhopper Flush
Water Cooler
Circulation Water
To Gasifier
(PFD-02)
To Train 2
Slag Handling
Lockhopper
Lockhopper
Circulation Pump
Quench Blowdown
(Startup Only)
From Train 2, 3 & 4
Slag Handling
Coarse Slag
To Disposal
(Offsite)
Drag Conveyor
& Slag Sump
Slag Screen
To Gasifier
Quench Ring
(Startup Only)
To Black Water Flash
(PFD-04)
Startup Quench
Water Pump
Slag Sump
Overflow Pump
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
DESIGNER
CHECKED
APPROVED
DATE
DATE
DATE
DATE
PROJECT
NO.
DRAWING
NO.
PFD-03
REV.

IEA GHG

Revision no.: 1
Date: November 2010

Water usage and loss Analysis in plants without and with CCS
Volume #4 - Section B – GEE IGCC without CCS, reference case



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

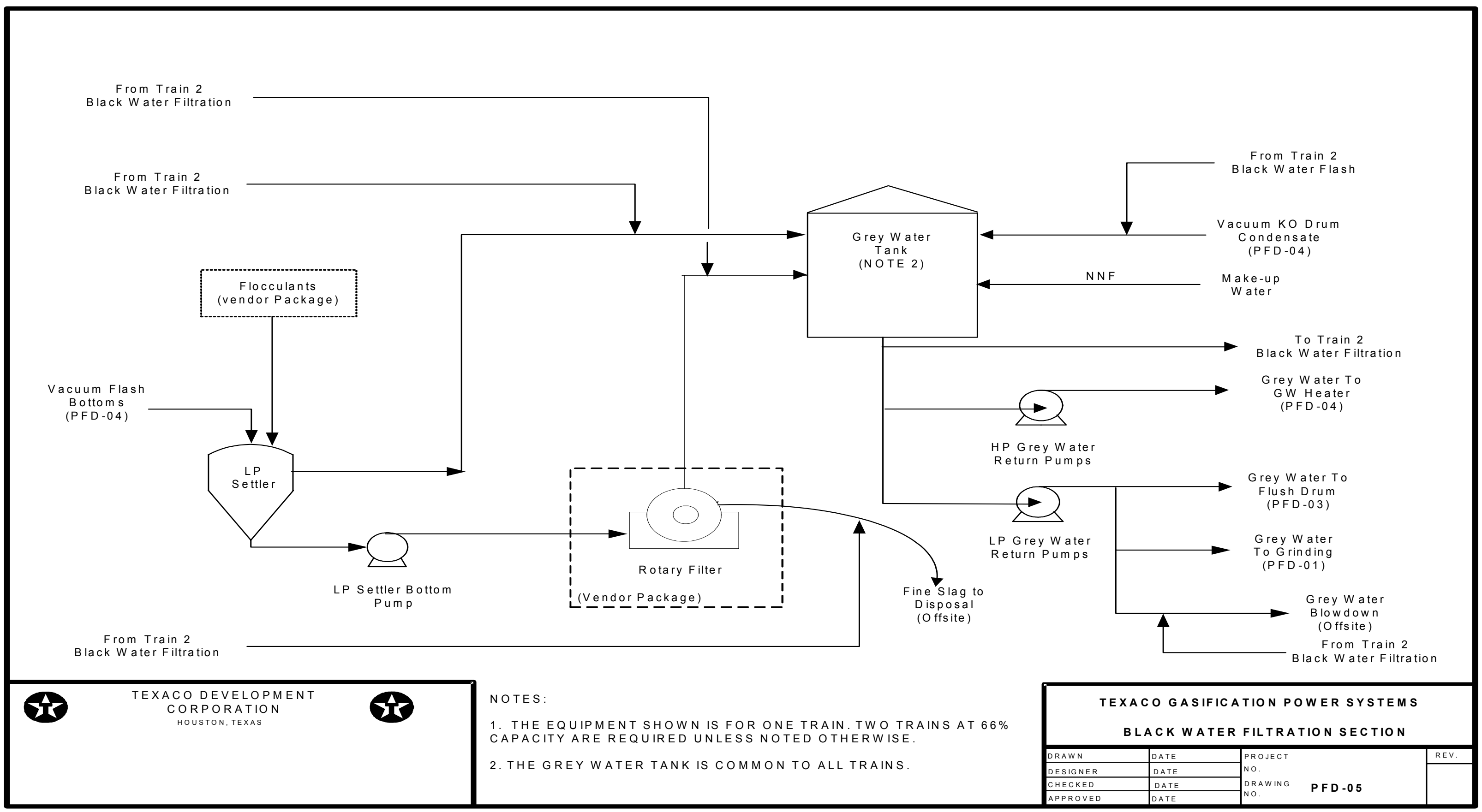
NOTES:

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
Grey Water To
GW Heater
(PFD-04)
Vacuum Flash
Bottoms
(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.

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 2.3.1 are produced according to the requirement of GEE technology.

Table 2.3.1

	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 and for solvent stripping in AGR
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

This Unit receives the raw syngas from the gasification section, which is hot, humid and contaminated with acid gases, CO_2 and H_2S, and other chemicals, mainly COS, HCN and NH_3.
Before using this syngas as fuel in the gas turbines it is necessary to remove all the contaminants and prepare the syngas at the proper conditions of temperature, pressure and water content in order to achieve in the combustion process of the gas turbine the desired environmental performance and stability of operation.

In order to follow the process description of this Unit, reference should be made to the Process Flow Diagram attached to the next paragraph 3.
Saturated raw syngas from Unit 1000, at approximately 240°C and 62 bar g enters Unit 2200. First is cooled in the LMP Steam Generator E-2201, producing 20 bar LMP steam.
After condensate separation syngas is cooled in the LP Steam Generator E-2202 and in the VLP Steam Generator E-2003. Process condensate, separated after each of these cooling steps is collected, under level control, in the high pressure process condensate accumulator D-2206, from where it is pumped back to the syngas scrubber in Unit 1000.
Raw syngas is reheated in E-2204 with the hydrolysis effluent and in E-2205 with LMP steam, before entering the hydrolysis reactor R-2201, converting COS to H_2S.
The reactor effluent is further cooled in E-2204 and E-2206, where VLP steam is generated. Finally raw syngas is cooled in E-2207 A/B where cold condensate is preheated for heat recovery Process Condensate. Part of the process condensate separated after E-2206-E-2207A/B, being heavily contaminated, is sent to Unit 4000, Sour Water Stripper.
Up to this point Unit 2200 is split in two parallel streams, each sized for 50% capacity of the total syngas flow, because of the size limitation of the exchangers involved. Downstream D-2205 Unit 2200 is a single line for 100% capacity.
Cold syngas goes to Unit 2300 and returns to Unit 2200, as clean syngas, after H_2S removal. Clean syngas is preheated in E-2208 with VLP steam and then reduced in pressure, down to 25 bar g in the Expander EX-2201, generating electric energy.
Expanded clean syngas is mixed with LP purified syngas from Unit 2300 and, after preheating with VLP and LP steam in E-2209 and E-2210, flows 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 5.05, this Unit utilises Selexol as acid gas solvent (physical solvent). A single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit is considered.

Unit 2300 is characterised by a high syngas pressure (54 bar g) and a high CO_2/H_2S ratio (60/1).

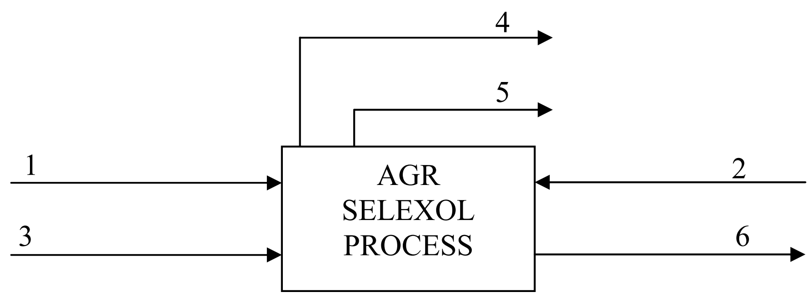
The interfaces of the Selexol process with the other Units are the following, as shown in the Process Flow Diagram attached to paragraph 3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Unit
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit
3. Nitrogen from ASU

Exit Streams

4. Treated Gas to Expander
5. Treated Gas to Gas Turbines
6. Acid Gas to Sulphur Recovery Unit



The Selexol solvent consumption, to make-up losses, is 85 m^3/year.
The proposed process matches the process specifications with reference to H_2S-COS concentration of the mixed streams of treated gas exiting the Unit. In fact, the first stream has an H_2S+COS concentration of 33 ppm, the second one of 57 ppm. After the expander the two streams are mixed before entering the gas turbine and the H_2S+COS concentration of the resulting stream is 36 ppm.

CO_2 slippage with respect to expansion through the gas turbine is virtually 100% and even CO_2 derived from the other minor acid streams fed to the SRU is recovered. A smaller CO_2 quantity flows through the expander.

The acid gas H_2S concentration is 30% dry basis, more than suitable to feed the oxygen blown Claus process.

The only disadvantage of the proposed process is the Nitrogen use, which requires some modifications to the ASU design with the production of the required Nitrogen quantity at a higher purity, higher pressure with respect to the Nitrogen stream fed as diluent into the gas turbine. This will increase the investment cost and the electric consumption of the ASU, but these impacts can be recovered by the feasible and less expensive design of the SRU.

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 having a normal sulphur production of 61.9 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, CS2 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 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 5.05 the integration between the Process Units and the Power Island consists of the following interfaces:

- Compressed Air : air extracted from the Gat 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 (85 barg) : steam exported to the Gasification Island users
- LMP steam (20 barg) : steam imported from Syngas Treatment and Conditioning Line. A small quantity is also generated in the Sulphur Recovery Unit. This steam is superheated in a dedicated coil inside the HRSG and further fed to the Steam Turbine.
- 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 : 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 Treatment and Conditioning Line and recycled back to the HRSG.

Because of the optimisation of the heat integration, HP and MP steam in the HRSG is generated at different pressure with respect to the Process Units. Generation levels inside the Power Island are listed here in after:

- HP steam : 160 barg
- MP steam : 40 barg
- LP steam : 6,5 barg

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;
- LMP Superheater;
- 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 LMP Superheated Steam and delivered to the LMP 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 Superheated LP Steam is mixed to the LMP Module of Steam Turbine exhaust and flow to the LP Module.

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.

2.8. 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

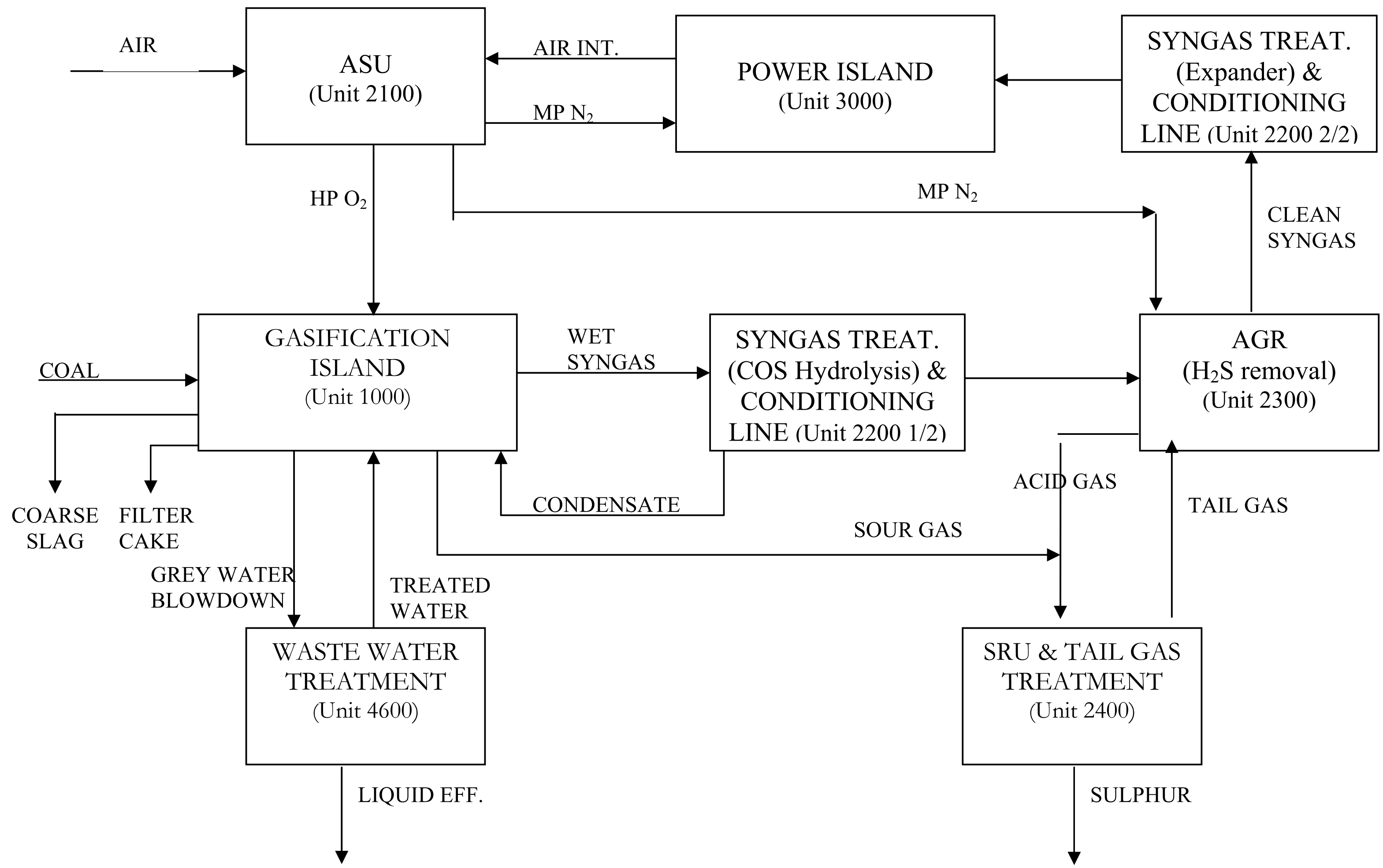
3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagrams of the GEE IGCC, Case 5.05, and the schematic Process Flow diagram of Units 2100, 2200, 2300, 2400 and 3000 are attached hereafter.

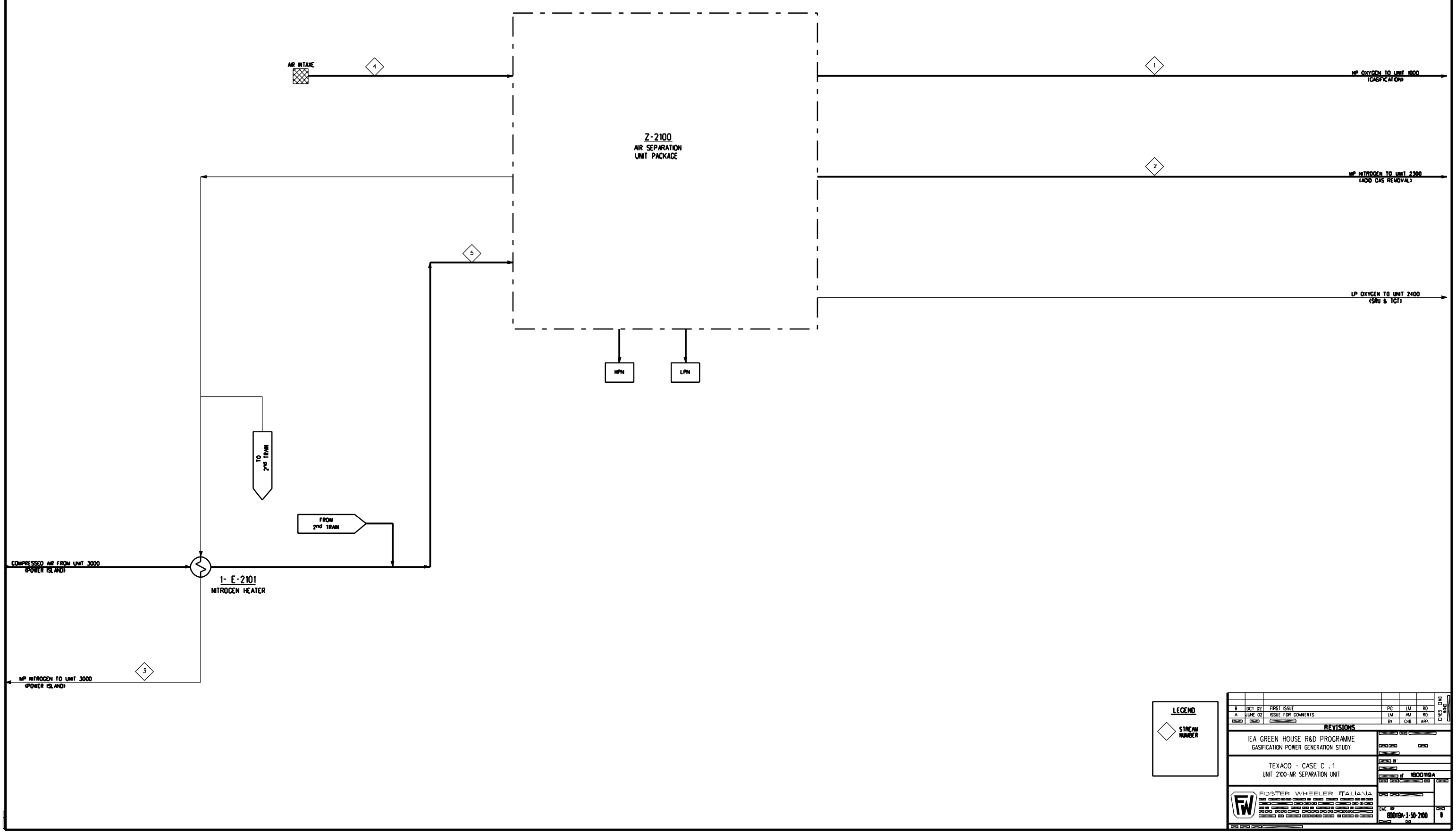
The IEA GHG study number PH4/19, May 2003, has been taken as reference for the plant Block Flow Diagrams and Process Flow diagram attached.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

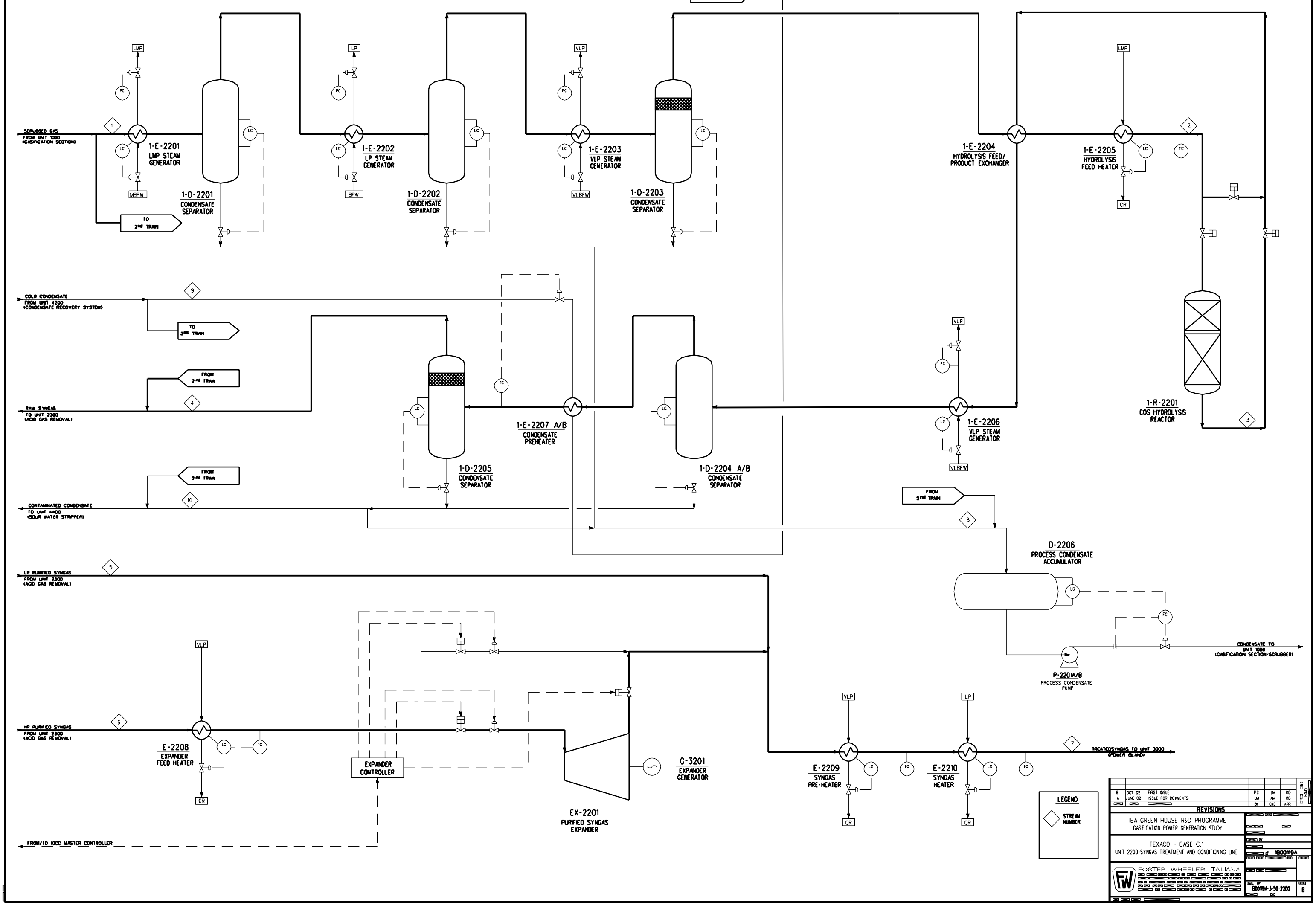
GEE 5.05 – IGCC COMPLEX BLOCK FLOW DIAGRAM



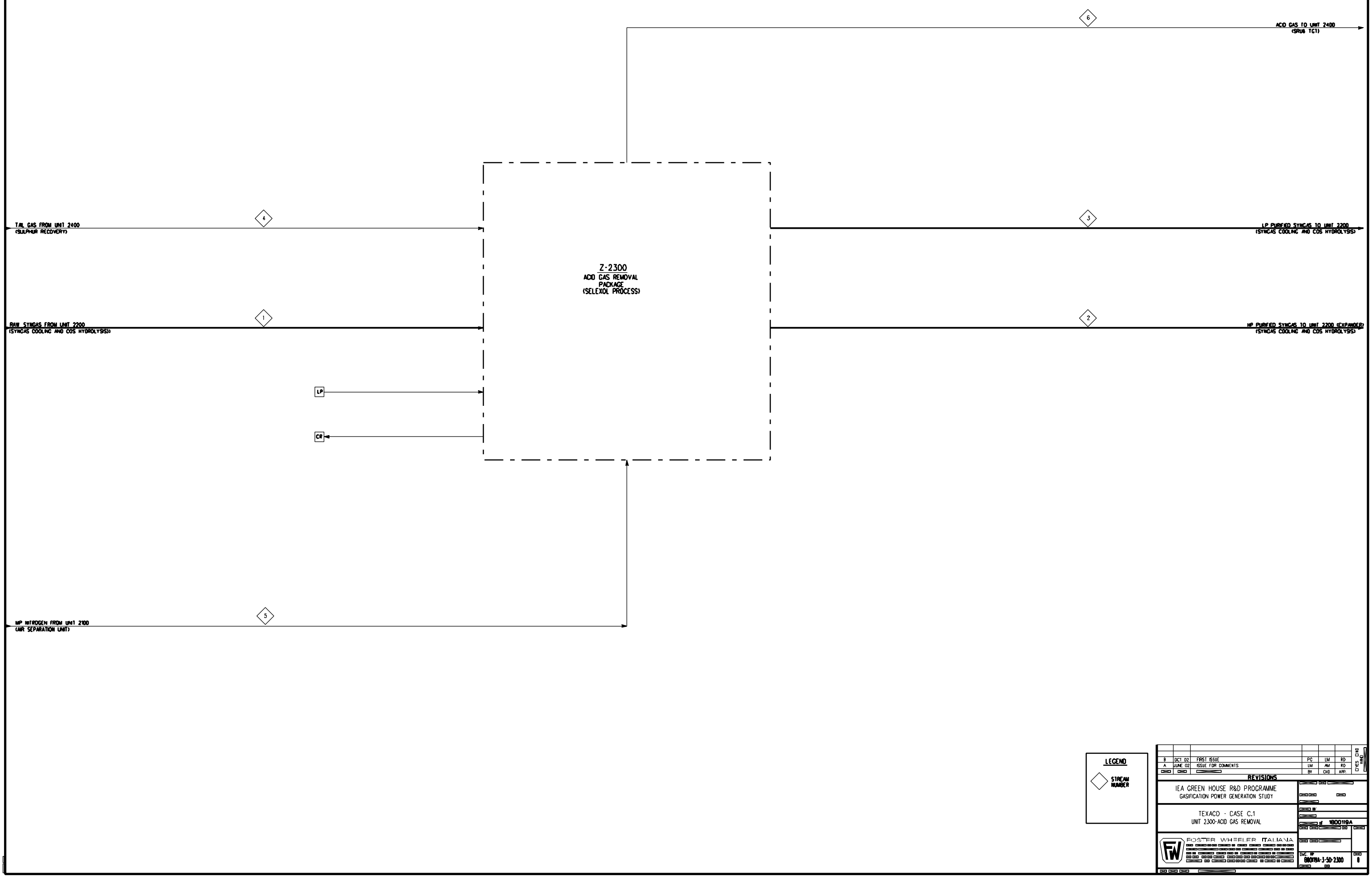
Case 5.05 - GE IGCC without CCS



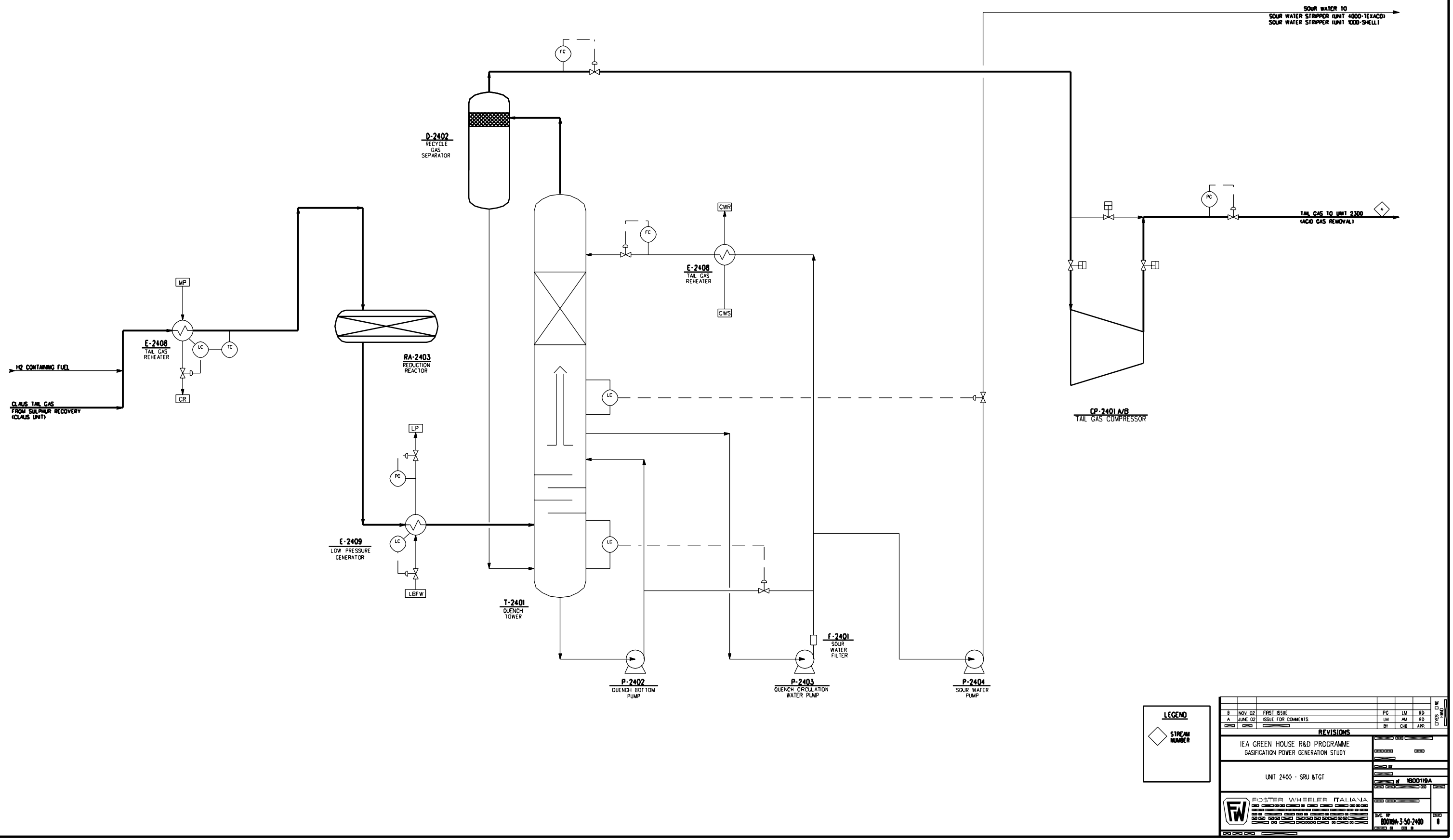
Case 5.05 - GE IGCC without CCS



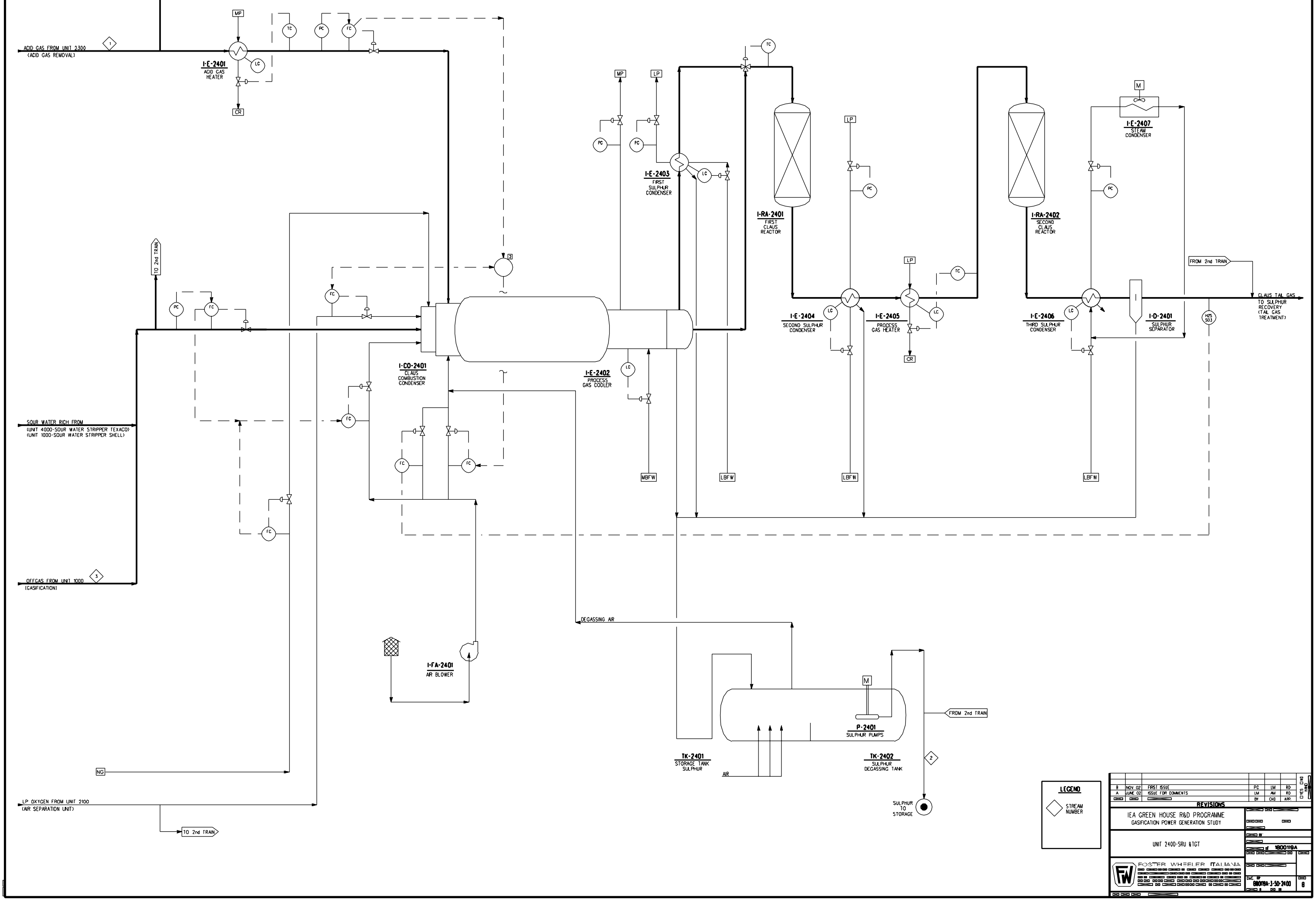
Case 5.05 - GE IGCC without CCS



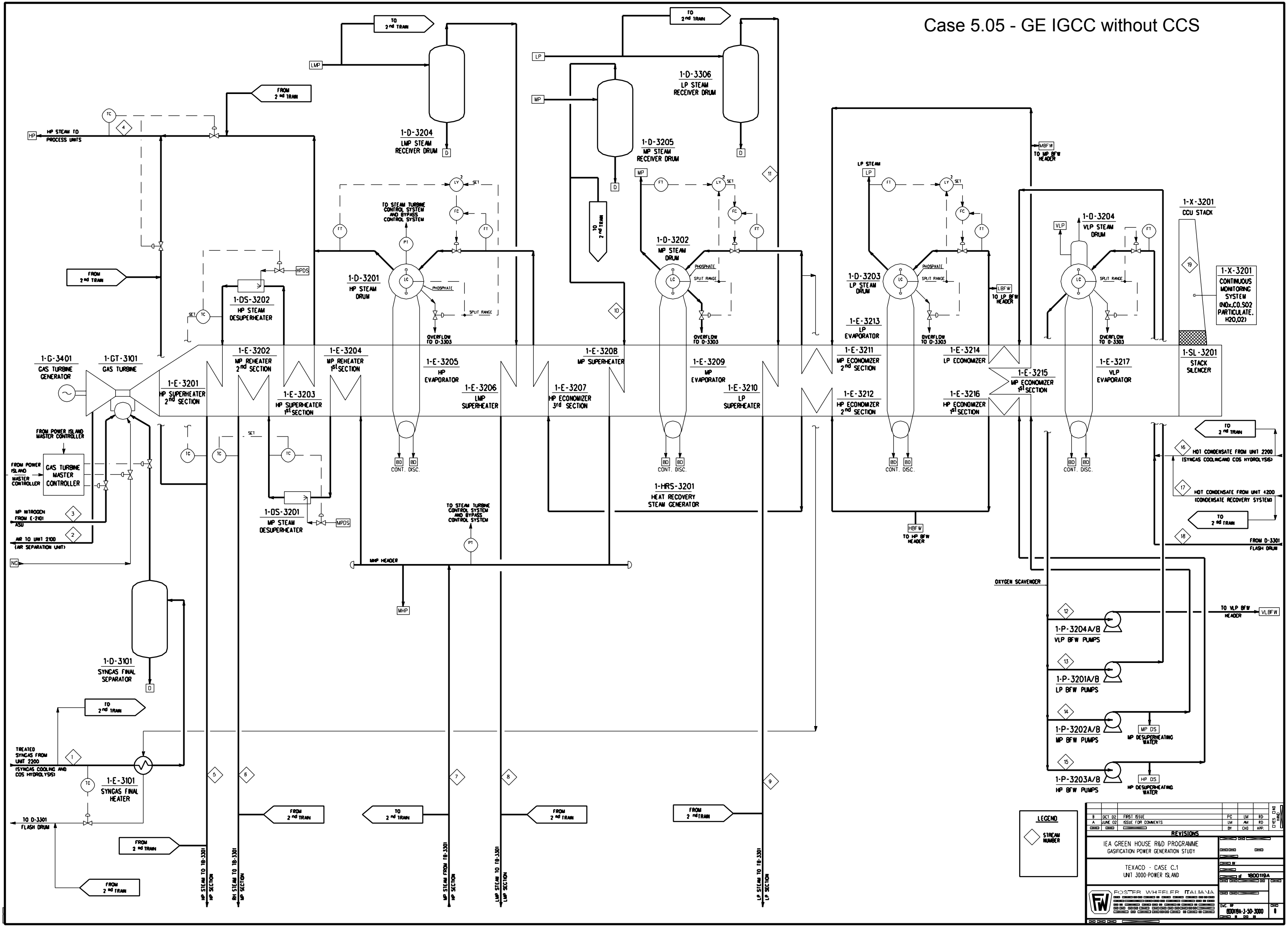
Case 5.05 - GE IGCC without CCS



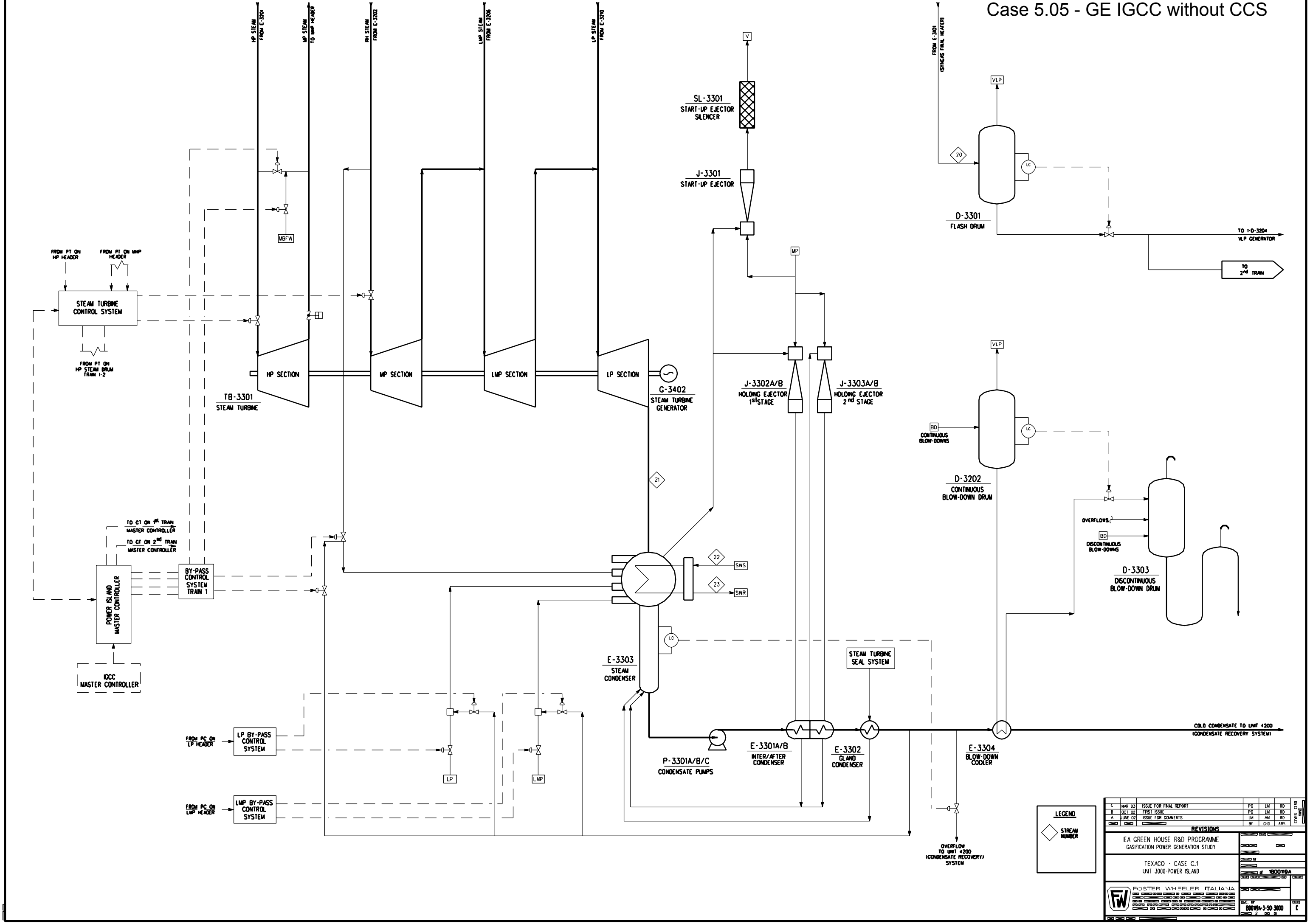
Case 5.05 - GE IGCC without CCS



Case 5.05 - GE IGCC without CCS



Case 5.05 - GE IGCC without CCS



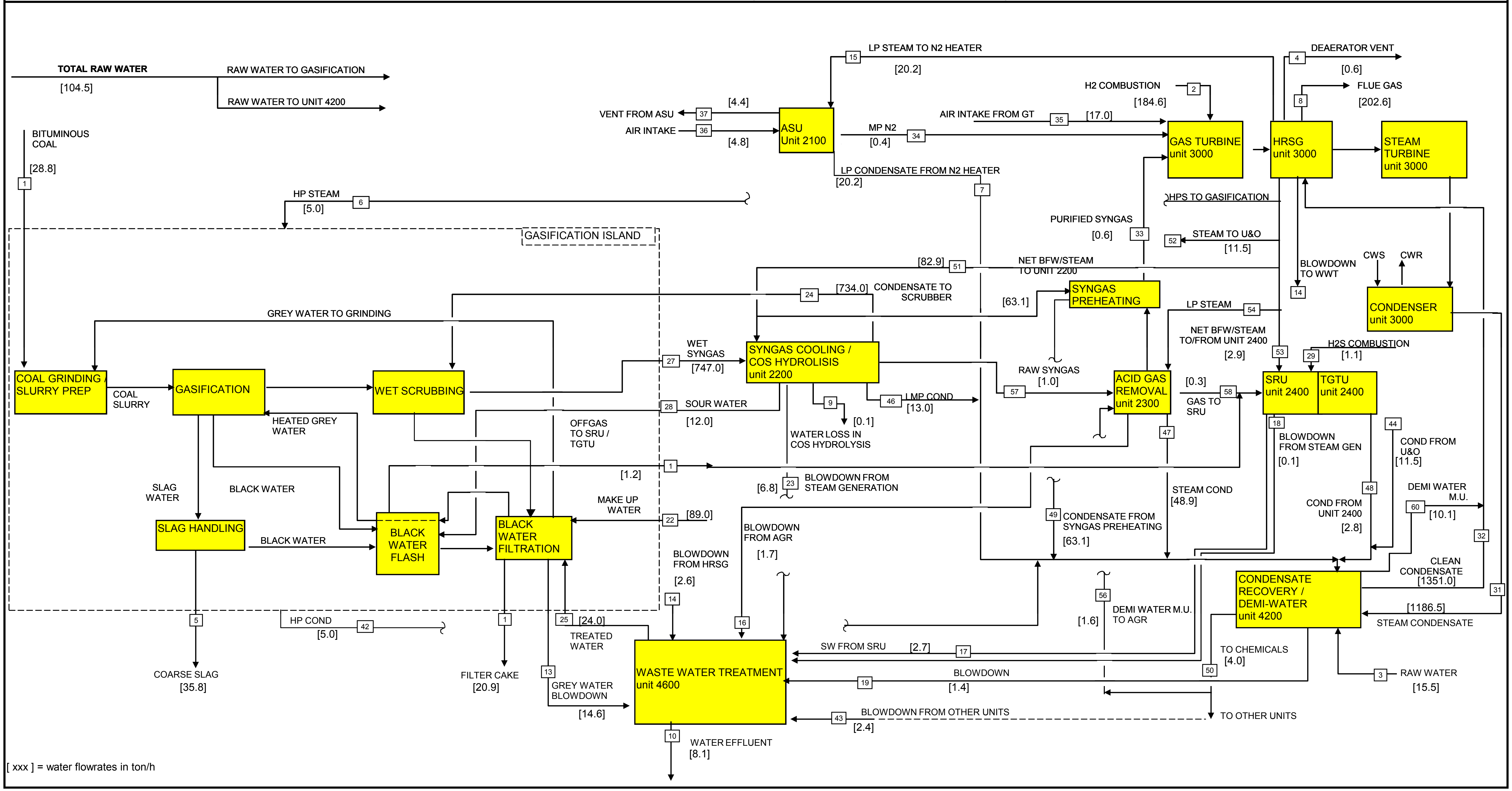
4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

- detailed water Flow Diagram relevant to the entire power plant;
- water balance around the major units.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

CASE 5.05 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 826.5 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



GEE IGCC fed by bituminous coal, w/o CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	28.8	5	Slag	35.8
2	Syngas combustion of H2 in GT	184.6	4	Deaerator vent	0.6
3	Raw water to Demi Plant	15.5	11	Filter cake	20.9
36	Moisture in air to ASU	4.8	8	Flue gas from GT	202.6
29	H2S combustion in SRU	1.1	9	Water loss in COS hydrolysis	0.1
35	Moisture in combustion air to GT	17.0	10	Water effluent from WWT	8.1
22	Raw Water make up to Gasific.	89.0	37	Moisture from ASU vent	4.4
Total		340.9	Total		272.4

delta (note 1)
68.4

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Gasification Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	28.8	11	Filter cake	20.9
28	Sour Water to Stripping	12.0	5	Slag	35.8
24	Condensate to Wet Scrubber	734.0	27	Wet syngas	747.0
22	Make up to Grey Water Tank	89.0	12	Sour Gas	1.2
25	Treated water from WWT	24.0	13	Grey Water Blowdown	14.6
6	HP steam	5.0	42	HP condensate	5.0
Total		892.8	Total		824.4

delta (note 1)
68.4

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around WWT (unit 4600)

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
13	Grey Water Blowdown	14.6	25	Treated water to Gasifier	24.0
14	Blowdown from HRSG	2.6	10	Water effluent from WWT	8.1
43	Blowdown from other units	2.4			
16	Blowdown from AGR	1.7			
17	Sour water from SRU	2.7			
18	Blowdown from SRU	0.1			
19	Blowdown from Demi Plant	1.4			
23	Blowdown from unit 2200	6.8			
Total		32.2	Total		32.2

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Cond Recovery/Demi Water Plant

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
3	Raw Water	15.5	32	Demi Water to HRSG and PRS ur	1351.0
31	Condensate from Steam Turbine	1186.5	19	Blowdown to WWT	1.4
44	Condensate from U&O	11.5	50	Demi water to chemicals	4.0
6	Condensate from Gasification	5.0	60	Demi water make up	10.1
7	Condensate from unit 2100	20.2			
46	Condensate from unit 2200	13.0			
47	Condensate from unit 2300	48.9			
48	Condensate from unit 2400	2.8			
49	Condensate from syngas preheating	63.1			
Total		1366.5	Total		1366.5

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Power Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	17.0	8	Flue gas from GT	202.6
2	Syngas combustion of H2 in GT	184.6	6	HP steam to Gasification	5.0
33	Water in syngas	0.6	52	Steam to U&O	11.5
34	Moisture in MP nitrogen from ASU	0.4	51	Net BFW/LMP steam to unit 2200	82.9
32	Clean condensate to HRSG	1351.0	54	MP steam to unit 2300	48.9
60	Demi water make up	10.1	53	Net BFW/Steam to unit 2400	2.9
			14	Blowdown from HRSG	2.6
			15	LP steam to N2 saturator HE	20.2
			31	Steam condensate from CCU	1186.5
			4	Deaerator vent	0.6
Total		1563.7	Total		1563.7

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around GT - HRSG

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	17.0	8	Flue gas from GT	202.6
2	Syngas combustion of H2 in GT	184.6			
33	Water in syngas	0.6			
34	Moisture in MP nitrogen from ASU	0.4			
Total		202.6	Total		202.6

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around unit 2200

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
27	Wet syngas	747.0	24	Condensate to scrubber	734.0
51	Net BFW/LMP steam to unit 2200	82.9	46	LMP condensate	13.0
			9	Water lost to hydrolysis	0.1
			28	Sour water	12.0
			23	Blowdown from steam gen.	6.8
			57	Raw syngas	1.0
			49	Condensate from syn. preheat.	63.1
Total		829.9	Total		829.9

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around AGR

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
57	Raw Syngas	1.0	58	Gas to SRU	0.3
56	Demiwater make up	1.6	33	Purified syngas	0.6
54	MP steam	48.9	47	Steam condensate	48.9
			16	blowdown from AGR	1.7
Total		51.5	Total		51.5

NOTE 1: Water balances around gasification island and around the entire Power Plant don't close to zero by the same amount. The difference between the streams of "water in" and "water out" is due to the shift reactions, occuring in the gasification island.

5. 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.

The IEA GHG study number PH4/19, May 2003, has been taken as reference for the plant H&M balance attached.

