POTENTIAL FOR IMPROVEMENT IN GASIFICATION COMBINED CYCLE POWER GENERATION WITH CO_2 CAPTURE

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Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) evaluates technologies for abatement of greenhouse gas emissions, with particular emphasis on capture and storage of CO_2 from use of fossil fuels. One of the most promising technologies for capture of CO_2 from power generation is Integrated Gasification Combined Cycle (IGCC). A study has been carried out to assess the current state of the art of coal-based IGCC and the potential for improvements between now and 2020.

The study was carried out by Foster Wheeler Energy Ltd in Italy and the UK. Foster Wheeler has extensive experience of gasification and CO_2 capture and has built a commercial heavy oil IGCC plant, without CO_2 capture, in Italy.

Study description

Coal-based IGCC plants based on the current state-of-the-art were assessed and sensitivities to some important parameters were studied. Plants with and without CO_2 capture were assessed, to enable the costs of avoiding CO_2 emissions to be calculated. The study was based on a set of standard assessment criteria used in all of IEA GHG's technology assessments.

Gasifier selection
Many different types of gasifier are currently available. This study is based on oxygen-blown entrained bed gasifiers, which are the most widely used type of gasifiers in IGCC plants and which are also likely to be the most suitable type for CO_2 capture. The state-of-the-art plant studies are based on two gasifiers:

- Texaco slurry feed gasifier, with product gas cooling by water quench
- Shell dry-feed gasifier, with product gas cooling in a heat recovery boiler

These two types of gasifier cover the broad range of entrained gasifier types currently available. The Texaco quench gasifier represents a lower-capital cost, lower efficiency option and the Shell gasifier represents a higher-capital cost, higher efficiency option. Other intermediate variants are also available, for example versions of the Texaco gasifier with product gas heat recovery boilers and the Noell dry feed gasifier with product gas quench. The Prenflo gasifier is a dry feed gasifier with heat recovery, similar in principle to the Shell gasifier and the E-gas slurry feed 2-stage gasifier with a heat recovery boiler is another commercially available option. At the time when this study was being carried out, commercial ownership of some of these alternative gasifier types was in the process of being transferred, so it may have been difficult to obtain the required performance and cost information. The selection of the two gasifier types for this study does not imply that they are the only types suitable for CO_2 capture.

The gasifier performance data and costs used in this study were provided by the gasifier technology providers, based on current commercial offerings.

Gas turbine selection
The state-of-the-art plants are based on 9FA gas turbines, which are representative of the current state-of-the-art of large commercial gas turbines suitable for use with IGCC fuel gas. This particular type of turbine has not yet been run on gasifier fuel gas, although other F type turbines have. Some modifications would be needed to run on hydrogen but they are considered to be minor. More advanced gas turbines are being introduced for natural gas firing. The first example of a more advanced "H" class gas turbine commenced start-up in 2002 but manufacturers will not provide performance data for operation on gasifier fuel gas until significant operating hours have been logged on natural gas.

Air separation
The state-of-the-art plants are based on cryogenic air separation. In most of the cases, 50% of the compressed air for the air separation unit (ASU) is extracted from the gas turbine during normal full load operation and the remaining 50% is provided by a separate electrically driven compressor. Pressurised nitrogen from the ASU is fed through booster compressors to the gas turbine, to maximise the loading on the turbine and reduce NO_x emissions. Various ASU configurations can be used in state-of-the-art IGCCs, ranging from complete integration, in which all of the air for the ASU is provided by the gas turbine, to zero integration in which the ASU is a completely stand-alone unit providing only oxygen. The optimum choice depends on various parameters, particularly the type of gas turbine, and whether the ASU is an off-site unit for commercial reasons, providing oxygen "over the fence".

CO_2 capture and compression
The Selexol solvent scrubbing process is used for CO_2 separation in all of the state-of-the-art plants with CO_2 capture except one of the Shell gasifier plants, with combined CO_2/H_2S capture, which uses MDEA. CO_2 is dehydrated and compressed on-site to 110 bar.

Plant size
IEA GHG's standard assessment criteria state that plants should have net power outputs of 500 MW_e. In practice it is not possible match this criteria for plants based on gas turbines. The advanced large gas turbines produced by all of the main manufacturers have similar power outputs and their outputs cannot be varied significantly. For this study there was a choice between basing the plant on 1 gas turbine, resulting in power outputs of less than 500 MW_e, or two turbines, resulting in greater power outputs. It was decided to base the plants on two turbines, resulting in net power outputs of around 750 MW_e. Having two gas turbines would result in economies of scale, for example in the common steam turbine and the offsites, and it would also provide greater operating flexibility, for example during equipment maintenance. Most of the combined cycle plant studies carried out in the past for IEA GHG have been based on 2 gas turbines. The natural gas fired plants in report PH3/14 (Leading Options Study) were based on 2 gas turbines but the IGCC plants were based on 1 turbine. The larger plant sizes in this study result in economies of scale and lower specific capital and operating costs.

The gasifier licensors were asked to specify the numbers of gasifiers that would be needed to achieve the required 85% overall plant load factor. Shell specified 2x50% capacity gasifiers and ChevronTexaco specified 4x33% capacity gasifiers. In this respect, ChevronTexaco appear to be more conservative.

Data sources
Foster Wheeler obtained performance and cost data from process technology and equipment suppliers for most of the main process sections, including gasification, shift conversion, acid gas removal, gas turbine and CO_2 compression. The overall plant performance and costs for the balance of plant and plant installation were estimated by Foster Wheeler using in-house information and modelling.

Economic parameters
The study was carried out using IEA GHG's standard assessment criteria. The main criteria are:

- Netherlands coastal location
- Australian bituminous coal
- Coal price $1.5/GJ (LHV)
- 85% load factor
- 10% discount rate (constant money values, excluding taxation)
- 25 year operating life
- 3 year construction period

The costs reported in Foster Wheeler's report are in Euros but during the time that the study was carried out, the Euro/$ exchange rate remained very close to 1. The costs in this summary have therefore been converted to $ using a 1:1 exchange rate.

Interest during construction is not calculated explicitly but the effect of the construction period is taken into account in the overall discounted electricity generation costs. The 10% discount rate, 25 year operating life and 3 year construction period used in this study corresponds to an annual capital charge factor of 12.0% (annual capital charges divided by total plant cost, excluding interest during construction).

Results and Discussion

Base case plants
Performances and costs of the base case state-of-the-art plants with and without CO_2 capture are shown in table 1.