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GE CASE 5.05						APPROVED	SA		
	UNIT : 2100 AIR SEPARATION UNIT						DATE	Feb 2010		
STREAM	1	2	3	4	5					
	HP OXYGEN to Gasification	MP NITROGEN to AGR	MP NITROGEN to one GT	Air Intake from Atmosphere	AIR to ASU from GTs					
Temperature (°C)	148.9	149	213	AMB.	232					
Pressure (bar)	79.8	27	22.1	AMB.	14.1					
TOTAL FLOW										
Mass flow (kg/h)	261351	33600	362996	570972	570972					
Molar flow (kgmole/h)	8111	1200	12927	19791	19791					
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	261351	33600	362996	570972	570972					
Molar flow (kgmole/h)	8111	1200	12927	19791	19791					
Molecular Weight	32.22	28.00	28.00	28.87	28.87					
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	1.50	99.99	97.50	77.57	77.57					
O_2	95.00	0.01	2.15	20.86	20.86					
CH_4										
H_2S + COS										
Ar	3.50		0.26	0.89	0.89					
H2O			0.09	0.68	0.68					

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GE CASE 5.05						APPROVED	SA		
	UNIT : 2200 SYNGAS Treatment and conditioning line						DATE	Feb 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	SYNGAS from Scrubber	SYNGAS at COS Hydrolysis Inlet	SYNGAS at COS Hydrolysis Out	RAW SYNGAS to Acid Gas Removal	LP SYNGAS from Acid Gas Removal	HP SYNGAS from Acid Gas Removal	Treated SYNGAS to Power Island	Return Condensate to Scrubber	Cold Condensate from Unit 4200	Contaminated Condensate to SWS
Temperature (°C)	243	200	200	38	45	44	150	192	21	53
Pressure (bar)	63	60.3	59.3	55	26.0	54.9	26.5	66.7	10.0	55.0
TOTAL FLOW										
Mass flow (kg/h)	648960	306550	306550	138850	86400	501400	587800	366985	594850	6000
Molar flow (kgmole/h)	33800	14785	14785	13195	2550	24981	27531			
LIQUID PHASE										
Mass flow (kg/h)								366985	594850	6000
GASEOUS PHASE										
Mass flow (kg/h)	648960	306550	306550	138850	86400	501400	587800			
Molar flow (kgmole/h)	33800	14785	14785	13195	2550	24981	27531			
Molecular Weight	19.2	20.7	20.7	10.5	33.9	20.1	21.4			
Composition (vol %)										
H_2	15.10	34.6	34.6	38.8	4.41	40.56	37.21			
CO	15.60	35.7	35.7	40.1	6.22	41.70	38.41			
CO_2	7.30	16.6	16.6	18.7	43.88	15.52	18.14			
N_2	(1)	0.8	0.8	0.9	45.04	0.98	5.07			
O_2		0.0	0.0	0.0	0.00	0.00	0.00			
CH_4		0.0	0.0	0.0	0.00	0.02	0.02			
H_2S + COS	0.12	0.28	0.27	0.31	0.01	0.00	0.00			
Ar	(1)	1.0	1.0	1.1	0.19	1.11	1.03			
H2O	61.00	11.0	11.0	0.2	0.25	0.11	0.12			

Note (1): N_2 + Ar: 0.8% - Others: 0.08%

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GE CASE 5.05						APPROVED	SA		
	UNIT : 2300 Acid Gas Removal						DATE	Feb 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP Purified Syngas to Syngas Cooling	Tail Gas from SRU	MP Nitrogen from ASU	Acid Gas to SRU & TGT				
Temperature (°C)	38	44	45	38	149	49				
Pressure (bar)	55.0	54.9	26.0	26.2	27.0	2.0				
TOTAL FLOW										
Mass flow (kg/h)	277700	501400	86400	9928	33600	9708				
Molar flow (kgmole/h)	26390	24981	2550	316	1200	296				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	277700	501400	86400	9928	33600	9708				
Molar flow (kgmole/h)	26390	24981	2550	316	1200	296				
Molecular Weight	10.5	20.1	33.9	31.4	28.0	32.8				
Composition (vol %)										
H_2	38.75	40.56	4.41	5.31	0.00	0.00				
CO	40.07	41.70	6.22	0.28	0.00	0.00				
CO_2	18.65	15.52	43.88	29.66	0.00	22.97				
N_2	0.93	0.98	45.04	63.36	99.99	43.02				
O_2	0.00	0.00	0.00	0.00	0.01	0.00				
CH_4	0.02	0.02	0.00	0.00	0.00	0.00				
H_2S	0.31	0.00	0.01	0.96	0.00	28.35				
Ar	1.07	1.11	0.19	0.25	0.00	0.00				
H2O	0.20	0.11	0.25	0.19	0.00	5.53				

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GE CASE 5.05						APPROVED	SA		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	Feb 2010		
STREAM	1	2	3	4	5	6	7	8	9	10
	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)	2.0		1.0	26.2						
TOTAL FLOW										
Mass flow (kg/h)	9708	61.9 t/d	4037	9928						
Molar flow (kgmole/h)	296		191	316						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	9708		4037	9928						
Molar flow (kgmole/h)	296		191	316						
Molecular Weight	32.8		21.2	31.4						
Composition (vol %)										
H_2	0.00		21.15	5.31						
CO	0.00		28.45	0.28						
CO_2	22.97		13.49	29.66						
N_2	43.02		0.00	63.36						
O_2	0.00		0.00	0.00						
CH_4	0.00		0.00	0.00						
H_2S	28.35		1.14	0.96						
Ar	0.00		0.00	0.25						
H2O	5.53		35.77	0.19						

	IGCC HEAT & MATERIAL BALANCE				
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME				
	CASE : GE CASE 5.05				
	UNIT : 3000 POWER ISLAND				
Stream	**Description**	**Flowrate t/h**	**Temperature °C**	**Pressure bar a**	**Entalphy kJ/kg**
1	Treated SYNGAS from Syngas Cooling (*) (1)	293.85	150	26.5	194.8
2	Extraction Air to Air Separation Unit (*)	285.49	402	14.6	-
3	MP Nitrogen from ASU (*)	363.00	213.00	22.10	-
4	HP Steam to Process Units	5.00	340	85.0	2935.6
5	HP Steam to Steam Turbine (*)	255.68	552	156.5	3447
6	Hot RH Steam to Steam Turbine (*)	311.13	537	36.7	3532
7	MP Steam from Steam Turbine (*)	255.68	344	39.7	3080
8	LMP Steam to Steam Turbine (*)	170.30	350	20.0	3138
9	LP Steam to Steam Turbine (*)	111.82	237	6.2	2930
10	MP Steam to MP -Superheater (*)	55.45	251.8	41.0	2800
11	LP Steam to LP Superheater (*)	111.82	166.8	7.2	2765
12	BFW to VLP Pumps (*)	28.30	119	1.9	499
13	BFW to LP BFW Pumps (*)	170.18	119	1.9	499
14	BFW to MP BFW Pumps (*)	277.83	119	1.9	499
15	BFW to HP BFW Pumps (*)	259.47	119	1.9	499
16	Hot Condensate returned from Unit 2200 (*)	594.85	92	2.5	348
17	Hot Condensate returned from CR (*)	82.25	94	2.5	394
18	Water from Flash Drum (*)	36.55	119	2.5	499
19	FLUE GAS AT STACK (*) (2)	2657.10	129	AMB.	117
20	Condensate from Syngas Final Heater (*)	87.82	118	2.5	495
21	LP Steam Turbine Exhaust	1189.70	21.7	0.026	2220
22	Sea Water Supply to Steam Condenser	85933	12	3.0	50.5
23	Sea Water Return from Steam Condenser	85933	19	2.1	79.8

(*) flowrate for one train
(1) Syngas Composition as per stream 7 of Material Balance for Unit 2200
(2) Flues gas molar composition: N_2: 74.0%; H_2O: 6.1%; O_2: 10.5%; CO_2: 8.5%; Ar: 0.9%.

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. *Italic* font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant.

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: Water usage and loss Analysis in Power plants without and with CO2 capture
LOCATION: THE NETHERLANDS
FWI Nº: 1- BD 0475A

REVISION	Draft	Rev.1	Rev.2	Rev. 3
DATE	Feb 2010			
ISSUED BY	L.So.			
CHECKED BY	PC			
APPROVED BY	SA			

CASE 5.05 - UTILITIES CONSUMPTION SUMMARY - GE IGCC w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 85 barg [t/h]	LMP Steam 20 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**		**5.0**								**5.0**	
2100	**Air Separation Unit**				**20.2**						**20.2**	
2200	**Syngas Cooling and COS Hydrolysis**			**-339.3**	**-250.6**	**-10.5**		*355.8*	*270.3*	*57.2*	**76.1**	*6.8*
2300	**Acid Gas Removal**				**48.9**						**48.9**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-1.3**	**-1.1**			*4.2*	**1.1**		**2.8**	*0.1*
3000	**POWER ISLANDS UNITS**		**-5.0**	**340.6**	**171.1**	**10.5**	**0.0**	*-360.1*	*-271.4*	*-57.2*		
4000 to 5300	**UTILITY and OFFSITE UNITS**				**11.5**						**11.5**	
	BALANCE		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**164.5**	**6.9**

Note: (1) Minus prior to figure means figure is generated
(2) Figures in ***Italic*** font style have been updated for the IEA report dated 2009, whereas figures in **Regular** font style are the same as for the IEA report dated 2003.

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Water usage and loss Analysis in plants w/o & w CCS	Feb 2010
	LOCATION:	THE NETHERLANDS	ISSUED BY: L.So.
	FWI Nº:	1- BD 0475A	CHECKED BY: PC
			APPR. BY: SA

CASE 5.05 - WATER CONSUMPTION SUMMARY - GE IGCC w/o CO2 capture

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**	*89.0*		**2941**	
2100	**Air Separation Unit**				**24077**
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**			**1262**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**319**	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**1772**	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		*10.1*		**85933**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				**11429**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	*15.5*	*-14.1*		
	Other Units		*4*	**364**	
	BALANCE	*104.5*	**0**	**6658**	**121439**

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FOSTER WHEELER CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Water usage and loss Analysis in plants w/o & w CC	Feb 2010
LOCATION:	THE NETHERLANDS	ISSUED BY: L.So.
FWI Nº:	1- BD 0475A	CHECKED BY: PC
		APPR. BY: SA

CASE 5.05 - ELECTRICAL CONSUMPTION SUMMARY - GE IGCC w/o CO2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**338**
1000	**Gasification Section**	**13055**
2100	**Air Separation Unit**	**119360**
2200	**Syngas treatment and conditioning line**	**307**
2300	**Acid Gas Removal**	**3102**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**1932**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4795**
3200	**Heat Recovery Steam Generator**	**5451**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2204**
3500	**Miscellanea**	**527**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9762**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**686**
	Other Units	**661**
	BALANCE	**162179**

Note: (1) Minus prior to figure means figure is generated

7. Overall performance

The table summarizing the Overall Performance of the GEE IGCC power plant, case 5.05, is attached hereafter.

GE

HIGH PRESSURE w/o CO_2 capture

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	303.0
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2177.3**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1535.2
Gasification Efficiency (based on coal LHV)	%	70.5
Thermal Power of Clean Syngas to GT (based on LHV) (F)	MWt	1521.4
Syngas treatment efficiency (F/E*100)	%	99.1
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	406.1
Expander power output	MWe	10.6
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**988.7**
ASU power consumption	MWe	119.4
Process Units consumption	MWe	18.4
Utility Units consumption	MWe	1.8
Offsite Units consumption (including sea cooling water system)	MWe	9.6
Power Islands consumption	MWe	13.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**162.2**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**826.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**38.0**

Specific fuel (coal) consumption per MW net produced	**MWt /MWe**	**2.634**
Specific CO_2 emissions per MW net produced	**t /MWh**	**0.818**
Specific water consumption per MW net produced	**t /MWh**	**0.126**

8. Environmental Impact

The GEE IGCC power plant, case 5.05, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 8.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	738,1
Flow, $Nm^3/h^{(1)}$	3.140.950
Temperature, °C	129
Composition	(%vol)
Ar	0,95
N_2	73,98
O_2	10,51
CO_2	8,46
H_2O	6,10
Emissions	$mg/Nm^{3\,(1)}$
NOx	51
SOx	10
CO	31
Particulate	4

(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 8.2

Table 8.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1476,2
Flow, $Nm^3/h^{(1)}$	6.281.900
Temperature, °C	129
Emissions	kg/h
NOx	321,4
SOx	60,8
CO	196,0
Particulate	25,8

(1) Dry gas, O_2 content 15%vol

8.1.2. 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.

8.2. Liquid Effluent

Most of the effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island (24.0 t/h water recovered from WWT vs 32.2 t/h total water effluent). The water effluent from WWT, which is not recycled to the gasification island (8.2 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 : 121.000 m^3/h
- Temperature : 19 °C
- Cl_2 : <0.05 ppm

8.3. 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 m3/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:

Fine Slag
Flow rate : 29,8 t/h
Water content : 70 %wt

Coarse Slag
Flow rate : 71,6 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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: Netherlands
PROJ. NAME: Water usage and loss Analysis w/o and w CCS
CONTRACT N. 1- BD- 0475 A

REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
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CHECKED BY	PC	PC		
APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 1000 - Gasification Unit - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Syngas scrubber								734 t/h of condensate from unit 2200	
		Black water flash drum								12 t/h sour water from unit 2200	
		Black water flash drum									1.2 t/h steam in sour gas
		Grey water tank								89 t/h raw water as make up	
		Grey water tank								24 t/h treated water from WWT	
		Grey water tank									14.6 t/h water blowdown
		Drag conveyor and slag screen									35.8 t/h in coarse slag
		Rotatory filter									20.9 t/h in fine slag
		Gasification section								5 t/h HP steam	condensate is recovered

LEGEND:
For the Gasification Unit, only the water consumer items are shown.

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		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT EXCHANGERS		**S, m2**		shell / tube	shell / tube				
1	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 26	430 / 243		DUTY = 14320 kW		
2	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 26	430 / 243		DUTY = 14320 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 = 274 t/h		85			Oxigen purity = 95 %	20.2 t/h steam to internal heaters	20.2 t/h steam condensate to recovery
				MP N_2 flow rate to GTs = 890 t/h		26			Nitrogen purity = 98 %		
				HMP N_2 flow rate to AGR = 36 t/h		34			Nitrogen purity = 99,9 %		
				LP N_2 flow rate to Proc Unit = 2.7 t/h		14			Nitrogen purity = 99,9 %		
				Air flow rate from GTs = 603 t/h							
		ASU Compressors		118.4 MW							
		ASU Heat Exchangers	Shell & tube Heat Exchangers	16 services; duty = 11 MWth each; surface = 1000 m2 each				tubes: titanium shell: CS	sea water coolers		
		ASU chiller		4 MW th @ 5°C							

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

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	APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube				
1	**E-2201**	**LMP Steam Generator**	Kettle			24 / 68	250 / 273		DUTY = 106350 kW H2 service H2/Wet H2S serv. on channel	355.8 t/h LMP BFW	352.3 t/h LMP steam + 3.5 t/h blowdown
2	**E-2201**	**LMP Steam Generator**	Kettle			24 / 68	250 / 273		DUTY = 106350 kW H2 service H2/Wet H2S serv. on channel		
1	**E-2202**	**LP Steam Generator**	Kettle			12 / 68	250 / 250		DUTY = 78600 kW H2 service H2/Wet H2S serv. on channel	270.3 t/h LP BFW	267.6 t/h LP steam + 2.7 t/h blowdown
2	**E-2202**	**LP Steam Generator**	Kettle			12 / 68	250 / 250		DUTY = 78600 kW H2 service H2/Wet H2S serv. on channel		
1	**E-2203**	**VLP Steam Generator**	Kettle			7 / 68	185 / 204		DUTY = 14305 kW H2 service H2/Wet H2S serv. on channel	57.2 t/h VLP BFW	56.6 t/h VLP steam + 0.6 t/h blowdown
2	**E-2203**	**VLP Steam Generator**	Kettle			7 / 68	185 / 204		DUTY = 14305 kW H2 service H2/Wet H2S serv. on channel		
1	**E-2206**	**VLP Steam Generator**	Kettle			7 / 68	175 / 210		DUTY = 3400 kW H2 service H2/Wet H2S serv. on channel		
2	**E-2206**	**VLP Steam Generator**	Kettle			7 / 68	175 / 210		DUTY = 3400 kW H2 service H2/Wet H2S serv. on channel		
1	**E-2204**	**Syngas Feed/ Product Exchanger**	Shell & Tube			68 / 68	230 / 185		DUTY = 2825 kW H2 service H2/Wet H2S serv. on channel		
2	**E-2204**	**Syngas Feed/ Product Exchanger**	Shell & Tube			68 / 68	230 / 185		DUTY = 2825 kW H2 service H2/Wet H2S serv. on channel		
1	**E-2205**	**Hydrolysis Feed Heater**	Shell & Tube			24 +FV / 68	250 / 230		DUTY = 3535 kW H2 service H2/Wet H2S serv. on channel	13 t/h LMP steam	recovered as condensate
2	**E-2205**	**Hydrolysis Feed Heater**	Shell & Tube			24 +FV / 68	250 / 230		DUTY = 3535 kW H2 service H2/Wet H2S serv. on channel		

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		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube				
1	E-2207 A/B	Condensate Preheater	Shell & Tube	exchanger area = 1700 m2 (exchanger A+B)		26 / 68	100 / 185		DUTY = 33602 kW H2 service H2/Wet H2S serv. on channel		
2	E-2207 A/B	Condensate Preheater	Shell & Tube	exchanger area = 1700 m2 (exchanger A+B)		26 / 68	100 / 185		DUTY = 33602 kW H2 service H2/Wet H2S serv. on channel		
	E-2208	Expander Feed Heater	Shell & Tube			7 / 68	175 / 140		DUTY = 14770 kW H2 service H2/Wet H2S serv. on channel	46.1 t/h VLP steam	recovered as condensate
	E-2209	Syngas pre-heater	Shell & Tube			7 / 68	175 / 140		DUTY = 12820 kW H2 service H2/Wet H2S serv. on channel		
	E-2210	Syngas heater	Shell & Tube			12 / 31	200 / 180		DUTY = 9870 kW H2 service H2/Wet H2S serv. on channel	17 t/h LP steam	recovered as condensate
		DRUMS		D,mm x TT,mm							
1	D-2201	Condensate Separator	Vertical			68	250		Wet H2S service/H2 service		734 t/h return condensate to Gasification; 12 t/h contaminated condensate to SWS
2	D-2201	Condensate Separator	Vertical			68	250		Wet H2S service/H2 service		
1	D-2202	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service		
2	D-2202	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service		
1	D-2203	Condensate Separator	Vertical			68	185		Equipped with demister Wet H2S service/H2 service		
2	D-2203	Condensate Separator	Vertical			68	185		Equipped with demister Wet H2S service/H2 service		
1	D-2204 A/B	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service		
2	D-2204 A/B	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service		
1	D-2205	Condensate Separator	Vertical			68	68		Equipped with demister Wet H2S service/H2 service		
2	D-2205	Condensate Separator	Vertical			68	68		Equipped with demister Wet H2S service/H2 service		

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		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		DRUMS (continued)		D,mm x TT,mm							
	D-2206	**Process Condensate Accumulator**	Horizontal			68	220				
		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**	**COS Hydrolysis Reactor**	vertical			68	230		H2 service Wet H2S service		0.1 t/h water loss to COS hydrolisis
2	**R-2201**	**COS Hydrolysis Reactor**	vertical			68	230		H2 service Wet H2S service		
		EXPANDERS									
	EX- 2201	**Purified Syngas Expander**	centrifugal	Pout/Pin = 0,50 Flow = 560 kNm^3/h Power = 11 MWe							
		GENERATORS		P, MWe							
	G-3201	**Expander Generator**									
		PACKAGE UNITS									
	Z-2201	**Catalyst Loading System**									
	Z-2202	**COS Hydrolysis Catalyst**							Catalyst volume: 160 m^3		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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.=61.9 t/d					Sulphur content = 99,9 wt min (dry basis)	5.3 t/h BFW to steam generators + 2.7 t/h water in sour gas and from reaction	2.4 t/h steam to Plant network; 2.8 t/h steam condensate to condensate unit 2.7t/h sour water to WWT; 0.1 t/h blowdown water to WWT
				Acid Gas from AGR = 300 kmol/h		3.5	80		Sulphur content = 28,3% (wet basis)		
				Off gas from Gasif. = 190 kmol/h					Sulphur content = 1,1 % (wet basis)		
				Expected Treated Tail Gas=316 kmol/h		30	70		Major components (wet basis): CO_2 = 29,66%, H_2=5,31%, N_2 = 63,36%		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube				
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 31	280 / 200		DUTY=2420 kW Tubes: H2 service		
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 31	280 / 200		DUTY=2420 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)	286 MW					Included in 1-Z- 3101 Included in 1-Z- 3101	Steam in syngas, in air to turbine and generated in combustion	202.6 t/h steam in flue gas to stack
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	286 MW					Included in 2-Z- 3101 Included in 2-Z- 3101		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage and loss Analysis w/o and w CCS CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		PUMPS		Q,m³/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-3204	LMP Steam Receiver Drum	horizontal			24	250				
2	D-3204	LMP Steam Receiver Drum	horizontal			24	250				
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		

FOSTER WHEELER

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		PACKAGES									
	Z-3201	**Fluid Sampling Package**									
	Z-3202 D-3204 P-3204 a/b/c	**Phosphate Injection Package** Phosphate storage tank Phosphate dosage pumps							Included in Z - 3202 Included in Z - 3202 One operating , one spare		
	Z-3203 D-3205 P-3205 a/b/c	**Oxygen Scavanger Injection Package** Oxygen scavanger storage tank Oxygen scavanger dosage pumps							Included in Z - 3203 Included in Z - 3203 One operating , one spare		
	Z-3204 D-3206 P-3206 a/b/c	**Amines Injection Package** Amines Storage tank Amines Dosage pumps							Included in Z - 3204 Included in Z - 3204 One operating , one spare		
		HEAT RECOVERY STEAMGENERATOR									
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		1.3 t/h blowdown from Steam Drums
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		0.3 t/h steam vented to atm
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	**LMP Superheater**							Included in 1-HRS-3201		
1	E-3207	**HP Economizer 3rd section**							Included in 1-HRS-3201		
1	E-3208	**MP Superheater**							Included in 1-HRS-3201		
1	E-3209	**MP Evaporator**							Included in 1-HRS-3201		
1	E-3210	**LP Superheater**							Included in 1-HRS-3201		
1	E-3211	**MP Economizer 2nd section**							Included in 1-HRS-3201		
1	E-3212	**HP Economizer 2nd section**							Included in 1-HRS-3201		
1	E-3213	**LP Evaporator**							Included in 1-HRS-3201		
1	E-3214	**LP Economizer**							Included in 1-HRS-3201		
1	E-3215	**MP Economizer 1st section**							Included in 1-HRS-3201		
1	E-3216	**HP Economizer 1st section**							Included in 1-HRS-3201		
1	E-3217	**VLP Evaporator**							Included in 1-HRS-3201		

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		ISSUED BY	L.So.	L.So.		
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		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT RECOVERY STEAMGENERATOR									
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		1.3 t/h blowdown from Steam Drums
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		0.3 t/h steam vented to atm
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	**LMP Superheater**							Included in 2-HRS-3201		
2	E-3207	**HP Economizer 3rd section**							Included in 2-HRS-3201		
2	E-3208	**MP Superheater**							Included in 2-HRS-3201		
2	E-3209	**MP Evaporator**							Included in 2-HRS-3201		
2	E-3210	**LP Superheater**							Included in 2-HRS-3201		
2	E-3211	**MP Economizer 2nd section**							Included in 2-HRS-3201		
2	E-3212	**HP Economizer 2nd section**							Included in 2-HRS-3201		
2	E-3213	**LP Evaporator**							Included in 2-HRS-3201		
2	E-3214	**LP Economizer**							Included in 2-HRS-3201		
2	E-3215	**MP Economizer 1st section**							Included in 2-HRS-3201		
2	E-3216	**HP Economizer 1st section**							Included in 2-HRS-3201		
2	E-3217	**VLP Evaporator**							Included in 2-HRS-3201		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube				
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	52 / 140		DUTY = 910 kW		
		DRUMS		D,mm x TT,mm							
	D-3301	**Flash Drum**	vertical			3.5	200				
	D-3302	**Continuous Blow-down Drum**	vertical			3.5	140			blowdown from Steam Drums	2.6 t/h water to WWT
	D-3303	**Discontinuous Blow-down Drum**	vertical			3.5	140				
		PACKAGES									
	Z-3301	**Steam Turbine & Condenser Package**									
	TB-3301	Steam Turbine		406 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	686 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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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		CHECKED BY	PC	PC					
		APPROVED BY	SA	SA					

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - GE Case 5.05 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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	93 MW th				plates: titanium frame: SS	sea water		
		Close loop CW pumps	centrifugal	6660 m3/h x 30m	992 kWe			CS	1 pump in operation + 1 spare		
		Waste water treatment plant									
		Sea water pumps	submerged	20000 m3/h x 20m	1400 kWe			casing, shaft: SS; impeller: duplex	6 pumps in operation + 1 spare		
		Seawater chemical injection									
		Sea water inlet/outlet works									

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : GEE IGCC WITH CCS, REFERENCE CASE – CASE 5.06

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
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SECTION B

GEE IGCC WITH CCS, REFERENCE CASE
I N D E X

1. Introduction

The present case 5.06 refers to a GEE IGCC power plant, fed with bituminous coal and provided with CO_2 capture unit.

The IEA GHG study number PH4-19, May 2003, has been taken as a reference for the configuration and performances of the plant here analysed. Plant description, process schemes and performance have been taken directly from reference study report. FWI integrated the reference study with additional information and in particular with the analysis of the water usage and the development of a detailed water flow diagram.

The main features of the GEE IGCC plant, case 5.06, are:

- High pressure (65 bar g) GEE Gasification (Texaco in reference study);
- 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	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

The IEA GHG study number PH4-19, May 2003, has been taken as a reference for the plant description and configuration.

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

Case 5.06 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 description of the Gasification Unit included in paragraph 2 of Report # 4, section B (case 5.05) is still valid for the present case 5.06 and is to be referred if a more detailed description is required.

2.3. Unit 2100 – Air Separation unit

The Air Separation Unit is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

The description of the Air Separation Unit included in paragraph 2 of Report # 4, section B (case 5.05) is still valid for the present case 5.06 (with the only exception that in case 5.06 there's no need for a nitrogen stream to be sent to Unit 2300 – AGR, due to the negative impact of the Nitrogen presence in CO_2 stream sent to storage) and is to be referred if a more detailed description is required.

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.

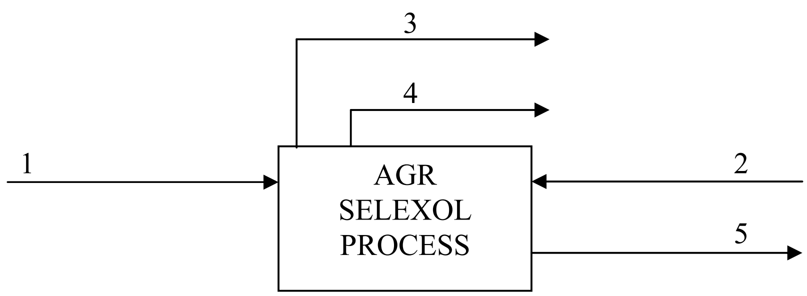
In the present case 5.06, this Unit utilises Selexol as acid gas solvent (physical solvent). A single train configuration that enhances the acid gases concentration without using Nitrogen from Air Separation Unit is considered.

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 description of the SRU and TGT Unit included in paragraph 2 of Report # 4, section B (case 5.05) is still valid for the present case 5.06 and is to be referred if a more detailed description is required.

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 5.06 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

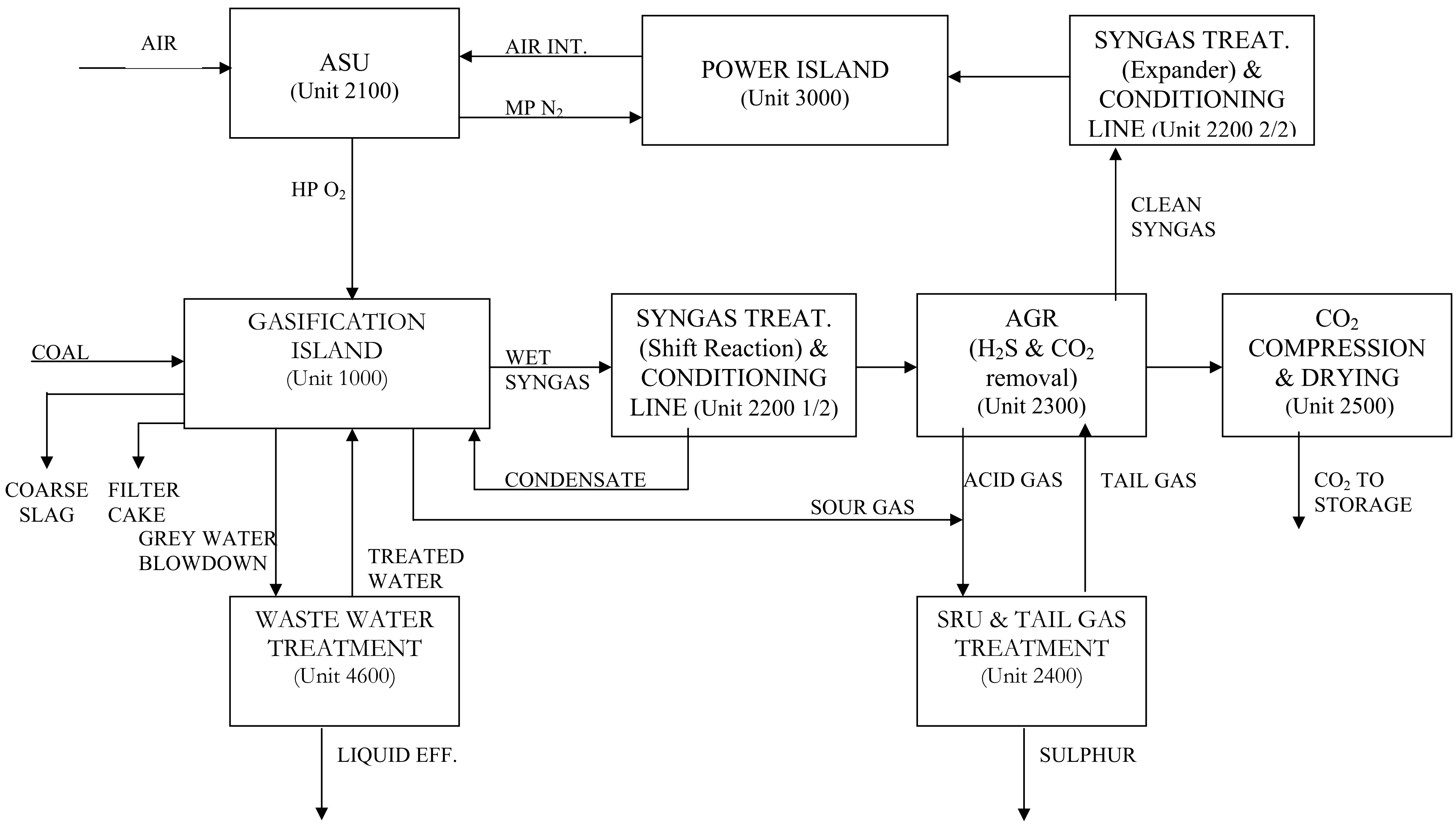
3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagram of the GEE IGCC, Case 5.06, and the schematic Flow Diagrams of Units 2100, 2200, 2300 and 3000 are attached hereafter.

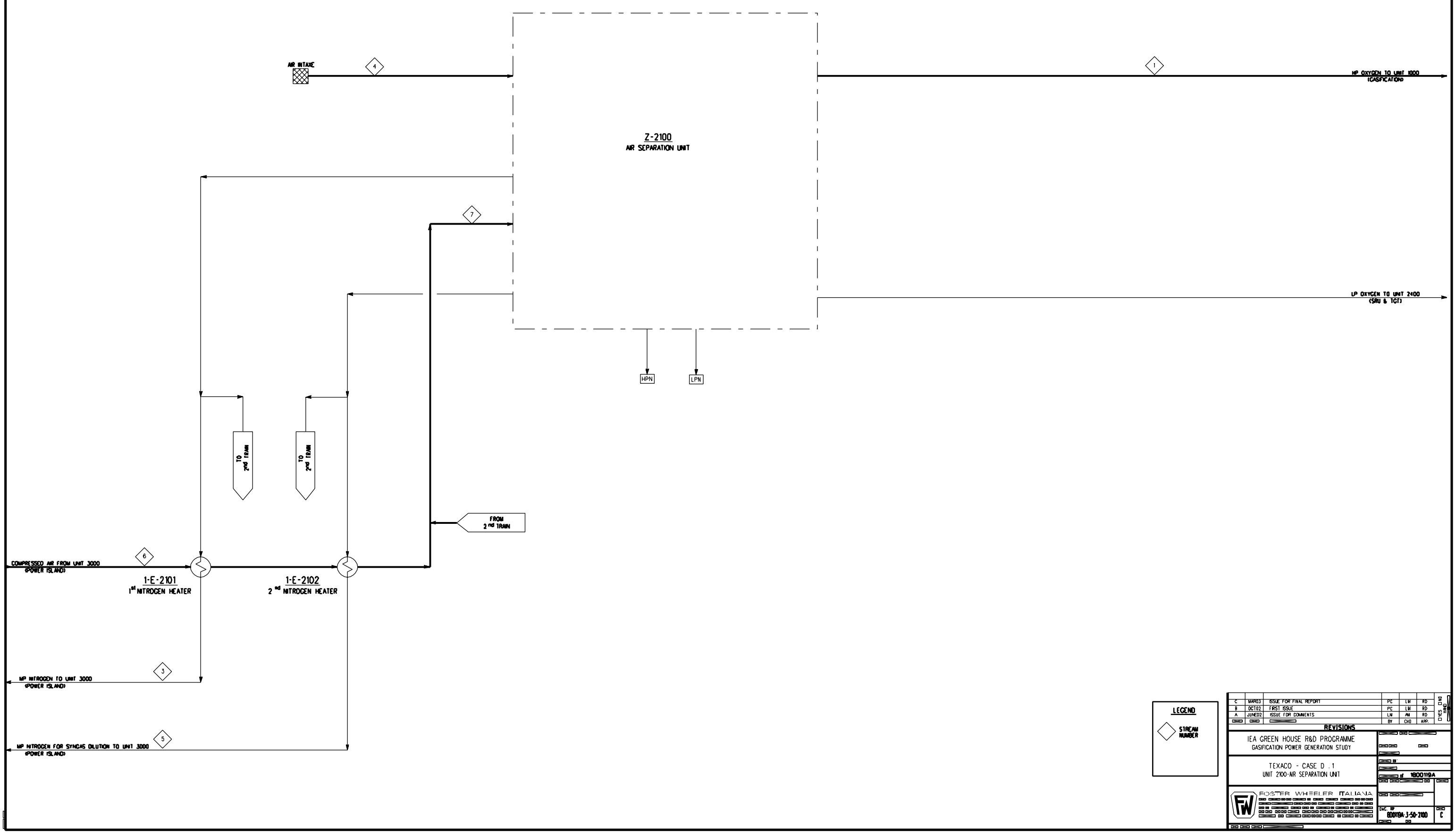
The IEA GHG study number PH4/19, May 2003, has been taken as reference for the plant Block Flow Diagrams and Process Flow Diagrams attached.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

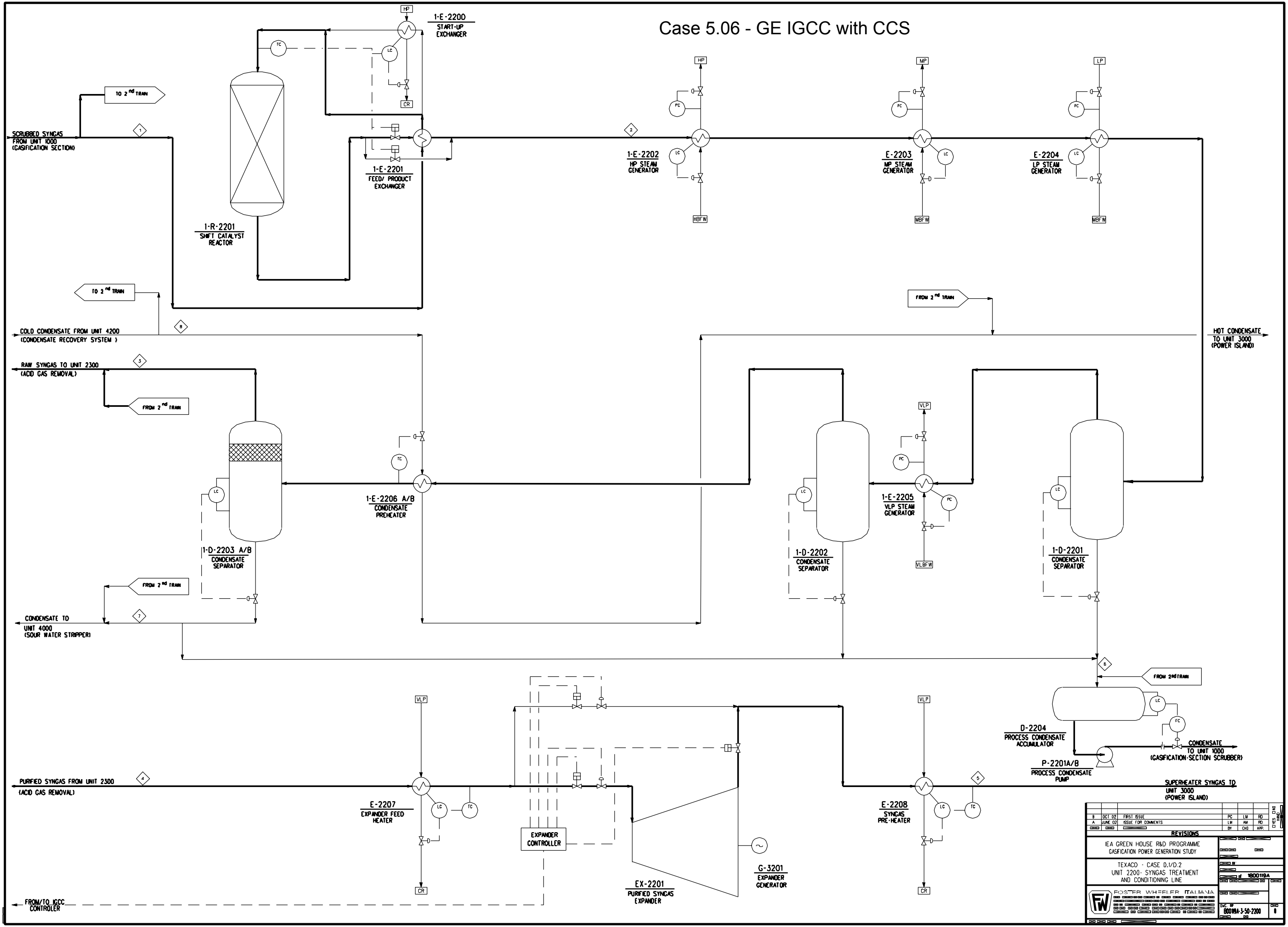
GEE CASE 5.06 – IGCC COMPLEX BLOCK FLOW DIAGRAM



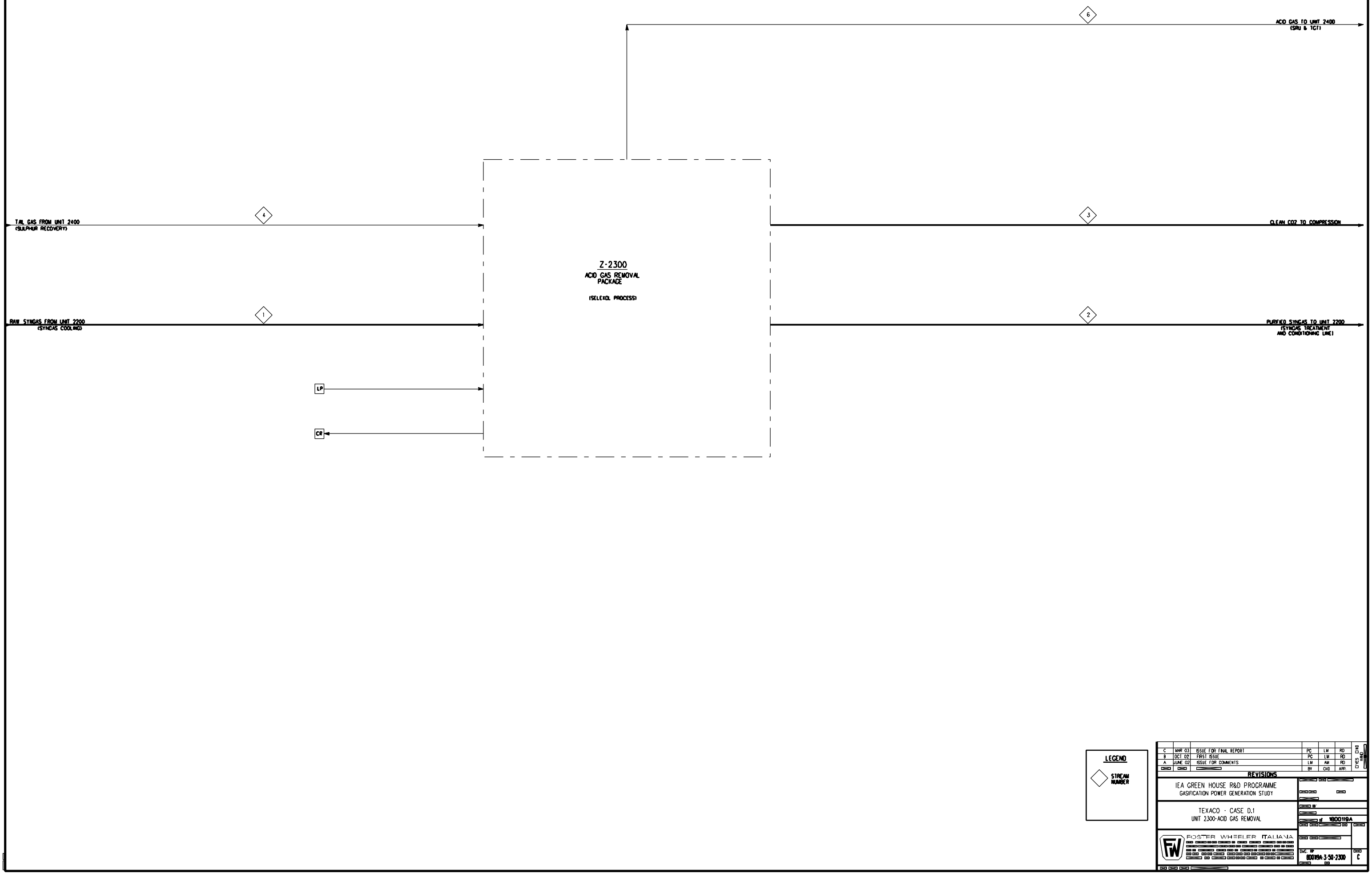
Case 5.06 - GE IGCC with CCS

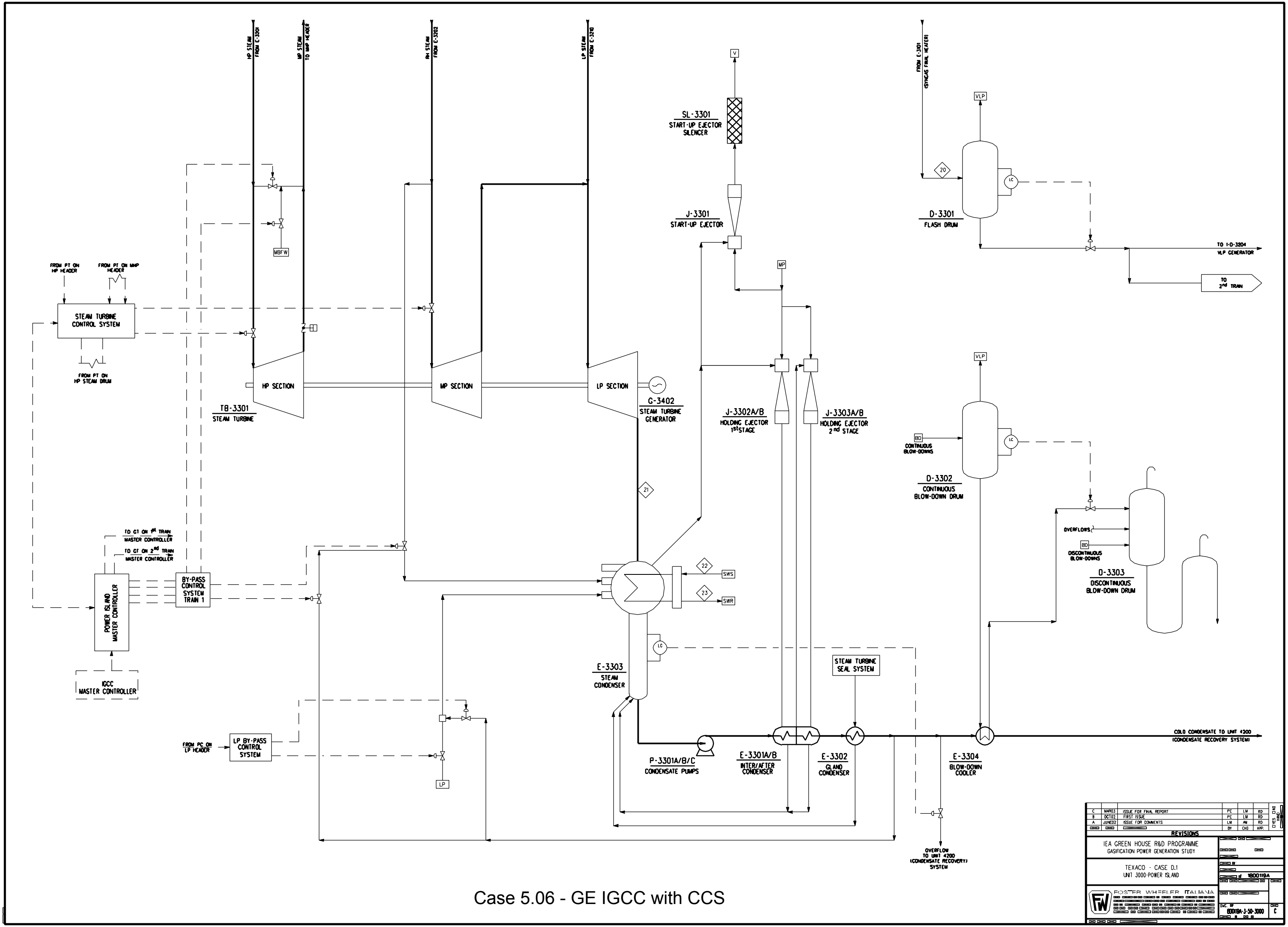


Case 5.06 - GE IGCC with CCS



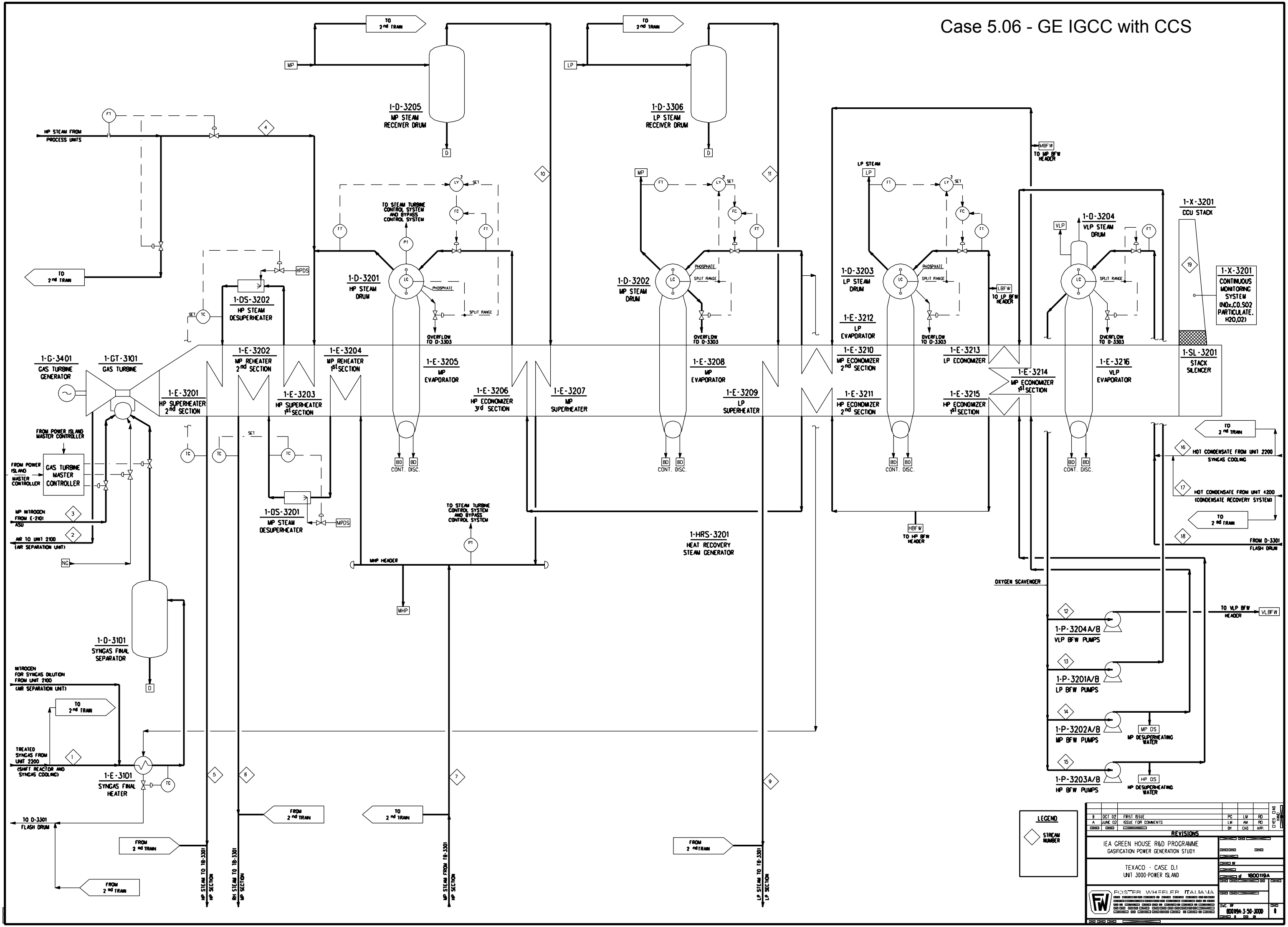
Case 5.06 - GE IGCC with CCS





Case 5.06 - GE IGCC with CCS

Case 5.06 - GE IGCC with CCS



4. Detailed Water Flow Diagram

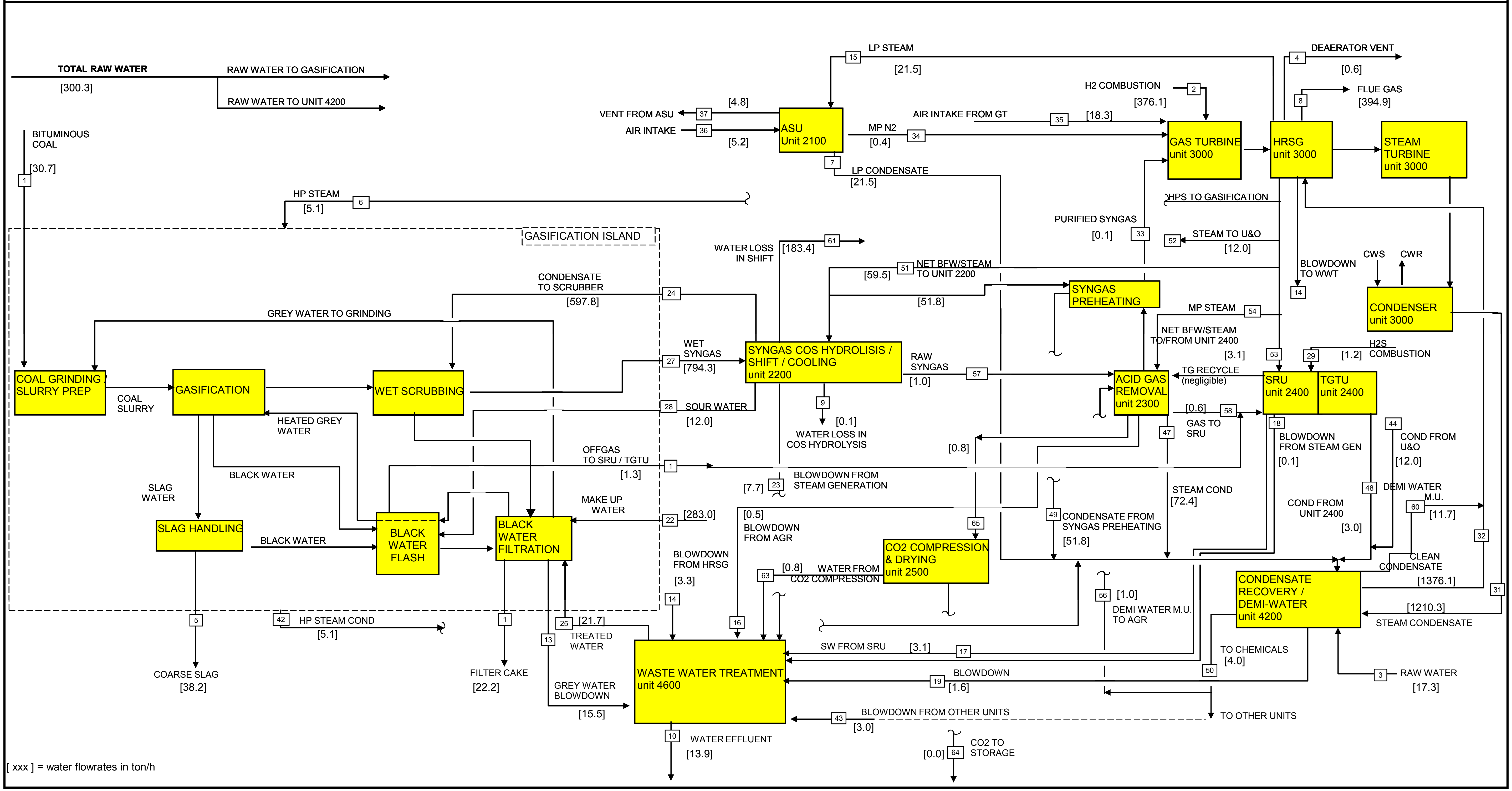
In the present paragraph the following documents are attached:

- detailed water Flow Diagram relevant to the entire power plant;
- water balance around the major units.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

IEA GHG R&D PROGRAMME	Revision no.:	1
Water usage & loss Analysis in Power plants without and with CCS	Date:	November 2010
Volume #4	Sheet:	

CASE 5.06 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 730.3 MWe) - BLOCK FLOW DIAGRAM - WATER BALANCE



FOSTER WHEELER

IEA GHG R&D PROGRAMME	Revision no.:	1
Water usage & loss Analysis in Power plants without and with CCS	Date:	November 2010
Volume #4	Sheet:	

GEE IGCC fed by bituminous coal, with CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	30.7	5	Slag	38.2
2	Syngas combustion of H2 in GT	376.1	4	Deaerator vent	0.6
3	Raw water to Demi Plant	17.3	11	Filter cake	22.2
36	Moisture in air to ASU	5.2	8	Flue gas from GT	394.9
29	H2S combustion in SRU	1.2	9	Water loss in COS hydrolysis	0.1
35	Moisture in combustion air to GT	18.3	10	Water effluent from WWT	13.9
22	Raw Water make up to Gasific.	283.0	37	Moisture from ASU vent	4.8
			61	Water loss in shift reaction in unit 2200	183.4
Total		731.8	Total		658.1

delta (note 1)
73.7

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Gasification Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	30.7	11	Filter cake	22.2
28	Sour Water to Stripping	12.0	5	Slag	38.2
24	Condensate to Wet Scrubber	597.8	27	Wet syngas	794.3
22	Make up to Grey Water Tank	283.0	12	Sour Gas	1.3
25	Treated water from WWT	21.7	13	Grey Water Blowdown	15.5
6	HP steam	5.1	42	HP condensate	5.1
Total		950.3	Total		876.6

delta (note 1)
73.7

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around WWT (unit 4600)

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
13	Grey Water Blowdown	15.5	25	Treated water to Gasifier	21.7
14	Blowdown from HRSG	3.3	10	Water effluent from WWT	13.9
43	Blowdown from other units	3.0			
16	Blowdown from AGR	0.5			
17	Sour water from SRU	3.1			
18	Blowdown from SRU	0.1			
19	Blowdown from Demi Plant	1.6			
23	Blowdown from unit 2200	7.7			
63	Water from CO2 compressor	0.8			
Total		35.6	Total		35.6

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Cond Recovery/Demi Water Plant

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
3	Raw Water	17.3	32	Demi Water to HRSG and PRS u	1376.1
31	Condensate from Steam Turbine	1210.3	19	Blowdown to WWT	1.6
44	Condensate from U&O	12.0	50	Demi water to chemicals	4.0
6	Condensate from Gasification	5.1	60	Demi water make up	11.7
7	Condensate from unit 2100	21.5			
47	Condensate from unit 2300	72.4			
48	Condensate from unit 2400	3.0			
49	Condensate from syngas preheating	51.8			
Total		1393.4	Total		1393.4

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Power Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	18.3	8	Flue gas from GT	394.9
2	Syngas combustion of H2 in GT	376.1	6	HP steam to Gasification	5.1
33	Water in syngas	0.1	52	Steam to U&O	12.0
34	Moisture in MP nitrogen from ASU	0.4	51	Net BFW/LMP steam to unit 2200	59.5
32	Clean condensate to HRSG	1376.1	54	MP steam to unit 2300	72.4
60	Demi water make up	11.7	53	Net BFW/Steam to unit 2400	3.1
			14	Blowdown from HRSG	3.3
			15	LP steam to N2 saturator HE	21.5
			31	Steam condensate from CCU	1210.3
			4	Deaerator vent	0.6
Total		1782.7	Total		1782.7

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around GT - HRSG

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	18.3	8	Flue gas from GT	394.9
2	Syngas combustion of H2 in GT	376.1			
33	Water in syngas	0.1			
34	Moisture in MP nitrogen from ASU	0.4			
Total		394.9	Total		394.9

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Unit 2200

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
27	Wet Syngas	794.3	9	Water loss in COS hydrolysis	0.1
51	Net BFW/steam to unit 2200	59.5	24	Condensate to scrubber	597.8
			28	sour water to SWS	12.0
			61	Water loss in shift reaction in unit	183.4
			57	Raw syngas to AGR	1.0
			23	Blowdown from Steam Gen	7.7
			49	Condensate from syn. preheat.	51.8
Total		853.8	Total		853.8

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around AGR

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
57	Raw Syngas	1.0	58	Gas to SRU	0.6
56	Demiwater make up	1.0	33	Purified syngas	0.1
54	MP steam	72.4	47	Steam condensate	72.4
			16	Blowdown from AGR	0.5
			65	CO2 to compression	0.8
Total		74.3	Total		74.3

NOTE 1: Water balances around gasification island and around the entire Power Plant don't close to zero by the same amount. The difference between the streams of "water in" and "water out" is due to the shift reactions, occuring in the gasification island.

5. 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.

The IEA GHG study number PH4/19, May 2003, has been taken as reference for the plant H&M balance attached.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.06						APPROVED	SA		
	UNIT : 2100 AIR SEPARATION UNIT						DATE	March 2010		
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		

	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.06						APPROVED	SA		
	UNIT : 2200 Syngas treatment and conditioning line						DATE	March 2010		

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 GREEN HOUSE R & D PROGRAMME	PREP.	L.So.		
	CASE : GEE IGCC CASE 5.06	APPROVED	SA		
	UNIT : 2300 Acid Gas Removal	DATE	March 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	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;

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	Draft	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.06						APPROVED	SA		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	March 2010		
STREAM	1	2	3	4	5	6	7	8	9	10
	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						

IGCC HEAT & MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : GEE IGCC CASE 5.06
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%.

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. Italic font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant.

FOSTER WHEELER	CLIENT:	IEA GHG R&D PROGRAMME	REVISION	Draft	Rev.1	Rev.2
	PROJECT:	Water usage and loss Analysis in Power plants without and with CO2 capture	DATE	March 2010		
	LOCATION:	Netherlands	ISSUED BY	L.So.		
	FWI Nº:	1- BD 0475A	CHECKED BY	PC		
			APPROVED BY	SA		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - CASE 5.06 - HP with CO_2 capture, separate removal of H_2S and CO_2

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
(3) Figures in ***Italic*** font style have been updated for the IEA report dated 2009, whereas figures in **Regular** font style are the same as for the IEA report dated 2003.

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	Water usage and loss Analysis in plants w/o & w CCS	March 2010
FOSTER WHEELER	LOCATION:	Netherlands	ISSUED BY: L.So.
	FWI Nº:	1- BD 0475A	CHECKED BY: PC
			APPR. BY: SA

WATER CONSUMPTION SUMMARY - GEE IGCC - CASE 5.06 - HP with CO_2 capture, separated H2S and CO2 removal

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 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
(2) Figures in ***Italic*** font style have been updated for the IEA report dated 2009, whereas figures in **Regular** font style are the same as for the IEA report dated 2003.

CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	Water usage & loss Analysis in plants w/o & w CCS	March 2010
LOCATION:	Netherlands	ISSUED BY: L.So.
FWI Nº:	1- BD 0475A	CHECKED BY: PC
		APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - GEE IGCC - CASE 5.06 - HP with CO_2 capture, separated H2S and CO2 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

7. Overall performance

The table summarizing the Overall Performance of the GEE IGCC power plant, case 5.06, is attached hereafter.

GEE IGCC		
- High pressure with CO_2 capture, separated H_2S and CO_2 removal		
OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	323,1
Coal LHV (air dried basis)	kJ/kg	25869,5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321,8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637,9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488,4
Syngas treatment efficiency (F/E*100)	%	90,9
Gas turbines total power output	MWe	563,4
Steam turbine power output	MWe	398,2
Expander power output	MWe	11,2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**972,8**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	128,6
Process Units consumption	MWe	50,8
Utility Units consumption	MWe	1,7
Offsite Units consumption (including sea cooling water system)	MWe	10,2
Power Islands consumption	MWe	12,2
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**203,5**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**769,3**
Gross electrical efficiency (D/A*100) (based on coal LHV)	**%**	**41,9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33,1**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	38,5
Offsite Units consumption (sea cooling water system)	MWe	0,5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**242,5**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**730,3**
Gross electrical efficiency (D/A*100) (based on coal LHV)	**%**	**41,9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**31,5**

Specific fuel (coal) consumption per MW net produced	**MWt/Mwe**	**3,018**
Specific CO2 emissions per MW net produced	**t/MWh**	**0,152**
Specific water consumption per MW net produced	**t/MWh**	**0,411**

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

8. Environmental Impact

The GEE IGCC power plant, case 5.06, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 8.1 – 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 8.2

Table 8.2 – 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

8.1.2. 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.

8.2. 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

8.3. 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 m3/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.

9. Equipment List

The list of main equipment and process packages is included in this paragraph.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage & loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	March 2010	November 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 1000 - Gasification Unit - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Syngas scrubber								597.8 t/h of condensate from unit 2200	
		Black water flash drum								12 t/h sour water from unit 2200	
		Black water flash drum									1.3 t/h steam in sour gas
		Grey water tank								283 t/h raw	
		Grey water tank								21.7 t/h treated water from WWT	
		Grey water tank									15.5 t/h water blowdown
		Drag conveyor and slag screen									38.2 t/h in coarse slag
		Rotatory filter									22.2 t/h in fine slag
		Gasification section								5.1 t/h HP steam	condensate is recovered

LEGEND:
For the Gasification Unit, only the water consumer items are shown.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
	LOCATION: Netherlands	DATE	March 2010	November 2010		
	PROJ. NAME: Water usage & loss Analysis	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - GEE IGCC Case 5.06 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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			Oxigen purity = 95 %	21.5 t/h steam to internal heaters	21.5 t/h steam condensate to recovery
				MP N_2 flow rate to GTs = 685 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 = 644 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							

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: Netherlands
PROJ. NAME: Water usage & loss Analysis
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DATE	March 2010	November 2010		
ISSUED BY	L.So.	L.So.		
CHECKED BY	PC	PC		
APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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	53.1 t/h HP BFW	52.6 t/h HP steam + 0.5 t/h blowdown
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	122.7 t/h MP BFW	121.5 t/h MP steam + 1.2 t/h blowdown
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	533.6 t/h LP BFW	528.3 t/h LP steam + 5.3 t/h blowdown
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	73.1 t/h LP BFW	72.3 t/h LP steam + 0.8 t/h blowdown
2	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel		

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Water usage & loss Analysis CONTRACT N. 1- BD- 0475 A	

REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
DATE	March 2010	November 2010		
ISSUED BY	L.So.	L.So.		
CHECKED BY	PC	PC		
APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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	51.8 t/h VLP steam	recovered as condensate
	E-2208	**Syngas pre-heater**	Shell & Tube			7 / 68	165 / 175		DUTY = 11270 kW H2 service H2/Wet H2S serv. on channel		

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: Netherlands
PROJ. NAME: Water usage & loss Analysis
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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		DRUMS		D,mm x TT,mm							
1	**D-2201**	**Condensate Separator**	Vertical			68	205		Wet H2S service/H2 service		597.8 t/h condensate to Gasification; 12 t/h contaminated condensate to SWS
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		0.1 t/h water loss to COS hydrolysis; 183.4 t/h water loss in Shift
2	**R-2201**	**Shift Catalyst Reactor**	vertical			68	464		H2 service Wet H2S service		

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		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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)	5.6 t/h BFW to steam generators + 3.1 t/h water in sour gas and from reaction	2.5 t/h steam to Plant network; 3.0 t/h steam condensate to condensate unit 3.1 t/h sour water to WWT; 0.1 t/h blowdown water to WWT
				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%		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 2500 - CO2 compression - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									Water to WWT (0.8 t/h)

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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	Steam in syngas, in air to turbine and generated in combustion	394.9 t/h steam in flue gas to stack
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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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 Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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		1.7 t/h blowdown from Steam Drums
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		0.3 t/h steam vented to atm
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		

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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		1.7 t/h blowdown from Steam Drums
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		0.3 t/h steam vented to atm
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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

FOSTER WHEELER

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LOCATION: Netherlands
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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			blowdown from Steam Drums	3.3 t/h water to WWT
	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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

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EQUIPMENT LIST

Unit 3400 - Electric Power Generation - GEE IGCC Case 5.06 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		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									

LEGEND:
The water consumer equipment is highlighted in the present equipment list.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : GEE IGCC WITHOUT CCS – DRY LAND – CASE 5.07

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

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SECTION D

GEE IGCC WITHOUT CCS – DRY LAND
I N D E X

1. Introduction

The present case 5.07 refers to the same GEE IGCC power plant, fed with bituminous coal and not provided with CO_2 capture unit, analysed in Report # 4, Section B (case 5.05). The difference with the power plant 5.05 is that the power plant analysed here is installed in the reference dry land country (South Africa) and far from the seaside, so that, technologies for saving water and reducing to zero the raw water intake have been applied. The configuration and the performance of the plant so modified are evaluated and the results are discussed in the present Section.

The main features of the GEE IGCC plant, case 5.07, are:

- High pressure (65 bar g) GEE Gasification (Texaco in reference study);
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- No CO Shift and CO_2 removal;
- Dry-land country.

The removal of acid gas (AGR) 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.

Looking at the Gas Turbine, the slightly higher ambient temperature of dry land cases with respect to the wet land cases should impact on machine performance.
GT gross power output should result slightly reduced as well as the GT appetite that should be reduced by approximately 2%.
Nevertheless, the appetite of GT and consequently the gasification capacity has been kept constant in order to see clearly the impact of the dry land design on performance and costs of the IGCC without the additional impact of the ambient temperature. The results of this study can be used, therefore, to evaluate the penalties on plant performance and the investment cost increase due to the limitations on water usage. These limitations can derive from ambient reasons (dry land design) or from political reasons that can force to the limitation on water consumption.
For the same reasons, also the overall GT performance, gross power output and flue gas characteristics in the dry land cases have been kept constant to the wet land figures.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the main process units is:

Unit		Trains
1000	Gasification	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 TGT	2 x 100% 1 x 100%
3000	Gas Turbine (PG – 9351 - FA) HRSG Steam Turbine	2 x 50% 2 x 50% 1 x 100%

2. Process Description

2.1. Overview

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

Case 5.07 is an IGCC power plant, based on GEE gasification technology, fed with bituminous coal and not provided with CO_2 capture Unit. The design is a market based design.

Due to the installation in a severely limited water supply area and far from the seaside, changes have been made on some process and utilities Units, compared with the reference case 5.05. The main peculiarities of the present case 5.07 are the deletion of the seawater cooling system, being the cooling effect provided by aircoolers and by machinery cooling water, and the installation of a Flue Gas Direct Contact Cooler system for condensing and recovering part of the water contained in the flue gas.

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.
As shown in paragraph 2.7, the gasification unit capacity has been kept constant as the relevant reference case 5.05.

The Gasification Unit includes the following sections:

- Coal Grinding/Slurry Preparation
- Gasification
- Slag Handling
- Black Water Flash
- Black Water Filtration

No modification of the equipment arrangement of the Gasification Island valid for case 5.05 has been judged necessary, when installing the power plant in a severely limited water supply area far from the seaside. Thus, for the Gasification Island of the present case 5.07 the same description as for the reference case 5.05 is still valid (see Report # 4, section B).

2.3. Unit 2100 – Air Separation unit

The Air Separation Unit is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

As regards the equipment arrangement of Unit 2100, case 5.07 differs from reference case 5.05 only for the type of coolers: in case 5.07 compressor intercoolers are aircoolers instead of sea water coolers, as used in case 5.05. Apart from this modification, the considerations relevant to Unit 2100 present in Report # 4, section B, are still valid.
The impact of the installation in a dry land country and far from the seaside is significant, in terms of power consumption: the power required by ASU compressor is increased by about 3%, compared with the relevant reference case 5.05, and the power required by the intercooler fan motors is to be added. It results that the power required by ASU in case 5.07 is about 4.5 MW higher than in the reference case 5.05 to the detriment of the power plant net power output.

2.4. Unit 2200 - Syngas Treatment and Conditioning line

This Unit receives the raw syngas from the gasification section, which is hot, humid and contaminated with acid gases, CO_2 and H_2S, and other chemicals, mainly COS, HCN and NH_3. In this Unit COS is hydrolyzed to H_2S and the gas is prepared for being fed to the following AGR Unit (Acid Gas Removal Unit). The clean syngas from AGR is then received and treated so that the proper conditions of temperature and pressure are met in order to achieve in the combustion process of the gas turbine the desired environmental performance and stability of operation.

As regards the equipment arrangement of Unit 2200, case 5.07 differs from reference case 5.05 only for the installation of a new aircooler (Syngas Trim Cooler) on the syngas line to AGR Unit between the Condensate Preheater 1-E-2207A/B and the Separator 1-E-2205. This aircooler is necessary in case 5.07 for delivering the syngas to AGR Unit at the required temperature (38°C), since the Condensate Preheater 1-E-2207A/B is no more able to provide all the required cooling effect. This is due to the fact that steam condensate from steam turbine condenser is generated at a higher temperature (40°C in case 5.07 vs. 21°C in case 5.05).
Apart from this modification, the description of Unit 2200 present in Report # 4, section B, is still valid.

2.5. Unit 2300 - Acid Gas Removal (AGR)

In this Unit H_2S and CO_2 are removed from syngas, by washing it with Selexol in an absorption column. Selexol rich in acid compounds is then regenerated in a stripping column and recycled to the absorption column.
All the considerations done in Report # 4, Section B, for the reference case 5.05 apply also to the present case.
As regards the equipment arrangement of Unit 2300, case 5.07 differs from reference case 5.05 only for the type of coolers: the sea water coolers present in case 5.05 are replaced with aircoolers in case 5.07.

2.6. Unit 2400 - SRU and TGT

This Unit 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 is based on Claus process.
No modification of the equipment arrangement of the SRU Unit valid for case 5.05 has been judged necessary, when installing the power plant in a severely limited water supply area far from the seaside. Thus, for the SRU Unit in the present case 5.07 the same considerations as for the reference case 5.05 are still valid (see Report # 4, section B).

2.7. 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 PG – 9351 - FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.
The gas turbine considered here is the same machine used in the relevant reference case 5.05. Considering that in the dry land cases the average ambient temperature is slightly higher than in the wet land cases, it has been evaluated that the GT appetite should be reduced by approximately 2%. Nevertheless, the appetite of GT and consequently the gasification capacity has been kept constant in order to see clearly the impact of the dry land design on performance and costs of the IGCC without the additional impact of the ambient temperature. Same considerations apply to the GT performance (gross power output, flue gas characteristics, etc…) that are maintained constant with respect to the performance of the machine in the reference wet land case.

As regards the steam turbine system, the major difference with the reference plant, case 5.05, is that the exhaust steam from the LP turbine is condensed in an aircooler and not in a sea water condenser. The condensing system with aircooler allows reaching lower steam turbine performances, since the condensing pressure that can be achieved by the air condenser is significantly higher (0.074 bara with aircooler vs 0.040 bara with sea water condenser). Therefore, condensate is generated in the condenser at higher temperature: 40°C using aircooler vs 21°C using sea water condenser.

In the present power plant, in order to reduce the request of raw water from outside the power plant battery limit, the condensation and recovery of part of the steam contained in the exhaust flue gases at stack is carried out.
Due to the additional pressure drops in the new condensing system, an additional flue gas fan is installed downstream of the HRSG.
The flue gas then passes through a Gas Gas Heat Exchanger (GGH), where flue gas from HRSG is cooled in one side, whereas in the other one the flue gas from Direct Contact Cooler is heated up. As for the GGH, an exchanger manufactured by GEA has been chosen: namely, a Rekugavo type exchanger. Rekugavo is a one stage counter flow plate-type heat recuperator, whose heating surface consists of shaped plates welded together and assembled into heat exchanger modules. The gas streams flow over the plates in counter flow to one another. It is claimed the welded shaped plates guarantee a high thermal efficiency, while maintaining the gases separate from each other, ensuring leak free operation.

Cooled flue gas from Rekugavo GGH is then partially condensed in the Flue Gas Direct Contact Cooler (FG DCC) system. FG DCC system of each HRSG consists of four vertical columns (due to size reasons), where the flue gas enters at the bottom and is cooled by contacting a stream of water, which is sprayed at the top. Due to the cooling effect, part of the water contained in the flue gas is condensed and collected at the towers bottom. The water circuit includes pumps for disposing of the excess of condensed water to the Waste Water Treatment plant and recycling part of the water to the spray nozzles at the top of the column, passing through an aircooled heat exchanger.
Flue Gas from the top of the contacting columns is heated up in the Rekugavo GGH and finally delivered to the stack.

2.8. 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:
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

2.8.1. Waste Water Treatment

The Waste Water Treatment plant required for the power plant case 5.07 includes some specific units necessary for reducing pollutants concentration and allowing reutilization of water. Their description follows hereafter.

Sulphites oxidation

The condensate water from flue gas condensate is contaminated with sulphites, differently from the other polluted streams. For this reason this stream is treated separately from the other polluted streams and then rejoined with the other in the equalization tank.
In order to remove HSO_3^-, hydrogen peroxide is added, giving as reaction product sulphuric acid.
The contact time that permits sulphites oxidation is circa 30 minutes and the oxidation basin is normally designed considering this parameter.
The oxidation basin can be equipped with an adequate number of mixers in order to favour a close contact between the reagents.

Equalization

The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed in order to make uniform the physical characteristics of the waste water to be fed to treatment (e.g. pollutants concentration, temperature, etc.).
So the different contaminated streams are sent to an equalization basin in order to make uniform the wastewater characteristic and optimize the following treatment units.

Equalization basin is normally designed in order to guarantee a hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

Physical-Chemical treatment

This section consists of two basins in series, where chemicals are added for chemical coagulation, flocculation and for specific pollutants removal. The purpose of wastewater clariflocculation is to form aggregates or flocs form finely divided particles and from chemical destabilized particles in order to remove them in the following sedimentation step.
In the first basin, coagulation basin, a coagulant as Ferric Chloride is added and a flash-mixing is performed. This basin is designed in order to guarantee a contact time of circa 5 minutes and specific mixing power of some hundreds of watts per cubic meter.
Simultaneously with ferric chloride, Ferrous Sulphate is added in order to remove H_2S. As the present reaction gives an acid contribution, NaOH is added in order to neutralize the sulphuric acid produced.
In the second basin, flocculation basin, polyelectrolyte is added and slow-mixing is performed. This basin is designed in order to guarantee a contact time of circa 25 minutes and a specific mixing power of some tens of watts per cubic meter.
In the flocculation basin H_2S oxidation and H_2SO_4 neutralization are also completed.

Chemical sludge settling

Effluent water from coagulation/flocculation section flows into a clarification basin where solids separation is performed and all setteable compounds are removed.
The produced sludge, constituted by settled solids, is removed from the bottom of each clarifier by a scraper.
The basin is designed in order to guarantee a contact time of about 2 hours and a surface loading rate of 1.5 $m^3/m^2/h$.

Sludge treatment

Chemical sludge from chemical sludge settler is subjected to a chemical conditioning in order to favour the sludge dewatering.
Ferric Chloride (10-30 mgFeCl3/kgSST) and polyelectrolyte (1-3 mgPoly/kgSST) are added in order to favour solids aggregation and to improve the subsequent dewatering treatment.
The conditioned sludge is so sent to a dewatering system (i.e. centrifugal system) in order to achieve a dry solids content of minimum 20%. The separated supernatant,

rich in suspended solids, is sent back to chemical treatment while the dewatered sludge is sent to final disposal.

Aerated lagoon

The clarified water from chemical sludge settler is sent to aerated lagoon in order to remove the organic load, expressed as COD and BOD, still present in the polluted water.
An aerated lagoon is an underground basin with a limited deepness (2-4 m), equipped with mechanical aerators in order to provide oxygen for biological degradation and to permit to keep solids in suspension.
Because a suspended growth aerobic flow-through lagoon can be considered to be a completely-mix reactor without recycle, the basis of design is SRT (sludge retention time) which, in this case, is equal to HRT (hydraulic retention time). This parameter ranges between 3 and 6 days for lagoons treating domestic wastes while can assume higher value for industrial wastes.
The oxygen required varies from 0.7 to 1.4 times the amount of BOD removed, while the mixing power ranges between 5 and 8 W/m3.
Despite of the requirement of big areas, aerated lagoons guarantee management simplicity and a low maintenance.
In order to remove part of present suspended solids an adequate calming section has to be designed with an hydraulic retention time of 24h circa.

Sand Filtration

The clarified water from aerated lagoon is delivered to the top of the sand filter bed in order to remove the remaining unsetteable solids.
As the water passes through the filter bed, the suspended matter in the wastewater is intercepted. With the passage of time, as material accumulates within the interstices of the granular medium, the headloss through the filter start to build up beyond the initial value. When the operating headloss through the filter reaches a predetermined headloss value, the filter must be cleaned.
The filters are designed in function of different parameters:

- Wastewater flowrate and characteristics;
- Granular medium geometric and dimensional characteristics;
- Admissible headloss and admissible filtration velocity;
- Flow control type.

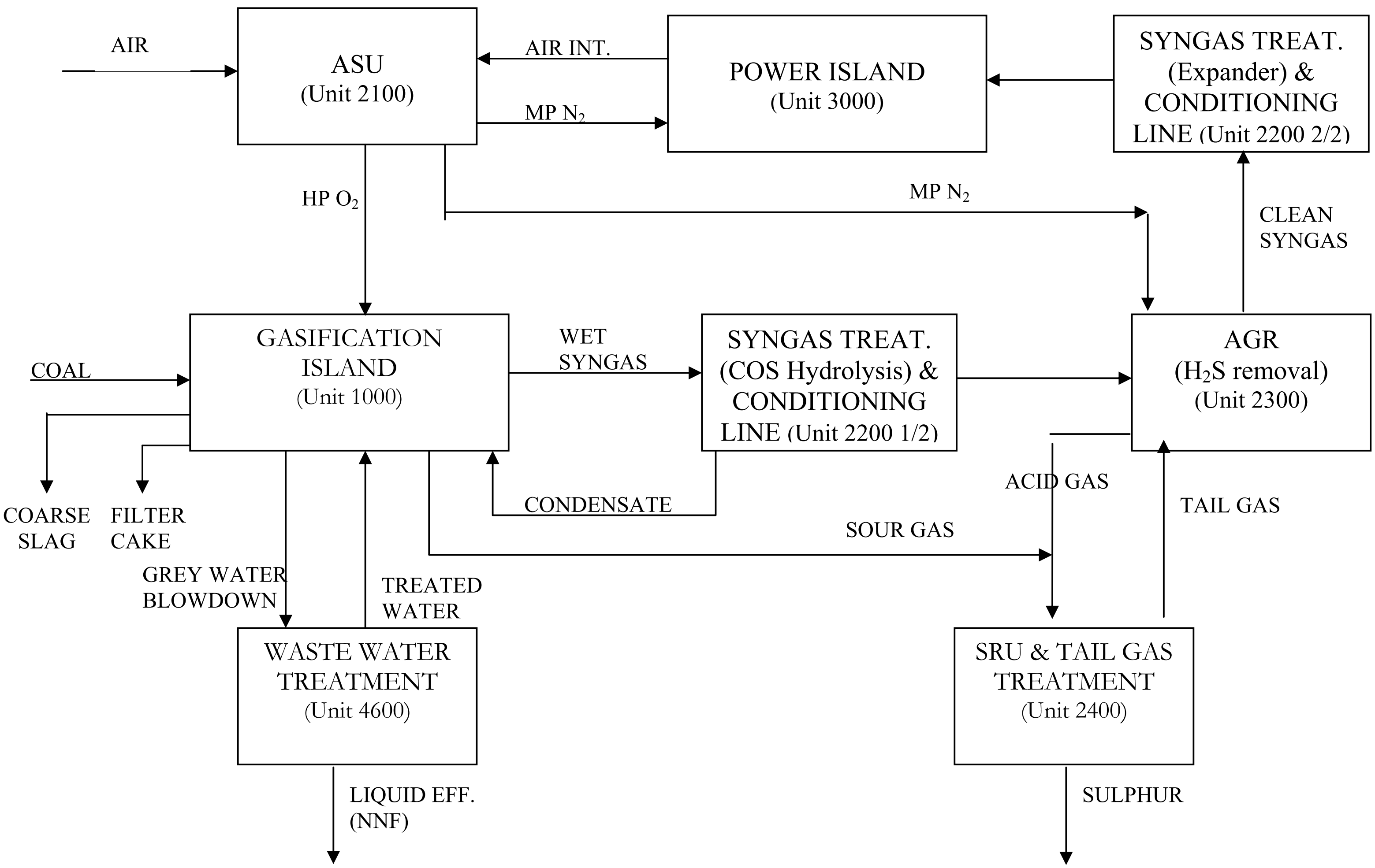
3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagrams of the GEE IGCC, Case 5.07, and the schematic Process Flow diagram of Units 2100, 2200, 2300, 2400, 3000 and WWT plant are attached hereafter.

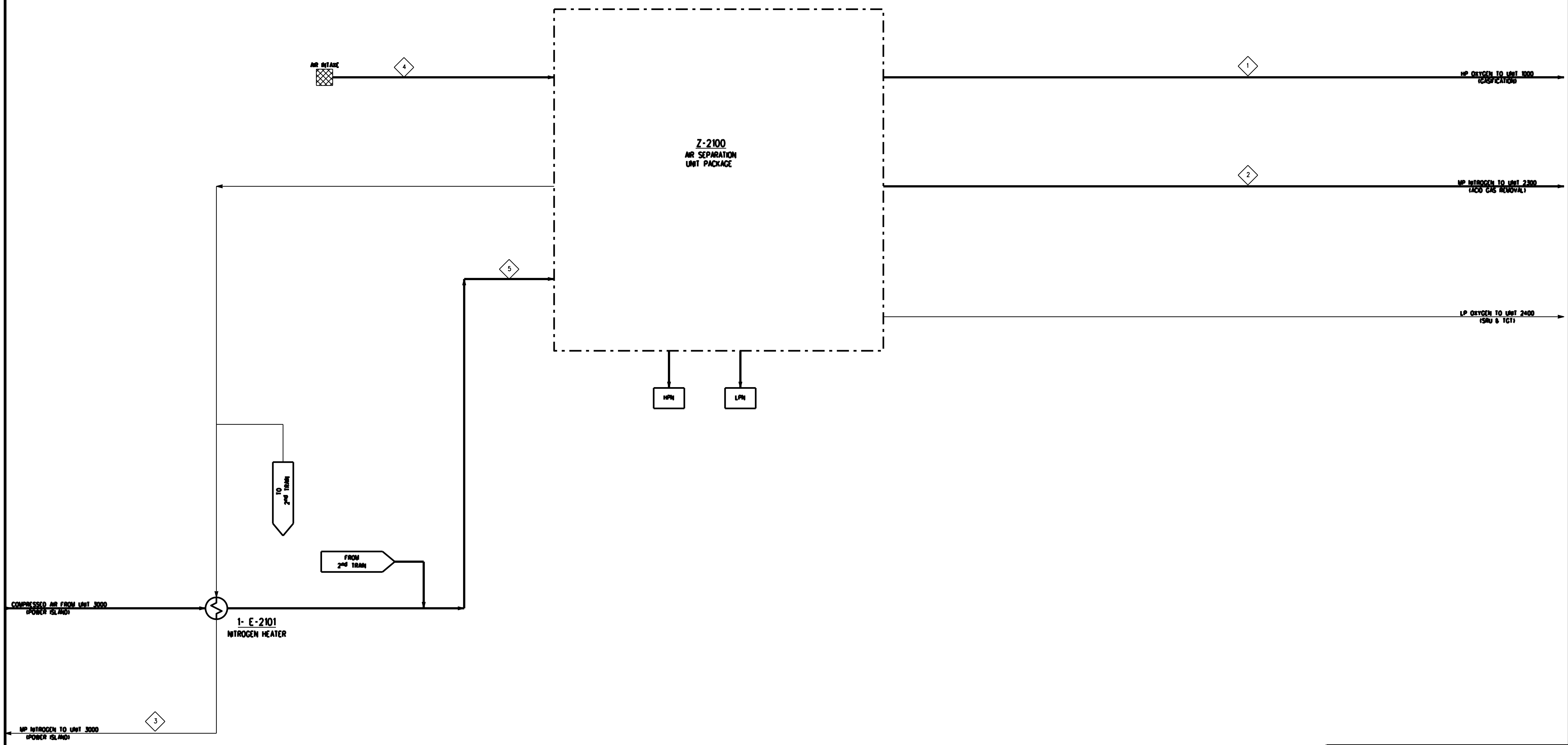
The Diagrams included in the Report # 4, section B (i.e. GEE IGCC, case 5.05) have been taken as reference for the Diagrams relevant to the present plant, case 5.07. Modifications required due to installation in a dry land country and far from the seaside have been highlighted in the drawings attached.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

GEE 5.07 – IGCC COMPLEX BLOCK FLOW DIAGRAM



Case 5.07 - GE IGCC without CCS - DRY LAND



LEGEND

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☐ YES ☐ NO HAND MODIFICATION

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

GE IGCC - CASE 5.07
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

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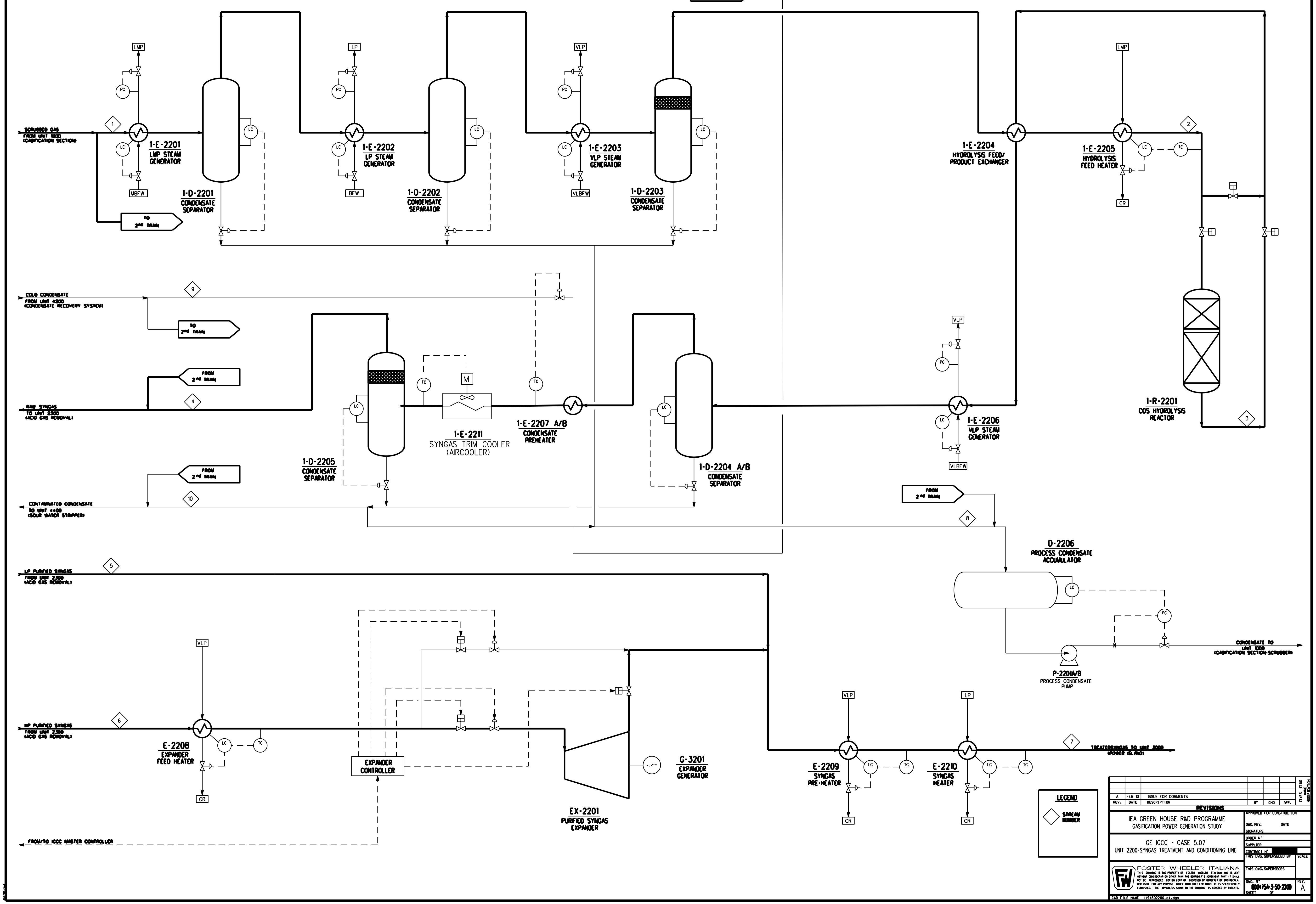
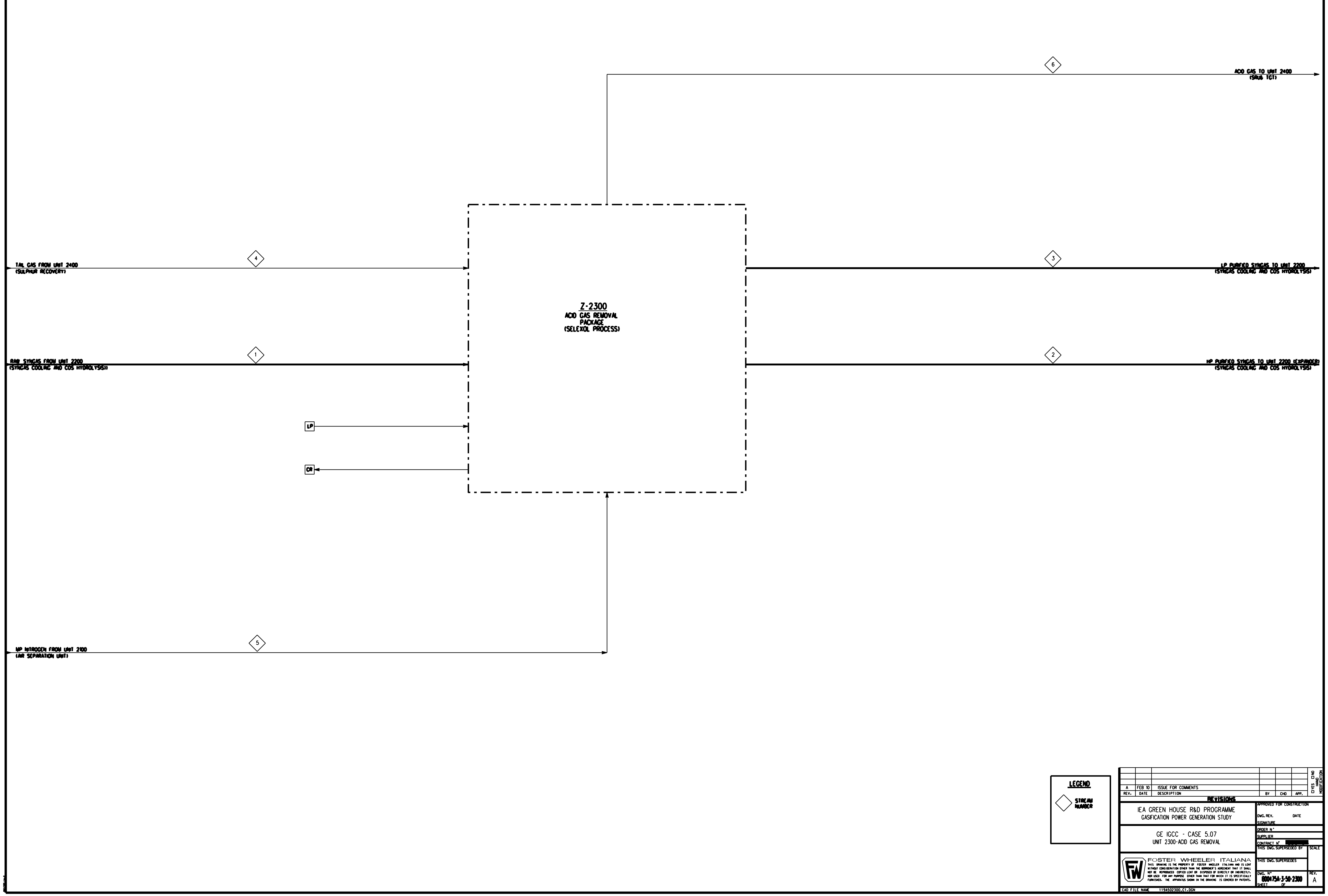
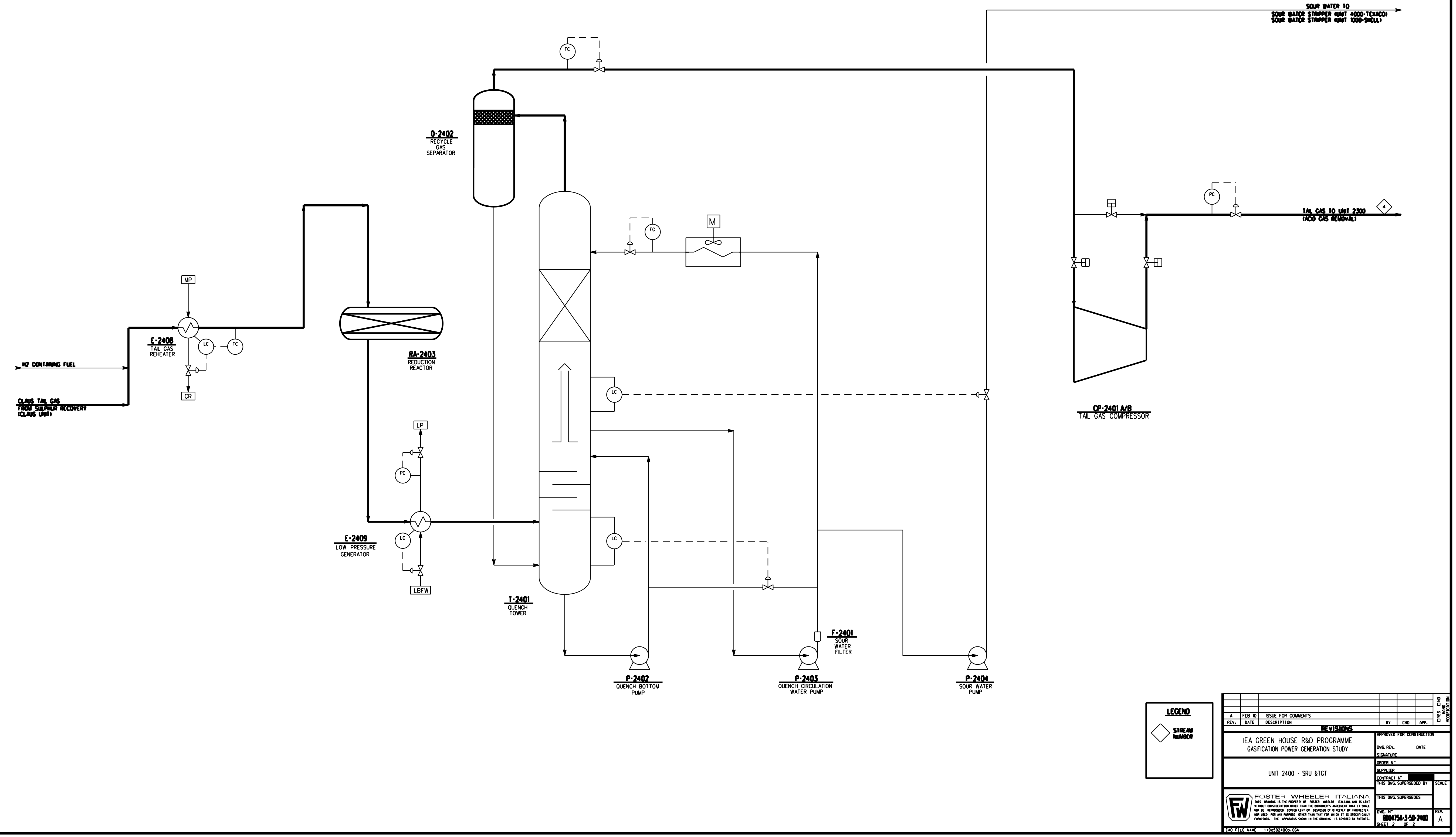
Case 5.07 - GE IGCC without CCS - DRY LAND