Table 1: Base case cost and performance summary

	Shell gasification			Texaco gasification		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Net power output, MW	776	676		826	730	
Efficiency, % (LHV)	43.1	34.5	8.6	38.0	31.5	6.5
Capital cost, \$/kW	1371	1860	489	1187	1495	308
Electricity cost, c/kWh	4.8	6.3	1.5	4.5	5.6	1.1
CO_2 emissions, g/kWh	763	142		833	152	
CO_2 captured, g/kWh	-	809		-	851	
Cost of CO_2 avoidance, \$/tCO_2			24			16

The Shell gasifier plants have higher thermal efficiencies, capital costs and costs of electricity than the corresponding Texaco gasifier plants. The cost of CO_2 capture is also higher for Shell gasification. The main reasons for the higher efficiencies of the Shell gasifier plants are the higher efficiency of conversion of coal-to-fuel gas in the gasifier and the method of cooling the product gas. Coal is fed to the Shell gasifier through dry lock hoppers; a water slurry is used in the Texaco gasifier. More oxidation of carbon with O_2 producing CO_2 and heat has to take place in the Texaco gasifier to evaporate and heat the water contained in the slurry, resulting in a lower coal-to-fuel gas efficiency. The extra oxidation in the gasifier requires more oxygen, which increases the ancillary power consumption. Another reason for the lower coal-to-fuel gas efficiency is that, according to the data provided by the vendors for the IEA GHG standard coal, the Texaco gasifier produces a larger amount of ungasified carbon. The product gas from the Shell gasifier is cooled in a heat recovery boiler which generates high pressure steam for the steam cycle. In the quench version of the Texaco gasifier the fuel gas is quenched which water, resulting in lower temperature heat recovery.

To enable CO_2 to be captured, the fuel gas has to be fed to a catalytic shift reactor, where most of the CO is reacted with steam to give H_2 and CO_2. In Shell gasifier plants a large amount of steam has to be taken from the steam cycle and added to the fuel gas feed to the shift converter but in the Texaco gasifier plants sufficient steam is already present in the fuel gas, from evaporation of the coal slurry water and from the quench cooling of the gasifier product gas. This is the main reason why the efficiency penalty for CO_2 capture is lower in the Texaco gasifier plant.

The reasons for the higher efficiency of the Shell gasifier plant are also the main reasons for the higher capital cost. Lock hopper feed systems and fuel-gas heat recovery boilers are relatively expensive. The overall cost of electricity is higher in the Shell gasifier plants because the economic benefits of the higher thermal efficiency do not fully compensate for the higher capital cost. However, it should be noted that the Shell gasifier plant emits and captures less CO_2 per kWh of electricity. If the Texaco plant had to emit the same amount of CO_2 as the Shell plant it would have to capture a slightly higher percentage of the CO_2, which would increase its costs. The costs of transporting and storing captured CO_2 would also be higher for the Texaco case but, even taking this into account, the Texaco gasifier is still likely to be the lower cost option. However, if the quantity of CO_2 that has to be stored is a major environmental concern, higher thermal efficiency processes such as the Shell gasifier may be favoured.

Process sensitivity cases

Sensitivities to a variety of potentially significant parameters were assessed, to help to determine the way forward for IGCC with CO_2 capture.

Production of combined CO_2/H_2S stream

The base case plants produce separate streams of CO_2 for storage and H_2S-rich gas, which is fed to a sulphur recovery unit. Producing a single stream containing all of the CO_2 and sulphur compounds would simplify the acid gas removal process and eliminate the need for the sulphur recovery unit. To quantify these benefits, Shell and Texaco plants producing a combined CO_2/H_2S output stream were assessed. Table 3 shows the performance and cost data for plants with combined capture, the penalties for capture compared to a plant without capture and the cost and efficiency benefits of combined capture of CO_2 and H_2S compared to production of pure CO_2 and sulphur. The concentration of H_2S in the CO_2 in the combined capture plants is about 0.6 vol%. The concentration is directly proportional to the sulphur content of the coal, which is 1.1% (dry-as-free basis) in this study.

Table 2: Production of a combined CO_2/H_2S stream for storage

	Shell gasification			Texaco gasification		
	Plant data	Capture penalty	Benefit of combined capture	Plant data	Capture penalty	Benefit of combined capture
Net power output, MW	683			742		
Efficiency, % (LHV)	35.0	8.1	0.5	32.0	6.0	0.5
Capital cost, \$/kW	1726	355	134	1414	227	81
Electricity cost, c/kWh	6.0	1.2	0.3	5.4	0.9	0.2
Cost of CO_2 avoidance, \$/t		19	5		13	3

Production of a combined stream of CO_2 and H_2S reduces the cost of CO_2 capture by about \$4/tonne of CO_2 emissions avoided, i.e. about 20%. Whether or not it would be acceptable and advantageous to transport and store H_2S along with CO_2 would depend on local circumstances. It may be more expensive to transport and inject CO_2 containing significant concentrations of H_2S and if the CO_2 had to transported long distances, these extra costs may be greater than the reductions in capture costs. It may also be more difficult to obtain permits to transport CO_2 containing H_2S. On the other hand, H_2S can be advantageous for CO_2-enhanced oil production (EOR), as it is enhances the miscibility of CO_2. Some of the H_2S injected with the CO_2 would pass through to the oil output; if the oil field is already sour, the additional oil processing costs and environmental impacts may not be significant but if the oil field is not sour, the H_2S could be a problem. Underground injection of mixtures of CO_2 and H_2S is an established practise. About 1 million tonnes/year of such gases, separated from natural gas, are injected in western Canada, as described in IEA GHG report PH4/15. In addition, CO_2 containing about 2% H_2S and other sulphur compounds such as mercaptans is used for EOR at the Weyburn oil field in Canada. This gas is transported by pipeline from the Great Plains gasification plant in the USA. The mercaptans result in significant odour problems, although they are a very effective way of detecting CO_2 leaks. The mercaptan concentrations in the acid gas from Shell and Texaco gasifiers should be much lower than from the Lurgi gasifiers used at the Great Plains plant.

If the CO_2 was to be fed into a transmission grid supplying many different users and storage reservoirs, it may be required to have low impurity concentrations, to meet the most stringent requirements of any of the users of CO_2. In this circumstance, combined capture would not be acceptable.

Gasifier pressure

Increasing the gasifier operating pressure increases the driving force for physical solvent scrubbing of CO_2. It can also have other benefits, for example it enables power to be generated by a fuel gas expander prior to the gas turbine but it increases the power consumption and cost of coal and oxygen pressurisation. The trade-off between the various factors is complex.

High and low pressure variants of the Texaco gasifier are commercially available. The base case Texaco gasifier plant in this study has a high gasifier operating pressure, 65 bar. A lower operating pressure (38 bar) was assessed as a sensitivity case. The Shell gasifier is currently not commercially proven at operating pressures of more than 40 bar. Some development effort would be needed to increase the pressure but Shell is confident that this limit on pressure can be removed in the future and they were willing to provide performance and cost data for a high pressure case operating at 61 bar. The performance and capital costs of IGCC plants with CO_2 capture based on high and low pressure gasifiers are summarised in table 3.

Table 3: Sensitivity to gasifier pressure, plants with CO_2 capture

	Shell gasification			Texaco gasification		
	Low pressure (base case)	High pressure	Difference	Low pressure	High pressure (base case)	Difference
Net power output, MW	676	639	-37	705	730	+25
Efficiency, % (LHV)	34.5	32.7	-1.8	30.6	31.5	+0.9
Capital cost, $/kW	1860	2061	+201	1585	1495	-90

A high operating pressure is an advantage for Texaco gasification, in terms of both efficiency and capital cost. In contrast, the lower operating pressure is preferred for Shell gasification. Increasing the pressure has a relatively small impact on the cost of coal slurry pumping, as used by the Texaco gasifier, but it has a much larger impact on the costs of dry-feed lock hoppers used by the Shell gasifier. There does not at present appear to be an incentive to develop a higher pressure version of the Shell gasifier unless an alternative method of dry coal feeding can be developed.

Costs of electricity and CO_2 capture were not estimated for the gasifier pressure sensitivity cases, because it was clear from the efficiency and capital cost results that they were not attractive.

Type of shift converter

There are two possible arrangements for shift conversion, sour shift and clean shift, as shown in figures 1 and 2.

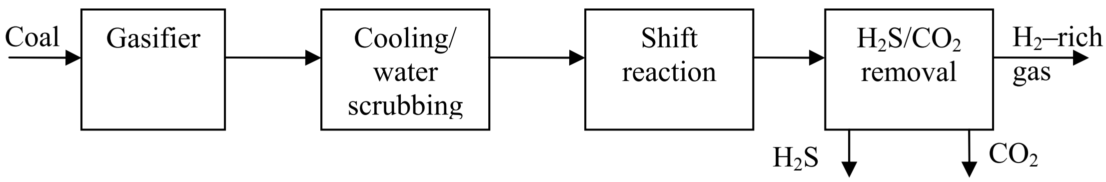

Figure 1 Sour shift conversion

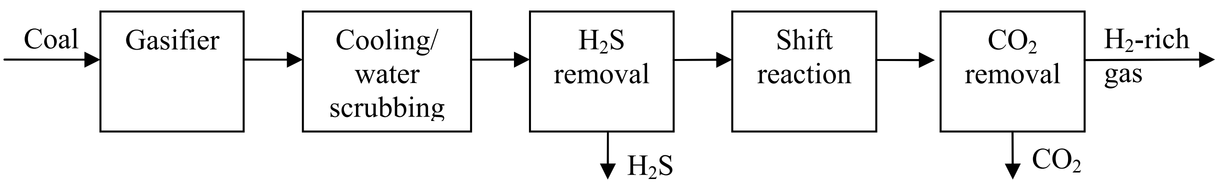

Figure 2 Clean shift conversion

In the "sour shift" arrangement the fuel gas from gasification, after water scrubbing, is reheated and fed to a shift conversion reactor which uses sulphur-tolerant catalyst. This catalyst also hydrolyses COS to H_2S. The fuel gas is then cooled, water is condensed and the gas is fed to a solvent scrubber which removes sulphur compounds and CO_2. In the "clean shift" arrangement, the fuel gas from water scrubbing is reheated and fed to a COS hydrolysis reactor. It is then cooled and fed to a solvent scrubber which removes sulphur compounds. The sulphur-free gas is reheated, fed a shift reactor, cooled and fed to a second solvent scrubber for removal of CO_2.

The clean shift arrangement is more complex, involving more heating and cooling of the fuel gas but it has some advantages for Shell-type gasifiers. Clean shift catalyst is much less expensive than sour shift catalyst, even allowing for the need for a separate COS hydrolysis catalyst. The ratio of CO_2:H_2S is lower in the gas stream prior to shift conversion, which makes it easier to produce the concentrated H_2S stream needed for a Claus sulphur recovery unit.

IEA GHG's previous study on IGCC with CO_2 capture (report PH3/14) was based on a Shell gasifier with a clean shift converter. At the time that study was carried out, Shell was only willing to provide data on this configuration. However, for this study Shell was willing to provide data for a plant with a higher water scrubber outlet temperature, suitable for use with a sour shift converter. The base case Shell gasifier plant in this study is based on a sour shift configuration but a clean shift configuration was assessed as a sensitivity study. A clean shift configuration was not assessed for the Texaco quench gasifier because the need to condense all of the steam from the fuel gas prior to the H_2S removal unit would undoubtedly make such a configuration unattractive.

The results of the Shell gasifier clean shift converter sensitivity case are shown in table 4, along with the results for the sour shift base case. The sour shift configuration is clearly preferred.

Table 4: Shell gasifier plants with different shift converter configurations

	Sour shift		Clean shift	
	Plant performance	Capture penalty	Plant performance	Capture penalty
Net power output, MW	676		651	
Efficiency, %	34.5	8.6	33.0	10.1
Capital cost, $/kW	1860	489	1937	566

Shift conversion without capture

In most locations at present there would be little incentive to include CO_2 capture in an IGCC plant. However, it may be necessary to retrofit capture to meet future emission regulations. IGCCs built in the near future could be designed in a way which minimises the extent of changes required to retrofit CO_2 capture. One such option would be to install a shift converter when the plant is built. Installing a shift converter can have some advantages. For example, when gasifier product gas is cooled, a large amount of steam is condensed but, if some of the steam is reacted with CO to give CO_2 and H_2, the mass of fuel gas remains higher, which increases the amount of power generated in the gas turbine. A Texaco gasifier IGCC with a shift converter but no CO_2 capture was assessed as a sensitivity case. The thermal efficiency was 1.4 percentage points lower than that of the base case Texaco gasifier plant without capture and the capital cost per kW increased but only by $12/kW. The results may be different for different gasifiers or heat integration arrangements.