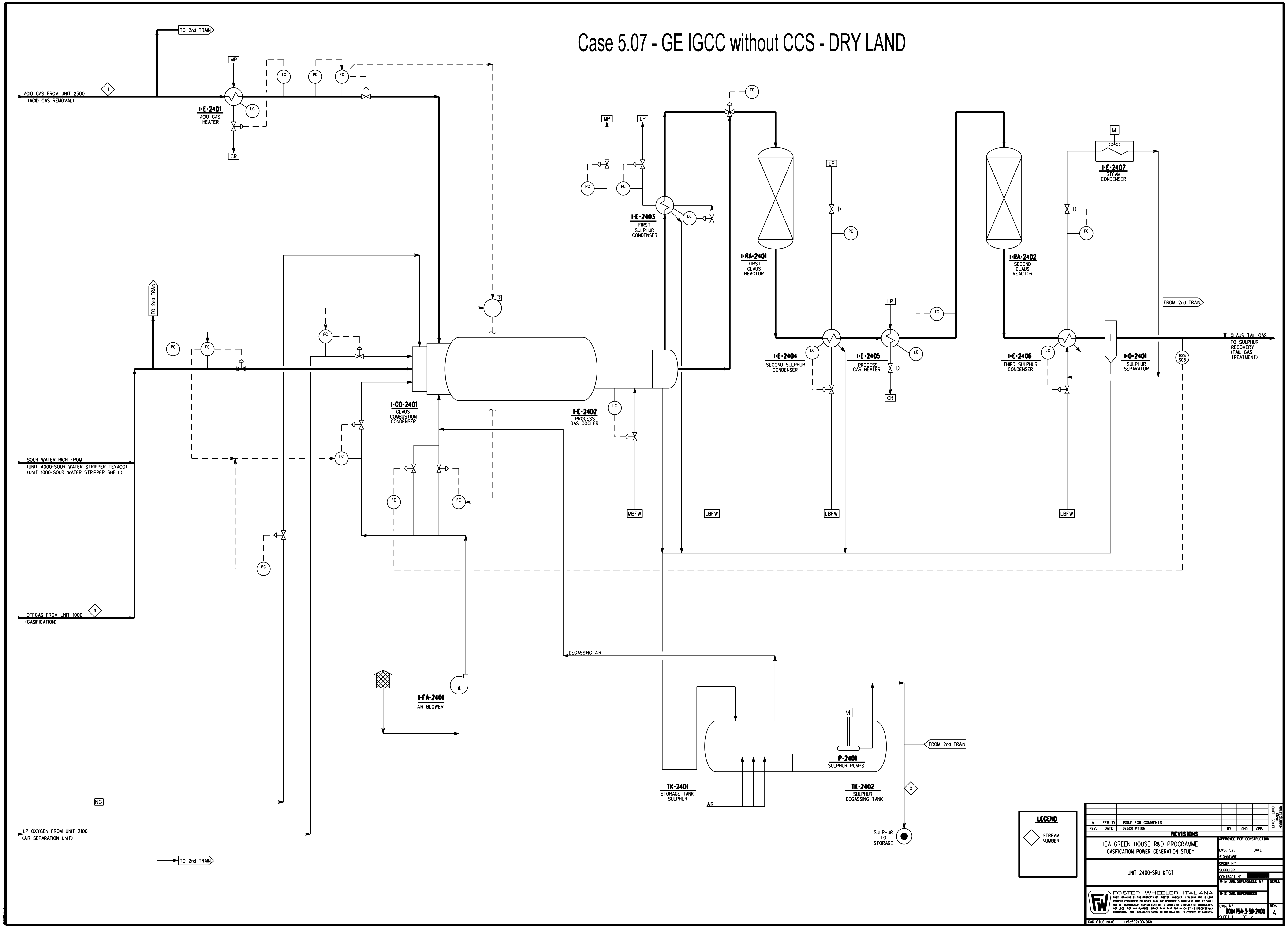
Case 5.07 - GE IGCC without CCS - DRY LAND



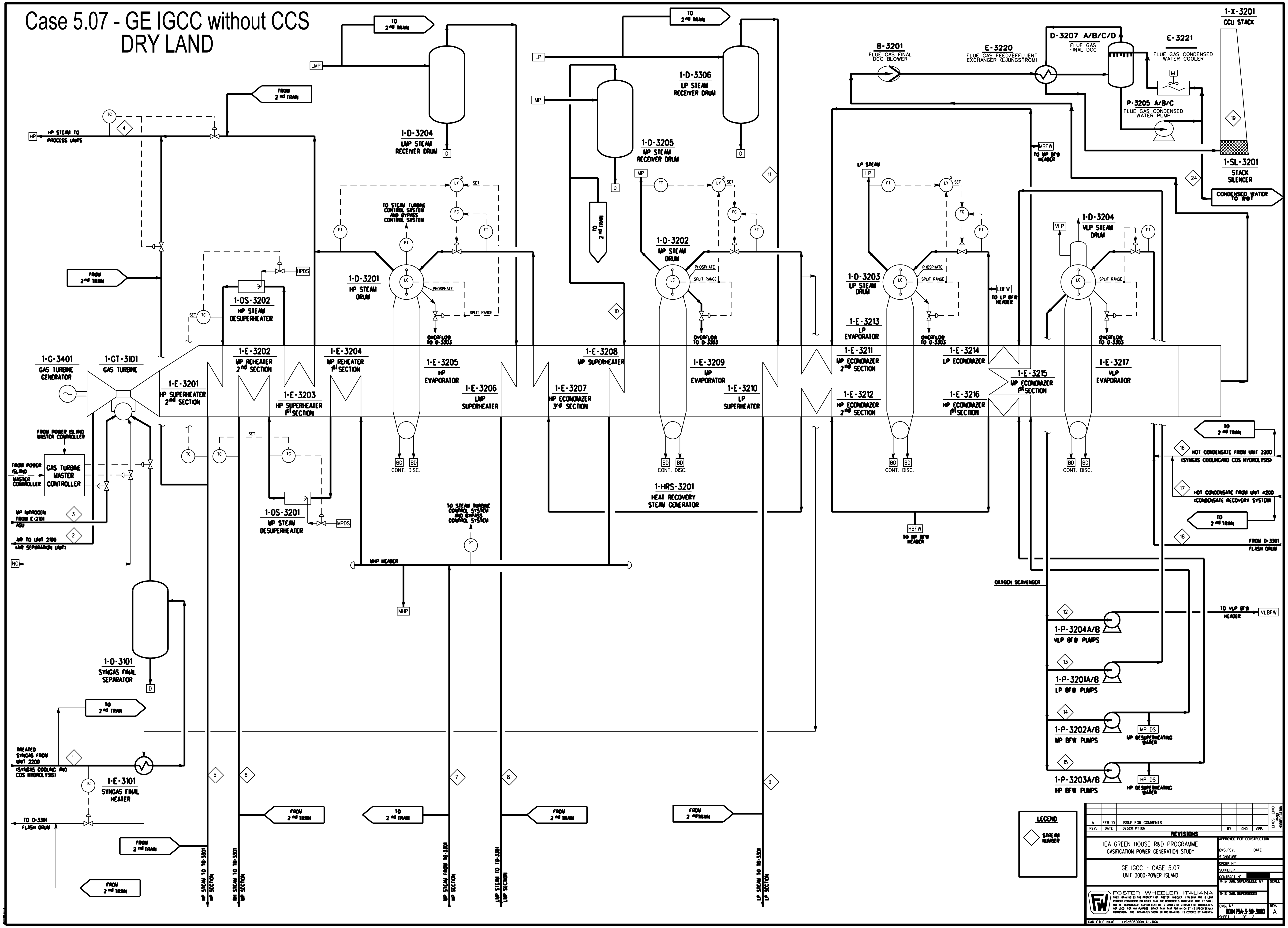
Case 5.07 - GE IGCC without CCS - DRY LAND

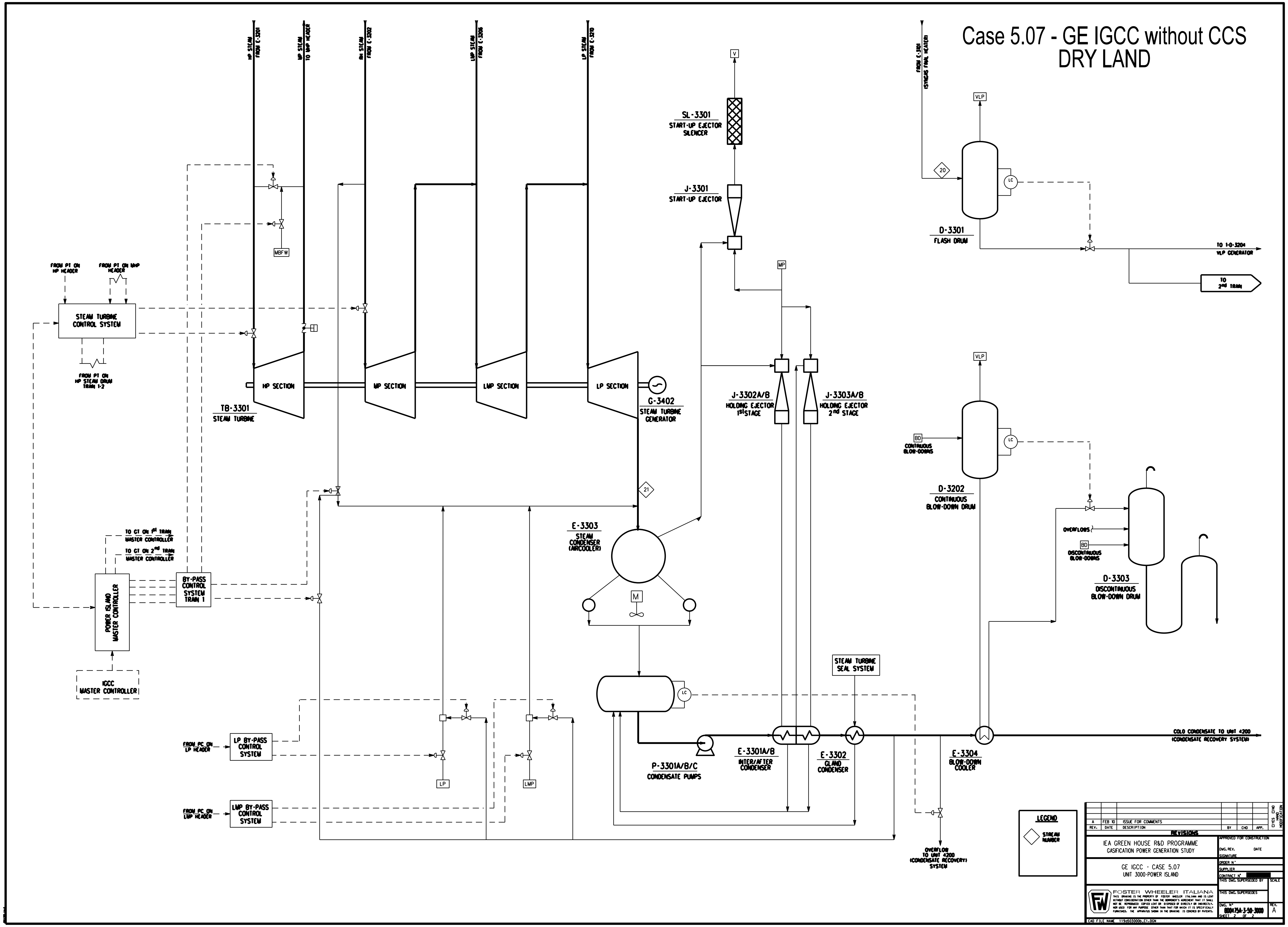


Case 5.07 - GE IGCC without CCS - DRY LAND



Case 5.07 - GE IGCC without CCS
DRY LAND





Case 5.07 - GE IGCC without CCS
DRY LAND
HP STEAM FROM E-3201
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LMP STEAM FROM E-3206
LP STEAM FROM E-3210
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MBFW
MP
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM TRAIN 1-2
HP SECTION
MP SECTION
LMP SECTION
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3101 (SYNGAS FINAL HEATER)
VLP
20
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
VLP
BD
CONTINUOUS BLOW-DOWNS
D-3202
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
BD
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
21
E-3303
STEAM CONDENSER (AIRCOOLER)
M
TO GT ON 1st TRAIN MASTER CONTROLLER
TO GT ON 2nd TRAIN MASTER CONTROLLER
POWER ISLAND MASTER CONTROLLER
BY-PASS CONTROL SYSTEM TRAIN 1
IGCC MASTER CONTROLLER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
LMP
FROM PC ON LMP HEADER
LMP BY-PASS CONTROL SYSTEM
P-3301A/B/C
CONDENSATE PUMPS
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
E-3304
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
LEGEND
STREAM NUMBER
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REV. DATE DESCRIPTION BY CHD APP.
YES NO HAND MODIFICATION
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
GE IGCC - CASE 5.07
UNIT 3000-POWER ISLAND
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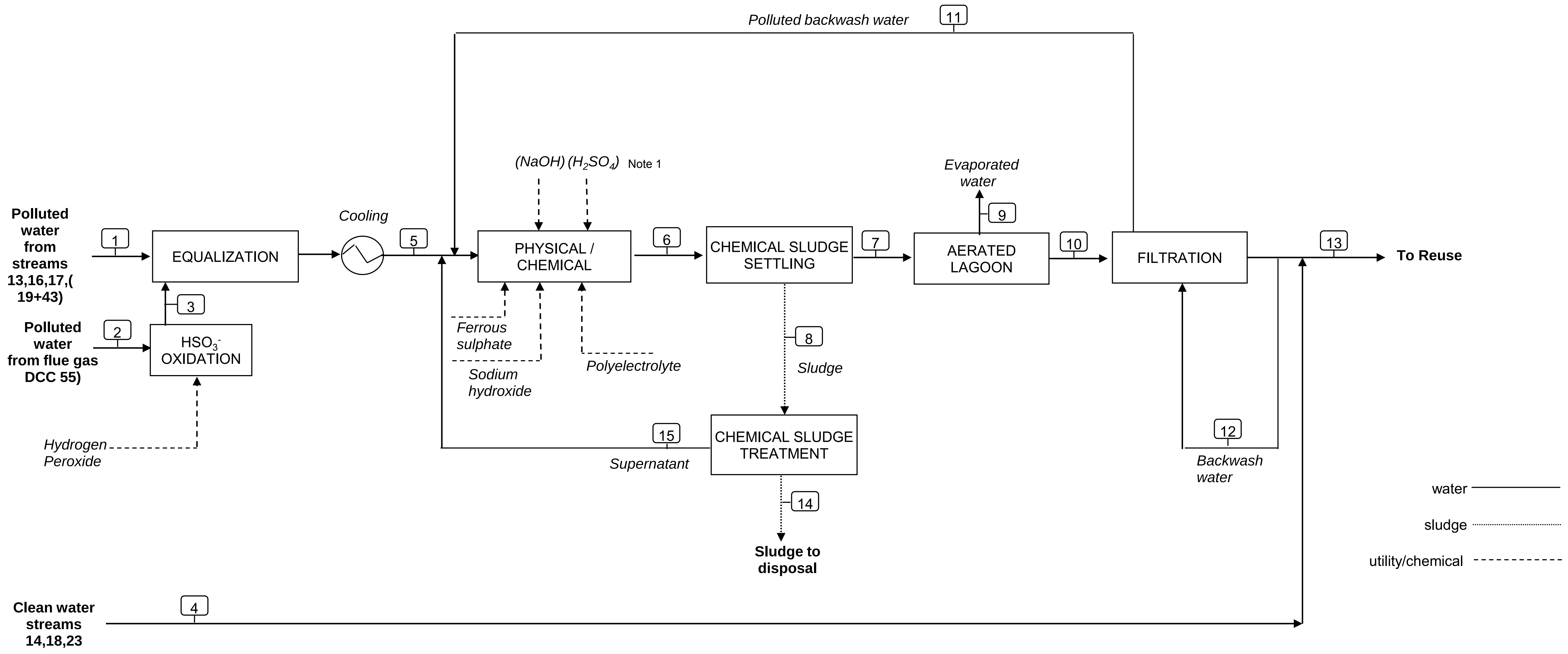
CASE 5.07 - GE IGCC, BITUMINOUS COAL FEED WITHOUT CO_2 CAPTURE (DRY LAND) – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



Notes:
1. Sulphuric acid or Caustic soda can be foreseen for pH adjustemnt; dosage is done under pH controll in order to mantain the pH at about 9.5
2. If the condition for water reuse requires better characteristics in terms of hardness, a specific softening treatment can be foreseen for Demi Plant Blowdown (stream "19+43")

4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

- detailed water flow diagram relevant to the entire power plant;
- water balance around the major units;
- flowrates and compositions of the streams of water to waster water treatment unit.

It is important to note that the introduction of a Flue Gas Direct Contact Cooler allows the recovery of a significant amount of water from flue gases. This water is mixed with other polluted water streams and sent to WWT unit, where contaminants are removed, so that treated water may be reused in the power plant itself in place of raw water.
It results that recycled treated water allows reducing the raw water demand, but it is not yet enough to allow a zero raw water intake.

The ambient temperature affects both the load of the plant and the minimum temperature that can be achieved in the air cooling systems.
The plant load in fact is influenced by the GT appetite that varies with the ambient air temperature. When the ambient temperature raises the GT appetite decreases and viceversa.
On the other hand, the higher ambient temperature leads to an higher temperature on the process streams downstream the air cooled exchanger. The material balance attached to water diagram is referred to the reference ambient temperature. Therefore, it is to be considered as an average between the cold and the warm season.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

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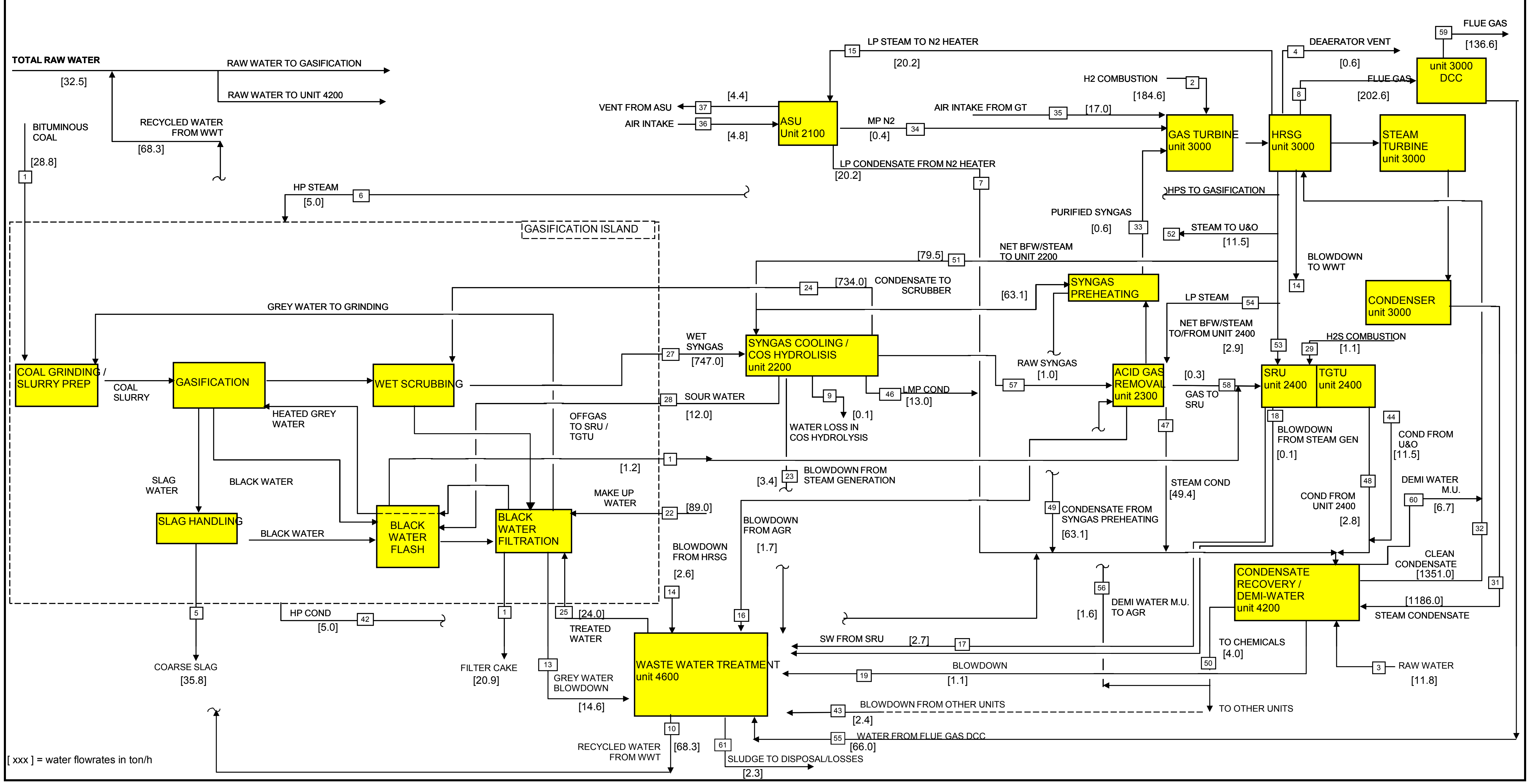
CASE 5.07 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITHOUT CO2 CAPTURE (NET POWER OUTPUT = 777.6 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



FOSTER WHEELER

IEA GHG R&D PROGRAMME	Revision no.: 1
Water usage and loss Analysis in Power plants without and with CCS	Date: November 2010
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GEE IGCC fed by bituminous coal, w/o CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	28.8	5	Slag	35.8
2	Syngas combustion of H2 in GT	184.6	4	Deaerator vent	0.6
3	Raw water to Demi Plant	11.8	11	Filter cake	20.9
36	Moisture in air to ASU	4.8	59	Flue gas from flue gas DCC	136.6
29	H2S combustion in SRU	1.1	9	Water loss in COS hydrolysis	0.1
35	Moisture in combustion air to GT	17.0	10	Water effluent from WWT	68.3
22	Raw Water make up to Gasific.	89.0	37	Moisture from ASU vent	4.4
			61	Sludge to disposal/losses	2.3
Total		337.2	Total		268.9

delta (note 1)
68.3

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Gasification Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	28.8	11	Filter cake	20.9
28	Sour Water to Stripping	12.0	5	Slag	35.8
24	Condensate to Wet Scrubber	734.0	27	Wet syngas	747.0
22	Make up to Grey Water Tank	89.0	12	Sour Gas	1.2
25	Treated water from WWT	24.0	13	Grey Water Blowdown	14.6
6	HP steam	5.0	42	HP condensate	5.0
Total		892.8	Total		824.5

delta (note 1)
68.3

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around WWT (unit 4600)

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
13	Grey Water Blowdown	14.6	25	Treated water to Gasifier	24.0
14	Blowdown from HRSG	2.6	10	Recycled water from WWT	68.3
43	Blowdown from other units	2.4	61	Sludge to disposal/losses	2.3
16	Blowdown from AGR	1.7			
17	Sour water from SRU	2.7			
18	Blowdown from SRU	0.1			
19	Blowdown from Demi Plant	1.1			
23	Blowdown from unit 2200	3.4			
55	Water from flue gas DCC	66.0			
Total		94.6	Total		94.6

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Cond Recovery/Demi Water Plant

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
3	Raw Water	11.8	32	Demi Water to HRSG and PRS ur	1351.0
31	Condensate from Steam Turbine	1186.0	19	Blowdown to WWT	1.1
44	Condensate from U&O	11.5	50	Demi water to chemicals	4.0
6	Condensate from Gasification	5.0	60	Demi water make up	6.7
7	Condensate from unit 2100	20.2			
46	Condensate from unit 2200	13.0			
47	Condensate from unit 2300	49.4			
48	Condensate from unit 2400	2.8			
49	Condensate from syngas preheating	63.1			
Total		1362.8	Total		1362.8

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around Power Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	17.0	59	Flue gas from flue gas DCC	202.6
2	Syngas combustion of H2 in GT	184.6	6	HP steam to Gasification	5.0
33	Water in syngas	0.6	52	Steam to U&O	11.5
34	Moisture in MP nitrogen from ASU	0.4	51	Net BFW/LMP steam to unit 2200	79.5
32	Clean condensate to HRSG	1351.0	54	MP steam to unit 2300	49.4
60	Demi water make up	6.7	53	Net BFW/Steam to unit 2400	2.9
			14	Blowdown from HRSG	2.6
			15	LP steam to N2 saturator HE	20.2
			31	Steam condensate from CCU	1186.0
			4	Deaerator vent	0.6
Total		1560.3	Total		1560.3

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around GT - HRSG

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	17.0	59	Flue gas from flue gas DCC	202.6
2	Syngas combustion of H2 in GT	184.6			
33	Water in syngas	0.6			
34	Moisture in MP nitrogen from ASU	0.4			
Total		202.6	Total		202.6

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around unit 2200

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
27	Wet syngas	747.0	24	Condensate to scrubber	734.0
51	Net BFW/LMP steam to unit 2200	79.5	46	LMP condensate	13.0
			9	Water lost to hydrolysis	0.1
			28	Sour water	12.0
			23	Blowdown from steam gen.	3.4
			57	Raw syngas	1.0
			49	Condensate from syn. preheat.	63.1
Total		826.5	Total		826.5

GEE IGCC fed by bituminous coal, w/o CO2 capture - Water Balance around AGR

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
57	Raw Syngas	1.0	58	Gas to SRU	0.3
56	Demiwater make up	1.6	33	Purified syngas	0.6
54	MP steam	49.4	47	Steam condensate	49.4
			16	blowdown from AGR	1.7
Total		52.0	Total		52.0

NOTE 1: Water balances around gasification island and around the entire Power Plant don't close to zero by the same amount. The difference between the streams of "water in" and "water out" is due to the shift reactions, occuring in the gasification island.

IEA GHG R&D PROGRAMME	Revision no.: 1
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CASE 5.07 - GEE IGCC, BITUMINOUS COAL FEED WITHOUT CO2 CAPTURE (DRY LAND) - WATER STREAMS SENT TO WWT

STREAM	13	14	16	17	18	19+43	23	55
SERVICE	Grey Water Blowdown	Blowdown from HRSG	Blowdown from AGR	Sour water from SRU	Blowdown from SRU	Blowdown from Demi Plant + other units	Blowdown from unit 2200	Water from flue gas DCC
Temperature (°C)	50	100	120	50	100	amb	100	40
Total flowrate (kg/h)	14600	2600	1700	2665	100	3500	3400	66000
Composition (ppm wt)								
SO2 / HSO3-								20
H2S	2		32	30				
CO2	0			100				150
NH3	25		5	10				
Na+	97					1090		
Cl-	148					4560		
PO4---		1			5		5	
SiO2		1			5	110	5	
CaCO3		20			100	406	100	
SO4--	25					830		
Sulfides	10							
CN-	< 5							
Formates	740							
NO3-						510		
Ca AAS						1410		
Mg AAS						420		
MDEA			3224					
HCO3-						250		
Suspended solids	100							352
K						30		
H2O (% wt)	99.8852	99.9978	99.6739	99.9860	99.9890	99.0384	99.9890	99.9478
TOTAL	100	100	100	100	100	100	100	100
NOTES:	NOC					**	*	

(*) = blowdown flowrate assumed equal to 0.5% steam production
(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

5. Heat and Material Balance

The Heat and Material Balance (H&MB), 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.

Modifications to the H&MB due to the installation of the power plant in a dry land country far from the seaside have been highlighted.
The H&MB relevant to WWT unit has also been included.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.07						APPROVED	SA		
	UNIT : 2100 AIR SEPARATION UNIT						DATE	March 2010		
STREAM	1	2	3	4	5					
	HP OXYGEN to Gasification	MP NITROGEN to AGR	MP NITROGEN to one GT	Air Intake from Atmosphere	AIR to ASU from GTs					
Temperature (°C)	148.9	149	213	AMB.	232					
Pressure (bar)	79.8	27	22.1	AMB.	14.1					
TOTAL FLOW										
Mass flow (kg/h)	261351	33600	362996	570972	570972					
Molar flow (kgmole/h)	8111	1200	12927	19791	19791					
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	261351	33600	362996	570972	570972					
Molar flow (kgmole/h)	8111	1200	12927	19791	19791					
Molecular Weight	32.22	28.00	28.00	28.87	28.87					
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	1.50	99.99	97.50	77.57	77.57					
O_2	95.00	0.01	2.15	20.86	20.86					
CH_4										
H_2S + COS										
Ar	3.50		0.26	0.89	0.89					
H2O			0.09	0.68	0.68					

	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.07						APPROVED	SA		
	UNIT : 2200 SYNGAS Treatment and conditioning line						DATE	March 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	SYNGAS from Scrubber	SYNGAS at COS Hydrolysis Inlet	SYNGAS at COS Hydrolysis Out	RAW SYNGAS to Acid Gas Removal	LP SYNGAS from Acid Gas Removal	HP SYNGAS from Acid Gas Removal	Treated SYNGAS to Power Island	Return Condensate to Scrubber	Cold Condensate from Unit 4200	Contaminated Condensate to SWS
Temperature (°C)	243	200	200	38	45	44	150	192	40	53
Pressure (bar)	63	60.3	59.3	55	26.0	54.9	26.5	66.7	10.0	55.0
TOTAL FLOW										
Mass flow (kg/h)	648960	306550	306550	138850	86400	501400	587800	366985	594850	6000
Molar flow (kgmole/h)	33800	14785	14785	13195	2550	24981	27531			
LIQUID PHASE										
Mass flow (kg/h)								366985	594850	6000
GASEOUS PHASE										
Mass flow (kg/h)	648960	306550	306550	138850	86400	501400	587800			
Molar flow (kgmole/h)	33800	14785	14785	13195	2550	24981	27531			
Molecular Weight	19.2	20.7	20.7	10.5	33.9	20.1	21.4			
Composition (vol %)										
H_2	15.10	34.6	34.6	38.8	4.41	40.56	37.21			
CO	15.60	35.7	35.7	40.1	6.22	41.70	38.41			
CO_2	7.30	16.6	16.6	18.7	43.88	15.52	18.14			
N_2	(1)	0.8	0.8	0.9	45.04	0.98	5.07			
O_2		0.0	0.0	0.0	0.00	0.00	0.00			
CH_4		0.0	0.0	0.0	0.00	0.02	0.02			
H_2S + COS	0.12	0.28	0.27	0.31	0.01	0.00	0.00			
Ar	(1)	1.0	1.0	1.1	0.19	1.11	1.03			
H2O	61.00	11.0	11.0	0.2	0.25	0.11	0.12			

Note (1): N_2 + Ar: 0.8% - Others: 0.08%

	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.07						APPROVED	SA		
	UNIT : 2300 Acid Gas Removal						DATE	March 2010		
STREAM	1	2	3	4	5	6	7	8	9	10
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP Purified Syngas to Syngas Cooling	Tail Gas from SRU	MP Nitrogen from ASU	Acid Gas to SRU & TGT				
Temperature (°C)	38	44	45	38	149	49				
Pressure (bar)	55.0	54.9	26.0	26.2	27.0	2.0				
TOTAL FLOW										
Mass flow (kg/h)	277700	501400	86400	9928	33600	9708				
Molar flow (kgmole/h)	26390	24981	2550	316	1200	296				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	277700	501400	86400	9928	33600	9708				
Molar flow (kgmole/h)	26390	24981	2550	316	1200	296				
Molecular Weight	10.5	20.1	33.9	31.4	28.0	32.8				
Composition (vol %)										
H_2	38.75	40.56	4.41	5.31	0.00	0.00				
CO	40.07	41.70	6.22	0.28	0.00	0.00				
CO_2	18.65	15.52	43.88	29.66	0.00	22.97				
N_2	0.93	0.98	45.04	63.36	99.99	43.02				
O_2	0.00	0.00	0.00	0.00	0.01	0.00				
CH_4	0.02	0.02	0.00	0.00	0.00	0.00				
H_2S	0.31	0.00	0.01	0.96	0.00	28.35				
Ar	1.07	1.11	0.19	0.25	0.00	0.00				
H2O	0.20	0.11	0.25	0.19	0.00	5.53				

	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE IGCC CASE 5.07						APPROVED	SA		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	March 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	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)	2.0		1.0	26.2						
TOTAL FLOW										
Mass flow (kg/h)	9708	61.9 t/d	4037	9928						
Molar flow (kgmole/h)	296		191	316						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	9708		4037	9928						
Molar flow (kgmole/h)	296		191	316						
Molecular Weight	32.8		21.2	31.4						
Composition (vol %)										
H_2	0.00		21.15	5.31						
CO	0.00		28.45	0.28						
CO_2	22.97		13.49	29.66						
N_2	43.02		0.00	63.36						
O_2	0.00		0.00	0.00						
CH_4	0.00		0.00	0.00						
H_2S	28.35		1.14	0.96						
Ar	0.00		0.00	0.25						
H2O	5.53		35.77	0.19						

IGCC HEAT & MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : GEE IGCC CASE 5.07
UNIT : 3000 POWER ISLAND

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	Treated SYNGAS from Syngas Cooling (*) (1)	293.85	150	26.5	194.8
2	Extraction Air to Air Separation Unit (*)	285.49	402	14.6	-
3	MP Nitrogen from ASU (*)	363.00	213.00	22.10	-
4	HP Steam to Process Units	5.00	340	85.0	2935.6
5	HP Steam to Steam Turbine (*)	255.68	552	156.5	3447
6	Hot RH Steam to Steam Turbine (*)	311.13	537	36.7	3532
7	MP Steam from Steam Turbine (*)	255.68	344	39.7	3080
8	LMP Steam to Steam Turbine (*)	170.30	350	20.0	3138
9	LP Steam to Steam Turbine (*)	111.82	237	6.2	2930
10	MP Steam to MP -Superheater (*)	55.45	251.8	41.0	2800
11	LP Steam to LP Superheater (*)	111.82	166.8	7.2	2765
12	BFW to VLP Pumps (*)	28.30	119	1.9	499
13	BFW to LP BFW Pumps (*)	170.18	119	1.9	499
14	BFW to MP BFW Pumps (*)	277.83	119	1.9	499
15	BFW to HP BFW Pumps (*)	259.47	119	1.9	499
16	Hot Condensate returned from Unit 2200 (*)	594.85	92	2.5	348
17	Hot Condensate returned from CR (*)	82.25	94	2.5	394
18	Water from Flash Drum (*)	36.55	119	2.5	499
19	FLUE GAS AT STACK (*) (2)	2624.1	107	AMB.	117
20	Condensate from Syngas Final Heater (*)	87.82	118	2.5	495
21	LP Steam Turbine Exhaust	1189.70	40	0.074	2249
22	Not Used				
23	Not Used				
24	Condensed water to WWT (*)	33	34	3.0	144

(*) flowrate for one train
(1) Syngas Composition as per stream 7 of Material Balance for Unit 2200
(2) Flues gas molar composition: N_2: 75.1%; H_2O: 4.6%; O_2: 10.7%; CO_2: 8.6%; Ar: 1.0%.

CASE 5.07 - GE IGCC, BITUMINOUS COAL FEED WITHOUT CO_2 CAPTURE (DRY LAND) – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM

STREAM		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Parameter	**Unit**	**polluted streams 13,16,17,(19+43) to equalization**	**polluted flue gas water (55) to HSO3- oxidation unit**	**treated flue gas water to equalization**	**Total clean stream 14,18,23**	**Water from equalization tank**	**Water to chemical sludge settling**	**Water to aerated lagoon**	**Chemical sludge**	**Evaporated water**	**Water to filtration**	**Backwash water**	**Polluted backwash water**	**Water to reuse**	**Supernatant from dewatering**	**Chemical sludge to disposal**
Temperature	(°C)	46,09	45,00	45,00	100,00	30,00	30,00	30,00	30,00	30,00	30,00	30,00	30,00	30,00	30,00	30,00
Total Flow	(ton/h)	23,30	66,000	66,00	6,10	89,30	94,90	93,70	1,20	3,00	90,70	4,54	4,54	92,27	1,07	0,13
H2S	(mg/l)	13,89	0,00	0,00	0,00	3,62	0,50	0,50	0,50		0,52	0,52	0,52	0,48	0,50	0,50
NH3 mg/l	(mg/l)	17,81	0,00	0,00	0,00	4,65	4,65	4,65	4,65		4,81	4,81	4,81	4,49	4,65	4,65
mg/l	(mg/l)	233,08	0,00	0,00	0,00	60,81	60,91	60,91	60,91		62,92	62,92	62,92	58,76	60,91	60,91
Cl- mg/l	(mg/l)	806,71	0,00	0,00	0,00	210,48	210,81	210,81	210,81		217,78	217,78	217,78	203,39	210,81	210,81
PO4--- mg/l	(mg/l)	0,00	0,00	0,00	3,30	0,00	0,00	0,00	0,00		0,00	0,00	0,00	0,22	0,00	0,00
SiO2 mg/l	(mg/l)	17,14	0,00	0,00	3,30	4,47	4,47	4,47	4,47		4,62	4,47	4,47	4,39	4,47	4,47
CaCO3 mg/l	(mg/l)	63,25	0,00	0,00	65,90	16,50	16,53	16,53	16,53		17,07	17,07	17,07	20,30	16,53	16,53
SO4-- mg/l	(mg/l)	145,56	0,00	23,11	0,00	55,06	70,00	70,00	70,00		72,31	72,31	72,31	67,53	70,00	70,00
NO3- mg/l	(mg/l)	79,46	0,00	0,00	0,00	20,73	20,76	20,76	20,76		21,45	21,45	21,45	20,03	20,76	20,76
Ca mg/l	(mg/l)	219,68	0,00	0,00	0,00	57,32	57,41	57,41	57,41		59,30	59,30	59,30	55,39	57,41	57,41
Mg mg/l	(mg/l)	65,44	0,00	0,00	0,00	17,07	17,10	17,10	17,10		17,67	17,67	17,67	16,50	17,10	17,10
MDEA mg/l	(mg/l)	243,97	0,00	0,00	0,00	63,66	61,16	61,16	61,16		12,23	12,23	12,23	11,42	61,16	61,16
K+ mg/l	(mg/l)	4,67	0,00	0,00	0,00	1,22	1,22	1,22	1,22		1,26	1,26	1,26	1,18	1,22	1,22
HCO3 mg/l	(mg/l)	38,95	0,00	0,00	0,00	10,16	10,18	10,18	10,18		10,51	10,51	10,51	9,82	10,18	10,18
TSS mg/l	(mg/l)	82,13	352	352	3,30	281,58	379,58	100,00	22541,44		60,00	10,00	2056,13	9,56	200,00	222826,09
COD mg/l	(mg/l)	797,84	0,00	0,00	0,00	208,17	200,45	200,45	200,45		120,00	49,00	49,00	45,76	200,45	200,45
BOD mg/l	(mg/l)	438,81	0,00	0,00	0,00	114,49	110,25	110,25	110,25		66,00	26,95	26,95	25,17	110,25	110,25
CN- tot. mg/l	(mg/l)	3,25	0,00	0,00	0,00	0,85	0,25	0,25	0,25		0,26	0,26	0,26	0,24	0,25	0,25
Formiates mg/l	(mg/l)	480,92	0,00	0,00	0,00	125,48	120,56	120,56	120,56		24,11	24,11	24,11	22,52	120,56	120,56
SO2/HSO3-	(mg/l)	0,00	20,00	0,50	0,00	0,37	0,37	0,37	0,37		0,38	0,38	0,38	0,36	0,37	0,37
H2O	(mg/l)	100	100	100	100	100	100	100	98	100	100	100	100	100	100	80

General notes

1. Present mass balance is indicative only and related to the process treatment selected.

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. Italic font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.05 (see Report # 4, section B).
WWT utility consumption is also attached.

FOSTER WHEELER

CLIENT: IEA GHG R&D PROGRAMME
PROJECT: WATER USAGE AND LOSS ANALYSIS
LOCATION: SOUTH AFRICA
FWI Nº: 1- BD 0475A

REVISION	Draft	Rev.1	Rev.2	Rev. 3
DATE	March 2010			
ISSUED BY	L.So.			
CHECKED BY	PC			
APPROVED BY	SA			

CASE 5.07 - UTILITIES CONSUMPTION SUMMARY - GEE IGCC - HP w/o CO_2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 85 barg [t/h]	LMP Steam 20 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**		**5.0**								**5.0**	
2100	**Air Separation Unit**				**20.2**						**20.2**	
2200	**Syngas Cooling and COS Hydrolysis**			**-339.3**	**-250.6**	**-10.5**		*354.1*	*268.9*	*56.9*	**76.1**	*3.4*
2300	**Acid Gas Removal**				*49.4*						*49.4*	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-1.3**	**-1.1**			**4.2**	**1.1**		**2.8**	**0.1**
3000	**POWER ISLANDS UNITS**		**-5.0**	**340.6**	*170.6*	**10.5**		*-358.3*	*-270.0*	*-56.9*		
4000 to 5300	**UTILITY and OFFSITE UNITS**				**11.5**						**11.5**	
	BALANCE		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	*165.0*	*3.5*

Note: (1) Minus prior to figure means figure is generated
(2) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.05.

FOSTER WHEELER		
CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
PROJECT:	WATER USAGE AND LOSS ANALYSIS	March 2010
LOCATION:	SOUTH AFRICA	ISSUED BY: L.So.
FWI Nº:	1- BD 0475A	CHECKED BY: PC
		APPR. BY: SA

CASE 5.07 - WATER CONSUMPTION SUMMARY - GEE IGCC - HP w/o CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water (2) [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**89.0**		*3529*	
2100	**Air Separation Unit**				SEA WATER IS NOT AVAILABLE IN POWER PLANTS INSTALLED IN DRY LAND
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**				
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**			*382*	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			*2126*	
3300/3400	**Steam Turbine and Generator auxiliaries**		*6.7*		
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (~~Sea Water /~~ Machinery Water)**				
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	*11.8*	*-10.7*		
	Other Units		**4**	*437*	
	BALANCE	*100.8*	**0**	*6475*	*0*

Note: (1) Minus prior to figure means figure is generated

(2) For the WET LAND scenarios, MCW delta T = 12°C. For the DRY LAND scenarios, MCW delta T = 10°C.

(3) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.05.

FOSTER WHEELER	CLIENT: PROJECT: LOCATION: FWI Nº:	IEA GHG R&D PROGRAMME WATER USAGE AND LOSS ANALYSIS SOUTH AFRICA 1- BD 0475A	Rev: Draft March 2010 ISSUED BY: L.So. CHECKED BY: PC APPR. BY: SA

CASE 5.07 - ELECTRICAL CONSUMPTION SUMMARY - GEE IGCC - HP w/o CO2 capture - DRY LAND

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**338**
1000	**Gasification Section**	**13055**
2100	**Air Separation Unit**	*123896*
2200	**Syngas treatment and conditioning line**	*505*
2300	**Acid Gas Removal**	*3302*
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**1932**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4795**
3200	**Heat Recovery Steam Generator**	*16269*
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	*7678*
3500	**Miscellanea**	**527**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (~~Sea Water /~~ Machinery Water)**	*3809*
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**686**
	Other Units	**661**
	BALANCE	*177452*

Note: (1) Minus prior to figure means figure is generated
(2) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.05.

FOSTER WHEELER	CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2
	LOCATION:	South Africa	DATE	March '10		
	PROJ. NAME:	Water usage and loss of Power in Plants with CCS	ISSUED BY	M.P.		
	CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.		
			APPROVED BY			

Utilities consumption

Waste Water Treatment Unit - GEE IGCC without CO_2 capture, fed with bituminous coal, case 5.07 - DRY LAND

	ITEM	DESCRIPTION	Absorbed Electical power [kW]	NaOH [kg/h]	H_2O_2 [kg/h]	$FeSO_4$ [kg/h]	Poly [kg/h]	Remarks
		WWT - waste water treament unit	~190	~6	~0.5	~1.5	~0.3	

Table below summarize specific consumpltion for each treatment section- reported values are indicative only

	ITEM	DESCRIPTION	Absorbed Electical power [kW]		NaOH [1]	H_2O_2 [1]	$FeSO_4$ [1]	Poly [1]	Remarks
			total	specific	[kg/h]	[kg/h]	[kg/h]	[kg/h]	
		Sulphides oxidation Section	1.4			0.32			
		Equalization Section	15.0						
		Physical-Chemical section	4.6		5.4		1.3	0.2	
		Sedimentation section	15.7						
		Aerated Lagoon section	130.0						
		Media filtration section	22.5						

Notes:
1. As pure products.

7. Overall performance

The table summarizing the Overall Performance of the GEE IGCC power plant, case 5.07, is attached hereafter.

GEE IGCC

Case 5.07 - HIGH PRESSURE w/o CO_2 capture - DRY LAND

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	303.0
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2177.3**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1535.2
Gasification Efficiency (based on coal LHV)	%	70.5
Thermal Power of Clean Syngas to GT (based on LHV) (F)	MWt	1521.4
Syngas treatment efficiency (F/E*100)	%	99.1
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	372
Expander power output	MWe	10.6
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**955.1**
ASU power consumption	MWe	123.9
Process Units consumption	MWe	19.1
Utility Units consumption	MWe	1.3
Offsite Units consumption ~~(including sea cooling water system)~~	MWe	3.8
Power Islands consumption	MWe	29.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**177.5**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**777.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.7**

Specific fuel (coal) consumption per MW net produced	**MWt/Mwe**	**2.800**
Specific CO2 emissions per MW net produced	**t/MWh**	**0.869**
Specific water consumption per MW net produced	**t/MWh**	**0.042**

8. Environmental Impact

The GEE IGCC power plant, case 5.07, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 8.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	728.9
Flow, $Nm^3/h^{(1)}$	3.140.950
Temperature, °C	107
Composition	(%vol)
Ar	1.0
N_2	75.1
O_2	10.7
CO_2	8,6
H_2O	4.6
Emissions	$mg/Nm^{3\ (1)}$
NOx	52
SOx	10
CO	31
Particulate	4

(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 8.2

Table 8.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1457.8
Flow, $Nm^3/h^{(1)}$	6.281.900
Temperature, °C	107
Emissions	kg/h
NOx	321,4
SOx	60,8
CO	196,0
Particulate	25,8

(1) Dry gas, O_2 content 15%vol

8.1.2. 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.

8.2. Liquid Effluent

The expected flow rate of treated water from Waste Water Treatment plant to be discharged outside power plant battery limit is in practice reduced to zero: in fact, apart from a negligible amount of water present in the stream of “Sludge To Disposal” (about 0.1 t/h of water), all the water received by Waste Water Treatment is treated and recycled back to the power plant.

8.3. Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment, mentioned above).
In addition, the Gasification Island is expected to produce the following solid by-products:

Fine Slag
Flow rate : 29,8 t/h
Water content : 70 %wt

Coarse Slag
Flow rate : 71,6 t/h
Water content : 50 %wt

Both slag products can be theoretically sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

Anyway, considering that it may be difficult to sell them and considering the modest revenue they can give, for the purposes of present study solids effluents are considered as neutral: neither as revenue nor as disposal cost.

9. Equipment List

The list of main equipment and process packages is included in this paragraph. WWT plant equipment list is included.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

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EQUIPMENT LIST

Unit 1000 - Gasification Unit - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			Syngas scrubber								734 t/h of condensate from unit 2200	
			Black water flash drum								12 t/h sour water from unit 2200	
			Black water flash drum									1.2 t/h steam in sour gas
			Grey water tank								89 t/h raw water as make up	
			Grey water tank								24 t/h treated water from WWT	
			Grey water tank									14.6 t/h water blowdown
			Drag conveyor and slag screen									35.8 t/h in coarse slag
			Rotatory filter									20.9 t/h in fine slag
			Gasification section								5 t/h HP steam	condensate is recovered

LEGEND:
For the Gasification Unit, only the water consumer items are shown.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2100 - Air Separation Unit - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS		S, m2		shell / tube	shell / tube				
	1	E-2101	Nitrogen heater	Shell & Tube			19 / 26	430 / 243		DUTY = 14320 kW		
	2	E-2101	Nitrogen heater	Shell & Tube			19 / 26	430 / 243		DUTY = 14320 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 = 274 t/h		85			Oxigen purity = 95 %	20.2 t/h steam to internal heaters	20.2 t/h steam condensate to recovery
					MP N_2 flow rate to GTs = 890 t/h		26			Nitrogen purity = 98 %		
					HMP N_2 flow rate to AGR = 36 t/h		34			Nitrogen purity = 99,9 %		
					LP N_2 flow rate to Proc Unit = 2.7 t/h		14			Nitrogen purity = 99,9 %		
					Air flow rate from GTs = 603 t/h							
Δ			ASU Compressors		122.0 MW					3% higher than in case 5.05		
Δ			ASU Heat Exchangers	Aircoolers	16 services; duty = 11 MWth each; 900 m2 (bare) each	80 kWe each			CS			
Δ			ASU chiller		6.5 MW th @ 5°C					66% bigger than in case 5.05		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS		S, m²		Shell/tube	Shell/tube				
	1	**E-2201**	**LMP Steam Generator**	Kettle			24 / 68	250 / 273		DUTY = 106350 kW H2 service H2/Wet H2S serv. on channel	354.1 t/h LMP BFW	352.3 t/h LMP steam + 1.8 t/h blowdown
	2	**E-2201**	**LMP Steam Generator**	Kettle			24 / 68	250 / 273		DUTY = 106350 kW H2 service H2/Wet H2S serv. on channel		
	1	**E-2202**	**LP Steam Generator**	Kettle			12 / 68	250 / 250		DUTY = 78600 kW H2 service H2/Wet H2S serv. on channel	268.9 t/h LP BFW	267.6 t/h LP steam + 1.3 t/h blowdown
	2	**E-2202**	**LP Steam Generator**	Kettle			12 / 68	250 / 250		DUTY = 78600 kW H2 service H2/Wet H2S serv. on channel		
	1	**E-2203**	**VLP Steam Generator**	Kettle			7 / 68	185 / 204		DUTY = 14305 kW H2 service H2/Wet H2S serv. on channel	56.9 t/h VLP BFW	56.6 t/h VLP steam + 0.3 t/h blowdown
	2	**E-2203**	**VLP Steam Generator**	Kettle			7 / 68	185 / 204		DUTY = 14305 kW H2 service H2/Wet H2S serv. on channel		
	1	**E-2206**	**VLP Steam Generator**	Kettle			7 / 68	175 / 210		DUTY = 3400 kW H2 service H2/Wet H2S serv. on channel		
	2	**E-2206**	**VLP Steam Generator**	Kettle			7 / 68	175 / 210		DUTY = 3400 kW H2 service H2/Wet H2S serv. on channel		
	1	**E-2204**	**Syngas Feed/ Product Exchanger**	Shell & Tube			68 / 68	230 / 185		DUTY = 2825 kW H2 service H2/Wet H2S serv. on channel		
	2	**E-2204**	**Syngas Feed/ Product Exchanger**	Shell & Tube			68 / 68	230 / 185		DUTY = 2825 kW H2 service H2/Wet H2S serv. on channel		
	1	**E-2205**	**Hydrolysis Feed Heater**	Shell & Tube			24 +FV / 68	250 / 230		DUTY = 3535 kW H2 service H2/Wet H2S serv. on channel	13 t/h LMP steam	recovered as condensate
	2	**E-2205**	**Hydrolysis Feed Heater**	Shell & Tube			24 +FV / 68	250 / 230		DUTY = 3535 kW H2 service H2/Wet H2S serv. on channel		

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube				
D	1	E-2207 A/B	Condensate Preheater	Shell & Tube	exchanger area = 550 m2 (exchanger A+B)		26 / 68	100 / 185		DUTY = 20900 kW H2 service H2/Wet H2S serv. on channel		
D	2	E-2207 A/B	Condensate Preheater	Shell & Tube	exchanger area = 550 m2 (exchanger A+B)		26 / 68	100 / 185		DUTY = 20900 kW H2 service H2/Wet H2S serv. on channel		
		E-2208	Expander Feed Heater	Shell & Tube			7 / 68	175 / 140		DUTY = 14770 kW H2 service H2/Wet H2S serv. on channel	46.1 t/h VLP steam	recovered as condensate
		E-2209	Syngas pre-heater	Shell & Tube			7 / 68	175 / 140		DUTY = 12820 kW H2 service H2/Wet H2S serv. on channel		
		E-2210	Syngas heater	Shell & Tube			12 / 31	200 / 180		DUTY = 9870 kW H2 service H2/Wet H2S serv. on channel	17 t/h LP steam	recovered as condensate
+	1		Syngas trim cooler	Aircooler	11.5 MWth	110 kWe			CS + 3mm C.A.	1000 m2 bare surface		
+	2		Syngas trim cooler	Aircooler	11.5 MWth	110 kWe			CS + 3mm C.A.	1000 m2 bare surface		
			DRUMS		D,mm x TT,mm							
	1	D-2201	Condensate Separator	Vertical			68	250		Wet H2S service/H2 service		734 t/h return condensate to Gasification; 12 t/h contaminated condensate to SWS
	2	D-2201	Condensate Separator	Vertical			68	250		Wet H2S service/H2 service		
	1	D-2202	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service		
	2	D-2202	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service		
	1	D-2203	Condensate Separator	Vertical			68	185		Equipped with demister Wet H2S service/H2 service		
	2	D-2203	Condensate Separator	Vertical			68	185		Equipped with demister Wet H2S service/H2 service		
	1	D-2204 A/B	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service		
	2	D-2204 A/B	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service		
	1	D-2205	Condensate Separator	Vertical			68	68		Equipped with demister Wet H2S service/H2 service		
	2	D-2205	Condensate Separator	Vertical			68	68		Equipped with demister Wet H2S service/H2 service		

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			DRUMS (continued)		D,mm x TT,mm							
		D-2206	Process Condensate Accumulator	Horizontal			68	220				
			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	COS Hydrolysis Reactor	vertical			68	230		H2 service Wet H2S service		0.1 t/h water loss to COS hydrolisis
	2	R-2201	COS Hydrolysis Reactor	vertical			68	230		H2 service Wet H2S service		
			EXPANDERS									
		EX- 2201	Purified Syngas Expander	centrifugal	Pout/Pin = 0,50 Flow = 560 kNm^3/h Pow = 11 MWe							
			GENERATORS		P, MWe							
		G-3201	Expander Generator									
			PACKAGE UNITS									
		Z-2201	Catalyst Loading System									
		Z-2202	COS Hydrolysis Catalyst							Catalyst volume: 160 m^3		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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.=61.9 t/d					Sulphur content = 99,9 wt min (dry basis)	5.3 t/h BFW to steam generators + 2.7 t/h water in sour gas and from reaction	2.4 t/h steam to Plant network; 2.8 t/h steam condensate to condensate unit 2.7t/h sour water to WWT; 0.1 t/h blowdown water to WWT
					Acid Gas from AGR = 300 kmol/h		3.5	80		Sulphur content = 28,3% (wet basis)		
					Off gas from Gasif. = 190 kmol/h					Sulphur content = 1,1 % (wet basis)		
					Expected Treated Tail Gas=316 kmol/h		30	70		Major components (wet basis): CO_2 = 29,66%, H_2=5,31%, N_2 = 63,36%		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube				
	1	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 31	280 / 200		DUTY=2420 kW Tubes: H2 service		
	2	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 31	280 / 200		DUTY=2420 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)	286 MW					Included in 1-Z- 3101 Included in 1-Z- 3101	Steam in syngas, in air to turbine and generated in combustion	202.6 t/h steam in flue gas to final DCC
	2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	286 MW					Included in 2-Z- 3101 Included in 2-Z- 3101		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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		
+	1	**P-3205 A/B/C**	**Flue gas condensed water pumps**	centrifugal	6100m3/h x 40m	930 kWe			casing: CS; internals: 12%Cr	2 pumps in operation; 1 pump spare		
+	1	**P-3205 A/B/C**	**Flue gas condensed water pumps**	centrifugal	6100m3/h x 40m	930 kWe			casing: CS; internals: 12%Cr	2 pumps in operation; 1 pump spare		
			DRUMS		D,mm x TT,mm							
	1	**D-3204**	**LMP Steam Receiver Drum**	horizontal			24	250				
	2	**D-3204**	**LMP Steam Receiver Drum**	horizontal			24	250				
	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				
+	1	**D-3207 A/B/C/D**	**Flue gas final DCC**	Vertical	D=8m; H=16m each				KCS+6 mm 304L clad	4 vessels		33 t/h cond'd water
+	2	**D-3207 A/B/C/D**	**Flue gas final DCC**	Vertical	D=8m; H=16m each				KCS+6 mm 304L clad	4 vessels		33 t/h cond'd water
			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	**B-3201**	**Flue gas final DCC blower**	Axial fan	2.000.000Nm3/h x 300 mm H2O	3.0 MW each			CS	1 blower in operation		
+	2	**B-3201**	**Flue gas final DCC blower**	Axial fan	2.000.000Nm3/h x 300 mm H2O	3.0 MW each			CS	1 blower in operation		
	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		
			HEAT EXCHANGERS		S, m^2							
+	1	**E-3220**	**Flue gas feed/effluent exchangers**	Rekugavo, plate exchanger	61 MWth				SS 316L			
+	2	**E-3220**	**Flue gas feed/effluent exchangers**	Rekugavo, plate exchanger	61 MWth				SS 316L			
+	1	**E-3221**	**Flue gas condensed water cooler**	Aircooler	45 MWth	46 motors x 25 kW			CS+2 mm 304L clad	Aircooler bare surface = 6.000 m2		
+	2	**E-3221**	**Flue gas condensed water cooler**	Aircooler	45 MWth	46 motors x 25 kW			CS+2 mm 304L clad	Aircooler bare surface = 6.000 m2		

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
	LOCATION: South Africa	DATE	March 2010	November 2010		
	PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			PACKAGES									
		Z-3201	**Fluid Sampling Package**									
		Z-3202	**Phosphate Injection Package**									
		D-3204	Phosphate storage tank							Included in Z - 3202		
		P-3204 a/b/c	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare		
		Z-3203	**Oxygen Scavanger Injection Package**									
		D-3205	Oxygen scavanger storage tank							Included in Z - 3203		
		P-3205 a/b/c	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare		
		Z-3204	**Amines Injection Package**									
		D-3206	Amines Storage tank							Included in Z - 3204		
		P-3206 a/b/c	Amines Dosage pumps							Included in Z - 3204 One operating , one spare		
			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		1.3 t/h blowdown from Steam Drums
	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		0.3 t/h steam vented to atm
	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	**LMP Superheater**							Included in 1-HRS-3201		
	1	E-3207	**HP Economizer 3rd section**							Included in 1-HRS-3201		
	1	E-3208	**MP Superheater**							Included in 1-HRS-3201		
	1	E-3209	**MP Evaporator**							Included in 1-HRS-3201		
	1	E-3210	**LP Superheater**							Included in 1-HRS-3201		
	1	E-3211	**MP Economizer 2nd section**							Included in 1-HRS-3201		
	1	E-3212	**HP Economizer 2nd section**							Included in 1-HRS-3201		
	1	E-3213	**LP Evaporator**							Included in 1-HRS-3201		
	1	E-3214	**LP Economizer**							Included in 1-HRS-3201		
	1	E-3215	**MP Economizer 1st section**							Included in 1-HRS-3201		
	1	E-3216	**HP Economizer 1st section**							Included in 1-HRS-3201		
	1	E-3217	**VLP Evaporator**							Included in 1-HRS-3201		

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER	LOCATION: South Africa	DATE	March 2010	November 2010		
	PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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		1.3 t/h blowdown from Steam Drums
	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		0.3 t/h steam vented to atm
	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	**LMP Superheater**							Included in 2-HRS-3201		
	2	E-3207	**HP Economizer 3rd section**							Included in 2-HRS-3201		
	2	E-3208	**MP Superheater**							Included in 2-HRS-3201		
	2	E-3209	**MP Evaporator**							Included in 2-HRS-3201		
	2	E-3210	**LP Superheater**							Included in 2-HRS-3201		
	2	E-3211	**MP Economizer 2nd section**							Included in 2-HRS-3201		
	2	E-3212	**HP Economizer 2nd section**							Included in 2-HRS-3201		
	2	E-3213	**LP Evaporator**							Included in 2-HRS-3201		
	2	E-3214	**LP Economizer**							Included in 2-HRS-3201		
	2	E-3215	**MP Economizer 1st section**							Included in 2-HRS-3201		
	2	E-3216	**HP Economizer 1st section**							Included in 2-HRS-3201		
	2	E-3217	**VLP Evaporator**							Included in 2-HRS-3201		

LEGEND:

The water consumer equipment is highlighted in the present equipment list.

(1) = reference shall be made to case 5.05; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
	LOCATION: South Africa	DATE	March 2010	November 2010		
	PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS		**S, m2**		shell / tube	shell / tube				
		E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	52 / 140		DUTY = 910 kW		
			DRUMS		**D,mm x TT,mm**							
		D-3301	**Flash Drum**	vertical			3.5	200				
		D-3302	**Continuous Blow-down Drum**	vertical			3.5	140			blowdown from Steam Drums	2.6 t/h water to WWT
		D-3303	**Discontinuous Blow-down Drum**	vertical			3.5	140				
			PACKAGES									
		Z-3301	**Steam Turbine & Condenser Package**									
Δ		TB-3301	Steam Turbine		372 MW gross					Included in Z - 3201		
		E-3301A/B	Inter/After condenser									
		E-3302	Gland Condenser							Included in Z - 3201		
Δ		E-3303	Steam Condenser	aircooler	699 MW th	68x95 kWe			CS	Included in Z - 3201 68 modules, 12x12 m2 each		
		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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: South Africa PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
		DATE	March 2010	November 2010		
		ISSUED BY	L.So.	L.So.		
		CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - GEE IGCC Case 5.07 - High Pressure w/o CO_2 capture - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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									
Δ			**Closed loop water cooler**	aircooler	75 MW th	1850 kWe			CS			
Δ			**Close loop CW pumps**	centrifugal	6475 m3/h x 30m	964 kWe			CS	1 pump in operation + 1 spare		
Δ			**Waste water treatment plant**									
–			**~~Sea water pumps~~**							DELETED		
–			**~~Seawater chemical injection~~**							DELETED		
–			**~~Sea water inlet/outlet works~~**							DELETED		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.05: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

	CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
FOSTER WHEELER	LOCATION:	Dry land	DATE	Jannuary '09			
	PROJ. NAME:	Water usage and loss of Power Plants with CCS	ISSUED BY	M.P.			
	CONTRACT N.	1- BD- 0475 A	CHECKED BY	A.S.			
			APPROVED BY				

EQUIPMENT LIST

Unit 4600 - BoP, Electrical, I&C - USC PC Oxyfuel without CO_2 capture, fed with bituminous coal, case 5.07 - DRY LAND

CHANGE (1)	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Sulphides oxidation Section									
	4600-Y1001	Oxidation Reactor		S= 20 m^2 ; H 2.5 m					1X100% (1op)		
	4600-MX1001 A/B	Mixer			0.35				2X50% (2op)		
	4600-PK1001 A/B	H_2O_2 dosage system		Φ=0.5 m; H=1 m	0.36				2X50% (about 30 day storage)		
		Equalization Section									
	4600-Y1002	Equalization basin		S=220 m^2 ; H= 5 m					1X100 (underground basin)		
	4600-P1001 A/B	Physical-chemical treatment feed pump	Centrifugal	105 mc/h; 2 bar	15				2X100% (1op + 1spare)		
		Physical-Chemical section									
	4600-Y1003	Coagulation basin		S= 4.5 m^2 ; H= 3 m					1X100 % coagulation		
	4600-MX1002 A/B	Coagulation basin mixer			0.50				2X50% (2op)		
	4600-Y1004 A/B	Flocculation basin		S= 22 m^2 ; H= 3 m					1X100 % flocculation		
	4600-MX1003 A/B	Flocculation basin mixer			0.36				2X50% (2op)		
	4600-PK1002 A/B	$FeSO_4$ dosage system		Φ=1.0 m; H=1.3 m	0.36				2X50% (about 30 day storage)		
	4600-PK1003 A/B	NaOH dosage system		Φ=1.6 m; H=2,0 m	0.72				2X50% (about 30 day storage)		
	4600-PK1004 A/B	polyelectrolite dosage system		Φ=0.7 m; H=0.9 m	0.36				2X50% (about 30 day storage)		
		Sedimentation section									
	4600-Y1005 A/B	Chemical sludge settling Basin		L= 11 m; W= 4.0 m; H= 3.5 m					2 op		
	4600-K1001 A/B	Sludge scraper			0.25				2 op		
	4600-P1002 A/B/C	chemical sludge settling water feed pump	Centrifugal	55 mc/h; 3.5 bar	7.5				3X50% (2op + 1 spare)		
	4600-P1003 A/B/C	chemical sludge treatment feed pump	Centrifugal	0.60 mc; 1 bar	0.12				3X50% (2op + 1 spare)		
		Aerated Lagoon section									
	4600-Y1006	Aerated lagoon		L= 100 m; W= 70 m; H= 4 m							
	4600-MX1003 A/B/C/D	Aerated lagoon basin mixer			30				4X25% (4op)		
	4600-B1001 A/B	Aerated lagoon basin blower		600 Nmc/h; 0.5 bar	10				2X100% (1op + 1spare)		
		Media filtration section									
	4600-P1004 A/B/C	sand filter water feed pump	centrifugal	55 mc/h; 2 bar	7.5				3X50% (2op + 1 spare)		
	4600-F1001 A/…/F	Sand filter		Φ=2.0 m; H=2.25 m					6 op		
	4600-Y1007	Filtered water basin		S=5 m^2 ; H= 3.5 m							
	4600-P1005 A/B	backwash pump	centrifugal	70 mc/h; 2 bar	7.5				2X100% (1op + 1 spare)		

Notes:

Present equipment list is indicateve only and related to the WWT layout selected.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS OF POWER IN PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME : GEE IGCC WITH CCS – DRY LAND – CASE 5.03

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
March 2010	Draft	L. Sobacchi	P. Cotone	S. Arienti
August 2010	Rev 0	L. Sobacchi	P. Cotone	S. Arienti
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SECTION B

GEE IGCC WITH CCS – DRY LAND

I N D E X

1. Introduction

The present case 5.03 refers to the same GEE IGCC power plant, fed with bituminous coal and provided with CO_2 capture unit, analysed in Report # 4, Section C (case 5.06). The difference with the power plant 5.06 is that the power plant analysed here is installed in the reference dry land country (South Africa) and far from the seaside, so that, technologies for saving water and reducing to zero the raw water intake have been applied. The configuration and the performance of the plant so modified are evaluated and the results are discussed in the present Section.

The main features of the GEE IGCC plant, case 5.03, are:

- High pressure (65 bar g) GEE Gasification (Texaco in reference study);
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- Single stage dirty shift;
- Separate removal of H_2S and CO_2;
- Dry-land country.

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.

Looking at the Gas Turbine, the slightly higher ambient temperature of dry land cases with respect to the wet land cases should impact on machine performance.
GT gross power output should result slightly reduced as well as the GT appetite that should be reduced by approximately 2%.
Nevertheless, the appetite of GT and consequently the gasification capacity has been kept constant in order to see clearly the impact of the dry land design on performance and costs of the IGCC without the additional impact of the ambient temperature. The results of this study can be used, therefore, to evaluate the penalties on plant performance and the investment cost increase due to the limitations on water usage. These limitations can derive from ambient reasons (dry land design) or from political reasons that can force to the limitation on water consumption.
For the same reasons, also the overall GT performance, gross power output and flue gas characteristics in the dry land cases have been kept constant to the wet land figures.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the main process units is:

Unit		Trains
1000	Gasification	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 TGT	2 x 100% 1 x 100%
2500	CO_2 Compression and Drying	2 x 50%
3000	Gas Turbine (PG – 9351 - FA) HRSG Steam Turbine	2 x 50% 2 x 50% 1 x 100%

2. Process Description

2.1. Overview

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

Case 5.03 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.

Due to the installation in a severely limited water supply area and far from the seaside, changes have been made on some process and utilities Units, compared with the reference case 5.06. The main peculiarities of the present case 5.03 are the deletion of the seawater cooling system, being the cooling effect provided by aircoolers and by machinery cooling water, and the installation of a Flue Gas Direct Contact Cooler system for condensing and recovering part of the water contained in the flue gas.

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.
As shown in paragraph 2.8, the gasification capacity has been kept constant as the relevant reference case 5.06.

The Gasification Unit includes the following sections:

- Coal Grinding/Slurry Preparation
- Gasification
- Slag Handling
- Black Water Flash
- Black Water Filtration

The description of the Gasification Unit included in paragraph 2 of Report # 4, section B (case 5.05) is still valid for the present case 5.03 and is to be referred if a detailed description is required.

2.3. Unit 2100 – Air Separation unit

The Air Separation Unit is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

As regards the equipment arrangement of Unit 2100, the description of case 5.03 differs from the description valid for case 5.05 (Report # 4, section B), since in case 5.03 there's no need for a nitrogen stream to be sent to Unit 2300 (AGR). Furthermore, in case 5.03 compressor intercoolers are aircoolers instead of sea water coolers, as used in case 5.05.
Apart from these two points, the considerations relevant to Unit 2100 present in Report # 4, section B, are still valid.
The impact of the installation in a dry land country and far from the seaside is significant, in terms of power consumption: the power required by ASU compressor is increased by about 3%, compared with the relevant reference case 5.06, and the power required by the intercooler fan motors is to be added. It results that the power required by ASU in case 5.03 is about 4.5 MW higher than in the reference case 5.06 to the detriment of the net power output from the power plant.

2.4. Unit 2200 – Syngas Treatment and Conditioning line

This Unit receives the raw syngas from the gasification section, which is hot, humid and contaminated with acid gases, CO_2 and H_2S, and other chemicals, mainly COS, HCN and NH_3. In this Unit, the raw syngas enters the Shift Reactor, where CO is shifted to H_2 and CO_2 and COS is converted to H_2S. The syngas is then cooled down and sent to the AGR unit for acid gas removal. The clean syngas from AGR is received and treated so that the proper conditions of temperature and pressure are met in order to achieve in the combustion process of the gas turbine the desired environmental performance and stability of operation.

As regards the equipment arrangement of Unit 2200, case 5.03 differs from reference case 5.06 only for the installation of a new aircooler (Syngas Trim Cooler) on the syngas line to AGR Unit between the Condensate Preheater 1-E-2206A/B and the Separator 1-E-2203A/B. This aircooler is necessary in case 5.03 for delivering the syngas to AGR Unit at the required temperature (38°C), since the Condensate Preheater 1-E-2206A/B is no more able to provide all the required cooling effect. This is due to the fact that steam condensate from steam turbine condenser is generated at a higher temperature (40°C in case 5.03 vs 21°C in case 5.06).
Apart from this modification, the description of Unit 2200 present in Report # 4, section C, is still valid.

2.5. Unit 2300 – Acid Gas Removal (AGR)

In this Unit H_2S and CO_2 are removed from syngas, by washing it with Selexol in an absorption column. Selexol rich in acid compounds is then regenerated in a stripping column and recycled to the absorption column.
All the considerations done in Report # 4, Section C, for the reference case 5.06 apply also to the present case.
As regards the equipment arrangement of Unit 2300, case 5.03 differs from reference case 5.06 only for the type of coolers: the sea water coolers present in case 5.03 are replaced with aircoolers in case 5.06.

2.6. Unit 2400 – SRU and TGT

This Unit 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 is based on Claus process.
The Sulphur Recovery Section consists of two trains each sized for a production of 66.8 t/day and normally operating at 50%.

No modification of the equipment arrangement has been judged necessary, when installing the power plant in a severely limited water supply area far from the seaside. Thus, for the SRU Unit in the present case 5.03 the same considerations as for the case 5.05 are still valid (see Report # 4, section B).

2.7. Unit 2500 – CO_2 Compression and Drying

CO_2 produced by the AGR Unit is required to be dried and compressed up to 110 bar g prior to export for sequestration, as per the IEA battery limit definition.

Apart from the fact that in case 5.03 compressor intercoolers are aircoolers instead of sea water coolers, as used in case 5.06, all the considerations relevant to Unit 2500 present in Report # 4, section C, are still valid.

The impact of the installation in a dry land country and far from the seaside is significant, in terms of power consumption: the power required by CO_2 compressor is increased by about 4%, compared with the relevant reference case 5.06, and the power required by the intercooler fan motors is to be added. It results that the power absorbed in case 5.03 is about 3.3 MW higher than in the reference case 5.06 to the detriment of the net power output from the power plant.

2.8. Unit 3000 – Power Island

The power island is based on two General Electric gas turbines, frame PG – 9351 - FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.
The gas turbine considered here is the same machine used in the relevant reference case 5.06. Considering that in the dry land cases the average ambient temperature is slightly higher than in the wet land cases, it has been evaluated that the GT appetite should be reduced by approximately 2%. Nevertheless, the appetite of GT and consequently the gasification capacity has been kept constant in order to see clearly the impact of the dry land design on performance and costs of the IGCC without the additional impact of the ambient temperature. Same considerations apply to the GT performance (gross power output, flue gas characteristics, etc…) that are maintained constant with respect to the performance of the machine in the reference wet land case.

As regards the steam turbine system, the major difference with the reference plant, case 5.06, is that the exhaust steam from the LP turbine is condensed in an aircooler and not in a sea water condenser. The condensing system with aircooler allows reaching lower steam turbine performances, since the condensing pressure that can be achieved by the air condenser is significantly higher (0.074 bara with aircooler vs 0.040 bara with sea water condenser). Therefore, condensate is generated in the condenser at higher temperature: 40°C using aircooler vs 21°C using sea water condenser.

In the present power plant, in order to reduce the request of raw water from outside the power plant battery limit, the condensation and recovery of part of the steam contained in the exhaust flue gases at stack is carried out.
Due to the additional pressure drops in the new condensing system, an additional flue gas fan is installed downstream of the HRSG.
The flue gas then passes through a Gas Gas Heat Exchanger (GGH), where flue gas from HRSG is cooled in one side, whereas in the other one the flue gas from Direct Contact Cooler is heated up. As for the GGH, an exchanger manufactured by GEA has been chosen: namely, a Rekugavo type exchanger. Rekugavo is a one stage counter flow plate-type heat recuperator, whose heating surface consists of shaped plates welded together and assembled into heat exchanger modules. The gas streams

flow over the plates in counter flow to one another. It is claimed the welded shaped plates guarantee a high thermal efficiency, while maintaining the gases separate from each other, ensuring leak free operation.
Cooled flue gas from Rekugavo GGH is then partially condensed in the Flue Gas Direct Contact Cooler (FG DCC) system. FG DCC system of each HRSG consists of four vertical columns (due to size reasons), where the flue gas enters at the bottom and is cooled by contacting a stream of water, which is sprayed at the top. Due to the cooling effect, part of the water contained in the flue gas is condensed and collected at the towers bottom. The water circuit includes pumps for disposing of the excess of condensed water to the Waste Water Treatment plant and recycling part of the water to the spray nozzles at the top of the column, passing through an aircooled heat exchanger.
Flue Gas from the top of the contacting columns is heated up in the Rekugavo GGH and finally delivered to the stack.

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:
- Machinery Cooling water
- Demi water
- Fire fighting system
- Instrument and Plant air
- Waste Water Treatment

2.9.1. Waste Water Treatment

The Waste Water Treatment plant required for the power plant case 5.03 includes some specific units necessary for reducing pollutants concentration and allowing reutilization of water. Their description follows hereafter.

Sulphites oxidation

The condensate water from flue gas condensate is contaminated with sulphites, differently from the other polluted streams. For this reason this stream is treated separately from the other polluted streams and then rejoined with the other in the equalization tank.

In order to remove HSO_3^-, hydrogen peroxide is added, giving as reaction product sulphuric acid.
The contact time that permits sulphites oxidation is circa 30 minutes and the oxidation basin is normally designed considering this parameter. The oxidation basin can be equipped with an adequate number of mixers in order to favour a close contact between the reagents.

Equalization

The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed in order to make uniform the physical characteristics of the waste water to be fed to treatment (e.g. pollutants concentration, temperature, etc.).
So the different contaminated streams are sent to an equalization basin in order to make uniform the wastewater characteristic and optimise the following treatment units.
Equalization basin is normally designed in order to guarantee a hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

Physical-Chemical treatment

This section consists of two basins in series, where chemicals are added for chemical coagulation, flocculation and for specific pollutants removal. The purpose of wastewater clariflocculation is to form aggregates or flocs form finely divided particles and from chemical destabilized particles in order to remove them in the following sedimentation step.
In the first basin, coagulation basin, a coagulant as Ferric Chloride is added and a flash-mixing is performed. This basin is designed in order to guarantee a contact time of circa 5 minutes and specific mixing power of some hundreds of watts for cubic meter. Ferrous Sulphate is also added in order to remove H_2S. As the present reaction give an acid contribution, NaOH is added in order to neutralize the sulphuric acid produced.
In the second basin, flocculation basin, polyelectrolyte is added and slow-mixing is performed. This basin is designed in order to guarantee a contact time of circa 25 minutes and a specific mixing power of some tens of watts for cubic meter.
In the flocculation basin H_2S oxidation and H_2SO_4 neutralization are also completed.

Chemical sludge settling

Effluent water from coagulation/flocculation section flows into a clarification basin, where solids separation is performed and all setteable compounds are removed.
The produced sludge, constituted by settled solids, is removed from the bottom of each clarifier by a scraper.
The basin is designed in order to guarantee a contact time of about 2 hours and a surface loading rate of about 1.5 $m^3/m^2/h$.

Chemical sludge treatment

Chemical sludge from chemical sludge settler is subjected to a chemical conditioning in order to favour the sludge dewatering.
Ferric Chloride (10-30 mg $FeCl_3$ / kg SST) and polyelectrolyte (1-3 mg Poly / kg SST) are added in order to favour solids aggregation and to improve the subsequent dewatering treatment.
The conditioned sludge is sent to a dewatering system (i.e. centrifugal system) in order to achieve a dry solids content of minimum 20%. The separated supernatant, rich in suspended solids, is sent back to chemical treatment, while the dewatered sludge is sent to final disposal.

Sand Filtration

The clarified water from clarification basin is delivered to the top of the sand filter bed in order to remove the remaining unsetteable solids.
As the water passes through the filter bed, the suspended matter in the wastewater is intercepted. With the passage of time, as material accumulates within the interstices of the granular medium, the headloss through the filter start to build up beyond the initial value. When the operating headloss through the filter reaches a predetermined headloss value, the filter must be cleaned.
The filters are designed taking into account the following parameters:
- Wastewater flowrate and characteristics;
- Granular medium geometric and dimensional characteristics;
- Admissible headloss and admissible filtration velocity;
- Flow control type.

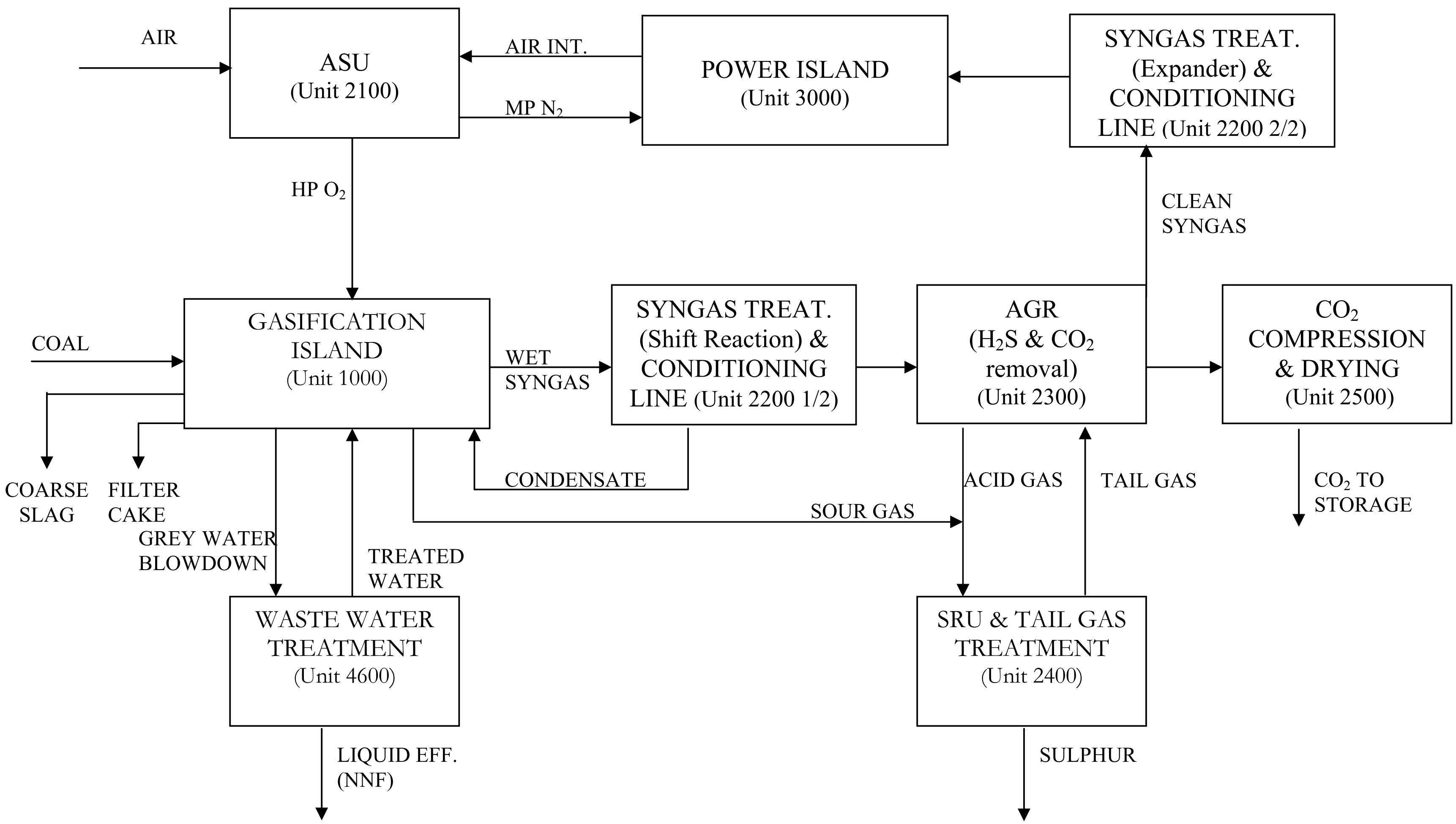
3. Block Flow Diagrams and Process Flow Diagrams

The Block Flow Diagram of the GEE IGCC, Case 5.03, and the schematic Flow Diagrams of Units 2100, 2200, 2300, 2400, 3000 and WWT plant are attached hereafter.

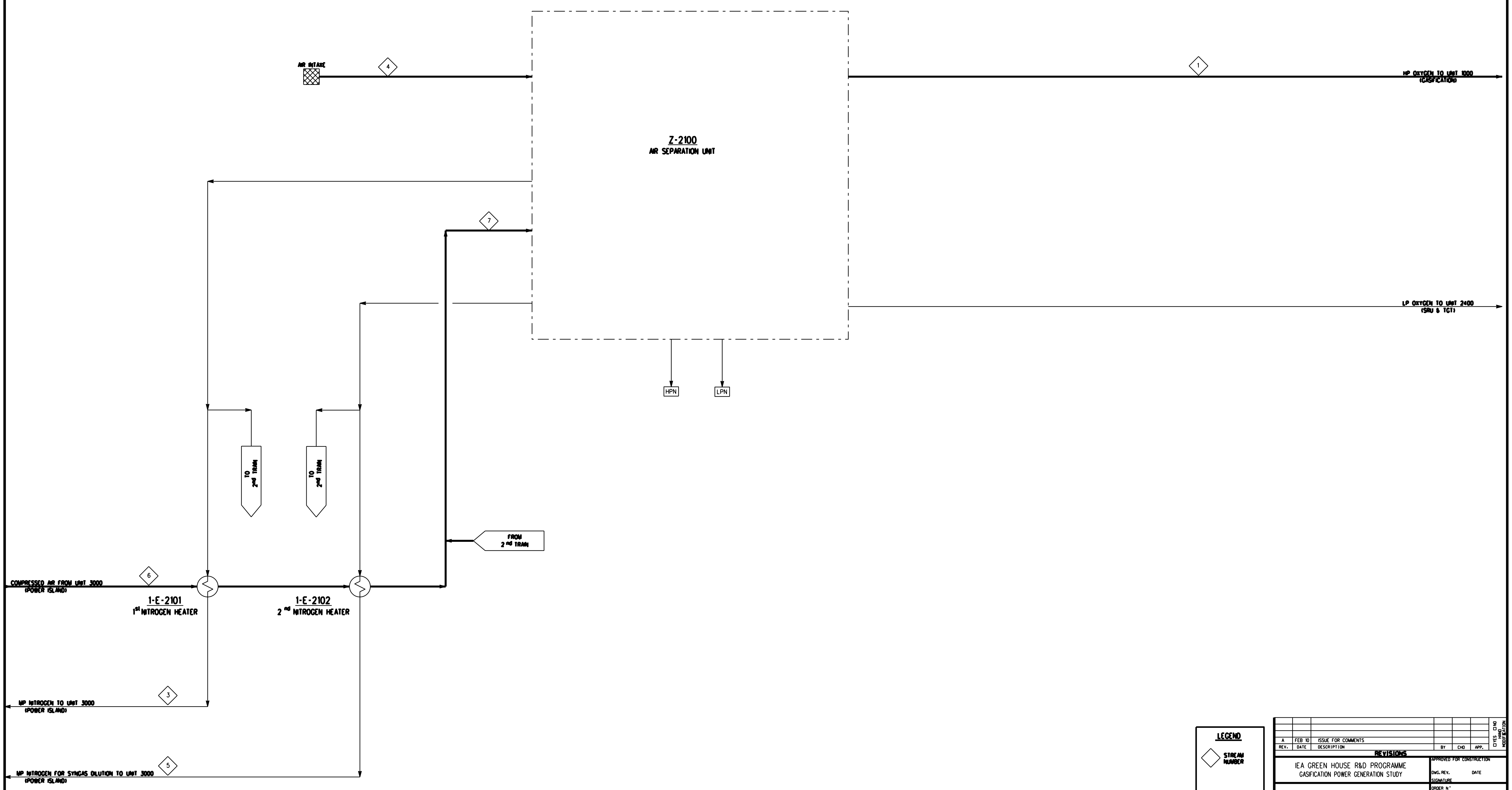
The Diagrams included in the Report # 4, section C (i.e. GEE IGCC, case 5.06) have been taken as reference for the Diagrams relevant to the present plant, case 5.03. Modifications required due to installation in a dry land country and far from the seaside have been highlighted in the drawings attached.

The H&M balances relevant to the scheme attached are shown in paragraph 5.

GEE 5.03 – IGCC COMPLEX BLOCK FLOW DIAGRAM



Case 5.03 - GE IGCC with CCS - DRY LAND



LEGEND

◇ STREAM NUMBER

REV.	DATE	DESCRIPTION	BY	CHD	APP.
A	FEB 10	ISSUE FOR COMMENTS			

HAND MODIFICATION ☐ YES ☐ NO

REVISIONS

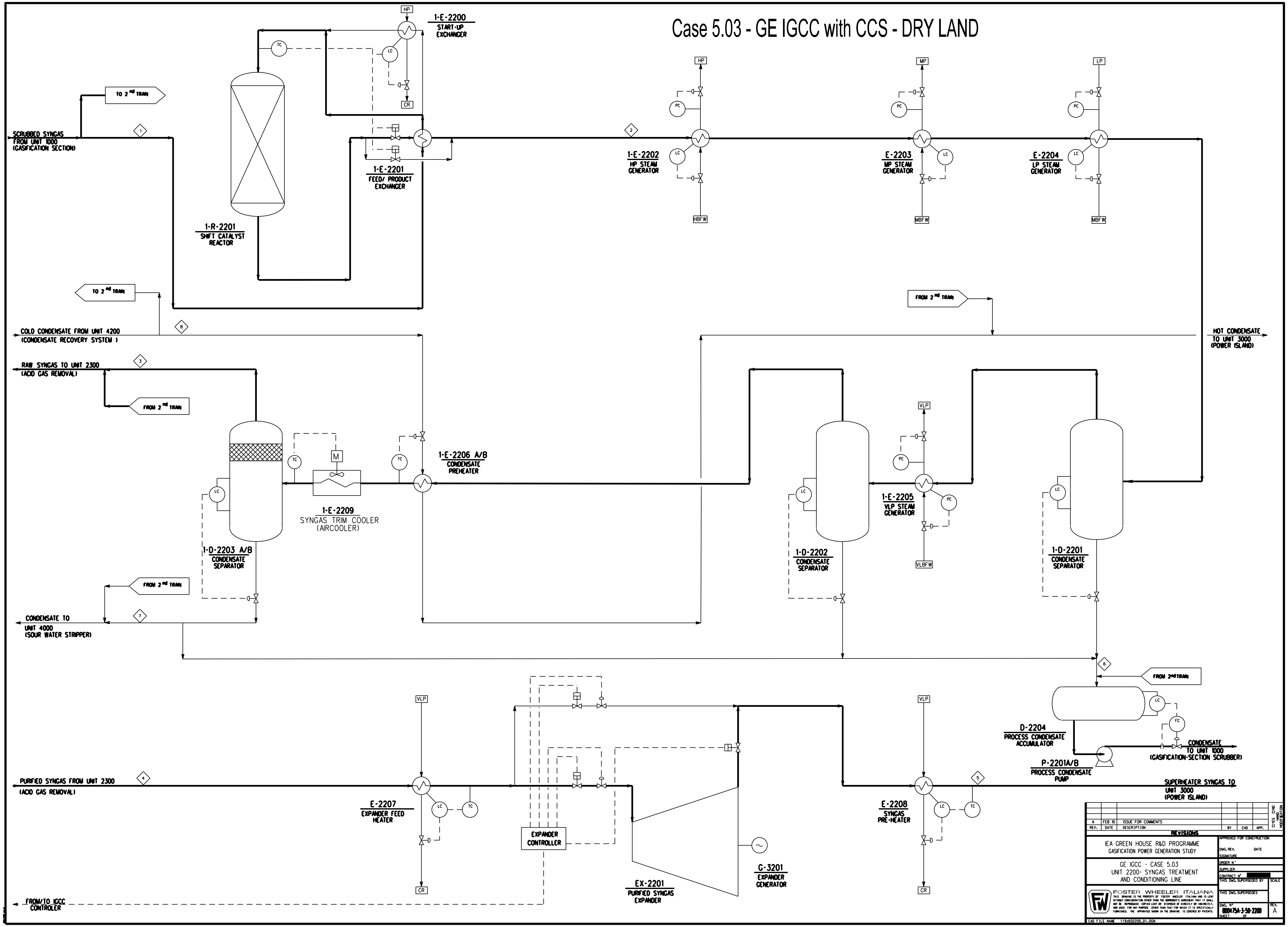
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

GE IGCC - CASE 5.03
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

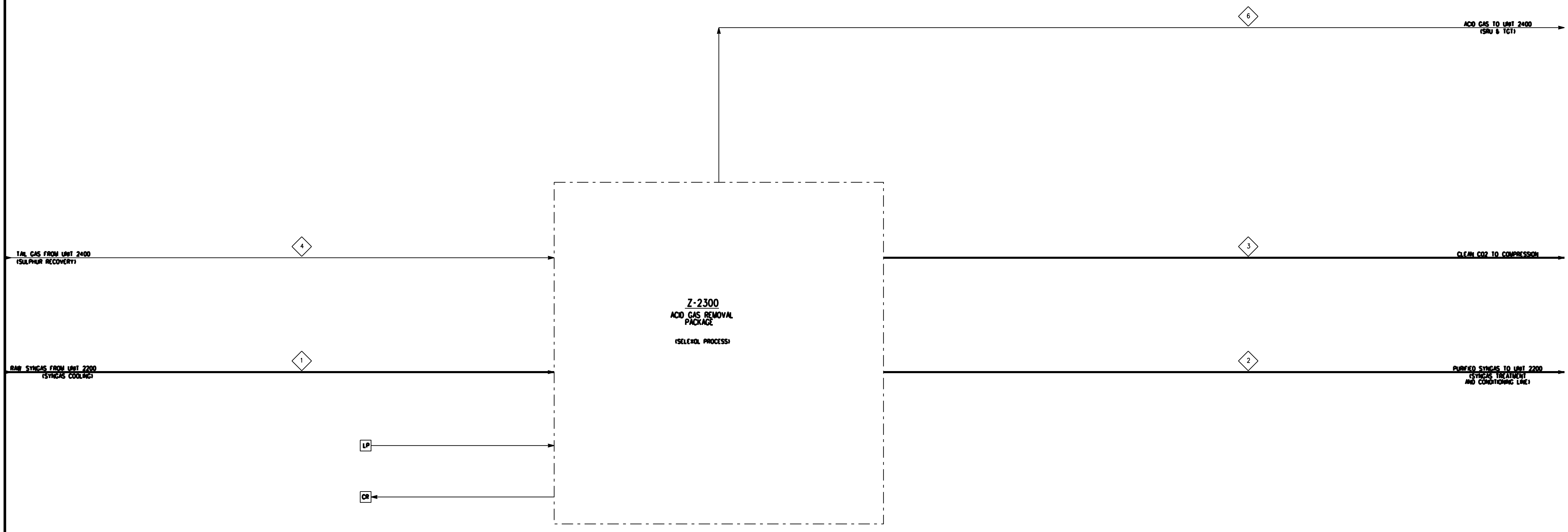
APPROVED FOR CONSTRUCTION
DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N° [redacted]
THIS DWG. SUPERSEDED BY
SCALE
THIS DWG. SUPERSEDES
DWG. N° BD0475A-3-50-2100
REV. A
SHEET OF

CAD FILE NAME 119a502100_01.DGN



Case 5.03 - GE IGCC with CCS - DRY LAND
1-E-2200
START-UP EXCHANGER
HP
CR
TC
LC
TO 2nd TRAIN
SCRUBBED SYNGAS FROM UNIT 1000 (GASIFICATION SECTION)
1
1-R-2201
SHIFT CATALYST REACTOR
1-E-2201
FEED/ PRODUCT EXCHANGER
2
1-E-2202
HP STEAM GENERATOR
HBFW
E-2203
MP STEAM GENERATOR
MP
MBFW
E-2204
LP STEAM GENERATOR
LP
PC
FROM 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
8
HOT CONDENSATE TO UNIT 3000 (POWER ISLAND)
RAW SYNGAS TO UNIT 2300 (ACID GAS REMOVAL)
3
M
1-E-2206 A/B
CONDENSATE PREHEATER
1-E-2209
SYNGAS TRIM COOLER (AIRCOOLER)
1-D-2203 A/B
CONDENSATE SEPARATOR
VLP
1-E-2205
VLP STEAM GENERATOR
VLBFW
1-D-2202
CONDENSATE SEPARATOR
1-D-2201
CONDENSATE SEPARATOR
CONDENSATE TO UNIT 4000 (SOUR WATER STRIPPER)
7
6
D-2204
PROCESS CONDENSATE ACCUMULATOR
FC
CONDENSATE TO UNIT 1000 (GASIFICATION-SECTION SCRUBBER)
P-2201A/B
PROCESS CONDENSATE PUMP
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
4
E-2207
EXPANDER FEED HEATER
EXPANDER CONTROLLER
EX-2201
PURIFIED SYNGAS EXPANDER
G-3201
EXPANDER GENERATOR
E-2208
SYNGAS PRE-HEATER
5
SUPERHEATER SYNGAS TO UNIT 3000 (POWER ISLAND)
FROM/TO IGCC CONTROLER
A FEB 10 ISSUE FOR COMMENTS
REV. DATE DESCRIPTION BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
GE IGCC - CASE 5.03
UNIT 2200- SYNGAS TREATMENT AND CONDITIONING LINE
APPROVED FOR CONSTRUCTION
DWG.REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N° [redacted]
THIS DWG.SUPERSEDED BY
SCALE
THIS DWG.SUPERSEDES
FOSTER WHEELER ITALIANA
DWG. N°
1BD0754-3-50-2200
REV.
A

Case 5.03 - GE IGCC with CCS - DRY LAND



LEGEND

STREAM NUMBER

REV.	DATE	DESCRIPTION	BY	CHD	APP.
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□YES □NO HAND MODIFICATION

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IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

GE IGCC - CASE 5.03
UNIT 2300-ACID GAS REMOVAL

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CONTRACT N° [redacted]
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SCALE
THIS DWG. SUPERSEDES