Economic sensitivities

Fuel price

The study is based on a coal price of $1.5/GJ (LHV basis), which is representative of the costs of internationally traded bituminous coal delivered to coastal sites in North West Europe. However, coal costs are different in some other countries, so the sensitivity of electricity cost to coal price is shown in figure 3. This table shows that the competitive position of the Shell gasifier IGCC improves slightly at higher coal prices, due to its higher efficiency.

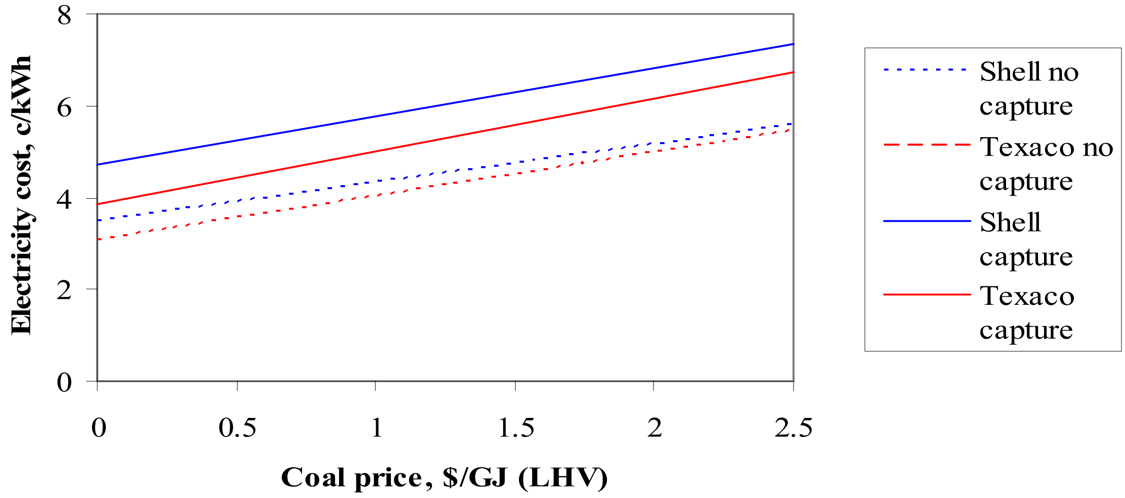

Figure 3 Sensitivity of electricity cost to fuel price

Discount rate

In line with IEA GHG's standard assessment criteria, a 10% discount rate in constant money values is used but the sensitivity to a 5% discount rate is evaluated. The results are summarised in table 5. Reducing the discount rate from 10% to 5% reduces the cost of electricity and the cost of CO_2 capture by about 20%.

Table 5: Sensitivity to 5% discount rate

	Shell gasification			Texaco gasification		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Electricity cost, c/kWh	3.8	5.0	1.2	3.7	4.6	0.9
Cost of CO_2 avoidance, $/t			19			13

CO_2 storage

The costs and efficiencies in this study include CO_2 compression to 110 bar but do not include transport and storage of CO_2. Costs of CO_2 storage depend greatly on local factors, such as the transport distance, the pipeline diameter and the type of storage reservoir. At some locations CO_2 could have a positive value for enhanced oil recovery but at other locations it may have to be transported a long distance to a storage reservoir, resulting in substantial costs. As an illustration of the possible effects of CO_2 transport and storage on the overall cost of electricity, a transport and storage cost of $10/tonne of CO_2 stored would increase the cost of electricity by 0.8 c/kWh. The corresponding cost of CO_2 emissions avoidance would be £13/t of CO_2. The efficiency penalty of CO_2 capture means that 1.25-1.3 tonnes of CO_2 has to be stored for every tonne of CO_2 emissions avoided.

Technology stretch to 2020

Potential improvements that could be made to the key components of IGCC by 2020 were identified and the performance and costs of a 2020 IGCC plant were predicted.

The most significant area of efficiency improvement is expected to be the gas turbine. There is a high probability of a significant improvement because of the large development effort being devoted to natural gas combined cycles. The first "H" class gas turbine with a higher inlet temperature than the current "F" turbines and steam cooled blades is currently being tested on natural gas and is expected to become available for use in IGCC later. The impact that the “H” turbine would have on IGCC efficiency is uncertain. Published studies have shown improvements between 1.3 and 3.4 percentage points. By 2020 the features included in the “H” turbine could be combined with other efficiency improvements such as two stage firing (already used in some Alstom turbines), improved thermal barrier and oxidation coatings, use of ceramic components and air compressor staging, resulting in IGCC efficiency improvements of 3-6 percentage points. The costs per kW of advanced gas turbines may not be lower than current turbines but the higher efficiency would significantly reduce the overall IGCC plant cost by reducing the required size of the gasifier, gas processing and ancillary equipment.

More radically different large gas turbines, such are humid air turbines, may become commercially available over the next 20 years but this is uncertain because of their high development costs and high water consumption. Fuel cells, particularly solid oxide cells, have the potential to provide large efficiency improvements in IGCC but their costs are currently very high and major technical development would be needed.

The exhaust temperatures of advanced gas turbines are expected to be higher than those of current turbines, which will make higher efficiency supercritical once-through heat recovery steam generators and steam cycles feasible.

Various improvements could be made to gasifiers to improve reliability and reduce maintenance costs. Feeding coal as a slurry with liquid CO_2 could provide large efficiency increases for lignite and other low rank coals but significant improvements are not expected for bituminous coals. Other advanced dry coal feeding systems may be developed by 2020.

2-stage gasifiers, in which part of the coal feed is injected into the product from the first gasification stage, have higher coal-to-fuel gas efficiencies than single stage gasifiers. The E-Gas gasifier, which is used in a commercial scale IGCC plant in the USA, is a 2-stage slurry feed gasifier and 2-stage dry feed gasifiers are being developed in Japan. Current 2-stage gasifiers include heat recovery boilers but a product gas water quench may be a more economic option for a plant with CO_2 capture. If there is a market demand, such a gasifier could be developed.

Cryogenic air separation is a mature technology but novel high temperature ceramic ion transport membranes are being developed. These membranes are particularly well suited for integration with IGCC. The overall IGCC efficiency improvement may be around 1 percentage point. There is considered to be a medium probability of this technology being state-of-the-art by 2020.

Physical solvent scrubbing to separate CO_2 and H_2S is a well established technology but improvements could probably be made compared to the Selexol process used in the state-of-the-art plants in this study, for example by using different solvents and optimisation for integration in IGCC with CO_2 capture. Marginal improvements may also be made in shift conversion, which is another established technology.

2020 plant performance and costs

The predicted performance and cost of a 2020 IGCC plant with CO_2 capture, and the improvements compared to the current state-of-the-art plants are shown in table 6. The 2020 plant has the following features:

- Dry-feed, 2-stage entrained flow gasification
- Product gas quench
- Sour shift conversion
- Physical solvent scrubbing acid gas removal
- 2020 gas turbine (see above)
- Once-through supercritical HRSG
- Ion transfer membrane air separation

Table 6: 2020 IGCC performance improvements (plants with CO_2 capture)

	2020 plant performance	2020 plant compared to current IGCC plants	
		Shell	Texaco
Efficiency, % (LHV)	43.2	+8.7	+11.7
Capital cost, $/kW	1250	-610	-250
Cost of electricity, c/kWh	4.5	-1.8	-1.1

The overall capital cost reduction is mainly a result of the increase in the overall plant efficiency, which reduces the size of the gasifier, gas processing and ancillary equipment per kW of electricity. The proposed 2020 gasifier is more expensive per tonne of coal feed than the current Texaco gasifier but is cheaper than the Shell gasifier. The cost of electricity from the 2020 plant is about 20% lower than from the current technology Texaco plant with capture and about 30% lower than from the current Shell plant, as shown in figure 4.

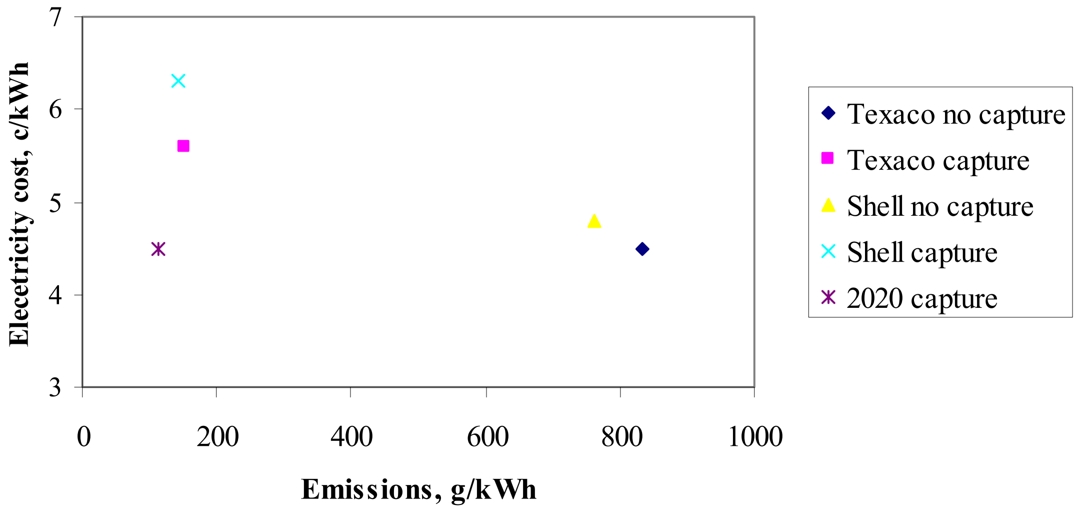

Figure 4 Relationship between cost and emissions

Research is currently being carried out on various radically different CO_2 separation technologies such as high temperature membranes and electric swing adsorption. If these developments are successful and the technologies become commercially proven by 2020, the costs of IGCC with CO_2 capture would be even lower than those projected in this study.

Effects of market size

Further cost reductions may result from widespread application of IGCC. Relatively small numbers of IGCC plants are in existence or under construction at present, most of which use oil residues. As a result, each plant and its equipment are built as one-offs. If IGCCs were built in large numbers, more standard designs would be used, which would reduce the engineering and design costs and a larger number of equipment manufacturers would enter the market, which may help to drive costs down. Greater operating experience would enable design margins to be reduced on individual components and the overall plant. IEA GHG may carry out a study in future to assess such factors by looking at how costs of analogous technologies reduced when they were applied on a large scale.

Expert Reviewers' Comments

Comments on the draft report were received from various reviewers with expertise in IGCC, including both of the gasification technology companies mentioned in this report, academic researchers, consultants and IGCC project developers. In general the reviewers thought the report was impressive in terms of both the amount of material and detail it contains, as well as the clear manner in which it was presented. Specific comments about the plant designs and costs were discussed with Foster Wheeler and some changes were made to the final version of the report.

Shell had provided Foster Wheeler with a basic equipment cost for their gasifier. They commented that Foster Wheeler's calculation of the overall installed costs of their gasifier were too high. However, Foster Wheeler said that they had based their installation cost estimates on information from real IGCC projects, so it was decided that no modifications would be made to the study report. If the installed gasifier cost proposed by Shell had been used, the overall costs of electricity would have been similar for Shell and Texaco IGCC plants.

ChevronTexaco also offers a configuration based on a gasifier with a radiant syngas cooler prior to the water quench. Using information provided by ChevronTexaco, Foster Wheeler assessed this option and concluded that the efficiency of an IGCC plant with CO_2 capture would be 1.2 percentage points higher. The capital cost was not assessed but it was expected to be slightly higher. ChevronTexaco stated that the efficiency advantage would be higher, around 2-2.5 percentage points, if the energy recovery was fully integrated. They also said that 3x50% gasifiers could be supplied for this option, compared to 4x33% gasifiers for the quench option. As a result, the capital cost of the radiant cooler option would be similar to that of the quench cooler option. Assuming the capital and non-fuel operating costs remained the same as for the quench option, and the efficiency was 2 percentage points higher, the overall cost of electricity for the Texaco plant with CO_2 capture would decrease by 0.10 c/kWh (i.e. 2%). This improvement would be very worthwhile but it would not affect the main conclusions of this report.

Some other reviewers suggested that the amount of ungasified carbon in the Texaco gasifiers was too high, and as a result the thermal efficiency was too low. However, ChevronTexaco confirmed the gasifier performance data they had provided to Foster Wheeler, so no changes were made.