FOSTER WHEELER ITALIANA

DWG. N° BD0475A-3-50-2300
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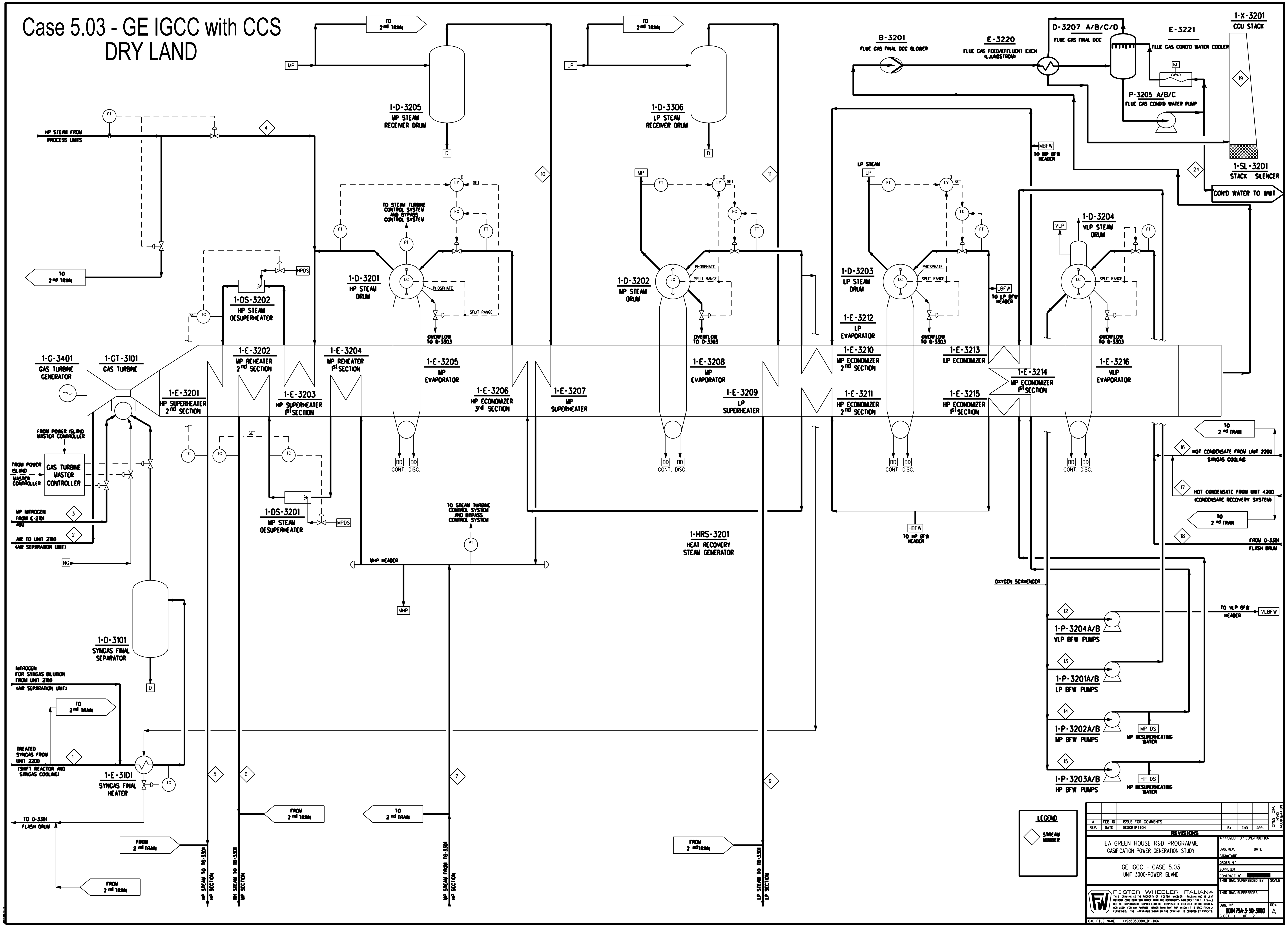
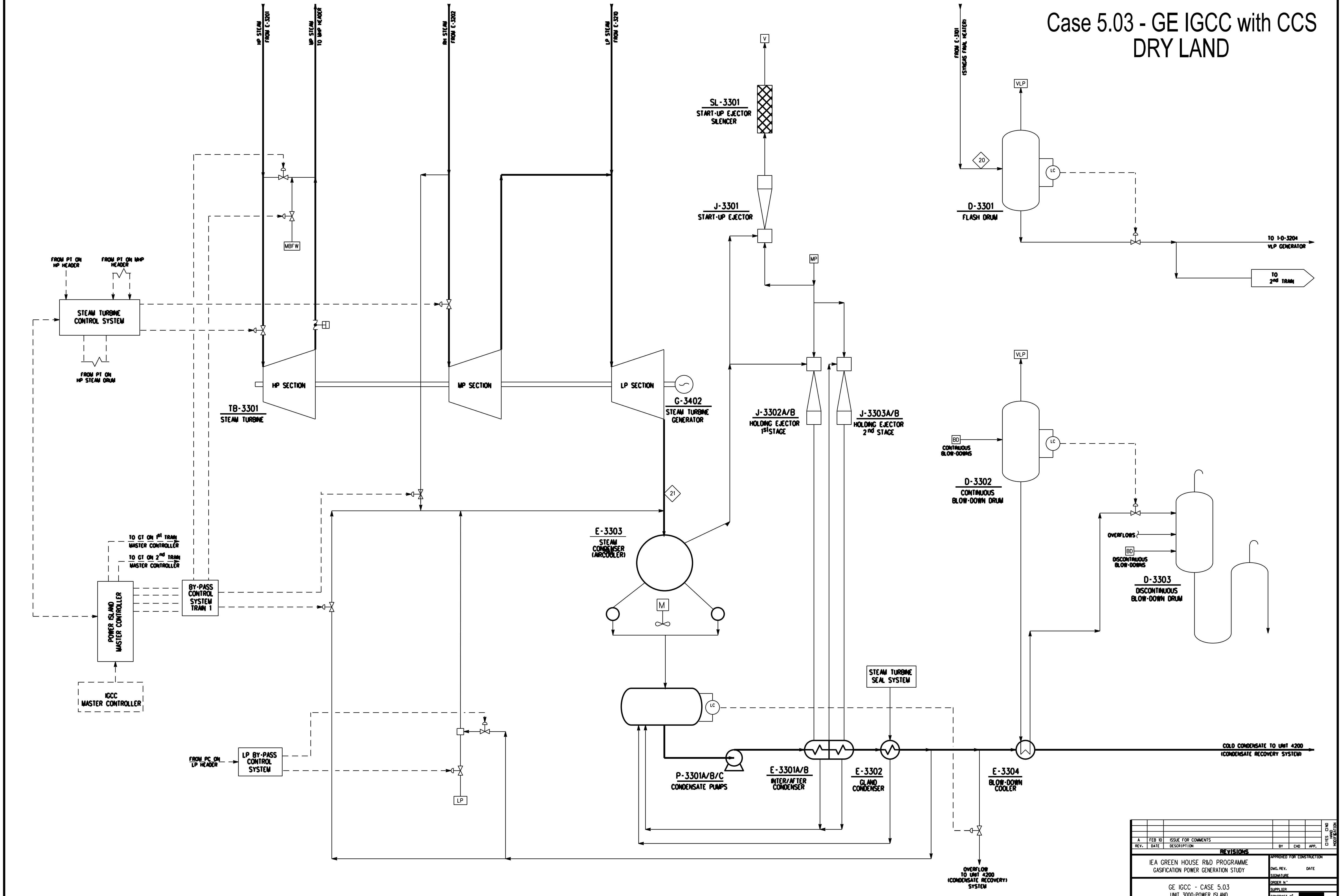
Case 5.03 - GE IGCC with CCS
DRY LAND



Case 5.03 - GE IGCC with CCS DRY LAND



REV.	DATE	DESCRIPTION	BY	CHD	APP.
A	FEB 10	ISSUE FOR COMMENTS			

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

GE IGCC - CASE 5.03
UNIT 3000-POWER ISLAND

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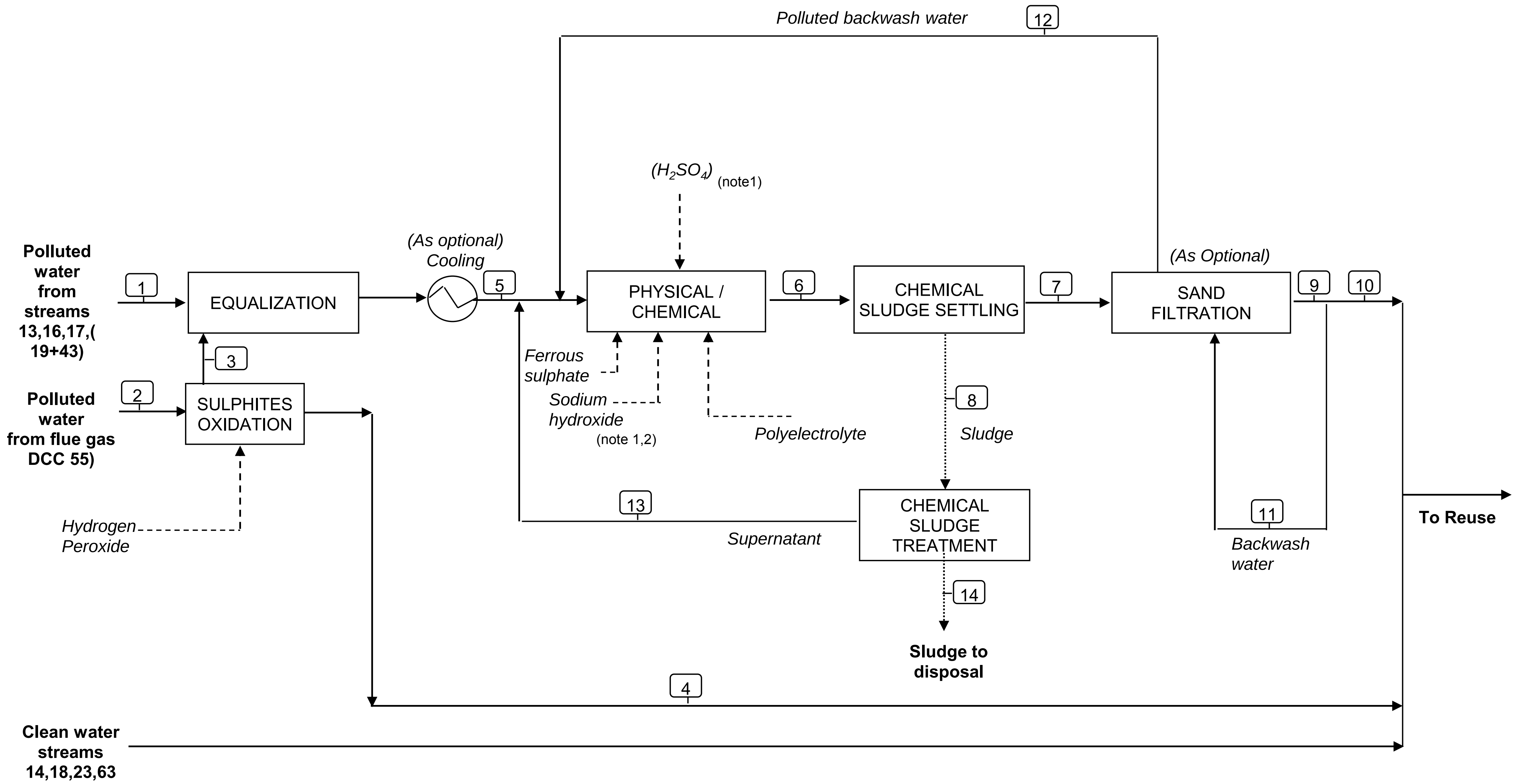
SUPPLIER
CONTRACT N° [redacted]
THIS DWG.SUPERSEDED BY
SCALE
THIS DWG.SUPERSEDES

FOSTER WHEELER ITALIANA

DWG. N° 1-BD0475A-3-50-3000
SHEET 2 OF 2
REV. A

CAD FILE NAME 1-19a503000b_01.DGN

CASE 5.03 - GEE IGCC, BITUMINOUS COAL FEED WITH CO_2 CAPTURE (DRY LAND) – WASTE WATER TREATMENT BLOCK FLOW DIAGRAM



Notes:
1. Sulphuric acid or Caustic soda can be foreseen for pH adjustemnt; dosage is done under pH control in order to mantain the pH at about 9.5.
2. Caustic soda dosage is provided in order to neutralize the acid contribution deriving from H_2S removal.

4. Detailed Water Flow Diagram

In the present paragraph the following documents are attached:

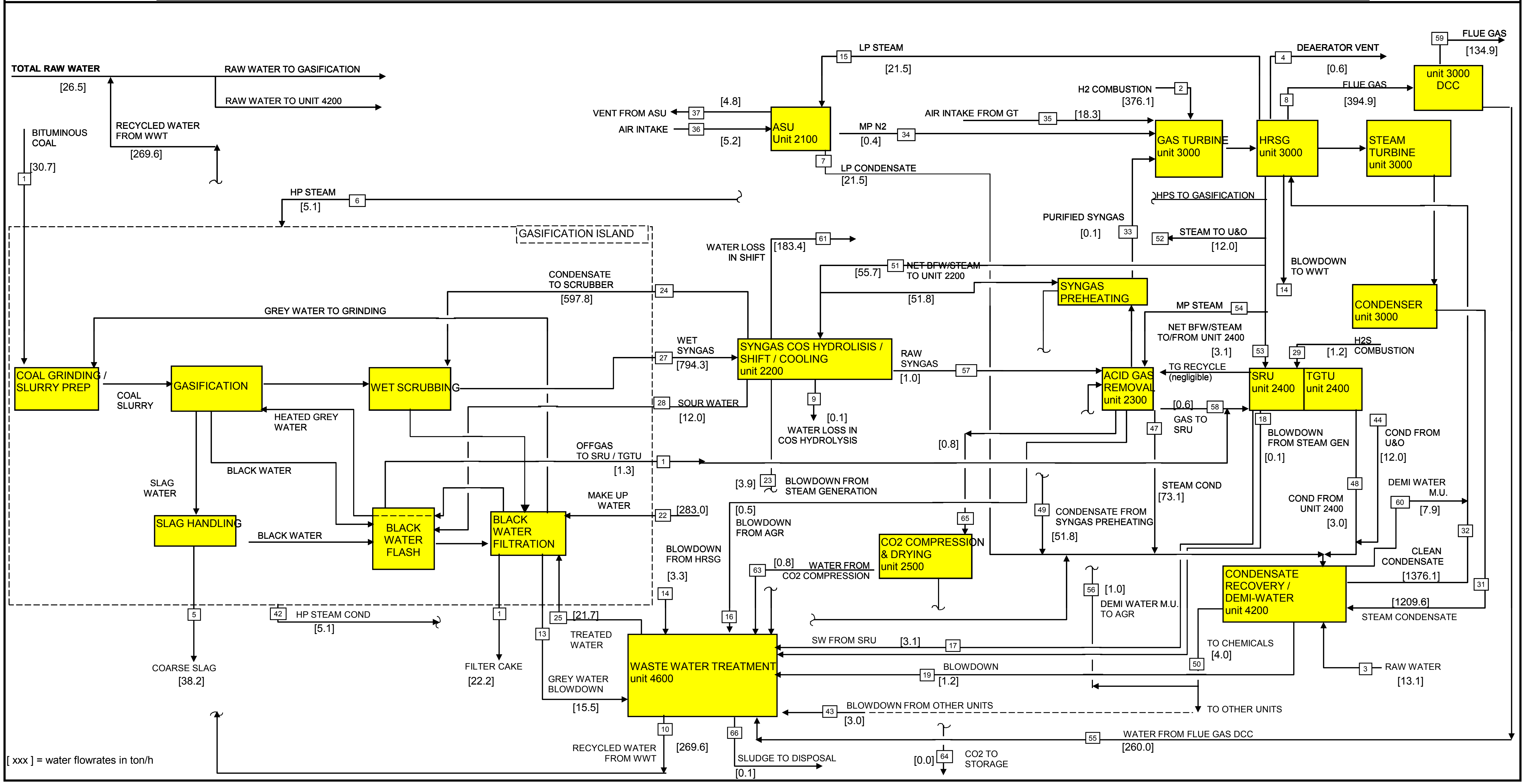
- detailed water Flow Diagram relevant to the entire power plant;
- water balance around the major units.
- flowrates and compositions of the streams of water to waste water treatment unit.

It is important to note that the introduction of a Flue Gas Direct Contact Cooler allows the recovery of a significant amount of water from flue gases. This water is mixed with other polluted water streams and sent to WWT unit, where contaminants are removed, so that treated water may be reused in the power plant itself in place of raw water.
It results that recycled treated water allows reducing the raw water demand, but it is not yet enough to allow a zero raw water intake.

The ambient temperature affects both the load of the plant and the minimum temperature that can be achieved in the air cooling systems.
The plant load in fact is influenced by the GT appetite that varies with the ambient air temperature. When the ambient temperature raises the GT appetite decreases and viceversa.
On the other hand, the higher ambient temperature leads to an higher temperature on the process streams downstream the air cooled exchanger. The material balance attached to water diagram is referred to the reference ambient temperature. Therefore, it is to be considered as an average between the cold and the warm season.

The water balance around the major units has been obtained from the H&M balance of the plant provided in paragraph 5. For the figure missing in the H&M balance, the flowrates have been derived from FWI experience, based on in-house data available from several projects based on same power plant technologies.

CASE 5.03 - GEE IGCC COMPLEX, BITUMINOUS COAL, WITH CO2 CAPTURE (NET POWER OUTPUT = 671.0 MWe) (DRY LAND) - BLOCK FLOW DIAGRAM - WATER BALANCE



IEA GHG R&D PROGRAMME | Revision no.: 1
Water usage & loss Analysis in Power plants without & with CCS | Date: November 2010
Volume #4 | Sheet:

GEE IGCC fed by bituminous coal, with CO2 capture - Overall Water Balance

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	30.7	5	Slag	38.2
2	Syngas combustion of H2 in GT	376.1	4	Deaerator vent	0.6
3	Raw water to Demi Plant	13.1	11	Filter cake	22.2
36	Moisture in air to ASU	5.2	59	Flue gas from flue gas DCC	134.9
29	H2S combustion in SRU	1.2	9	Water loss in COS hydrolysis	0.1
35	Moisture in combustion air to GT	18.3	10	Water effluent from WWT	269.6
22	Raw Water make up to Gasific.	283.0	37	Moisture from ASU vent	4.8
			61	Water loss in shift reaction in unit 2200	183.4
Total		727.6	Total		653.8

delta (note 1) 73.8

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Gasification Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
1	Moisture in coal	30.7	11	Filter cake	22.2
28	Sour Water to Stripping	12.0	5	Slag	38.2
24	Condensate to Wet Scrubber	597.8	27	Wet syngas	794.3
22	Make up to Grey Water Tank	283.0	12	Sour Gas	1.3
25	Treated water from WWT	21.7	13	Grey Water Blowdown	15.5
6	HP steam	5.1	42	HP condensate	5.1
Total		950.3	Total		876.6

delta (note 1) 73.7

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around WWT (unit 4600)

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
13	Grey Water Blowdown	15.5	25	Treated water to Gasifier	21.7
14	Blowdown from HRSG	3.3	10	Recycled water from WWT	269.6
43	Blowdown from other units	3.0	66	Sludge to disposal/losses	0.1
16	Blowdown from AGR	0.5			
17	Sour water from SRU	3.1			
18	Blowdown from SRU	0.1			
19	Blowdown from Demi Plant	1.2			
23	Blowdown from unit 2200	3.9			
55	Water from flue gas DCC	260.0			
63	Water from CO2 compressor	0.8			
Total		291.4	Total		291.4

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Cond Recovery/Demi Water Plant

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
3	Raw Water	13.1	32	Demi Water to HRSG and PRS u	1376.1
31	Condensate from Steam Turbine	1209.6	19	Blowdown to WWT	1.2
44	Condensate from U&O	12.0	50	Demi water to chemicals	4.0
6	Condensate from Gasification	5.1	60	Demi water make up	7.9
7	Condensate from unit 2100	21.5			
47	Condensate from unit 2300	73.1			
48	Condensate from unit 2400	3.0			
49	Condensate from syngas preheating	51.8			
Total		1389.2	Total		1389.2

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Power Island

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	18.3	59	Flue gas from flue gas DCC	394.9
2	Syngas combustion of H2 in GT	376.1	6	HP steam to Gasification	5.1
33	Water in syngas	0.1	52	Steam to U&O	12.0
34	Moisture in MP nitrogen from ASU	0.4	51	Net BFW/LMP steam to unit 2200	55.7
32	Clean condensate to HRSG	1376.1	54	MP steam to unit 2300	73.1
60	Demi water make up	7.9	53	Net BFW/Steam to unit 2400	3.1
			14	Blowdown from HRSG	3.3
			15	LP steam to N2 saturator HE	21.5
			31	Steam condensate from CCU	1209.6
			4	Deaerator vent	0.6
Total		1778.8	Total		1778.8

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around GT - HRSG

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
35	Moisture in combustion air to GT	18.3	59	Flue gas from flue gas DCC	394.9
2	Syngas combustion of H2 in GT	376.1			
33	Water in syngas	0.1			
34	Moisture in MP nitrogen from ASU	0.4			
Total		394.9	Total		394.9

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around Unit 2200

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
27	Wet Syngas	794.3	9	Water loss in COS hydrolysis	0.1
51	Net BFW/steam to unit 2200	55.7	24	Condensate to scrubber	597.8
			28	sour water to SWS	12.0
			61	Water loss in shift reaction in unit	183.4
			57	Raw syngas to AGR	1.0
			23	Blowdown from Steam Gen	3.9
			49	Condensate from syn. preheat.	51.8
Total		849.9	Total		849.9

GEE IGCC fed by bituminous coal, with CO2 capture - Water Balance around AGR

Water In			Water Out		
No	Location	Flow (ton/h)	No	Location	Flow (ton/h)
57	Raw Syngas	1.0	58	Gas to SRU	0.6
56	Demiwater make up	1.0	33	Purified syngas	0.1
54	MP steam	73.1	47	Steam condensate	73.1
			16	Blowdown from AGR	0.5
			65	CO2 to compression	0.8
Total		75.1	Total		75.1

NOTE 1: Water balances around gasification island and around the entire Power Plant don't close to zero by the same amount. The difference between the streams of "water in" and "water out" is due to the shift reactions, occuring in the gasification island.

IEA GHG R&D PROGRAMME | Revision no.: 1

Water usage & loss Analysis in Power plants without & with CCS | Date: November 2010

Volume #4 | Sheet:

CASE 5.03 - GEE IGCC, BITUMINOUS COAL FEED WITH CO2 CAPTURE (DRY LAND) - WATER STREAMS SENT TO WWT

STREAM	13	14	16	17	18	19+43	23	55	63			
SERVICE	Grey Water Blowdown	Blowdown from HRSG	Blowdown from AGR	Sour water from SRU	Blowdown from SRU	Blowdown from Demi Plant + other units	Blowdown from unit 2200	Water from flue gas DCC	Water from CO2 compressor			
Temperature (°C)	50	100	120	50	100	amb	100	45	30			
Total flowrate (kg/h)	15500	3300	500	3100	100	4200	3850	260000	800			
Composition (ppm wt)												
SO_2 / HSO_3^-								10				
H_2S	2		800	30								
CO_2	0		400	100				20	150			
NH_3	25			10								
Na^+	97					1090						
Cl^-	148					4560						
PO_4^{---}		1			5		5					
SiO_2		1			5	110	5					
$CaCO_3$		20			100	406	100					
SO_4^{--}	25					830						
Sulfides	10											
CN^-	< 5											
Formates	740											
NO_3^-						510						
Ca AAS						1410						
Mg AAS						420						
Selexol			3224									
HCO_3^-						250						
Suspended solids	100							87				
K						30						
H_2O (% wt)	99.8852	99.9978	99.5576	99.9860	99.9890	99.0384	99.9890	99.9883	99.9850			
TOTAL	100	100	100	100	100	100	100	100	100			
NOTES:	NOC					**	*					

(*) = blowdown flowrate assumed equal to 0.5% steam production

(**) = eluate flowrate assumed equal to 10% demineralized water unit normal flowrate

5. Heat and Material Balance

The Heat and Material Balance (H&MB), 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.

Modifications to the H&MB due to the installation of the power plant in a dry land country far from the seaside have been highlighted.
The H&MB relevant to WWT unit has also been included.

	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE CASE 5.03						APPROVED	SA		
	UNIT : 2100 AIR SEPARATION UNIT						DATE	March 2010		
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		

	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.So.		
	CASE : GEE CASE 5.03						APPROVED	SA		
	UNIT : 2200 Syngas treatment and conditioning line						DATE	March 2010		
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	40		
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	0	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	L.So.		
	CASE : GEE CASE 5.03	APPROVED	SA		
	UNIT : 2300 Acid Gas Removal	DATE	March 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	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;

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	2
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	L.So.		
	CASE : GEE CASE 5.03	APPROVED	SA		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)	DATE	March 2010		

STREAM	1	2	3	4	5	6	7	8	9	10
	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 GREEN HOUSE R & D PROGRAMME				
	CASE : GEE CASE 5.03				
	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)	2426.0	107	AMB.	117
20	Condensate from Syngas Final Heater (*)	46.56	170	1.9	722
21	LP Steam Turbine exhaust	1210.31	40	0.074	2249
22	Not Used				
23	Not Used				
24	Condensed water to WWT (*)	130	34.5	3.0	144

(*) flowrate for one train
(1) Syngas composition as per stream 5 of Material Balance for Unit 2200 .
(2) Flues gas molar composition: N_2: 81.7%; H_2O: 4.7%; O_2: 11.0%; CO_2: 1.5%; Ar: 1.1%.

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Water Usage and Loss of Power in Power Plants with CCS	Date:	March 2010
Volume #4	Sheet:	1 of 1

CASE 5.03 - GEE IGCC, BITUMINOUS COAL FEED WITH CO_2 CAPTURE (DRY LAND) – WASTE WATER TREATMENT H&MB

STREAM	**N°**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Parameter	**Unit**	**Polluted streams 13,16,17,(19+43) to equalization**	**Polluted flue gas water (55) to HSO3- oxidation unit**	**treated flue gas water to equalization**	**treated flue gas water to reuse**	**Water from equalizaton basin**	**Water to chemical sludge settling**	**Water to filtration**	**Chemical sludge**	**Water from filtration**	**Treated water**	**Backwash water**	**Polluted backwash water**	**Supernatant from chemical sludge dewatering**	**Chemical sludge to disposal**
Temperature	°C	46.09	45.00	45.00	45.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Total Flow	ton/h	23.30	260.00	140.00	120.00	163.30	172.50	171.84	0.66	171.84	163.25	8.59	8.59	0.58	0.08
H2S	mg/l	29.20	0.00	0.00	0.00	4.17	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
NH3	mg/l	17.96	0.00	0.00	0.00	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Na+	mg/l	261.24	0.00	0.00	0.00	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27
Cl-	mg/l	920.51	0.00	0.00	0.00	131.34	131.32	131.32	131.32	131.32	131.32	131.32	131.32	131.32	131.32
PO4--	mg/l	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	0.00
SiO2	mg/l	19.83	0.00	0.00	0.00	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83
CaCO3	mg/l	73.18	0.00	0.00	0.00	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44
SO4--	mg/l	166.24	0.00	20.91	20.91	41.65	41.64	41.64	41.64	41.64	41.64	41.64	41.64	41.64	41.64
NO3-	mg/l	91.93	0.00	0.00	0.00	13.12	13.11	13.11	13.11	13.11	13.11	13.11	13.11	13.11	13.11
Ca++	mg/l	254.16	0.00	0.00	0.00	36.26	36.26	36.26	36.26	36.26	36.26	36.26	36.26	36.26	36.26
Mg++	mg/l	75.71	0.00	0.00	0.00	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
MDEA	mg/l	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	0.00
K+	mg/l	5.41	0.00	0.00	0.00	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
HCO3-	mg/l	45.06	0.00	0.00	0.00	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43	6.43
TSS	mg/l	86.35	87.00	87.00	87.00	86.91	116.80	20.00	25271.24	5.00	5.26	5.00	395.00	200.00	222826.09
COD	mg/l	303.67	0.00	0.00	0.00	43.33	43.32	43.32	43.32	43.32	43.32	43.32	43.32	43.32	43.32
BOD	mg/l	167.02	0.00	0.00	0.00	23.83	23.83	23.83	23.83	23.83	23.83	23.83	23.83	23.83	23.83
CN- tot.	mg/l	3.23	0.00	0.00	0.00	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Formiates	mg/l	492.27	0.00	0.00	0.00	70.24	70.23	70.23	70.23	70.23	70.23	70.23	70.23	70.23	70.23
Selexol	mg/l	69.18	0.00	0.00	0.00	9.87	9.87	9.87	9.87	9.87	9.87	9.87	9.87	9.87	9.87
SO2/HSO3-	mg/l	0.00	10.00	0.50	0.50	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
H2O	%	100	100	100	100	100	100	100	97	100	100	100	100	100	80

General notes

1. Present mass balance is indicative only and related to the process treatment selected

6. Utility consumption

The Utility Consumptions of the process / utility & offsite units are attached hereafter. *Italic* font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.06 (see Report # 4, section C).
WWT utility consumption is also attached.

		REVISION	Draft	Rev.1	Rev.2
CLIENT:	IEA GHG R&D PROGRAMME	DATE	March 2010		
PROJECT:	WATER USAGE AND LOSS ANALYSIS	ISSUED BY	L.So.		
LOCATION:	SOUTH AFRICA	CHECKED BY	PC		
FWI Nº:	1-BD-0475A	APPROVED BY	SA		

UTILITIES CONSUMPTION SUMMARY - GEE IGCC - CASE 5.03 - HP with CO_2 capture, separate removal of H_2S and CO_2 - DRY LAND

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**	*52.8*	*122.1*	*530.9*	*72.7*	**51.8**	*3.9*
2300	**Acid Gas Removal**			*73.1*						*73.1*	
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**	*422.9*	**20.5**	*-52.8*	*-126.5*	*-532.1*	*-72.7*		
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**	*166.5*	*4.0*

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg
(2) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.06.

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
	PROJECT:	WATER USAGE AND LOSS ANALYSIS	March 2010
	LOCATION:	SOUTH AFRICA	ISSUED BY: L.So.
	FWI Nº:	1-BD-0475A	CHECKED BY: PC
			APPR. BY: SA

WATER CONSUMPTION SUMMARY - GEE IGCC - CASE 5.03 - HP with CO_2 capture, separate H2S and CO2 removal
DRY LAND

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				SEA WATER IS NOT AVAILABLE IN POWER PLANTS INSTALLED IN DRY LAND
1000	**Gasification Section**	**283.0**		*3746*	
2100	**Air Separation Unit**				
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**				
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			*396*	
2500	**CO2 Compression and drying**				
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			*2090*	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		*7.9*		
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	*13.1*	*-11.9*		
	Other Units		**4.0**	*437*	
	BALANCE excluding CO2 compression	*296.1*	**0**	*6670*	*0*
	BALANCE including CO2 compression	*296.1*	**0**	*6670*	*0*

Note: (1) Minus prior to figure means figure is generated
(2) For the WET LAND scenarios, MCW delta T = 12°C. For the DRY LAND scenarios, MCW delta T = 10°C.
(3) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.06.

	CLIENT:	IEA GHG R&D PROGRAMME	Rev: Draft
FOSTER WHEELER	PROJECT:	WATER USAGE AND LOSS ANALYSIS	March 2010
	LOCATION:	SOUTH AFRICA	ISSUED BY: L.So.
	FWI Nº:	1-BD-0475A	CHECKED BY: PC
			APPR. BY: SA

ELECTRICAL CONSUMPTION SUMMARY - GEE IGCC - CASE 5.03 - HP with CO_2 capture, separate H2S and CO2 removal - DRY LAND

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13923**
2100	**Air Separation Unit**	*133100*
2200	**Syngas treatment and conditioning line**	*468*
2300	**Acid Gas Removal**	*33528*
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3555**
2500	**CO2 Compression and drying**	*(41768)*
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	*23489*
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	*8143*
3500	**Miscellanea**	**598**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (~~Sea Water /~~ Machinery Water)**	*1581*
	Additional consumption including CO_2 compression and drying	*(0)*
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**368**
	Other Units	**719**
	BALANCE excluding CO2 compression	**224540**
	BALANCE including CO2 compression	**266308**

Notes: (1) Minus prior to figure means figure is generated
(2) ***Italic*** font style indicates that the figure in the table has been updated, compared with the analogous figure in reference plant, case 5.06.

CLIENT:	IEA GREENHOUSE R&D PRO	REVISION	Rev.0	Rev.1	Rev.2
LOCATION:	South Africa	DATE	March '10		
PROJ. NAME:	Water usage and loss of power in	ISSUED BY	M.P.		
CONTRACT N.	1-BD-0475 A	CHECKED BY	A.S.		
		APPROVED BY			

Utilities consumption

WWT Unit - GEE IGCC with CO2 capture, fed with bituminous coal, case 5.03 - DRY LAND

	ITEM	DESCRIPTION	Absorbed Electical power [kW]	NaOH [kg/h]	H_2O_2 [kg/h]	$FeSO_4$ [kg/h]	Poly [kg/h]	Remarks
		WWT - waste water treament unit	~90	~1.5	~0.7	~3.5	~0.5	

Table below summarizes specific consumption for each treatment section - reported values are indicative only.

	ITEM	DESCRIPTION	Absorbed Electical power [kW] total	Absorbed Electical power [kW] specific	NaOH (1) [kg/h]	H_2O_2 (1) [kg/h]	$FeSO_4$ (1) [kg/h]	Poly (1) [kg/h]	Remarks
		Sulphides oxidation Section	3			0.6			
		Equalization Section	22						
		Physical-Chemical section	4		1.4		3.2	0.4	
		Sedimentation section	23						
		Media filtration section	37						

Notes:
1. As pure products.

7. Overall performance

The table summarizing the Overall Performance of the GEE IGCC power plant, case 5.03, is attached hereafter.

GEE IGCC

CASE 5.03 - High press with CO_2 capture, separate H_2S and CO_2 removal - DRY LAND

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	323.1
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2321.8**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1637.9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4
Syngas treatment efficiency (F/E*100)	%	90.9
Gas turbines total power output	MWe	563.4
Steam turbine power output	MWe	362.8
Expander power output	MWe	11.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**937.4**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	133.1
Process Units consumption	MWe	51.8
Utility Units consumption	MWe	1.1
Offsite Units consumption ~~(including sea cooling water system)~~	MWe	1.6
Power Islands consumption	MWe	36.9
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**224.5**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**712.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**40.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**30.7**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	41.8
Offsite Units consumption ~~(sea cooling water system)~~	MWe	0.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**266.3**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**671.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**40.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**28.9**

Specific fuel (coal) consumption per MW net produced	**MWt/Mwe**	**3.460**
Specific CO2 emissions per MW net produced	**t/MWh**	**0.165**
Specific water consumption per MW net produced	**t/MWh**	**0.039**

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

8. Environmental Impact

The GEE IGCC power plant, case 5.03, is designed to process coal, whose characteristic is shown at Section A 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.

8.1. Gaseous Emissions

8.1.1. 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 8.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 8.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	673.9
Flow, $Nm^3/h^{(1)}$	2.881.500
Temperature, °C	107
Composition	(%vol)
Ar	1.1
N_2	81.7
O_2	11.0
CO_2	1.5
H_2O	4.7
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 8.2

Table 8.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1347.8
Flow, $Nm^3/h^{(1)}$	5.763.000
Temperature, °C	107
Emissions	kg/h
NOx	291,8
SOx	4,0
CO	183,2
Particulate	24,9

(1) Dry gas, O_2 content 15%vol

8.1.2. 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.

8.2. Liquid Effluent

The expected flow rate of treated water from Waste Water Treatment plant to be discharged outside power plant battery limit is in practice reduced to zero: in fact, apart from a negligible amount of water present in the stream of "Sludge To Disposal" (less than 0.1 t/h of water), all the water received by Waste Water Treatment is treated and recycled back to the power plant.

8.3. 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: 0.1 m3/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:

Fine Slag

Flow rate	:	31,8	t/h
Water content	:	70	%wt

Coarse Slag

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.

Anyway, considering that it may be difficult to sell them and considering the modest revenue they can give, for the purposes of present study solids effluents are considered as neutral: neither as revenue nor as disposal cost.

9. Equipment List

The list of main equipment and process packages is included in this paragraph. WWT plant equipment list is included.

In the equipment list, the major water consumers/producers have been highlighted with the relevant water production/consumption.

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EQUIPMENT LIST

Unit 1000 - Gasification Unit - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			Syngas scrubber								597.8 t/h of condensate from unit 2200	
			Black water flash drum								12 t/h sour water from unit 2200	
			Black water flash drum									1.3 t/h steam in sour gas
			Grey water tank								283 t/h raw water as make up	
			Grey water tank								21.7 t/h treated water from WWT	
			Grey water tank									15.5 t/h water blowdown
			Drag conveyor and slag screen									38.2 t/h in coarse slag
			Rotatory filter									22.2 t/h in fine slag
			Gasification section								5.1 t/h HP steam	condensate is recovered

LEGEND:
For the Gasification Unit, only the water consumer items are shown.
(1) = reference shall be made to case 5.06: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2100 - Air Separation Unit - GEE IGCC Case 5.03 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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			Oxigen purity = 95 %	21.5 t/h steam to internal heaters	21.5 t/h steam condensate to recovery
					MP N_2 flow rate to GTs = 685 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 = 644 t/h					Nitrogen purity = 99,99 %		
Δ			**ASU Compressors**		130.7 MW					3% higher than in case 5.06		
Δ			**ASU Heat Exchangers**	Aircooler	16 services; duty=12 MWth each; 1000 m2 (bare) each	85 kWe each service			CS			
Δ			**ASU chiller**		8.7 MW th @ 5°C					66% bigger than in case 5.06		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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 side		
	2	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16670 kW H2 service H2/Wet H2S serv. on channel side		
	1	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 14840 kW H2 service H2/Wet H2S serv. on channel side	52.8 t/h HP BFW	52.6 t/h HP steam + 0.3 t/h blowdown
	2	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 14840 kW H2 service H2/Wet H2S serv. on channel side		
	1	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37055 kW H2 service H2/Wet H2S serv. on channel side	122.1 t/h MP BFW	121.5 t/h MP steam + 0.6 t/h blowdown
	2	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37055 kW H2 service H2/Wet H2S serv. on channel side		
	1	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 155600 kW H2 service H2/Wet H2S serv. on channel side	530.9 t/h LP BFW	528.3 t/h LP steam + 2.6 t/h blowdown
	2	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 155600 kW H2 service H2/Wet H2S serv. on channel side		
	1	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel side	72.7 t/h LP BFW	72.3 t/h LP steam + 0.4 t/h blowdown
	2	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel side		

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.03 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube				
1 Δ	1	E-2206 A/B	Condensate Preheater	Shell & Tube	exchanger area = 1500 m2 (exchanger A+B)		20 / 68	130 / 185		DUTY = 38000 kW H2 service H2/Wet H2S serv. on channel side		
2 Δ	2	E-2206 A/B	Condensate Preheater	Shell & Tube	exchanger area = 1500 m2 (exchanger A+B)		20 / 68	130 / 185		DUTY = 38000 kW H2 service H2/Wet H2S serv. on channel side		
		E-2207	Expander Feed Heater	Shell & Tube			7 / 68	165 / 175		DUTY = 19690 kW H2 service H2/Wet H2S serv. on channel side	51.8 t/h VLP steam	recovered as condensate
		E-2208	Syngas pre-heater	Shell & Tube			7 / 68	165 / 175		DUTY = 11270 kW H2 service H2/Wet H2S serv. on channel side		
1 +	1	E-2209	Syngas trim cooler	Aircooler	11.5 MWth	120 kWe			CS + 3mm C.A.	1200 m2 bare surface		
2 +	2	E-2209	Syngas trim cooler	Aircooler	11.5 MWth	120 kWe			CS + 3mm C.A.	1200 m2 bare surface		

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EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			DRUMS		D,mm x TT,mm							
	1	D-2201	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service		597.8 t/h condensate to Gasification; 12 t/h contaminated condensate to SWS
	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		0.1t/h water loss to COS hydrolysis; 183.4 t/h water loss in shift reaction
	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 Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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)	5.6 t/h BFW to steam generators + 3.1 t/h water in sour gas and from reaction	2.5 t/h steam to Plant network; 3.0 t/h steam condensate to condensate unit 3.1 t/h sour water to WWT; 0.1 t/h blowdown water to WWT
					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%		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 2500 - CO2 compression and drying - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			Compression package									
	Δ		**Compressor**	3 stage compressor	165000 Nm3/h x overall β = 73; β per stage = 4.5	motor = 22 MW each machine			SS	2 x 50% machines (165000 Nm3/h each)		
	Δ		**Intercoolers**	aircooler	16 MWth	320 kWe			tubes: SS header: CS	6 aircoolers, 16 MWth (320 kWe) each		
			Dryer									Water condensed from CO2 stream (0.8 t/h)

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06: "+" means that the item shall be added: "-" means that the item shall be deleted: "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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	Steam in syngas, in air to turbine and generated in combustion	394.9 t/h steam in flue gas to final DCC
	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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			PUMPS		$Q, m^3/h \times H, m$							
	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		
+	1	P-3205 A/B/C	Flue gas condensed water pumps	centrifugal	8400m3/h x 40m	1.3 MW each			casing: CS; internals: 12%Cr	3 pumps in operation; 1 pump spare		
+	2	P-3205 A/B/C	Flue gas condensed water pumps	centrifugal	8400m3/h x 40m	1.3 MW each			casing: CS; internals: 12%Cr	3 pumps in operation; 1 pump 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				
+	1	D-3207 A/B/C/D	Flue gas final DCC	Vertical	D=8m; H=16m each				KCS+6 mm 304L clad	4 vessels		133 t/h cond'd water
+	2	D-3207 A/B/C/D	Flue gas final DCC	Vertical	D=8m; H=16m each				KCS+6 mm 304L clad	4 vessels		133 t/h cond'd water
			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	B-3201	Flue gas final DCC blower	Axial fan	2.000.000Nm3/h x 300 mm H2O	3.0 MW each			CS	1 blower in operation		
+	2	B-3201	Flue gas final DCC blower	Axial fan	2.000.000Nm3/h x 300 mm H2O	3.0 MW each			CS	1 blower in operation		
	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-		

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			PACKAGES									
		Z-3201	**Fluid Sampling Package**									
		Z-3202	**Phosphate Injection Package**									
		D-3204	Phosphate storage tank							Included in Z - 3202		
		P-3204 a/b/c	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare		
		Z-3203	**Oxygen Scavanger Injection Package**									
		D-3205	Oxygen scavanger storage tank							Included in Z - 3203		
		P-3205 a/b/c	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare		
			HEAT EXCHANGERS		S, m^2							
+	1	**E-3220**	**Flue gas feed/effluent exchangers**	Rekugavo, plate exchanger	59 MWth				SS 316L			
+	2	**E-3220**	**Flue gas feed/effluent exchangers**	Rekugavo, plate exchanger	59 MWth				SS 316L			
+	1	**E-3221**	**Flue gas condensed water cooler**	Aircooler	130 MWth	100 motors x 35 kW			CS+2 mm 304L clad	Aircooler bare surface = 18.000 m2		
+	2	**E-3221**	**Flue gas condensed water cooler**	Aircooler	130 MWth	100 motors x 35 kW			CS+2 mm 304L clad	Aircooler bare surface = 18.000 m2		

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3	
LOCATION: SOUTH AFRICA	DATE	March 2010	November 2010			
PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.			
CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC			
	APPROVED BY	SA	SA			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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		1.7 t/h blowdown from Steam Drums
	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		0.3 t/h steam vented to atm
	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		

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER			DATE	March 2010	November 2010		
			ISSUED BY	L.So.	L.So.		
			CHECKED BY	PC	PC		
			APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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		1.7 t/h blowdown from Steam Drums
	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		0.3 t/h steam vented to atm
	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		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

FOSTER WHEELER			CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: SOUTH AFRICA PROJ. NAME: Water usage and loss Analysis CONTRACT N. 1- BD- 0475 A				REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3	
							DATE	March 2010	November 2010			
							ISSUED BY	L.So.	L.So.			
							CHECKED BY	PC	PC			
							APPROVED BY	SA	SA			

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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			blowdown from Steam Drums	3.3 t/h water to WWT
		D-3303	**Discontinuous Blow-down Drum**	vertical			3.5	140				
			PACKAGES									
		Z-3301	**Steam Turbine & Condenser Package**									
Δ		TB-3301	Steam Turbine		393 MW gross					Included in Z - 3201		
		E-3301A/B	Inter/After condenser									
		E-3302	Gland Condenser							Included in Z - 3201		
Δ		E-3303	Steam Condenser	aircooler	715 MW th	70x95 kWe			CS	Included in Z - 3201 70 modules, 12x12 m2 each		
		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-3301 A/B/C	Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare		
		SL-3301	Start-up Ejector Silencer							Included in Z - 3201		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.: Draft	Rev.1	Rev.2	Rev.3
FOSTER WHEELER	LOCATION: SOUTH AFRICA	DATE	March 2010	November 2010		
	PROJ. NAME: Water usage and loss Analysis	ISSUED BY	L.So.	L.So.		
	CONTRACT N. 1- BD- 0475 A	CHECKED BY	PC	PC		
		APPROVED BY	SA	SA		

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - GEE IGCC Case 5.03 - High Pressure with CO2 capture, dirty shift reaction, separate removal of H2S and CO2 - DRY LAND

CHANGE (1)	TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
			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									
Δ			**Closed loop water cooler**	aircooler	78 MW th	1930 kWe			CS			
Δ			**Closed loop CW pumps**	centrifugal	6670 m3/h x 30m	1000 kWe			CS	1 pump in operation + 1 spare		
Δ			**Waste water treatment plant**									
–			~~**Sea water pumps**~~							DELETED		
–			~~**Seawater chemical injection**~~							DELETED		
–			~~**Sea water inlet/outlet works**~~							DELETED		

LEGEND:
The water consumer equipment is highlighted in the present equipment list.
(1) = reference shall be made to case 5.06; "+" means that the item shall be added; "-" means that the item shall be deleted; "Δ" means that the item is changed.

EQUIPMENT LIST

Unit 4600 - BoP, Electrical, I&C - GEE IGCC with CO2 capture, fed with bituminous coal, case 5.03 - DRY LAND

	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks	Water in	Water out
		Sulphides oxidation Section									
	4600-Y1001	Oxidation Reactor		S= 40 m^2 ; H 2,5 m					1X100% (1op)		
	4600-MX1001A/B/C/D	Mixer			0.35				4X25% (4op)		
	4600-PK1001 A/B	H_2O_2 dosage system		Φ=0,8 m; H=1,5 m	0.74				2X50% (about 30 day storage)		
		Equalization Section									
	4600-Y1002	Equalization basin		S=700 m^2 ; H= 5 m					1X100 (underground basin)		
	4600-P1001 A/B	Physical-chemical treatment feed pump	Centrifugal	180 mc/h; 2 bar	22				2X100% (1op + 1spare)		
		Physical-Chemical section									
	4600-Y1003	Coagulation basin		S= 7,5 m^2 ; H= 3 m					1X100 % coagulation		
	4600-MX1002 A/B/C/D	Coagulation basin mixer			0.35				4X25% (4op)		
	4600-Y1004	Flocculation basin		S= 38 m^2 ; H= 3 m					1X100 % flocculation		
	4600-MX1003 A/B/C/D	Flocculation basin mixer			0.18				4X25% (4op)		
	4600-PK1002 A/B	$FeSO_4$ dosage system		Φ=1,6 m; H=2,4 m	0.36				2X50% (about 30 day storage)		
	4600-PK1003 A/B	NaOH dosage system		Φ=1,3 m; H=1,6 m	0.36				2X50% (about 30 day storage)		
	4600-PK1004 A/B	polyelectrolite dosage system		Φ=1 m; H=1,6 m	0.36				2X50% (about 30 day storage)		
		Sedimentation section									
	4600-Y1005 A/B	Chemical sludge settling Basin		L= 16 m; W= 4 m; H= 3,5 m					2 op		
	4600-K1001 A/B	Sludge scraper			0.25				2 op		
	4600-P1002 A/B/C	chemical sludge settling water feed pump	Centrifugal	95 mc/h; 2 bar	11				3X50% (2op + 1 spare)		
	4600-P1003 A/B/C	chemical sludge treatment feed pump	Centrifugal	0,36 mc/h; 2 bar	0.12				3X50% (2op + 1 spare)		
		Media filtration section									
	4600-P1004 A/B/C	sand filter water feed pump	centrifugal	95 mc/h; 2 bar	11				3X50% (2op + 1 spare)		
	4600-F1001 A/…/F	Sand filter		Φ=2.2 m; H=2,25 m					6 op		
	4600-Y1006	Filtered water basin		S=10 m^2 ; H= 3,5 m							
	4600-P1005 A/B	backwash pump	centrifugal	130 mc/h; 2 bar	15				2X100% (1op + 1 spare)		

Notes:
Present equipment list is indicative only and related to the WWT layout selected.

CLIENT	:	IEA GHG
PROJECT NAME	:	WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME	:	TECHNO-ECONOMICAL EVALUATION OF THE ALTERNATIVES

ISSUED BY	:	L. SOBACCHI
CHECKED BY	:	P. COTONE
APPROVED BY	:	S. ARIENTI

Date	Revised Pages	Issued by	Checked by	Approved by
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TECHNO-ECONOMICAL EVALUATION OF THE ALTERNATIVES

I N D E X

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : TECHNO-ECONOMICAL EVALUATION - GENERAL INFORMATION

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

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SECTION A

TECHNO-ECONOMICAL EVALUATION - GENERAL INFORMATION

I N D E X

1. Introduction

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate and evaluate water usage and loss of power in power plants with CO_2 capture.

The work is developed thought the establishment of a rigorous accounting of water usage throughout the power plant in order to establish an acceptable methodology that can be used to compare water usage in power plants with and without CO_2 capture. This can provide a baseline set of cases and water loss data for assessing potential improvements and evaluating R&D programs.

Cost effective water reduction technologies that could be applied for power plants with CO_2 capture are identified. Finally, an evaluation of the performance of power plants with CO_2 capture and potential impacts on the water usage applicable to areas where water supply could be severely limited is performed.

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
These studies shall be used as a basis for present study.

In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

Foster Wheeler Italiana included in the whole report the outcomes of the 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 purposes of the study, therefore, include:

- A review and assessment of the available information of water usage from power plants such as PC and IGCC with or without CO_2 capture from various previous studies done for IEA GHG, based on oxyfuel, pre- or post combustion CO_2 capture technologies.
- A review and assessment of the available technologies that would allow reduction of water usage from power plants;
- An evaluation and assessment of the applicable technologies for power plants with CO_2 capture in areas where water supplies could be severely limited.

The study is based on the current state-of-the-art technologies, evaluating costs and performances of plants which can be presently engineered and built.

Present report #5 makes the technical and economical evaluation of the alternatives analysed in the whole report.

The following alternatives are therefore evaluated:

- Case 3.21: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (**wet land** case).
- Case 3.25: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (**dry land** case).

- Case 3.22: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (**wet land** case).
- Case 3.23: USC PC Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (**dry land** case).

- Case 4.11: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (**wet land** case).
- Case 4.12: USC PC oxyfired Boiler reference case, based on standard ultra supercritical design, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (**dry land** case).

- Case 5.05: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and without limitation on water usage (**wet land** case).
- Case 5.07: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, without CO_2 capture and with limitation on water usage (**dry land** case).

- Case 5.06: IGCC plant reference case, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and without limitation on water usage (**wet land** case).

- Case 5.03: IGCC plant, based on GEE gasification technology, 750 MWe nominal power output, with CO_2 capture and with limitation on water usage (**dry land** case).