One reviewer said that a stand-alone ASU would be preferred for IGCC, rather than an ASU which is partially integrated with the gas turbine. The optimum ASU arrangement would depend on commercial factors and would need to be decided on a case by case basis. Discussion of ASU integration issues in the report was expanded in the final report.

Some reviewers pointed out differences between the overall costs and efficiencies estimated in this study and those estimated in studies carried out by other organisations. IEA GHG intends to produce a note which will compare the results of this study and other studies on IGCC with CO_2 capture. As far as possible, reasons for any differences will be identified.

Major Conclusions

The cost of electricity from an IGCC plant with CO_2 capture would be 5.6 c/kWh for a plant based on Texaco gasifiers and 6.3 c/kWh for a plant based on Shell gasifiers. These costs are based on IEA GHG's standard assessment criteria.

CO_2 capture would add 1.1-1.5 c/kWh to the cost of electricity generation. This corresponds to $16-24/tonne of CO_2 emissions avoided, compared with IGCC plants without capture.

Producing a combined stream of CO_2 and H_2S for storage instead of producing pure CO_2 and converting the H_2S into sulphur would reduce the cost of CO_2 capture by about 20%. Whether or not this option is acceptable would depend on how the CO_2 was to be transported and stored.

Improvements in IGCC technology between now and 2020 are expected to reduce the cost of electricity generation with CO_2 capture by 20-30%, to about 4.5 c/kWh. It should be noted that improvements will also affect IGCC without capture.

Recommendations

The results of this study should be compared to results of other studies on IGCC with CO_2 capture and, as far as possible, reasons for any differences should be identified.

A study should be carried out to assess the potential for improvements in other coal fired power generation with the latest amine scrubbing and oxyfuel combustion technologies. Such a study should be carried out on a basis consistent with this study.

This study was based on the Australian bituminous coal that has so far been used as standard in IEA GHG's technology assessments. The performance and costs of IGCC and CO_2 capture may depend significantly on the coal analysis. A study should be carried out to assess the sensitivity to coal analysis of the design, performance and costs of power plants with CO_2 capture.

IEA GREENHOUSE GAS R&D PROGRAMME

GASIFICATION POWER GENERATION STUDY

Final Report

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Rev. 1

FOSTER WHEELER

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GASIFICATION POWER GENERATION STUDY REPORT

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SECTION A

EXECUTIVE SUMMARY

I N D E X

SECTION A

SECTION A

1.0 Scope of the Study

The IEA Greenhouse Gas R&D Programme has retained Foster Wheeler to investigate alternative power generation plant designs, based on coal gasification, with and without capture of the produced CO_2 in order to determine the increase of the cost of the electricity due to the capture of CO_2. The primary purpose of this study is, therefore, the evaluation of the technologies that can be used in these complex power generation schemes to optimize efficiency and capital cost and reduce, at the same time, emissions to the atmosphere.
The plant of the study has a nominal capacity of 750 MWe and is fed with a typical coal having a low heating value (LHV) equal to 25870 kJ/kg and a sulphur content equal to 1.1% wt (dry ash free).
The study is based on commercially available technologies and developing technologies close to commercialization, evaluating costs and performances of plants which can be presently engineered and built. The study does, however, consider possible improvements to current technologies and also potential future technologies in order to assess the likely performance of a plant in the year 2020.

The study investigates 13 alternative designs of the power generation plant, which differ for the gasification technology, the gasification pressure, the presence or not of shift step, the acid gas removal process. For each alternative sufficient basic design data have been developed in order to evaluate performance and capital cost. For some alternatives specific optimization studies have been made in order to select the most convenient acid gas removal process and the best arrangement of the shift reactors.
The study is finally completed with a comparison of the various alternative designs, confronting for the various technology combinations cost and performance data.

FW like to acknowledge the following companies for their fruitful support to the preparation of this study:

- Dow
- General Electric
- Shell
- Synetix
- Sud-Chemie
- Texaco
- UOP.

2.0 Bases of Design

The IGCC Complex is designed to process, in an environmentally acceptable manner, an open-cut coal from eastern Australia (see Section B, paragraph 2.1) and produce electric energy (750 MWe nominal capacity) to be delivered to the local grid.

For each of the alternatives considered, the IGCC design capacity has been fixed to match the appetite of the selected gas turbines. The design capacity for each of the alternative considered is summarized in paragraph 4.0.

The Power Island inside the IGCC Complex is also able to process Natural Gas as back-up fuel but use of back-up fuel was not taken into account in the economic assessment.

The IGCC Complex main product is electric energy. By-products are:

- Sulphur (liquid or solid)
- Carbon Dioxide for the Alternatives recovering CO_2
- Solid by-products: slag, fly ash and filter cake, depending on the gasification technology

The environmental limits set up for the IGCC Complex are outlined hereinafter.

The overall gaseous emissions from the IGCC Complex referred to dry flue gas with 15% volume O_2 shall not exceed the following limits:

NO_x (as NO_2)	:	≤	80 mg/Nm^3
SOx (as SO_2)	:	≤	10 mg/Nm^3
Particulate	:	≤	10 mg/Nm^3
CO	:	≤	50 mg/Nm^3

Characteristics of waste water discharged from the IGCC Complex shall comply with the limits stated by the following EU directives:
- 1991/271/EU
- 2000/60/EU

The bases of design of the IGCC Complex, such as capacity, required availability, location, climatic data etc., are defined in Section B, of the Report.

3.0 Alternative IGCC Processing Schemes

Several design alternatives of the IGCC Complex have been developed in the Study. The contemplated alternatives attempt to compare the following key process aspects:

- Two gasification technologies: Texaco and Shell;
- Performance penalties for the capture of CO_2 to reduce environmental impact;
- Performance penalties for the simultaneous capture of CO_2 and H_2S;
- Two levels of gasification pressure;
- Syngas utilization in the gas turbine without and with prior conversion of CO to H_2;
- Different arrangements of the CO conversion reactors: number of reactors and dirty shift vs. clean shift;

Cases identified with A and B are based on Shell gasification; the first group, A, is without CO_2 capture, while the second group, B, is with CO_2 capture. The same is applicable to groups C and D, except that Texaco gasification is used in place of the Shell gasification.

The following Table A.3.1 provides a summary of the 13 cases with some of the most significant performance data. It is interesting to note in Table A.3.1, that only two Acid Gas Removal (AGR) processes have been considered: MDEA and Selexol. This is a limitation that we have tried to remove, proposing other processes, such as Rectisol and Purisol, which in our opinion should be interesting, specially for the Cases with CO_2 removal. Unfortunately the owners of these processes were not available to provide the required design information.

Table A.3.1 – Most significant data for all the process alternatives

CASE	Gasification Process	Gasification Pressure Bar g	Shift	CO_2 Capture	AGR Process (3)
A.1	Shell	36	NO	NO	MDEA
A.2	Shell	61	NO	NO	MDEA
B.1	Shell	39	Sour	YES	Selexol
B.2	Shell	39	Clean	YES	Selexol
B.3	Shell	39	Sour	YES (1)	MDEA
B.4	Shell	61	Sour	YES	Selexol
C.1	Texaco	65	NO	NO	Selexol
C.2	Texaco	65	Sour	NO	Selexol
C.3	Texaco	38	NO	NO	MDEA + AGE
D.1	Texaco	65	Sour	YES	Selexol
D.2	Texaco	65	Sour	YES (1)	Selexol
D.3	Texaco	65	Sour	YES (2)	Selexol
D.4	Texaco	38	Sour	YES	Selexol

Note (1) : Combined removal of CO_2 and H_2S
(2) : Lower Capture rate
(3) : MDEA is MethylDiEthanolAmine (chemical solvent); Selexol is polyethylene glycol dimethylether (physical solvent), AGE is Acid Gas Enrichment (installation downstream AGR of another MDEA washing)

4.0 Performance Data

The most important performance data of the 13 IGCC process schemes studied, are summarized in the following Table A.4.1.

The cold gas efficiency, which is an indication of the efficiency of the gasification process, being the ratio of combustion energy of the raw syngas and the combustion energy of the coal feed, shows a distinct advantage for the Shell process. The efficiency difference between the two processes is due to the type of coal feed system.
Texaco uses a slurry of pulverized coal in water; this implies that a fraction of the coal energy is used in the gasifier to vaporize the water of the slurry. In the Shell process pulverized coal is fed dry to the gasifier, pneumatically transported by pressurized nitrogen, so without energy waste. Texaco feed system is however less costly and the gasification pressure can be much higher because the slurry is pumped by volumetric pumps. Shell feed system is more expensive and is currently limited to a maximum pressure of 40 bar.
The superior cold gas efficiency of Shell is reflected in the net electrical efficiency, which is also distinctly better for the Shell process.

The coal feed rates shown in Table A.4.1, vary for each case because all the 13 IGCC alternatives are based on two equal gas turbines, GE 9 FA; so in each IGCC scheme the optimum target is to produce sufficient syngas to saturate the appetite of these two gas turbines. Since the efficiency of conversion of coal to syngas changes from case to case, the coal feed rate of the 13 cases is different.

Table A.4.1

Performance Data

Case	Gasification Process	Pressure bar g	Coal t/h	Cold Gas Efficiency %	Gross Power Output MW	Auxiliary Consumptions MW	Net Power Output MW	Net Electrical Efficiency %
A.1	Shell	36	250.6	83.5	909.8	133.9	775.9	43.1
A.2	Shell	61	252.1	83.0	895.0	146.7	748.3	41.3
B.1	Shell	39	273.1	83.5	896.2	220.0	676.2	34.5
B.2	Shell	39	274.6	83.5	875.0	223.7	651.3	33.0
B.3	Shell	39	271.4	83.5	883.3	200.0	683.3	35.0
B.4	Shell	61	271.9	83.5	879.2	240.3	638.9	32.7
C.1	Texaco	65	303.0	70.5	988.7	162.2	826.5	38.0
C.2	Texaco	65	327.6	70.5	1012.8	152.2	860.6	36.6
C.3	Texaco	38	300.9	71.0	954.3	154.4	799.9	37.0
D.1	Texaco	65	323.1	70.5	972.8	242.5	730.3	31.5
D.2	Texaco	65	323.2	70.5	979.9	237.6	742.3	32.0
D.3	Texaco	65	323.1	70.5	978.7	234.4	744.3	32.1
D.4	Texaco	38	320.4	71.0	942.1	237.1	705.0	30.6

5.0 Investment Cost Data

The investment cost data of the 13 IGCC cases are reported in the attached Table A.5.1.

The IGCC cases, based on Texaco gasification, show with respect to the analogous IGCC cases based on Shell gasification, a distinct advantage. This trend goes in the usual direction of a lower investment associated with a lower efficiency and viceversa.

Since the coal processing capacity is not the same for all cases it is more important to make the comparison on the base of the specific investment rather than the total investment.

Table A.5.1
Investment Cost Data

CASE	Gasification Process	MAIN IGCC SECTIONS INVESTMENT										Total Investment 10^6 Euro	Specific Investment Euro/kW	
		Air Separation		Process Units		CO_2 Compr.		Power Island		Utilities Offsites				
		10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%			
A.1	Shell	106	10	480	45	0	0	365	34	113	11	1064	1372	
A.2	Shell	112	10	557	49	0	0	361	32	113	10	1143	1528	
B.1	Shell	112	9	636	51	23	2	363	29	124	10	1258	1860	
B.2	Shell	113	9	642	51	25	2	359	28	124	10	1262	1937	
B.3	Shell	112	9	561	48	26	2	361	31	121	10	1180	1726	
B.4	Shell	118	9	695	53	25	2	358	27	122	9	1317	2061	2
C.1	Texaco	128	13	360	37	0	0	363	37	130	13	981	1187	
C.2	Texaco	131	13	400	39	0	0	366	36	135	13	1032	1199	
C.3	Texaco	125	13	335	35	0	0	360	38	140	15	960	1200	
D.1	Texaco	131	12	424	39	27	2	362	33	147	14	1092	1495	
D.2	Texaco	131	13	382	36	27	3	362	35	147	14	1050	1414	
D.3	Texaco	131	12	429	39	25	2	362	33	148	14	1095	1471	
D.4	Texaco	129	12	455	41	27	2	359	32	147	13	1117	1585	

6.0 Production Costs

The following Table A.6.1 provides the cost of electricity (C.O.E.) and the cost of the CO_2 recovery for the cases designed for the capture of CO_2.
The cost of electricity has been calculated on the following assumptions:

- cost of coal: 1.5 Euro/GJ (38.8 Euro/t);
- 7446 equivalent operating hours of IGCC fed by syngas at 100% capacity;
- total investment cost as given in para. 5.0 of this Section;
- O&M costs as evaluated in Section E;
- 10% discount rate on the investment cost over 25 operating years;
- other financial parameters as per Project Design Basis, Section B.