For each of the above mentioned cases the following information are provided:

- ✓ Summary of main technical data;
- ✓ Technical evaluation of the alternatives;
- ✓ Investment cost estimate for each case. CAPEX is broken down to major sections (e.g. fuel handling, boiler island, steam turbine island, etc.) for the dry land cases, while a single overall figure is provided for wet land cases;
- ✓ The OPEX defined and broken down to major items;
- ✓ Economical evaluation of the alternatives.

2. Project design bases

The Power Plants are designed to process, in an environmentally acceptable manner, a coal from eastern Australia and produce electric energy to be delivered to the local grid.

2.1. Feedstock specification

The feedstock characteristics are listed hereinafter.

2.1.1. Design Feedstock

	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. Back-up Fuel

	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 plant are listed here below with their specifications.

2.2.1. Electric Power

Net Power Output:	750	MWe	nominal capacity
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:	32 °C

Purity:

CO_2:	> 99% mol
Moisture:	<10 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 seriously degrades the performance of CO_2 in EOR, unlike H_2S, which enhances it.

Capture rate : 85% (as per reference study).

2.2.3. Sulphur (only for IGCC cases)

The Sulphur characteristics at 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. Solid By-products

The IGCC Plants produce slag and filter cake while the USC PC Plants produce Gypsum and Mill rejects (pyritic) as solid by-products. Those products are potentially saleable to the building industry.
The Oxyfuel Plants do not produce any solid by-product.

2.3. Environmental Limits

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

2.3.1. Gaseous Emissions

The overall gaseous emissions from the IGCC plants referred to dry flue gas with 15% volume O_2 shall not exceed the following limits:

NOx (as NO_2):	≤	80	mg/Nm^3
SOx (as SO_2):	≤	10	mg/Nm^3
CO:	≤	50	mg/Nm^3
Particulate :	≤	10	mg/Nm^3

The overall gaseous emissions from the USC PC and Oxyfuel plants referred to dry flue gas with 6% volume O_2 shall not exceed the following limits:

NOx (as NO_2):	≤	200	mg/Nm^3
SOx (as SO_2):	≤	200	mg/Nm^3
Particulate :	≤	30	mg/Nm^3

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 from the plant is the sea cooling water return stream (for wet land cases only).

The 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.

In agreement with IEA GHG, industrial wastewater discharge limits into surface water bodies of Italian law (DLgs 152/2006) are considered. Discharge limits are listed in Volume 1 – para 1.5.

2.3.3. Solid Wastes

The USC PC and oxyfuel plants produce the following solid wastes:

- Bottom ash
- Fly Ash
- Sludges from WWT

The IGCC plants do not produce any solid waste, except for typical industrial plant waste e.g. (sludge from WasteWater Treatment etc.). However even the wastewater sludge is recovered and recycled back to the Gasification Island to be processed by the Gasifiers

2.4. Plant Operation

2.4.1. Capacity

For all the cases the nominal design capacity is 750 MWe.

For more details reference shall be made to the specific cases general information and descriptions, reports #2, #3 and #4.

The following operating hours have been considered for the different cases:

USC PC without CO_2 capture: 80% first year of operation
90% from second of operation

USC PC with CO_2 capture: 75% first year of operation
88% from second of operation

Oxyfuel: 45% first year of operation
85% from second of operation

IGCC without CO_2 capture: 45% first year of operation
85% from second of operation

IGCC with CO_2 capture: 45% first year of operation
85% from second of operation

2.5. Location

Reference cases – wet land
The site for the reference cases, wet land, is a green field located 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 harbor equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

Dry land cases
The site for dry land cases is a green field located in a dry in land region in South Africa.

The plant area is assumed to be close to a river. Coal transport is assumed to be assured by rail connection.

No special civil works implications are assumed.

2.6. 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

Reference cases – wet land

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

Dry land cases

minimum air temperature:	2	°C	
maximum air temperature:	30	°C	
average air temperature:	14	°C	(*)

2.7. Main economical/Financial factors

2.7.1. Contingencies

The estimating contingency is a provisional sum that will give to an estimate equal chance of overrun or underrun within certain limits and it is meant to cover:
- estimating errors
- estimating omissions

Contingency is included in the estimate as a percentage of the estimated costs on the basis of:
- definition of the technical documentation in term of quality and completeness;
- estimate quality;
- methodology adopted to develop the estimate.

The same contingency as in reference studies has been considered and therefore:

USC PC cases:	10%
Oxyfuel cases:	7%
IGCC cases:	7%

Contingency for Oxyfuel cases has been slightly reduced to be consistent with the other cases.

2.7.2. Insurance and local taxes

1% of the installed plant cost per year is assumed to cover local taxation. Taxation on profits is not included. The same percentage of the installed plant cost per year is assumed for insurance.

This is in line with the figures considered in all the reference studies.

2.7.3. Other costs

Different *other costs* have been considered reflecting reference studies bases, for the different alternatives.
As per the invesmtment cost, also for *other costs* FWI did not modify at all the figures shown in the reference studies that are listed here below:

USC PC cases:
A 7% allowance based on the Total Installed Cost (TIC) has been made to cover owners costs. License fees were applicable have been consolidated into the Direct Materials.

Oxyfuel cases:
A 8% allowance based on the TIC has been made to cover owner costs. The figure is slightly lower than the one included in the original report to be consistent with the other cases.
For license fees a 2% of TIC has been assumed.

IGCC cases:

For land purchase, surveys, general site preparation 5% of the installed plant cost has been assumed.
2% of the installed plant cost has been assumed to cover process/patent fees, consultant services other than EPC Contractor's services, fees for agents, legal and planning costs.

The *other costs* are part of the Total Investment cost.

2.7.4. Operation and Maintenance

Labour and Maintenance data used for the economical evaluation are summarized in Section C.

2.7.5. Fuel Cost

Cost of coal delivered to site is 1.5 €/GJ in line with the figures considered in all the reference studies.

2.7.6. By-Products and Wastes

Some of solids effluent could be theoretically dispatched to cement industries and therefore they could be treated as revenue for the plant economics. They are fly and bottom ash.
Vice versa, sludges from WWT have to be sent outside the Power Plant battery limit for disposal.

For the purposes of present study solids effluents are considered as neutral: neither as revenue nor as disposal cost.

2.7.7. Currency exchange rate

The final estimate is developed in Euro.

The following exchange Euro to US $ rate has been used for the USC PC cases that were estimated in US $ in the reference study:

1.23 US $ equivalent to 1 Euro (II Q 2004)

The reference for the exchange rate is 2004 as in the 2004 original IEA GHG study the investment cost estimate has been provided in USD. In order to adjust such an investment cost estimate to today cost, the original exchange rate shall be consider to convert USD to Euro with the original exchange rate.

3. Basic Engineering Design Data

Reference shall be made to the Basic Engineering Design Data summarised in each report.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : PERFORMANCE EVALUATION

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APPROVED BY : S. ARIENTI

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SECTION B

PERFORMANCE COMPARISON
I N D E X

1. Introduction

Purpose of the present study is to compare (from the point of view of economics and performance) the power plants installed in countries without water limitations (referred to as "wet land" cases in the present report) with the power plants installed in countries where water supply is severely limited and far from the seaside (referred to as "dry land" cases). When installed in dry land countries, power plants have been provided with technologies for reducing as much as possible the water requirement and aircoolers are used instead of sea water coolers present in the wet land countries. In this section the impact of applying such technologies to the dry land case is analysed considering the performance of the power plant in terms of net electrical efficiency and of specific water consumption per MW produced.

2. Performance summary

Ten different power plants have been subjected to the present study, as mentioned in Section A of the present Report.

In the following table the main parameters of such plants are summarized. An analysis of such data is then performed in the following paragraphs.

PLANT TYPE		USCPC, without CCS		USCPC, with CCS		USCPC, Oxyfuel		GEE IGCC, without CCS		GEE IGCC, with CCS	
DRY LAND OR WET LAND?		WET LAND	DRY LAND	WET LAND	DRY LAND	WET LAND	DRY LAND	WET LAND	DRY LAND	WET LAND	DRY LAND
CASE NUMBER:		3.21	3.25	3.22	3.23	4.11	4.12	5.05	5.07	5.06	5.03
OVERALL PERFORMANCES OF THE POWER PLANT											
Coal Flowrate (fresh, air dried basis)	t/h	239.8	239.8	266.3	266.3	209.1	209.1	303.0	303.0	323.1	323.1
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	MWt	1723.2	1723.2	1913.7	1913.7	1502.2	1502.2	2177.3	2177.3	2321.8	2321.8
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	MWe	831.0	802.0	827.0	799.0	737.0	710.0	988.7	955.1	972.8	937.4
POWER PLANT PERFORMANCES											
AGR and CO2 compression Unit	MWe	-	-	77.0	96.7	64.9	70.5	-	-	72.0 (2)	75.3 (2)
Flue Gas Treatment (DeNOx + FGD)	MWe	6.3	6.3	7.4	7.4	-	-	-	-	-	-
Other Process Units and Utilities	MWe	67.0	70.7	77.0	71.8	140.7	148.1	162.2 (1)	177.5 (1)	170.5	191.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	MWe	73.3	77.0	161.4	175.9	205.6	218.6	162.2	177.5	242.5	266.3
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	MWe	757.7	725.0	665.6	623.2	531.4	491.4	826.5	777.6	730.3	671.1
Gross electrical efficiency (D/A *100) (based on coal LHV)	%	48.2	46.5	43.2	41.8	49.1	47.3	45.4	43.9	41.9	40.4
Net electrical efficiency (C/A*100) (based on coal LHV)	%	44.0	42.1	34.8	32.6	35.4	32.7	38.0	35.7	31.5	28.9
Delta net electrical efficiency (dry land minus wet land)			-1.9		-2.2		-2.7		-2.2		-2.6
Specific fuel (coal) consumption per MW net produced	MWt / MWe	2.074	2.149	2.875	3.071	2.827	3.057	2.634	2.800	3.179	3.460
Specific CO_2 emissions per MW net produced	t / MWh	0.743	0.777	0.117	0.125	0.085	0.092	0.818	0.869	0.152	0.165
Specific water consumption per MW net produced	t / MWh	0.104	0.000	0.410	0.000	0.063	0.000	0.126	0.042	0.411	0.039

(1) Including the consumption of AGR unit for H2S removal.
(2) Including the consumption of AGR unit for H2S and CO2 removal.

3. Performance comparison

3.1. USCPC without CO_2 capture plants: Case 3.21 vs case 3.25

From the comparison of these two USCPC power plants, it appears that it is possible to reduce to zero the specific water consumption in the dry land case. This result may be achieved by installing facilities (Final Direct Contact Coolers, Final Water Aircoolers and Water Pumps) for condensing part of the water present in the offgas and by adequately treating the collected waste water in the WWT unit, so that the treated water may be reused.

As regards the net electrical efficiency, from the previous table it may be noticed that in the dry land case it drops to 42.1% from the value of 44% reached in the reference wet land case.
This reduction is mainly due to the following reasons:

1. Power consumption of the steam turbine aircooler condenser. It accounts for almost 7 MW and it's a penalty typical of the dry land case, where a sea water condenser cannot be used.
2. The deletion of the sea water cooling system allows reducing electrical power requirement by about 5 MW (due to sea water pumps).
3. Reduced power produced by the steam turbine. Due to the presence of the air condenser mentioned in the previous point the steam condensation pressure increases from 40 to 74 mbar, so that it has been estimated that the steam turbine produces about 3.5% less electrical power (corresponding to 29 MW) in dry land than in wet land.
4. Increased power consumption of the Flue Gas Blower. Since in the dry land case new equipment is installed on the flue gas line for condensing water, as explained above, it results that the flue gas blower will require more electrical power for compensating for the increased flue gas pressure drop. The consumption increment has been estimated equal to about 1.2 MW.
5. Power consumption of the Flue Gas Final Direct Contact Cooler system added in the dry land case for condensing water from flue gas. The consumption of Water Pumps and Water Aircoolers is estimated to be about 1.5 MW.

In general, as it can be inferred from the above points, the use of the aircoolers in the dry land case constitutes a significant penalty, as it negatively affects in a direct or indirect way the net electrical power generated by the plant. Furthermore, even though an evaluation of the plot area required in the dry land case is outside the scope of the present study, it shall be considered that the installation of aircoolers will significantly increase the plot area required by the plant.

3.2. USCPC with CO_2 capture plants: Case 3.22 vs case 3.23

From the comparison of these two USCPC power plants, it appears that it is possible to reduce to zero the specific water consumption in the dry land case. As explained in the previous paragraph, this result may be achieved by installing facilities (Final Direct Contact Coolers, Final Aircoolers and Water Pumps) for condensing part of the water present in the offgas and by adequately treating the collected waste water in the WWT unit, so that the treated water may be reused.

As regards the net electrical efficiency, from the previous table it may be noticed that in the dry land case it drops to 32.6% from the value of 34.8% reached in the reference wet land case.
This reduction is mainly due to the following reasons:

1. Power consumption of the steam turbine aircooler condenser. It accounts for about 5.1 MW and it's a penalty typical of the dry land case, where a sea water condenser cannot be used.
2. The deletion of the sea water cooling system allows reducing electrical power requirement by about 10.2 MW (due to sea water pumps).
3. Reduced power produced by the steam turbine. Due to the presence of the air condenser mentioned in the previous point, the steam condensation pressure increases from 40 mbar to 74 mbar, so that it has been estimated that the steam turbine produces about 3.5% less electrical power (corresponding to 28 MW) in dry land than in wet land. The Steam Turbine gross power production can be slightly higher (about 4 MWe) as it has been conservatively considered a penalty due to dry land plant location in line with the case without CO_2 capture.
4. Increased power consumption of the Flue Gas Blower. Since in the dry land case new equipment is installed on the flue gas line for condensing water, as explained above, it results that the flue gas blower will require more electrical power for compensating for the increased flue gas pressure drop. The consumption increment has been estimated equal to about 1.4 MW.
5. Increased power consumption of the AGR and CO_2 compression units. This rise has been evaluated equal to about 25% (corresponding to 19.7 MW) in the dry land case, compared with the wet land case. About 40% of such increment is due to the consumption of the aircoolers, which replace the sea water coolers used in the wet land case, in services as absorber pumparound coolers, amine stripper condenser, direct contact cooler and CO_2 compressor intercooler. About 10% of such increment is due to the fact that the aircoolers used as compressor intercoolers also affects the performance of the CO_2 compressor, since intercooler outlet temperature results higher, with the consequence that

also the compressor power consumption is increased (by about 4%) compared with the wet land case. Finally, about 50% of such increment is due to the replacement of the CO_2 booster pump (which required 2.5 MW) with another compression stage (which requires about 10 MW). The replacement is motivated by the fact that the temperature obtained downstream of the last compressor aircooler is higher than when using the sea water cooler, so that CO_2 is not yet liquefied and the use of a booster pump is unfeasible.

6. Power consumption of the Flue Gas Final Direct Contact Cooler system added in the dry land case for condensing water from flue gas. The consumption of Water Pumps and Water Aircoolers is estimated to be about 0.5 MW.

In general, as it can be inferred from the above points, the use of the aircoolers in the dry land case constitutes a significant penalty, as it negatively affects in a direct or indirect way the net electrical power generated by the plant. Furthermore, even though an evaluation of the plot area required in the dry land case is outside the scope of the present study, it shall be considered that the installation of aircoolers will significantly increase the plot area required by the plant.

3.3. USCPC Oxyfuel plants: Case 4.12 vs case 4.11

From the comparison of these two USCPC Oxyfuel plants, it appears that it is possible to reduce to zero the specific water consumption in the dry land case. For the USCPC Oxyfuel plants, this result is achieved without introducing any specific technology for water saving, but by adequately treating the waste water already generated by the power plant and sent to the WWT unit, so that the treated water may be reused. Indeed, since the peculiarity of the plant is to burn coal in presence of almost pure oxygen, the boiler offgas contains CO_2 (about 60% vol), a reduced quantity of inerts (about 20% vol) and a high concentration of water (the remaining 20% vol). Water is concentrated enough to be completely condensed by compression and cooling in the CO_2 compression unit. The composition of boiler offgas is not affected by operating in wet land or in dry land country, so that the zero water intake can be achieved also in both cases without significant plant changes. On the contrary, for this typology of power plant, it results that the water coming from the WWT exceeds by far the plant needs, so that a significant flowrate of treated water (more than 100t/h) has to be sent to the plant battery limit for disposal or reuse in civil or other purposes.

As regards the net electrical efficiency, from the previous table it may be noticed that in the dry land case it drops to 32.7% from the value of 35.4% reached in the reference wet land case.
This reduction is mainly due to the following reasons:

1. Power consumption of the steam turbine aircooler condenser. It accounts for about 5.3 MW and it’s a penalty typical of the dry land case, where a sea water condenser cannot be used.
2. The deletion of the sea water cooling system allows reducing electrical power requirement by about 5.6 MW (due to sea water pumps).
3. Reduced power produced by the steam turbine. Due to the presence of the air condenser mentioned in the previous point, the steam condensation pressure increases from 40 mbar to 74 mbar, so that it has been estimated that the steam turbine produces about 4% less electrical power (corresponding to 27 MW) in dry land than in wet land.
4. Power consumption of the CO_2 compression unit rises by about 8.6% (corresponding to 5.6 MW) in the dry land case, compared with the wet land case. Partially this is due to the consumption of the aircoolers, which replace the sea water coolers used in the wet land case. On its turn, the presence of aircoolers as compressor intercoolers also affects the performance of the CO_2

compressor, since intercooler outlet temperature results higher, with the consequence that also the compressor power consumption is increased (by about 4%) compared with the wet land case.

5. Power consumption of the ASU rises by about 7% (corresponding to 6.2 MW) in the dry land case. As explained in the previous point, partially this increment is due to the consumption of the aircoolers, which replace the sea water coolers used in the wet land case. The presence of aircoolers as compressor intercoolers also affects the performance of the ASU compressor, since intercooler outlet temperature is increased, with the consequence that also compressor power consumption results higher (by about 3%) compared with the wet land case. A portion of the increment in the ASU is due the rise of power consumption required by the water chiller package included in the unit (estimated rise is equal to about 40% compared with the wet land case).

In general, as it can be inferred from the above points, the use of the aircoolers in the dry land case constitutes a significant penalty, as it negatively affects in a direct or indirect way the net electrical power generated by the plant. Furthermore, even though an evaluation of the plot area required in the dry land case is outside the scope of the present study, it shall be considered that the installation of aircoolers will significantly increase the plot area required by the plant.

3.4. GEE IGCC without CO_2 capture plants: Case 5.05 vs case 5.07

From the comparison of these two IGCC power plants, it appears that it is not possible to reduce to zero the specific water consumption in the dry land case, but only to reduce it to a certain extent. Indeed, even installing Final Direct Contact Coolers with relevant Aircoolers and Pumps the water condensed from flue gas is not sufficient for covering the entire water requirements. This is due to the low concentration of water in flue gas at HRSG outlet (it is about 6% vol), which allows only a small portion of the total water to be condensed at the temperature achieved by the aircoolers included in the Direct Contact Cooler system.

As regards the net electrical efficiency, from the previous table it may be noticed that in the dry land case it drops to 35.7% from the value of 38% reached in the reference wet land case.
This reduction is mainly due to the following reasons:

1. Power consumption of the steam turbine aircooler condenser. It accounts for about 5.5 MW and it's a penalty typical of the dry land case, where a sea water condenser cannot be used.
2. The deletion of the sea water cooling system allows reducing electrical power requirement by about 7.5 MW (due to sea water pumps).
3. Reduced power produced by the steam turbine. Due to the presence of the air condenser mentioned in the previous point, the steam condensation pressure increases from 40 mbar to 74 mbar, so that it has been estimated that the steam turbine produces about 9% less electrical power (corresponding to about 34 MW) in dry land than in wet land case. The gas turbine performances have been considered not affected by dry land conditions.
4. Power consumption of the Flue Gas Blower. Since in the dry land case new equipment is installed on the flue gas line for condensing water, as explained above, it results that a new flue gas blower is to be installed for compensating for the increased flue gas pressure drop. The electrical power consumption has been estimated equal to about 6 MW.
5. Power consumption of the ASU rises by about 3.5% (corresponding to 5 MW) in the dry land case. Partially this increment is due to the consumption of the aircoolers, which replace the sea water coolers used in the wet land case. The presence of aircoolers as compressor intercoolers also affects the performance of the ASU compressor, since intercooler outlet temperature is increased, with the consequence that also compressor power consumption results higher (by about 3%) compared with the wet land case. A portion of the increment in the ASU is due the rise of power consumption required by the water chiller

package included in the unit (estimated rise is equal to about 60% compared with the wet land case).

6. Power consumption of the Flue Gas Final Direct Contact Cooler system added in the dry land case for condensing water from flue gas. The consumption of Water Pumps and Water Aircoolers is estimated to be about 5.5 MW.

In general, as it can be inferred from the above points, the use of the aircoolers in the dry land case constitutes a significant penalty, as it negatively affects in a direct or indirect way the net electrical power generated by the plant. Furthermore, even though an evaluation of the plot area required in the dry land case is outside the scope of the present study, it shall be considered that the installation of aircoolers will significantly increase the plot area required by the plant.

3.5. GEE IGCC with CO_2 capture plants: Case 5.06 vs case 5.03

From the comparison of these two IGCC power plants, it appears that it is not possible to reduce to zero the specific water consumption in the dry land case, but only to reduce it to a certain extent. Indeed, even installing Final Direct Contact Coolers with relevant Aircoolers and Pumps the water condensed from flue gas is not sufficient for covering the entire water requirements. Even though the water concentration in flue gas at HRSG outlet is higher than in the previous IGCC cases without CO_2 capture (here it is 11.7% vol), so that more water is condensed in the Direct Contact Cooler system, the water recovered is still not sufficient for covering the plant requirement.

As regards the net electrical efficiency, from the previous table it may be noticed that in the dry land case it drops to 28.9% from the value of 31.5% reached in the reference wet land case.
This reduction is mainly due to the following reasons:

1. Power consumption of the steam turbine aircooler condenser. It accounts for about 6 MW and it’s a penalty typical of the dry land case, where a sea water condenser cannot be used.
2. The deletion of the sea water cooling system allows reducing electrical power requirement by about 10 MW (due to sea water pumps).
3. Reduced power produced by the steam turbine. Due to the presence of the air condenser mentioned in the previous point, the steam condensation pressure increases from 40 mbar to 74 mbar, so that it has been estimated that the steam turbine produces about 9% less electrical power (corresponding to 35.4 MW) in dry land than in wet land case. The gas turbine performances have been considered not affected by dry land conditions.
4. Power consumption of the Flue Gas Blower. Since in the dry land case new equipment is installed on the flue gas line for condensing water, as explained above, it results that a new flue gas blower is to be installed for compensating for the increased flue gas pressure drop. The electrical power consumption has been estimated equal to about 6 MW.
5. Power consumption of the ASU rises by about 3.5% (corresponding to 4.4 MW) in the dry land case. Partially this increment is due to the consumption of the aircoolers, which replace the sea water coolers used in the wet land case. The presence of aircoolers as compressor intercoolers also affects the performance of the ASU compressor, since intercooler outlet temperature is increased, with the consequence that also compressor power consumption results higher (by about 3%) compared with the wet land case. A portion of the increment in the ASU is also due the rise of power consumption required by

the water chiller package included in the unit (estimated rise is equal to about 60% compared with the wet land case).

6. Power consumption of the Flue Gas Final Direct Contact Cooler system added in the dry land case for condensing water from flue gas. The consumption of Water Pumps and Water Aircoolers is estimated to be about 13 MW.
7. Increased power consumption of the AGR and CO_2 compression units. This rise has been evaluated equal to about 5% (corresponding to 3.7 MW) in the dry land case, compared with the wet land case. Such increment is partly due to the consumption of the new aircoolers used as compressor intercooler, which replace the sea water coolers used in the wet land case. The presence of aircoolers as compressor intercoolers also affects the performance of the CO_2 compressor, since intercooler outlet temperature is increased, with the consequence that also compressor power consumption results higher (by about 4%) compared with the wet land case.

In general, as it can be inferred from the above points, the use of the aircoolers in the dry land case constitutes a significant penalty, as it negatively affects in a direct or indirect way the net electrical power generated by the plant. Furthermore, even though an evaluation of the plot area required in the dry land case is outside the scope of the present study, it shall be considered that the installation of aircoolers will significantly increase the plot area required by the plant.

CLIENT : IEA GHG
PROJECT NAME : WATER USAGE AND LOSS ANALYSIS IN POWER PLANTS WITHOUT AND WITH CO2 CAPTURE
DOCUMENT NAME : ECONOMICS EVALUATION

ISSUED BY : L. SOBACCHI
CHECKED BY : P. COTONE
APPROVED BY : S. ARIENTI

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SECTION C

ECONOMICS EVALUATION
I N D E X

1. Introduction

IEA GHG R&D Programme has already issued reports assessing power generation with and without CO_2 capture from coal fired power plants.
In particular some studies were executed by FW between 2002 and 2009. The other studies are made available by IEA GHG.

Foster Wheeler Italiana included in the whole report the outcomes of the 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. FWI did not review and comment the economics included in the reference studies: both Capex and Opex have been taken from the original studies and modified only taking into account the impact of dry land design.

These studies are used as a basis for the present study. The evaluation of the economics in present study has the same bases as the reference studies provided by IEA.

The following table summarises the reference studies with the relevant cost level, location and currency.

Case	Original Cost level	Original Location	Original Currency
USC PC – without CO_2 capture	II Q 2004	The Netherlands	US $
USC PC – with CO_2 capture	II Q 2004	The Netherlands	US $
USC PC – oxyfuel	IV Q 2004	The Netherlands	€
IGCC – without CO_2 capture	IV Q 2002	The Netherlands	€
IGCC – with CO_2 capture	IV Q 2002	The Netherlands	€

This section summarises the economic data evaluated for each alternative of the study, including:

a. Investment cost;
b. Operation & Maintenance costs;

For the dry land cases the investment cost is broken down to major sections, while for the wet land cases only the overall investment cost is given.

2. Basis of investment cost evaluation

2.1. Basis of the estimate

The basis of the estimate for each alternative is the technical documentation collected in technical Reports #2, #3 and #4 and summarised in section B of present report.

For each of the alternatives analysed the estimate is based on the investment cost estimate provided in reference case. The same cost structure, unit brake down and bases have been considered.

Depending on the alternative considered, the investment cost of the following main Units or blocks of Units is detailed:

USC PC cases

Unit 100:	Coal & ash handling
Unit 200:	Boiler Island
Unit 300:	FGD
Unit 400:	DeNOx
Unit 500:	Steam Turbine
Unit 600:	CO_2 capture (for cases with CO_2 capture)
Unit 700:	CO_2 compression and drying (for cases with CO_2 capture)
Unit 800:	BOP

Oxyfuel cases

Unit 100:	Coal & ash handling
Unit 200:	Boiler Island
Unit 300:	FGD
Unit 400:	DeNOx
Unit 500:	Steam Turbine
Unit 600:	ASU
Unit 700:	CO_2 compression and drying
Unit 800:	BOP

IGCC cases

Unit 900:	Coal Handling and Storage
Unit 1000:	Gasification Section
Unit 2100:	Air Separation Unit
Unit 2200:	Syngas Treatment and Conditioning Line

Unit 2300: Acid Gas Removal
Unit 2400: Sulphur Recovery Unit and Tail Gas Treatment
Unit 2500: CO_2 Compression and Drying (for cases with CO_2 capture)
Unit 3000: Power Island
Units 4000 to 5200: Utilities and Offsites

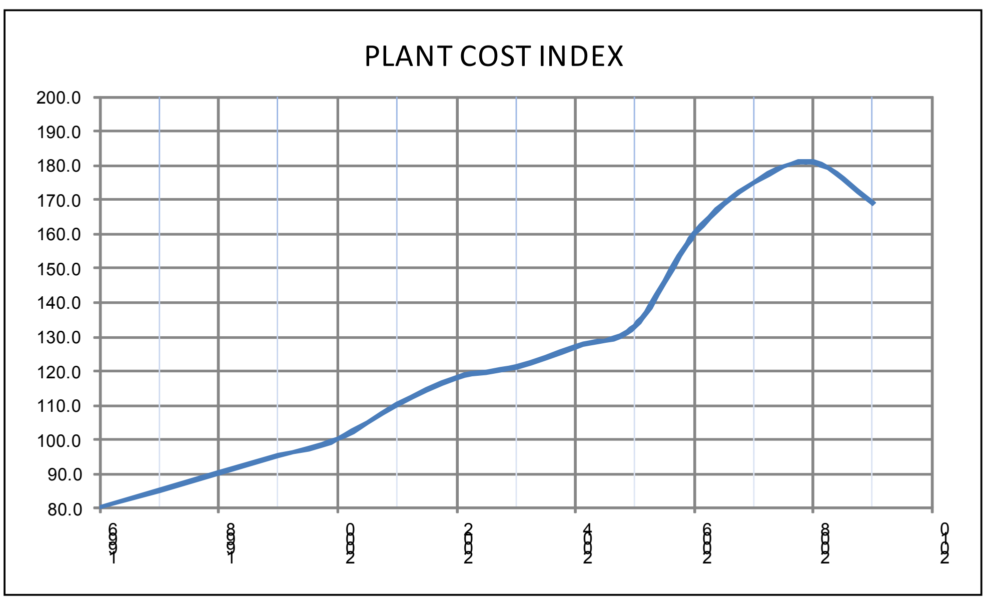
Depending on the different alternative, in accordance to the reference study structure, the overall investment cost of each unit or block of units is split into different items as detailed in the following paragraph.

2.2. Estimate methodology and Cost Basis

The investment cost estimate for all the different alternatives has been based on the data contained in the reference study for wet land cases.

For each case, starting from reference case capital cost estimate, the following methodology has been applied:

a. Adjustment based on different currency: US$ to Euro. Capital cost conversion has been made at reference year, and therefore taking into account the currency exchange rate in place during the estimate period. Currency adjustment was necessary only for USC PC cases whose original estimate was made in US$.
b. Cost level escalation: escalation from reference estimate cost level to IVQ2009 has been made using FWI in-house multiplicative factors. The plant cost indexes used for the escalations are shown in the following graph.



c. Location adjustment: escalation from reference location (the Netherlands for all cases) to South Africa has been made using FWI in-house multiplicative factors. The following table shows multiplicative factors for materials and construction.

Material K factor for South Africa	
K factor material	**0.93**
Construction K factor for South Africa	
Labour all-in rate ZAR/mhrs	225,00
Labour all-in rate Euro/mhrs	21.5
Productivity Europe/Soth A.	2.25
Labour Netherlands Euro/mhrs	65.7
Rate x productivity	48.38
K factor construction	0.736
K factor construction USED	**0.75**

The result of this first step is the investment cost estimate of the reference case in Euro, at IVQ2009 cost level and in South Africa.

Direct materials for dry land cases have been evaluated by considering the differences between the dry land case and the relevant wet land case. As shown in the equipment lists attached to the end of each section in technical reports #2, #3 and #4, in fact, the differences between each reference wet land case and relevant dry land case have been highlighted.

The investment cost of the direct material, for the equipment added or modified, was estimated by FWI by means of K_Base estimate program runs, based on the equipment list attached in Reports #2, #3 and #4.
The K_Base results have been then double checked with in-house data based on competitive bids received and technically evaluated by FWI in the past for similar projects.

For all the other costs (construction, engineering etc…) the same percentages with respect to direct materials as per reference cases have been considered.

FWI did not review and comment the original estimate made by other engineering companies.

2.3. Estimate Accuracy

The estimate accuracy cannot be better than the reference studies as they are the starting points for present estimate.

Therefore the estimate accuracy is in the range of +/-35%.

3. Investment Cost of the Alternatives

3.1. USC PC cases – dry land (Cases 3.25 and 3.23)

The following Tables 3.1/2 show the investment break down and the total figures for each alternative investigated.

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : January 2010
Rev. : 0

TABLE 3.1 - CASE 3.25 797MWe USC PC without carbon dioxide capture

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	35,196,000	131,348,000	73,409,000	12,067,000	111,743,000			127,637,500	491,400,500	
2	CONSTRUCTION	12,164,000	73,237,000	-	2,433,000	32,634,000			33,179,000	153,647,000	
	DIRECT FIELD COST	47,360,000	204,585,000	73,409,000	14,500,000	144,377,000	-	-	160,816,500	645,047,500	
3	CONSTRUCTION MANAGEMENT	947,000	4,092,000	1,468,000	290,000	2,888,000			3,216,000	12,901,000	
4	COMMISSIONING	947,000	4,092,000	1,468,000	290,000	2,888,000			3,216,000	12,901,000	
5	COMMISSIONING SPARES	237,000	1,023,000	367,000	73,000	722,000			804,000	3,226,000	
6	TEMPORARY FACILITIES	2,368,000	10,229,000	3,670,000	725,000	7,219,000			8,041,000	32,252,000	
7	FREIGHT, TAXES & INSURANCE	474,000	2,046,000	734,000	145,000	1,444,000			1,608,000	6,451,000	
	INDIRECT FIELD COSTS	4,973,000	21,482,000	7,707,000	1,523,000	15,161,000	-	-	16,885,000	67,731,000	
8	ENGINEERING COSTS	5,683,000	24,550,000	8,809,000	1,740,000	17,325,000			19,298,000	77,405,000	
											BUSINESS CONFIDENTIAL
	TOTAL INSTALLED COST	58,016,000	250,617,000	89,925,000	17,763,000	176,863,000	-	-	196,999,500	790,183,500	
9	CONTINGENCY	5,800,000	25,100,000	9,000,000	1,800,000	17,700,000			19,700,000	79,100,000	
10	LICENSE FEES OWNER COSTS	4,100,000	17,500,000	6,300,000	1,200,000	12,400,000			13,800,000	55,300,000	
	OVERALL PROJECT COST	67,916,000	293,217,000	105,225,000	20,763,000	206,963,000	-	-	230,499,500	924,583,500	

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : January 2010
Rev. : 0

TABLE 3.2 - CASE 3.23 827 MWe USCPF with carbon dioxide capture

cost code	DESCRIPTION	UNIT 100 Coal Ash handling	UNIT 200 Bolier island	UNIT 300 FGD	UNIT 400 Denox	UNIT 500 Steam turbine	UNIT 600 CO_2 capture	UNIT 700 CO_2 comp drying	UNIT 800 BOP	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	38,213,000	142,410,000	79,442,000	13,073,000	101,668,000	66,301,500	34,995,000	125,911,000	602,013,500	
2	CONSTRUCTION	12,976,000	79,725,000	-	2,433,000	31,584,000	48,668,000	17,909,000	32,671,000	225,966,000	
	DIRECT FIELD COST	51,189,000	222,135,000	79,442,000	15,506,000	133,252,000	114,969,500	52,904,000	158,582,000	827,979,500	
3	CONSTRUCTION MANAGEMENT	1,024,000	4,443,000	1,589,000	310,000	2,665,000	2,299,000	1,058,000	3,172,000	16,560,000	
4	COMMISSIONING	1,024,000	4,443,000	1,589,000	310,000	2,665,000	2,299,000	1,058,000	3,172,000	16,560,000	
5	COMMISSIONING SPARES	256,000	1,111,000	397,000	78,000	666,000	575,000	265,000	793,000	4,141,000	
6	TEMPORARY FACILITIES	2,559,000	11,107,000	3,972,000	775,000	6,663,000	5,748,000	2,645,000	7,929,000	41,398,000	
7	FREIGHT, TAXES & INSURANCE	512,000	2,221,000	794,000	155,000	1,333,000	1,150,000	529,000	1,586,000	8,280,000	
	INDIRECT FIELD COSTS	5,375,000	23,325,000	8,341,000	1,628,000	13,992,000	12,071,000	5,555,000	16,652,000	86,939,000	
8	ENGINEERING COSTS	6,143,000	26,656,000	9,533,000	1,861,000	15,990,000	13,796,000	6,348,000	19,030,000	99,357,000	
	TOTAL INSTALLED COST	62,707,000	272,116,000	97,316,000	18,995,000	163,234,000	140,836,500	64,807,000	194,264,000	1,014,275,500	**BUSINESS CONFIDENTIAL**
9	CONTINGENCY	6,300,000	27,200,000	9,700,000	1,900,000	16,300,000	14,100,000	6,500,000	19,400,000	101,400,000	
10	LICENSE FEES OWNER COSTS	4,400,000	19,000,000	6,800,000	1,300,000	11,400,000	9,900,000	4,500,000	13,600,000	70,900,000	
	OVERALL PROJECT COST	73,407,000	318,316,000	113,816,000	22,195,000	190,934,000	164,836,500	75,807,000	227,264,000	1,186,575,500	

3.2. Oxyfuel case – dry land (Case 4.12)

The following Table 3.3 shows the investment break down and the total figures for the alternative investigated.

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : 12-Aug-10
Rev. : 0

TABLE 3.3 - CASE 4.12 ASC PF POWER PLANT WITH CO2 CAPTURE

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	40,362,000	151,032,000			111,228,000	120,635,000	65,487,500	127,791,500	616,536,000	
2	CONSTRUCTION	13,650,000	84,000,000			35,750,000	36,544,000	27,550,000	33,573,000	231,067,000	
3	OTHER COSTS	2,100,000	8,400,000			6,780,000	10,002,000	3,450,000	7,290,000	38,022,000	
4	EPC SERVICES	3,150,000	11,550,000			9,000,000	10,052,000	7,700,000	10,830,000	52,282,000	
	TOTAL INSTALLED COST	59,262,000	254,982,000			162,758,000	177,233,000	104,187,500	179,484,500	937,907,000	
5	CONTINGENCY	4,100,000	17,800,000			11,400,000	12,400,000	7,300,000	12,600,000	65,600,000	
6	LICENSE FEES	1,200,000	5,100,000			3,300,000	3,500,000	2,100,000	3,600,000	18,800,000	
7	OWNER COSTS	4,700,000	20,400,000			13,000,000	14,200,000	8,300,000	14,400,000	75,000,000	
	TOTAL INVESTMENT COST	69,262,000	298,282,000			190,458,000	207,333,000	121,887,500	210,084,500	1,097,307,000	

3.3. IGCC cases – dry land (Cases 5.07 and 5.03)

The following Tables 3.4/5 show the investment break down and the total figures for each alternative investigated.

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : 12-Aug-10
Rev. : 0

TABLE 3.4 - CASE 5.07 IGCC WITHOUT CCS -DRY LAND

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 3000 Power island	UNIT 4000 UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	7,301,000	141,267,000	110,844,000	26,478,000	18,547,000	17,652,000	357,490,000	85,964,000	765,543,000	
2	CONSTRUCTION	1,177,000	51,266,000	26,592,000	10,606,000	9,461,000	6,406,000	68,493,000	36,356,000	210,357,000	
3	OTHER COSTS	589,000	17,089,000	3,376,000	4,303,000	5,978,000	1,993,000	26,218,000	6,610,000	66,156,000	
4	EPC SERVICES	883,000	39,874,000	12,946,000	6,498,000	4,399,000	2,136,000	22,174,000	13,220,000	102,130,000	
	TOTAL INSTALLED COST	9,950,000	249,496,000	153,758,000	47,885,000	38,385,000	28,187,000	474,375,000	142,150,000	1,144,186,000	
5	CONTINGENCY	700,000	17,500,000	7,700,000	3,400,000	2,700,000	2,000,000	33,200,000	7,100,000	74,300,000	
6	LICENSE FEES	200,000	5,000,000	3,100,000	1,000,000	800,000	600,000	9,500,000	2,800,000	23,000,000	
7	OWNER COSTS	500,000	12,500,000	7,700,000	2,400,000	1,900,000	1,400,000	23,700,000	7,100,000	57,200,000	
	TOTAL INVESTMENT COST	11,350,000	284,496,000	172,258,000	54,685,000	43,785,000	32,187,000	540,775,000	159,150,000	1,298,686,000	

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : 12-Aug-10
Rev. : 0

TABLE 3.5 - CASE 5.03 IGCC WITH CCS- DRYLAND

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	7,910,000	146,735,000	114,427,000	36,225,000	34,596,000	23,436,000	25,896,500	369,753,000	95,628,000	854,606,500	
2	CONSTRUCTION	1,276,000	53,251,000	27,159,000	14,506,000	12,902,000	8,505,000	5,400,000	73,716,000	41,086,000	237,801,000	
3	OTHER COSTS	638,000	17,750,000	3,452,000	7,981,000	12,514,000	2,646,000	1,011,000	26,927,000	8,070,000	80,989,000	
4	EPC SERVICES	956,000	41,417,000	13,230,000	8,953,000	6,297,000	2,835,000	1,424,000	21,596,000	17,041,000	113,749,000	
	TOTAL INSTALLED COST	10,780,000	259,153,000	158,268,000	67,665,000	66,309,000	37,422,000	33,731,500	491,992,000	161,825,000	1,287,145,500	
5	CONTINGENCY	800,000	18,100,000	7,900,000	4,700,000	4,600,000	2,600,000	1,700,000	34,400,000	8,100,000	82,900,000	
6	LICENSE FEES	200,000	5,200,000	3,200,000	1,400,000	1,300,000	700,000	700,000	9,800,000	3,200,000	25,700,000	
7	OWNER COSTS	500,000	13,000,000	7,900,000	3,400,000	3,300,000	1,900,000	1,700,000	24,600,000	8,100,000	64,400,000	
	TOTAL INVESTMENT COST	12,280,000	295,453,000	177,268,000	77,165,000	75,509,000	42,622,000	37,831,500	560,792,000	181,225,000	1,460,145,500	

3.4. Wet land cases (3.22; 3.21; 4.11; 5.05 and 5.06)

As references, the following Tables 3.6/10 show the investment break down and the total figures for each of the wet land alternatives investigated.

FOSTER WHEELER

ESTIMATE SUMMARY

Table 3.6 - CASE 3.21 830 MWe USC PC without carbon dioxide capture

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : January 2010
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	REMARKS / COMMENTS
1	DIRECT MATERIAL	35,196,000	130,728,000	73,409,000	12,067,000	88,493,000			125,700,000	465,593,000	
2	CONSTRUCTION	12,164,000	72,987,000	included above	2,433,000	28,384,000			32,439,000	148,407,000	
	DIRECT FIELD COST	47,360,000	203,715,000	73,409,000	14,500,000	116,877,000	-	-	158,139,000	614,000,000	
3	CONSTRUCTION MANAGEMENT	947,000	4,074,000	1,468,000	290,000	2,338,000			3,163,000	12,280,000	
4	COMMISSIONING	947,000	4,074,000	1,468,000	290,000	2,338,000			3,163,000	12,280,000	
5	COMMISSIONING SPARES	237,000	1,019,000	367,000	73,000	584,000			791,000	3,071,000	
6	TEMPORARY FACILITIES	2,368,000	10,186,000	3,670,000	725,000	5,844,000			7,907,000	30,700,000	
7	FREIGHT, TAXES & INSURANCE	474,000	2,037,000	734,000	145,000	1,169,000			1,581,000	6,140,000	
	INDIRECT FIELD COSTS	4,973,000	21,390,000	7,707,000	1,523,000	12,273,000	-	-	16,605,000	64,471,000	
8	ENGINEERING COSTS	5,683,000	24,446,000	8,809,000	1,740,000	14,025,000			18,977,000	73,680,000	
	TOTAL INSTALLED COST	58,016,000	249,551,000	89,925,000	17,763,000	143,175,000	-	-	193,721,000	752,151,000	BUSINESS CONFIDENTIAL
9	CONTINGENCY	5,800,000	25,000,000	9,000,000	1,800,000	14,300,000			19,400,000	75,300,000	
10	LICENSE FEES OWNER COSTS	4,100,000	17,500,000	6,300,000	1,200,000	10,000,000			13,600,000	52,700,000	
	OVERALL PROJECT COST	67,916,000	292,051,000	105,225,000	20,763,000	167,475,000	-	-	226,721,000	880,151,000	

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : January 2010
Rev. : 0

ESTIMATE SUMMARY

Table 3.7 - CASE 3.22 827 MWe USC PC with carbon dioxide capture

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	38,213,000	141,790,000	79,442,000	13,073,000	88,493,000	32,279,000	22,595,000	136,761,000	552,646,000	
2	CONSTRUCTION	12,976,000	79,475,000	-	2,433,000	28,384,000	43,468,000	14,209,000	34,871,000	215,816,000	
	DIRECT FIELD COST	51,189,000	221,265,000	79,442,000	15,506,000	116,877,000	75,747,000	36,804,000	171,632,000	768,462,000	
3	CONSTRUCTION MANAGEMENT	1,024,000	4,425,000	1,589,000	310,000	2,338,000	1,515,000	736,000	3,433,000	15,370,000	
4	COMMISSIONING	1,024,000	4,425,000	1,589,000	310,000	2,338,000	1,515,000	736,000	3,433,000	15,370,000	
5	COMMISSIONING SPARES	256,000	1,106,000	397,000	78,000	584,000	379,000	184,000	858,000	3,842,000	
6	TEMPORARY FACILITIES	2,559,000	11,063,000	3,972,000	775,000	5,844,000	3,787,000	1,840,000	8,582,000	38,422,000	
7	FREIGHT, TAXES & INSURANCE	512,000	2,213,000	794,000	155,000	1,169,000	757,000	368,000	1,716,000	7,684,000	
	INDIRECT FIELD COSTS	5,375,000	23,232,000	8,341,000	1,628,000	12,273,000	7,953,000	3,864,000	18,022,000	80,688,000	
8	ENGINEERING COSTS	6,143,000	26,552,000	9,533,000	1,861,000	14,025,000	9,090,000	4,416,000	20,596,000	92,216,000	
	TOTAL INSTALLED COST	62,707,000	271,049,000	97,316,000	18,995,000	143,175,000	92,790,000	45,084,000	210,250,000	941,366,000	BUSINESS CONFIDENTIAL
9	CONTINGENCY	6,300,000	27,100,000	9,700,000	1,900,000	14,300,000	9,300,000	4,500,000	21,000,000	94,100,000	
10	LICENSE FEES OWNER COSTS	4,400,000	19,000,000	6,800,000	1,300,000	10,000,000	6,500,000	3,200,000	14,700,000	65,900,000	
	OVERALL PROJECT COST	73,407,000	317,149,000	113,816,000	22,195,000	167,475,000	108,590,000	52,784,000	245,950,000	1,101,366,000	

ESTIMATE SUMMARY

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date :
Rev. : 0

Table 3.8 - CASE 4.11 Oxyfuel POWER PLANT

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	40,362,000	151,032,000			102,858,000	116,295,000	52,421,000	126,164,000	589,132,000	
2	CONSTRUCTION	13,650,000	84,000,000			32,550,000	35,574,000	24,800,000	33,023,000	223,597,000	
3	OTHER COSTS	2,100,000	8,400,000			6,300,000	9,702,000	3,270,000	7,140,000	36,912,000	
4	EPC SERVICES	3,150,000	11,550,000			8,400,000	9,702,000	7,500,000	10,710,000	51,012,000	
	TOTAL INSTALLED COST	59,262,000	254,982,000			150,108,000	171,273,000	87,991,000	177,037,000	900,653,000	
5	CONTINGENCY	4,100,000	17,800,000			10,500,000	12,000,000	6,200,000	12,400,000	63,000,000	
6	LICENSE FEES	1,200,000	5,100,000			3,000,000	3,400,000	1,800,000	3,500,000	18,000,000	
7	OWNER COSTS	4,700,000	20,400,000			12,000,000	13,700,000	7,000,000	14,200,000	72,000,000	
	TOTAL INVESTMENT COST	69,262,000	298,282,000			175,608,000	200,373,000	102,991,000	207,137,000	1,053,653,000	

Contract : 1-BD-0475A
Client : IEA
Plant : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : 22-Dec-10
Rev. : 0

FOSTER WHEELER

ESTIMATE SUMMARY

Table 3.9 - CASE 5.05 IGCC WITHOUT CCS

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 3000 Power island	UNIT UTILITY & OFF SITES	TOTAL	REMARKS / COMMENTS
1	DIRECT MATERIAL	7,301,000	141,267,000	99,994,000	26,013,000	17,772,000	17,652,000	318,895,000	81,964,000	710,858,000	
2	CONSTRUCTION	1,177,000	51,266,000	24,192,000	10,406,000	9,111,000	6,406,000	64,293,000	36,356,000	203,207,000	
3	OTHER COSTS	589,000	17,089,000	3,226,000	4,278,000	5,978,000	1,993,000	25,718,000	6,610,000	65,481,000	
4	EPC SERVICES	883,000	39,874,000	12,096,000	6,453,000	4,399,000	2,136,000	20,574,000	13,220,000	99,635,000	
	TOTAL INSTALLED COST	9,950,000	249,496,000	139,508,000	47,150,000	37,260,000	28,187,000	429,480,000	138,150,000	1,079,181,000	
5	CONTINGENCY	700,000	17,500,000	7,000,000	3,300,000	2,600,000	2,000,000	30,100,000	6,900,000	70,100,000	
6	LICENSE FEES	200,000	5,000,000	2,800,000	900,000	700,000	600,000	8,600,000	2,800,000	21,600,000	
7	OWNER COSTS	500,000	12,500,000	7,000,000	2,400,000	1,900,000	1,400,000	21,500,000	6,900,000	54,100,000	
	TOTAL INVESTMENT COST	11,350,000	284,496,000	156,308,000	53,750,000	42,460,000	32,187,000	489,680,000	154,750,000	1,224,981,000	

Contract : 1-BD-0475A
Client : IEA
Project : POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE
Date : 2-Dec-10
Rev. : 0

ESTIMATE SUMMARY

Table 3.10 - CASE 5.06 IGCC WITH CCS

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	7,910,000	146,735,000	102,337,000	35,884,000	33,046,000	23,436,000	22,564,000	332,398,000	92,628,000	796,938,000	
2	CONSTRUCTION	1,276,000	53,251,000	24,759,000	14,356,000	12,452,000	8,505,000	4,550,000	67,016,000	41,086,000	227,251,000	
3	OTHER COSTS	638,000	17,750,000	3,302,000	7,931,000	12,514,000	2,646,000	911,000	26,807,000	7,470,000	79,969,000	
4	EPC SERVICES	956,000	41,417,000	12,380,000	8,903,000	6,297,000	2,835,000	1,274,000	21,446,000	14,941,000	110,449,000	
	TOTAL INSTALLED COST	10,780,000	259,153,000	142,778,000	67,074,000	64,309,000	37,422,000	29,299,000	447,667,000	156,125,000	1,214,607,000	
5	CONTINGENCY	800,000	18,100,000	7,100,000	4,700,000	4,500,000	2,600,000	2,100,000	31,300,000	7,800,000	79,000,000	
6	LICENSE FEES	200,000	5,200,000	2,900,000	1,300,000	1,300,000	700,000	600,000	9,000,000	3,100,000	24,300,000	
7	OWNER COSTS	500,000	13,000,000	7,100,000	3,400,000	3,200,000	1,900,000	1,500,000	22,400,000	7,800,000	60,800,000	
	TOTAL INVESTMENT COST	12,280,000	295,453,000	159,878,000	76,474,000	73,309,000	42,622,000	33,499,000	510,367,000	174,825,000	1,378,707,000	

3.5. Investment costs summary

The following Table 3.11 summarises overall investment cost for all the alternatives analysed: wet land and dry land cases.

Table 3.11 – investment costs summary

CASE	DESCRIPTION	Total inv. Costs South Africa basis M€
3.21	USC PC WITHOUT CO2 CAPTURE	880,151,000
3.25	USC PC WITHOUT CO2 CAPTURE DRY LAND	924,583,500
3.22	USC PC WITH CO2 CAPTURE	1,101,366,000
3.23	USC PC WITH CO2 CAPTURE DRY LAND	1,186,575,500
4.11	OXYFUEL WITH CO2 CAPTURE	1,053,653,000
4.12	OXYFUEL WITH CO2 CAPTURE DRY LAND	1,097,307,000
5.05	GE IGCC W/O CO2 CAPTURE	1,224,981,000
5.07	GE IGCC W/O CO2 CAPTURE DRY LAND	1,298,686,000
5.06	GE IGCC WITH CO2 CAPTURE	1,378,707,000
5.03	GE IGCC WITH CO2 CAPTURE DRY LAND	1,460,145,500

4. Operation and Maintenance Cost of the Alternatives

Operating and Maintenance (O&M) costs include:

- Feedstock
- 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 operating costs are directly proportional to the amount of kilowatt-hours produced and are referred as incremental costs. They may be expressed in €/kWh.
Fixed operating costs are essentially independent of the amount of kilowatt-hours produced. They may be expressed in €/h or €/year.
However, accurately distinguishing the variable and fixed operating costs is not always simple. Certain cost items may have both, variable and fixed, components; for instance the planned maintenance and inspection of the gas turbine, that are known to occur based on number of running hours, should be allocated as variable component of maintenance cost.

4.1. Variable Costs

The consumption of the various items and the corresponding costs are yearly, based on the following expected equivalent availabilities:

USC PC without CO_2 capture:	90%
USC PC with CO_2 capture:	88%
Oxyfuel:	85%
IGCC without CO_2 capture:	85%
IGCC with CO_2 capture:	85%

The variable costs are directly derived from the reference studies with the following exceptions:

- USC PC operating hours are slightly higher than in reference case where 85% has been considered for cases with and without CO_2 capture.
- In IGCC cases a higher cost of water (0.5 vs 0.1 €/t) has been considered due to the limitation imposed on water usage in present study.

4.2. Fixed Costs

The fixed costs of the different Power Plants operation include the following items:
- Direct labour.
- Administrative and general overhead.
- Maintenance.

4.2.1. Direct Labour

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

USC PC without CO_2 capture:	124 operators
USC PC with CO_2 capture:	130 operators
Oxyfuel:	136 operators
IGCC without CO_2 capture:	128 operators
IGCC with CO_2 capture:	128 operators

4.2.2. Administrative and General Overheads

All other Company services not directly involved in the operation of the Complex 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.

4.2.3. Maintenance

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the Complex. 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 Complex is normally estimated, as a percentage of the installed capital cost of the facilities. The same percentage of reference studies have been used for each case and are listed hereinafter:

USC PC without CO_2 capture:	4%
USC PC with CO_2 capture:	3.8%
Oxyfuel:	4%
IGCC without CO_2 capture:	3.7%
IGCC with CO_2 capture:	3.6%

4.3. Summary

The following table summarizes the total Operating and Maintenance Costs on yearly basis for all the alternatives. Figures shown are in M€/y.

Case	3.25	3.23	4.12	5.07	5.03
Description	USC PC w/o CCS	USC PC with CCS	Oxyfuel	IGCC w/o CCS	IGCC with CCS
Fuel	73.27	79.54	60.40	87.60	93.40
Make up water				**0.12**	**0.10**
Chemicals and consumables	5.81	18.03		2.40	3.60
Maintenance	31.29	38.28	37.52	42.86	46.95
Operating Labour	7.44	7.80	8.16	7.68	7.68
Labour Overhead	2.23	2.34	2.45	2.30	2.30
Insurance & local taxes	15.80	20.29	18.76	22.88	25.74
Waste					
Miscellanea			0.28		
total, M€/y	135.85	166.28	127.56	165.85	179.78

5. Evaluation of Cost of Electricity and Cost of Water saved

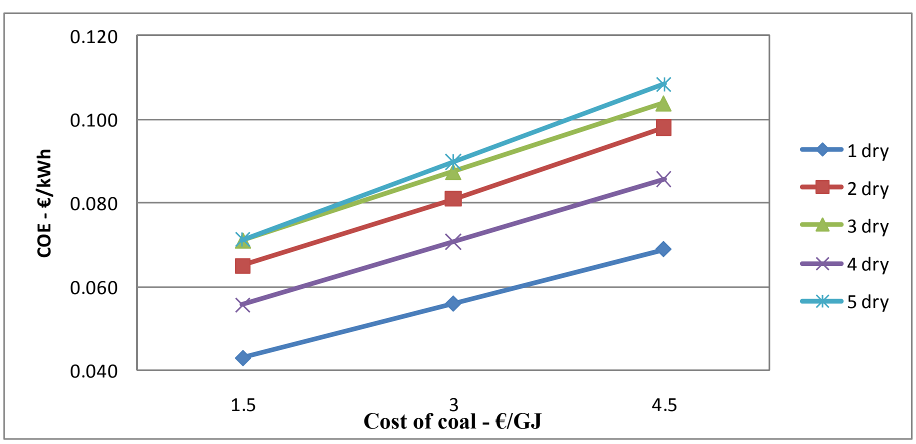
5.1. Cost of electricity

The following table summarizes the cost of electricity for each case. The economic analyses performed are attached to the end of this section C.
The cost of electricity is calculated based on the following main assumptions:

- Investment cost given at 4Q2009 cost level in South Africa;
- Fuel costs: 1.5 €/GJ;
- 10% discount rate on the investment cost over 25 operating years;
- No selling price is attributed to the sequestered CO_2.

Case		COE, €c/kWh
3.21	USC PC without CCS – wet land	4.0
3.25	USC PC without CCS – dry land	4.3
3.22	USC PC with CCS – wet land	5.8
3.23	USC PC with CCS – dry land	6.5
4.11	Oxyfuel USC PC – wet land	6.4
4.12	Oxyfuel USC PC – dry land	7.1
5.05	IGCC without CCS – wet land	5.0
5.07	IGCC without CCS – dry land	5.6
5.06	IGCC with CCS – wet land	6.3
5.03	IGCC with CCS – dry land	7.1

A sensitivity to cost of coal is also performed. It is assumed a variation of cost of coal from 1.5 to 4 €/GJ. From the attached graph it can be noted that the impact of coal cost on COE is similar for each case.



5.2. Cost of water saved

The following table summarizes the cost of electricity for each case. The economic analyses performed are attached to the end of this section C.

The cost of water saved is calculated based on the following main assumptions:

- Electricity cost: 50 c€/kWh;
- 10% discount rate on the investment cost over 25 operating years;
- Differential investment cost between the case without and with water limitation;
- Delta net power output between the case without and with water limitation;
- Delta O&M Costs between the case without and with water limitation.

Case		Cost of water, €c/t
3.21	USC PC without CCS – wet land	-
3.25	USC PC without CCS – dry land	3.3
3.22	USC PC with CCS – wet land	-
3.23	USC PC with CCS – dry land	0.8
4.11	Oxyfuel USC PC – wet land	-
4.12	Oxyfuel USC PC – dry land	9.0
5.05	IGCC without CCS – wet land	-
5.07	IGCC without CCS – dry land	7.3
5.06	IGCC with CCS – wet land	-
5.03	IGCC with CCS – dry land	0.9

6. Economics evaluation

The following table summarizes the total investment cost and O&M costs for all the dry land alternatives analyzed. The overall investment cost of the relevant wet land cases is also shown.

CASE	DESCRIPTION	Total Inv. Cost M€	Ratio	O&M Costs M€/y
3.21	USC PC WITHOUT CO2 CAPTURE	880.2	100.0%	
3.25	USC PC WITHOUT CO2 CAPTURE DRY LAND	924.6	105.0%	135.9
3.22	USC PC WITH CO2 CAPTURE	1,101.4	100.0%	
3.23	USC PC WITH CO2 CAPTURE DRY LAND	1,186.6	107.7%	166.3
4.11	OXYFUEL WITH CO2 CAPTURE	1,053.7	100.0%	
4.12	OXYFUEL WITH CO2 CAPTURE DRY LAND	1,097.3	104.1%	127.6
5.05	GE IGCC W/O CO2 CAPTURE	1,225.0	100.0%	
5.07	GE IGCC W/O CO2 CAPTURE DRY LAND	1,298.7	106.0%	165.9
5.06	GE IGCC WITH CO2 CAPTURE	1,378.7	100.0%	
5.03	GE IGCC WITH CO2 CAPTURE DRY LAND	1,460.1	105.9%	179.8

The table shows the percentage increase of the Total Investment Cost for each dry land case with respect to the relevant reference wet land case.

The following main conclusion can be drawn:

- The TIC percentage increase for all the dry land cases falls in a relatively narrow range of variation, between 4% and 8%, despite the differences of the various technologies involved.

- Cases without CO_2 capture: the percentage increase of TIC due to dry land design is higher in IGCC than in USC PC. This is because of the different impact of cost increment in the different process units: the dry land design mainly impacts on the IGCC case on ASU, Power Island and utilities investment cost. The impact on investment cost for USC PC, instead, is limited to Power Island and utilities.

- Cases with CO_2 capture: the percentage increase of TIC due to dry land design is higher in USC PC than in IGCC. The dry land design, in fact, in USC PC strongly impacts the investment cost of CO_2 capture and compression units, other than the units mentioned in previous bullet. The impact on performance and investment cost of CO_2 capture unit in IGCC is marginal as explained in Section B of present report. The effect is slightly more significant in the CO_2 compression unit of IGCC, even if still much lower than in USC PC compression unit. In the IGCC in fact, the CO_2 is made available from the AGR at a pressure much higher than the one in the USC PC case. The CO_2 compression unit is therefore smaller in the IGCC cases (if the same CO_2 total flow is considered) and the dry land percentage impact is therefore much lower.

- The TIC percentage increase (dry land vs. wet land) in the IGCC with and without CO_2 capture is similar because the only difference between the two cases is in the CO_2 compression unit that, from an overall point of view, counts only for less than a percentage point.

- The TIC percentage increase (dry land vs. wet land) in the USC PC with and without CO_2 capture is much higher since the cost of CO_2 capture and compression units represents a significant part of the overall investment cost.

- The TIC percentage increase for the oxyfuel case remains lower than the other ones for the following reasons:
  - The CO_2 purification system itself leads to the condensation of the water from the boiler flue gases and therefore there is no need to add any further water recovery system in the dry land cases;
  - The ASU configuration is different from the one of IGCC and therefore the impact of dry land on costs is lower. In the oxyfuel case, in fact, the oxygen is made available at a lower pressure with respect to the IGCC case and therefore the dry land impact on compressors and intercoolers is much lower.

- The O&M yearly costs are not significantly affected by the dry land design. The only difference, in fact, is represented by the make-up of water in the IGCC cases. Anyway, the cost of water has a very limited impact on the overall O&M Costs (0.1 M€/y, see paragraph 4.3). Part of the remaining O&M costs remains constant (fuel, labour and consumables), while a part in increased proportionally with investment cost of the plant under the same bases as reference wet land case (maintenance, insurance and local taxes).

- The main parasitic load due to the dry land design is represented both by the loss of gross electric power production and by the increase of electricity consumptions leading to a significant reduction of net electricity exported to the grid. This is not reflected in O&M Costs, but strongly reduces the incomes from the electricity sold to the market and therefore the overall plant economics.

1. COE calculation sheets

The COE calculation sheets for each case are attached here below.

Case 3.21 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	239.8	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	757.7	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	880.2

Operating Costs [MM Euro/year] (90% availability)	
Fuel Cost	73.3
Maintenance	29.8
Miscellanea	0.0
Chemicals + Consumable	5.8
Insurance and local taxes	15.0

Working Capital	**MM Euro**
30 days Chemical Storage	0.5
30 days Coal Storage	6.7
Total Working capital	7.2

Labour Cost		**MM Euro/year**
# operators		124
Salary		0.06
Direct Labour Cost		7.4
Administration	30% L.C.	2.2
Total Labour Cost		9.7

Electricity Production Cost	0.040	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	240.7	MM Euro/year

NPV	0.00
IRR	10.00%

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours				6570	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				200.6	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	240.7	
Operating Costs																													
Fuel Cost				-55.0	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	
Maintenance				-19.9	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	-29.8	
Labour				-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	
Chemicals & Consumables				-4.4	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	-15.0	
Working Capital Cost				-7.2																									7.2
Fixed Capital Expenditures	-176.0	-396.1	-308.1																										
Total Cash flow (yearly)	-176.0	-396.1	-308.1	89.5	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	107.1	7.2
Total Cash flow (cumulated)	-176.0	-572.1	-880.2	-790.7	-683.6	-576.5	-469.4	-362.3	-255.2	-148.1	-41.0	66.1	173.2	280.3	387.4	494.5	601.6	708.7	815.8	922.9	1030.0	1137.1	1244.2	1351.3	1458.4	1565.5	1672.6	1779.7	1786.9
Discounted Cash Flow (Yearly)	-160.0	-327.3	-231.4	61.1	66.5	60.5	55.0	50.0	45.4	41.3	37.5	34.1	31.0	28.2	25.6	23.3	21.2	19.3	17.5	15.9	14.5	13.2	12.0	10.9	9.9	9.0	8.2	7.4	0.5
Discounted Cash Flow (Cumul.)	-160.0	-487.4	-718.8	-657.7	-591.2	-530.7	-475.8	-425.8	-380.4	-339.1	-301.6	-267.4	-236.4	-208.2	-182.6	-159.3	-138.1	-118.8	-101.3	-85.4	-70.9	-57.8	-45.8	-34.9	-25.0	-16.1	-7.9	-0.5	0.0

Case 3.22 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	266.3	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	665.6	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1101.4

Operating Costs [MM Euro/year] **(88% availability)**	
Fuel Cost	79.5
Maintenance	35.5
Miscellanea	0.0
Chemicals + Consumable	18.0
Insurance and local taxes	18.8

Working Capital	**MM Euro**
30 days Chemical Storage	1.7
30 days Coal Storage	7.4
Total Working capital	9.1

Labour Cost		**MM Euro/year**
# operators		130
Salary		0.06
Direct Labour Cost		7.8
Administration	30% L.C.	2.3
Total Labour Cost		10.1

Electricity Production Cost	0.058	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	295.5	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours				6570	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				251.8	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	295.5	
Operating Costs																													
Fuel Cost				-59.7	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	
Maintenance				-23.7	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	-35.5	
Labour				-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	
Chemicals & Consumables				-13.5	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	
Working Capital Cost				-9.1																									9.1
Fixed Capital Expenditures	-220.3	-495.6	-385.5																										
Total Cash flow (yearly)	-220.3	-495.6	-385.5	116.9	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	133.5	9.1
Total Cash flow (cumulated)	-220.3	-715.9	-1101.4	-984.4	-851.0	-717.5	-584.1	-450.6	-317.1	-183.7	-50.2	83.3	216.7	350.2	483.7	617.1	750.6	884.1	1017.5	1151.0	1284.4	1417.9	1551.4	1684.8	1818.3	1951.8	2085.2	2218.7	2227.8
Discounted Cash Flow (Yearly)	-200.2	-409.6	-289.6	79.9	82.9	75.3	68.5	62.3	56.6	51.5	46.8	42.5	38.7	35.1	32.0	29.0	26.4	24.0	21.8	19.8	18.0	16.4	14.9	13.6	12.3	11.2	10.2	9.3	0.6
Discounted Cash Flow (Cumul.)	-200.2	-609.8	-899.5	-819.6	-736.7	-661.4	-592.9	-530.6	-474.0	-422.6	-375.8	-333.3	-294.6	-259.5	-227.5	-198.5	-172.1	-148.1	-126.3	-106.4	-88.4	-72.0	-57.1	-43.5	-31.2	-20.0	-9.8	-0.6	0.0

FOSTER WHEELER

Case 4.11 - Cost Evaluation - Discount Rate = 10%

Production
Coal Florate 209.12 t/h
Fuel Price 1.5 Euro/GJ

Net Power Output 531.4 MW

Capital Expenditures **MM Euro**
Total Investment Cost 1053.7

Operating Costs [MM Euro/year]
(85% availability)

Fuel Cost	60.40
Maintenance	36.03
Miscellanea	0.28
Chemicals + Consumable	0.00
Insurance and local taxes	18.01

Working Capital **MM Euro**

30 days Chemical Storage	0.0
30 days Coal Storage	5.8
Total Working capital	5.8

Labour Cost **MM Euro/year**

# operators		136
Salary		0.06
Direct Labour Cost		8.2
Administration	30% L.C.	2.4
Total Labour Cost		10.61

Electricity Production Cost	0.064	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	252.3	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				222.6	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	252.3	
Operating Costs																													
Fuel Cost				-45.3	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	
Maintenance				-24.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	
Labour				-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea				-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	
Insurance				-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	
Working Capital Cost				-5.8																									5.8
Fixed Capital Expenditures	-210.7	-474.2	-368.8																										
Total Cash flow (yearly)	-210.7	-474.2	-368.8	118.6	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	5.8
Total Cash flow (cumulated)	-210.7	-684.9	-1053.7	-935.1	-808.1	-681.1	-554.2	-427.2	-300.3	-173.3	-46.3	80.6	207.6	334.6	461.5	588.5	715.5	842.4	969.4	1096.4	1223.3	1350.3	1477.3	1604.2	1731.2	1858.2	1985.1	2112.1	2117.9
Discounted Cash Flow (Yearly)	-191.6	-391.9	-277.1	81.0	78.8	71.7	65.2	59.2	53.8	49.0	44.5	40.5	36.8	33.4	30.4	27.6	25.1	22.8	20.8	18.9	17.2	15.6	14.2	12.9	11.7	10.7	9.7	8.8	0.4
Discounted Cash Flow (Cumul.)	-191.6	-583.5	-860.5	-779.5	-700.7	-629.0	-563.9	-504.6	-450.8	-401.8	-357.3	-316.9	-280.1	-246.7	-216.3	-188.6	-163.5	-140.7	-119.9	-101.1	-83.9	-68.3	-54.1	-41.2	-29.5	-18.9	-9.2	-0.4	0.0

Production		
Coal Florate	303	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	826.5	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1225.0

Operating Costs [MM Euro/year]	
(85% availability)	
Fuel Cost	87.60
Maintenance	40.43
Miscellanea	0.12
Chemicals + Consumable	2.40
Insurance and local taxes	21.58

Working Capital	**MM Euro**
30 days Chemical Storage	0.2
30 days Coal Storage	8.5
Total Working capital	8.7

Labour Cost		**MM Euro/year**
# operators		128
Salary		0.06
Direct Labour Cost		7.7
Administration	30% L.C.	2.3
Total Labour Cost		9.98

Electricity Production Cost	0.050	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	309.6	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				273.2	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	309.6	
Operating Costs																													
Fuel Cost				-65.7	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	
Maintenance				-27.0	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	-40.4	
Labour				-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	
Chemicals & Consumables				-1.8	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	
Miscellanea				-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Insurance				-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	-21.6	
Working Capital Cost				-8.7																									8.7
Fixed Capital Expenditures	-245.0	-551.3	-428.8																										
Total Cash flow (yearly)	-245.0	-551.3	-428.8	138.4	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	147.5	8.7
Total Cash flow (cumulated)	-245.0	-796.3	-1225.0	-1086.6	-939.1	-791.5	-644.0	-496.5	-348.9	-201.4	-53.9	93.6	241.2	388.7	536.2	683.8	831.3	978.8	1126.4	1273.9	1421.4	1569.0	1716.5	1864.0	2011.5	2159.1	2306.6	2454.1	2462.8
Discounted Cash Flow (Yearly)	-222.7	-455.6	-322.1	94.5	91.6	83.3	75.7	68.8	62.6	56.9	51.7	47.0	42.7	38.8	35.3	32.1	29.2	26.5	24.1	21.9	19.9	18.1	16.5	15.0	13.6	12.4	11.3	10.2	0.5
Discounted Cash Flow (Cumul.)	-222.7	-678.3	-1000.4	-905.9	-814.3	-731.0	-655.3	-586.5	-523.9	-467.0	-415.3	-368.3	-325.6	-286.7	-251.4	-219.3	-190.1	-163.6	-139.5	-117.5	-97.6	-79.5	-63.0	-48.0	-34.4	-22.0	-10.8	-0.5	0.0

Case 5.06 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	323.1	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	730.3	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1378.7

Operating Costs [MM Euro/year]	
(85% availability)	
Fuel Cost	93.40
Maintenance	44.31
Miscellanea	0.10
Chemicals + Consumable	3.60
Insurance and local taxes	24.29

Working Capital		**MM Euro**
30 days Chemical Storage		0.3
30 days Coal Storage		9.0
Total Working capital		9.4
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.06
Direct Labour Cost		7.7
Administration	30% L.C.	2.3
Total Labour Cost		9.98

Electricity Production Cost	0.063	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	341.8	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				301.5	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8
Operating Costs															
Fuel Cost				-70.1	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4
Maintenance				-29.5	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3
Labour				-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
Chemicals & Consumables				-2.7	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6
Miscellanea				-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Insurance				-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3
Working Capital Cost				-9.4											
Fixed Capital Expenditures	-275.7	-620.4	-482.5												
Total Cash flow (yearly)	-275.7	-620.4	-482.5	155.5	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1
Total Cash flow (cumulated)	-275.7	-896.2	-1378.7	-1223.2	-1057.1	-891.0	-725.0	-558.9	-392.8	-226.7	-60.7	105.4	271.5	437.6	603.6
Discounted Cash Flow (Yearly)	-250.7	-512.7	-362.5	106.2	103.1	93.7	85.2	77.5	70.4	64.0	58.2	52.9	48.1	43.7	39.8
Discounted Cash Flow (Cumul.)	-250.7	-763.4	-1126.0	-1019.7	-916.6	-822.9	-737.6	-660.2	-589.7	-525.7	-467.5	-414.6	-366.5	-322.8	-283.0

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	341.8	
Operating Costs														
Fuel Cost	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	
Maintenance	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	-44.3	
Labour	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	
Chemicals & Consumables	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	
Miscellanea	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Insurance	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	
Working Capital Cost														9.4
Fixed Capital Expenditures														
Total Cash flow (yearly)	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	166.1	9.4
Total Cash flow (cumulated)	769.7	935.8	1101.8	1267.9	1434.0	1600.1	1766.1	1932.2	2098.3	2264.3	2430.4	2596.5	2762.6	2771.9
Discounted Cash Flow (Yearly)	36.1	32.9	29.9	27.2	24.7	22.4	20.4	18.5	16.9	15.3	13.9	12.7	11.5	0.6
Discounted Cash Flow (Cumul.)	-246.9	-214.0	-184.1	-157.0	-132.3	-109.8	-89.4	-70.9	-54.0	-38.7	-24.8	-12.1	-0.6	0.0

FOSTER WHEELER

Case 3.25 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	239.8	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	725.0	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	924.6

Operating Costs [MM Euro/year] **(90% availability)**	
Fuel Cost	73.3
Maintenance	31.3
Miscellanea	0.0
Chemicals + Consumable	5.8
Insurance and local taxes	15.8

Working Capital		**MM Euro**
30 days Chemical Storage		0.5
30 days Coal Storage		6.7
Total Working capital		7.2
Labour Cost		**MM Euro/year**
# operators		124
Salary		0.06
Direct Labour Cost		7.4
Administration	30% L.C.	2.2
Total Labour Cost		9.7

Electricity Production Cost	0.043	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	248.3	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours				6570	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				207.0	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	248.3	
Operating Costs																													
Fuel Cost				-55.0	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	-73.3	
Maintenance				-20.9	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	
Labour				-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	
Chemicals & Consumables				-4.4	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	
Working Capital Cost				-7.2																									7.2
Fixed Capital Expenditures	-184.9	-416.1	-323.6																										
Total Cash flow (yearly)	-184.9	-416.1	-323.6	94.1	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	112.5	7.2
Total Cash flow (cumulated)	-184.9	-601.0	-924.6	-830.5	-718.0	-605.5	-493.0	-380.5	-268.0	-155.5	-43.0	69.5	182.0	294.5	407.0	519.5	632.0	744.5	857.0	969.5	1082.0	1194.5	1307.0	1419.5	1532.0	1644.5	1757.0	1869.5	1876.7
Discounted Cash Flow (Yearly)	-168.1	-343.9	-243.1	64.3	69.9	63.5	57.7	52.5	47.7	43.4	39.4	35.8	32.6	29.6	26.9	24.5	22.3	20.2	18.4	16.7	15.2	13.8	12.6	11.4	10.4	9.4	8.6	7.8	0.5
Discounted Cash Flow (Cumul.)	-168.1	-512.0	-755.1	-690.8	-621.0	-557.5	-499.7	-447.3	-399.5	-356.2	-316.7	-280.9	-248.3	-218.7	-191.8	-167.3	-145.0	-124.8	-106.4	-89.7	-74.5	-60.6	-48.1	-36.7	-26.3	-16.8	-8.3	-0.5	0.0

FOSTER WHEELER

Case 3.23 - Cost Evaluation - Discount Rate = 10%

Production

Coal Florate	266.3	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	623.2	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1186.6

Operating Costs [MM Euro/year]
(88% availability)

Fuel Cost	79.5
Maintenance	38.3
Miscellanea	0.0
Chemicals + Consumable	18.0
Insurance and local taxes	20.3

Working Capital	**MM Euro**
30 days Chemical Storage	1.7
30 days Coal Storage	7.4
Total Working capital	9.1

Labour Cost		**MM Euro/year**
# operators		130
Salary		0.06
Direct Labour Cost		7.8
Administration	30% L.C.	2.3
Total Labour Cost		10.1

Electricity Production Cost	0.065	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	310.1	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				264.3	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1
Operating Costs															
Fuel Cost				-59.7	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5
Maintenance				-25.5	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3
Labour				-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1
Chemicals & Consumables				-13.5	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3
Working Capital Cost				-9.1											
Fixed Capital Expenditures	-237.3	-534.0	-415.3												
Total Cash flow (yearly)	-237.3	-534.0	-415.3	126.0	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8
Total Cash flow (cumulated)	-237.3	-771.3	-1186.6	-1060.6	-916.8	-773.0	-629.2	-485.4	-341.6	-197.8	-54.0	89.8	233.6	377.4	521.1
Discounted Cash Flow (Yearly)	-215.7	-441.3	-312.0	86.1	89.3	81.2	73.8	67.1	61.0	55.4	50.4	45.8	41.7	37.9	34.4
Discounted Cash Flow (Cumul.)	-215.7	-657.0	-969.1	-883.0	-793.7	-712.5	-638.7	-571.7	-510.7	-455.2	-404.8	-359.0	-317.4	-279.5	-245.1

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	
Expediture Factor														
Revenues														
Electric Energy	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	310.1	
Operating Costs														
Fuel Cost	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	-79.5	
Maintenance	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	-38.3	
Labour	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	-10.1	
Chemicals & Consumables	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	-18.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	-20.3	
Working Capital Cost														9.1
Fixed Capital Expenditures														
Total Cash flow (yearly)	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	143.8	9.1
Total Cash flow (cumulated)	664.9	808.7	952.5	1096.3	1240.1	1383.9	1527.7	1671.5	1815.3	1959.1	2102.8	2246.6	2390.4	2399.5
Discounted Cash Flow (Yearly)	31.3	28.4	25.9	23.5	21.4	19.4	17.7	16.1	14.6	13.3	12.1	11.0	10.0	0.6
Discounted Cash Flow (Cumul.)	-213.8	-185.3	-159.5	-136.0	-114.6	-95.2	-77.5	-61.4	-46.8	-33.6	-21.5	-10.5	-0.6	0.0

Case 4.12 - Cost Evaluation - Discount Rate = 10%

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Production		
Coal Florate	209.12	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	491.4	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1097.3

Operating Costs [MM Euro/year] **(85% availability)**	
Fuel Cost	60.40
Maintenance	37.52
Miscellanea	0.28
Chemicals + Consumable	0.00
Insurance and local taxes	18.76

Working Capital		**MM Euro**
30 days Chemical Storage		0.0
30 days Coal Storage		5.8
Total Working capital		5.8
Labour Cost		**MM Euro/year**
# operators		136
Salary		0.06
Direct Labour Cost		8.2
Administration	30% L.C.	2.4
Total Labour Cost		10.61

Electricity Production Cost	0.071	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	259.8	MM Euro/year
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				229.2	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8
Operating Costs															
Fuel Cost				-45.3	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4
Maintenance				-25.0	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5
Labour				-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Insurance				-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8
Working Capital Cost				-5.8											
Fixed Capital Expenditures	-219.5	-493.8	-384.1												
Total Cash flow (yearly)	-219.5	-493.8	-384.1	123.5	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2
Total Cash flow (cumulated)	-219.5	-713.2	-1097.3	-973.8	-841.6	-709.4	-577.1	-444.9	-312.7	-180.5	-48.2	84.0	216.2	348.4	480.7
Discounted Cash Flow (Yearly)	-199.5	-408.1	-288.5	84.4	82.1	74.6	67.9	61.7	56.1	51.0	46.3	42.1	38.3	34.8	31.7
Discounted Cash Flow (Cumul.)	-199.5	-607.6	-896.1	-811.8	-729.7	-655.1	-587.2	-525.5	-469.4	-418.5	-372.1	-330.0	-291.7	-256.9	-225.2

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	
Operating Costs														
Fuel Cost	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	-60.4	
Maintenance	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	-37.5	
Labour	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	-10.6	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	
Insurance	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	-18.8	
Working Capital Cost														5.8
Fixed Capital Expenditures														
Total Cash flow (yearly)	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	132.2	5.8
Total Cash flow (cumulated)	612.9	745.1	877.3	1009.6	1141.8	1274.0	1406.2	1538.5	1670.7	1802.9	1935.1	2067.4	2199.6	2205.4
Discounted Cash Flow (Yearly)	28.8	26.2	23.8	21.6	19.7	17.9	16.2	14.8	13.4	12.2	11.1	10.1	9.2	0.4
Discounted Cash Flow (Cumul.)	-196.4	-170.3	-146.5	-124.9	-105.2	-87.4	-71.1	-56.3	-42.9	-30.7	-19.6	-9.5	-0.4	0.0

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Case 5.07 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	303	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	777.6	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1298.7

Operating Costs [MM Euro/year]	
(85% availability)	
Fuel Cost	87.60
Maintenance	42.86
Miscellanea	0.12
Chemicals + Consumable	2.40
Insurance and local taxes	22.88

Working Capital		**MM Euro**
30 days Chemical Storage		0.2
30 days Coal Storage		8.5
Total Working capital		8.7
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.06
Direct Labour Cost		7.7
Administration	30% L.C.	2.3
Total Labour Cost		9.98

Electricity Production Cost	0.056	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	322.3	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				284.4	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3
Operating Costs															
Fuel Cost				-65.7	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6
Maintenance				-28.6	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9
Labour				-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
Chemicals & Consumables				-1.8	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4
Miscellanea				-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Insurance				-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9
Working Capital Cost				-8.7											
Fixed Capital Expenditures	-259.7	-584.4	-454.5												
Total Cash flow (yearly)	-259.7	-584.4	-454.5	146.6	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4
Total Cash flow (cumulated)	-259.7	-844.2	-1298.7	-1152.1	-995.7	-839.2	-682.8	-526.4	-370.0	-213.5	-57.1	99.3	255.7	412.2	568.6
Discounted Cash Flow (Yearly)	-236.1	-483.0	-341.5	100.1	97.1	88.3	80.3	73.0	66.3	60.3	54.8	49.8	45.3	41.2	37.4
Discounted Cash Flow (Cumul.)	-236.1	-719.1	-1060.6	-960.5	-863.3	-775.1	-694.8	-621.8	-555.5	-495.2	-440.3	-390.5	-345.2	-304.0	-266.5

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	322.3	
Operating Costs														
Fuel Cost	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	-87.6	
Maintenance	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	-42.9	
Labour	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	
Chemicals & Consumables	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	
Miscellanea	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Insurance	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	-22.9	
Working Capital Cost														8.7
Fixed Capital Expenditures														
Total Cash flow (yearly)	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	156.4	8.7
Total Cash flow (cumulated)	725.0	881.4	1037.9	1194.3	1350.7	1507.1	1663.6	1820.0	1976.4	2132.8	2289.2	2445.7	2602.1	2610.8
Discounted Cash Flow (Yearly)	34.0	30.9	28.1	25.6	23.3	21.1	19.2	17.5	15.9	14.4	13.1	11.9	10.8	0.5
Discounted Cash Flow (Cumul.)	-232.5	-201.6	-173.4	-147.8	-124.6	-103.5	-84.2	-66.8	-50.9	-36.5	-23.3	-11.4	-0.5	0.0

Case 5.03 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	323.1	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	671.1	MW

Capital Expenditures	**MM Euro**
Total Investment Cost	1460.1

Operating Costs [MM Euro/year] (85% availability)	
Fuel Cost	93.40
Maintenance	46.95
Miscellanea	0.10
Chemicals + Consumable	3.60
Insurance and local taxes	25.74

Working Capital	**MM Euro**
30 days Chemical Storage	0.3
30 days Coal Storage	9.0
Total Working capital	9.4

Labour Cost		**MM Euro/year**
# operators		128
Salary		0.06
Direct Labour Cost		7.7
Administration	30% L.C.	2.3
Total Labour Cost		9.98

Electricity Production Cost	0.071	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	355.7	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				313.8	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7
Operating Costs														
Fuel Cost				-70.1	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4
Maintenance				-31.3	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0
Labour				-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0
Chemicals & Consumables				-2.7	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6
Miscellanea				-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Insurance				-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Working Capital Cost				-9.4										
Fixed Capital Expenditures	-292.0	-657.0	-511.0											
Total Cash flow (yearly)	-292.0	-657.0	-511.0	164.6	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9
Total Cash flow (cumulated)	-292.0	-949.1	-1460.1	-1295.5	-1119.6	-943.7	-767.8	-591.9	-416.0	-240.1	-64.2	111.7	287.6	463.5
Discounted Cash Flow (Yearly)	-265.5	-543.0	-383.9	112.4	109.2	99.3	90.3	82.1	74.6	67.8	61.7	56.0	51.0	46.3
Discounted Cash Flow (Cumul.)	-265.5	-808.5	-1192.4	-1080.0	-970.8	-871.5	-781.2	-699.2	-624.6	-556.8	-495.1	-439.1	-388.1	-341.8

CASH FLOW ANALYSYS Millions Euro	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	355.7	
Operating Costs															
Fuel Cost	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	-93.4	
Maintenance	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	-47.0	
Labour	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	
Chemicals & Consumables	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	
Miscellanea	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Insurance	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Working Capital Cost															9.4
Fixed Capital Expenditures															
Total Cash flow (yearly)	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	175.9	9.4
Total Cash flow (cumulated)	639.4	815.2	991.1	1167.0	1342.9	1518.8	1694.7	1870.6	2046.5	2222.4	2398.3	2574.2	2750.1	2926.0	2935.4
Discounted Cash Flow (Yearly)	42.1	38.3	34.8	31.6	28.8	26.1	23.8	21.6	19.6	17.9	16.2	14.8	13.4	12.2	0.6
Discounted Cash Flow (Cumul.)	-299.7	-261.4	-226.6	-195.0	-166.2	-140.1	-116.3	-94.7	-75.1	-57.2	-41.0	-26.2	-12.8	-0.6	0.0

2. Cost of water saved calculation sheets

The cost of water saved calculation sheets for each case are attached here below.

Case 3.25 - Cost Evaluation - Discount Rate = 10%

Production

Coal Florate	239.8	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	-32.7	MW
Water saving	78.9	t/h

Capital Expenditures	**MM Euro**
Total Investment Cost	44.4

Operating Costs [MM Euro/year]
(90% availability)

Fuel Cost	0.0
Maintenance	1.5
Miscellanea	0.0
Chemicals + Consumable	0.0
Insurance and local taxes	0.8

Working Capital	**MM Euro**
30 days Chemical Storage	0.0
30 days Coal Storage	0.0
Total Working capital	0.0

Labour Cost	**MM Euro/year**
# operators	0
Salary	0.06
Direct Labour Cost	0.0
Administration 30% L.C.	0.0
Total Labour Cost	0.0

water cost	0.033	Euro/t
EE selling price	0.05	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year		MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS
Millions Euro

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				-10.7	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9
Water saving				17.1	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
Operating Costs															
Fuel Cost				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance				-1.0	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Labour				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8
Working Capital Cost				0.0											
Fixed Capital Expenditures	-8.9	-20.0	-15.5												
Total Cash flow (yearly)	-8.9	-20.0	-15.5	4.6	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Total Cash flow (cumulated)	-8.9	-28.8	-44.4	-39.8	-34.4	-29.0	-23.6	-18.2	-12.8	-7.4	-2.0	3.4	8.8	14.2	19.6
Discounted Cash Flow (Yearly)	-8.1	-16.5	-11.7	3.1	3.3	3.0	2.8	2.5	2.3	2.1	1.9	1.7	1.6	1.4	1.3
Discounted Cash Flow (Cumul.)	-8.1	-24.6	-36.2	-33.1	-29.7	-26.7	-23.9	-21.4	-19.1	-17.1	-15.2	-13.4	-11.9	-10.5	-9.2

	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expediture Factor														
Revenues														
Electric Energy	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	-12.9	
Water saving	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	
Operating Costs														
Fuel Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Maintenance	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	
Labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	
Working Capital Cost														0.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	0.0
Total Cash flow (cumulated)	24.9	30.3	35.7	41.1	46.5	51.9	57.3	62.7	68.1	73.5	78.9	84.3	89.7	89.7
Discounted Cash Flow (Yearly)	1.2	1.1	1.0	0.9	0.8	0.7	0.7	0.6	0.5	0.5	0.5	0.4	0.4	0.0
Discounted Cash Flow (Cumul.)	-8.0	-6.9	-6.0	-5.1	-4.3	-3.5	-2.9	-2.3	-1.7	-1.2	-0.8	-0.4	0.0	0.0

Case 3.23 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	266.3	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	-42.6	MW
Water saving	272.7	t/h

Capital Expenditures	**MM Euro**
Total Investment Cost	85.2

Operating Costs [MM Euro/year] **(88% availability)**	
Fuel Cost	0.0
Maintenance	2.8
Miscellanea	0.0
Chemicals + Consumable	0.0
Insurance and local taxes	1.5

Working Capital	**MM Euro**
30 days Chemical Storage	0.0
30 days Coal Storage	0.0
Total Working capital	0.0

Labour Cost	**MM Euro/year**
# operators	0
Salary	0.06
Direct Labour Cost	0.0
Administration 30% L.C.	0.0
Total Labour Cost	0.0

water cost	0.008	Euro/t
EE selling price	0.05	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	-2.7	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS
Millions Euro

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				-2.3	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7
Water saving				14.7	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Operating Costs															
Fuel Cost				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance				-1.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8
Labour				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Working Capital Cost				0.0											
Fixed Capital Expenditures	-17.0	-38.3	-29.8												
Total Cash flow (yearly)	-17.0	-38.3	-29.8	9.1	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Total Cash flow (cumulated)	-17.0	-55.4	-85.2	-76.1	-65.8	-55.4	-45.1	-34.8	-24.5	-14.1	-3.8	6.5	16.8	27.1	37.5
Discounted Cash Flow (Yearly)	-15.5	-31.7	-22.4	6.2	6.4	5.8	5.3	4.8	4.4	4.0	3.6	3.3	3.0	2.7	2.5
Discounted Cash Flow (Cumul.)	-15.5	-47.2	-69.6	-63.3	-56.9	-51.1	-45.8	-41.0	-36.6	-32.6	-29.0	-25.7	-22.7	-20.0	-17.6

	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	7709	
Expediture Factor														
Revenues														
Electric Energy	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	-2.7	
Water saving	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	
Operating Costs														
Fuel Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Maintenance	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	-2.8	
Labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	
Working Capital Cost														0.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	0.0
Total Cash flow (cumulated)	47.8	58.1	68.4	78.8	89.1	99.4	109.7	120.1	130.4	140.7	151.0	161.3	171.7	171.7
Discounted Cash Flow (Yearly)	2.2	2.0	1.9	1.7	1.5	1.4	1.3	1.2	1.0	1.0	0.9	0.8	0.7	0.0
Discounted Cash Flow (Cumul.)	-15.3	-13.3	-11.4	-9.7	-8.2	-6.8	-5.5	-4.4	-3.3	-2.4	-1.5	-0.7	0.0	0.0

FOSTER WHEELER

Case 4.12 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	209.12	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	-40.0	MW
Water saving	33.3	t/h

Capital Expenditures	**MM Euro**
Total Investment Cost	43.6

Operating Costs [MM Euro/year] **(85% availability)**	
Fuel Cost	0.00
Maintenance	1.49
Miscellanea	0.00
Chemicals + Consumable	0.00
Insurance and local taxes	0.75

Working Capital		**MM Euro**
30 days Chemical Storage		0.0
30 days Coal Storage		0.0
Total Working capital		0.0
Labour Cost		**MM Euro/year**
# operators		0
Salary		0.06
Direct Labour Cost		0.0
Administration	30% L.C.	0.0
Total Labour Cost		0.00

water cost	0.090	Euro/t
EE selling price	0.05	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	-14.9	MM Euro/year
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				-13.2	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9
Water saving				19.8	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Operating Costs															
Fuel Cost				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance				-1.0	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Labour				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8
Working Capital Cost				0.0											
Fixed Capital Expenditures	-8.7	-19.6	-15.3												
Total Cash flow (yearly)	-8.7	-19.6	-15.3	4.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Total Cash flow (cumulated)	-8.7	-28.3	-43.6	-38.7	-33.5	-28.2	-22.9	-17.7	-12.4	-7.2	-1.9	3.4	8.6	13.9	19.1
Discounted Cash Flow (Yearly)	-7.9	-16.2	-11.5	3.3	3.3	3.0	2.7	2.5	2.2	2.0	1.8	1.7	1.5	1.4	1.3
Discounted Cash Flow (Cumul.)	-7.9	-24.1	-35.6	-32.3	-29.0	-26.0	-23.3	-20.9	-18.7	-16.6	-14.8	-13.1	-11.6	-10.2	-8.9

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	-14.9	
Water saving	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	
Operating Costs														
Fuel Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Maintenance	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	
Labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	-0.8	
Working Capital Cost														0.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	0.0
Total Cash flow (cumulated)	24.4	29.7	34.9	40.2	45.4	50.7	56.0	61.2	66.5	71.7	77.0	82.3	87.5	87.5
Discounted Cash Flow (Yearly)	1.1	1.0	0.9	0.9	0.8	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.0
Discounted Cash Flow (Cumul.)	-7.8	-6.8	-5.8	-5.0	-4.2	-3.5	-2.8	-2.2	-1.7	-1.2	-0.8	-0.4	0.0	0.0

Case 5.07 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	303	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	-48.9	MW
Water saving	72.0	t/h

Capital Expenditures	**MM Euro**
Total Investment Cost	73.7

Operating Costs [MM Euro/year]	
(85% availability)	
Fuel Cost	0.00
Maintenance	2.43
Miscellanea	0.00
Chemicals + Consumable	0.00
Insurance and local taxes	1.30

Working Capital		**MM Euro**
30 days Chemical Storage		0.0
30 days Coal Storage		0.0
Total Working capital		0.0
Labour Cost		**MM Euro/year**
# operators		0
Salary		0.06
Direct Labour Cost		0.0
Administration	30% L.C.	0.0
Total Labour Cost		0.00

water cost	0.073	Euro/t
EE selling price	0.05	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	-26.7	MM Euro/year
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				-23.5	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7
Water saving				34.7	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3
Operating Costs															
Fuel Cost				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance				-1.6	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4
Labour				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3
Working Capital Cost				0.0											
Fixed Capital Expenditures	-14.7	-33.2	-25.8												
Total Cash flow (yearly)	-14.7	-33.2	-25.8	8.2	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Total Cash flow (cumulated)	-14.7	-47.9	-73.7	-65.5	-56.6	-47.7	-38.8	-29.9	-21.0	-12.1	-3.2	5.7	14.6	23.5	32.3
Discounted Cash Flow (Yearly)	-13.4	-27.4	-19.4	5.6	5.5	5.0	4.6	4.1	3.8	3.4	3.1	2.8	2.6	2.3	2.1
Discounted Cash Flow (Cumul.)	-13.4	-40.8	-60.2	-54.6	-49.1	-44.0	-39.5	-35.3	-31.5	-28.1	-25.0	-22.2	-19.6	-17.3	-15.1

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	-26.7	
Water saving	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	39.3	
Operating Costs														
Fuel Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Maintenance	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	
Labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	
Working Capital Cost														0.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	0.0
Total Cash flow (cumulated)	41.2	50.1	59.0	67.9	76.8	85.7	94.6	103.5	112.4	121.3	130.2	139.1	148.0	148.0
Discounted Cash Flow (Yearly)	1.9	1.8	1.6	1.5	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.7	0.6	0.0
Discounted Cash Flow (Cumul.)	-13.2	-11.4	-9.8	-8.4	-7.1	-5.9	-4.8	-3.8	-2.9	-2.0	-1.3	-0.6	0.0	0.0

FOSTER WHEELER

Case 5.03 - Cost Evaluation - Discount Rate = 10%

Production

Coal Florate	323.1	t/h
Fuel Price	1.5	Euro/GJ
Net Power Output	-59.2	MW
Water saving	273.8	t/h

Capital Expenditures	**MM Euro**
Total Investment Cost	81.4

Operating Costs [MM Euro/year] (85% availability)	
Fuel Cost	0.00
Maintenance	2.64
Miscellanea	0.00
Chemicals + Consumable	0.00
Insurance and local taxes	1.45

Working Capital		**MM Euro**
30 days Chemical Storage		0.0
30 days Coal Storage		0.0
Total Working capital		0.0

Labour Cost		**MM Euro/year**
# operators		0
Salary		0.06
Direct Labour Cost		0.0
Administration	30% L.C.	0.0
Total Labour Cost		0.00

water cost	0.009	Euro/t
EE selling price	0.05	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	-3.8	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Equivalent yearly hours				6570	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				-3.4	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8
Water saving				15.7	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Operating Costs															
Fuel Cost				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance				-1.8	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6
Labour				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chemicals & Consumables				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellanea				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
Working Capital Cost				0.0											
Fixed Capital Expenditures	-16.3	-36.6	-28.5												
Total Cash flow (yearly)	-16.3	-36.6	-28.5	9.1	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Total Cash flow (cumulated)	-16.3	-52.9	-81.4	-72.3	-62.5	-52.7	-42.9	-33.0	-23.2	-13.4	-3.6	6.3	16.1	25.9	35.7
Discounted Cash Flow (Yearly)	-14.8	-30.3	-21.4	6.2	6.1	5.5	5.0	4.6	4.2	3.8	3.4	3.1	2.8	2.6	2.4
Discounted Cash Flow (Cumul.)	-14.8	-45.1	-66.5	-60.3	-54.2	-48.6	-43.6	-39.0	-34.8	-31.1	-27.6	-24.5	-21.6	-19.1	-16.7

CASH FLOW ANALYSYS Millions Euro	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	
Water saving	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	
Operating Costs														
Fuel Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Maintenance	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	
Labour	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & Consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Miscellanea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	
Working Capital Cost														0.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	0.0
Total Cash flow (cumulated)	45.6	55.4	65.2	75.0	84.8	94.7	104.5	114.3	124.1	134.0	143.8	153.6	163.4	163.4
Discounted Cash Flow (Yearly)	2.1	1.9	1.8	1.6	1.5	1.3	1.2	1.1	1.0	0.9	0.8	0.7	0.7	0.0
Discounted Cash Flow (Cumul.)	-14.6	-12.6	-10.9	-9.3	-7.8	-6.5	-5.3	-4.2	-3.2	-2.3	-1.4	-0.7	0.0	0.0