The CO_2 removal cost is calculated as follows:

$$\frac{\Delta\, Electric\ Power\ Cost}{\Delta\, Specific\ CO_2\ emission}\,[=]\,\frac{Euro}{t\ of\ CO_2\ captured}$$

where:

- Δ Electric Power Cost = Electric Power Cost of the alternative with CO2 capture – Electric Power Cost of corresponding alternative w/o CO2 capture. The Unit of measurement is Euro/kWh.

- Δ Specific CO_2 Emission = Ratio of (CO_2 emission/Power production) of alternative with CO_2 capture – ratio of (CO_2 emission/Power production) of the corresponding alternative with CO_2 capture. The unit of measurement is t CO_2/kWh.

For Shell and Texaco alternatives, the reference cases for the evaluation of the CO_2 removal cost are respectively case A.1 and C.1.

The cost of electricity of the IGCC based on Texaco gasification is marginally lower than the cost of electricity from Shell based IGCC. This result is a consequence of the advantage of Texaco in the specific investment cost which more than compensates the advantage of Shell in efficiency. Considering that C.O.E. has been calculated with a DCF=10%, which is very low for the industry, the C.O.E. advantage of the Texaco alternatives would be more substantial with a DCF in the 15-20% range.
Similar considerations can be applied to the cost of CO_2 recovery.

Table A.6.1

Cost of Electric Power Production

Case	Gasification Process	C.O.E. (DCF= 10%) Cent/kWh	Cost of CO_2 (DCF = 10%) Euro/t
A.1	Shell	4.8	-
B.1	Shell	6.3	24.2
B.3	Shell	6.0	19.0
C.1	Texaco	4.5	-
D.1	Texaco	5.6	16.5
D.2	Texaco	5.4	13.5
D.3	Texaco	5.3	15.2

Note: Some cases (A.2, B.2, C.2, C.3, D.4) developed during the study to select the main process parameters (i.e gasification pressure) and resulted loosers from the technoecomic point of view are not included in this Table.

7.0 Summary and Conclusions

IGCC is a complex combination of different technologies. The primary purpose of this study is the evaluation of the technologies that can be used in an IGCC in order to optimize capital cost and efficiency and reduce, at the same time, emissions to the atmosphere.

The most important conclusions of the study are:

A. Shell based IGCC displays a superior coal to power efficiency (Table A.4.1: A.1 vs C.1 or B.1 vs. D.1).
Texaco based IGCC requires a lower investment, given in Euro per unit of installed power production (Table A.5.1: see same cases listed above for power efficiency).
In the calculation of cost of production of electricity the Texaco advantage in investment more than compensates the Shell advantage in efficiency, resulting, at the conditions established for the study (cost of coal and discounted cash flow rate of return), a cost of electricity marginally inferior for the Texaco based IGCC (Table A.6.1).

B. The pressure at which gasification is operated is an important design parameter for IGCC optimization. Shell gasification shows superior efficiency and lower investment at medium pressure, 30-40 bar. The maximum limit of 40 bar is set by the type of coal feed system chosen by Shell, which is based on lock hoppers. These devices are currently proven for pressures not exceeding 40 bar. The study has, however, also investigated the Shell gasification at 61 bar, to compare with the medium pressure cases at 36-39 bar, but the higher pressure 61 bar penalizes both efficiency and specific investment (Tables, A.4.1 and A.5.1: A.1 vs A.2).
High pressure (61 bar) Shell gasification is not commercial but the Licensor is confident to be able to develop it, if required.

Texaco based IGCCs, on the contrary, are more competitive when gasification pressure is increased, 65 bar or even higher. This conclusion is valid for both options, without and with CO_2 removal (see Table A.4.1 and A.5.1: C.1 vs. C.3 or D.4 vs D.1).

C. There is no advantage in an IGCC producing power without recovery of CO_2, to shift CO to H_2. For reference see Tables A.4.1 and A.5.1, comparing Cases C.2 vs. C.1.

D. If sequestration of CO_2 together with H_2S will become possible there is advantage in capturing and compressing together the two acid gases for disposal. Both performance efficiency and specific investment cost become more attractive, compared to the capture of CO_2 alone.
For reference see Table A.4.1 and A.5.1: case B.3 vs B.1 for Shell, and case D.2 vs D.1 for Texaco.

E. The use of sour shift catalyst, compared to clean shift catalyst, gives better performance efficiency and lower specific investment in a Shell based IGCC. For reference A.4.1 and A.5.1: case B.1 vs B.2.
In a Texaco based IGCC, utilizing Texaco quench gasifier, the clean shift catalyst option does not exist because sour shift catalyst is perfect for processing the syngas from a quench gasifier, with only a small temperature trim. On the contrary the use of a clean shift would require upstream the expenditure of substantial amount of energy and investment.

F. The environmental performance of IGCC technology is far superior to that of any other power producing technology known today based on fossil fuels. Further the impact on environment of IGCC is independent from the quality of feedstock, which permits to process in the IGCC the worst coals or residue and still meet the most severe limits.

G. Section G of the study attempts to assess the improvements, expected in the next 20 years, for the technologies and major equipment. The impact of these improvements has been transferred into an hypothetical IGCC called 2020 best available technology (BAT).
If these improvements will become available the cost and performance benefits will be large. If many IGCC plant are built there will be an added cost reduction benefit linked to the larger number of applications.

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SECTION B

GENERAL INFORMATION

I N D E X

SECTION B GENERAL INFORMATION

SECTION B

1.0 Purpose of the Study

The IEA Greenhouse Gas R&D Programme has retained Foster Wheeler to investigate alternative power generation plant designs, based on coal gasification, with and without capture of the produced CO_2. The primary purpose of this study is, therefore, the evaluation of the technologies that can be used in these complex power generation schemes to optimize efficiency and capital cost and reduce, at the same time, emissions to the atmosphere.
The plant of the study has a nominal capacity of 800 MWe and is fed with a typical coal having a low heating value (LHV) equal to 25870 kJ/kg and a sulphur content equal to 1.1 % wt.
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. The study does, however, consider possible improvements to current technologies and also potential future technologies in order to assess the likely performance of a plant in the year 2020.

The study investigates 13 alternative designs of the power generation plant, which differ for the gasification technology, the gasification pressure, the presence or not of shift step, the acid gas removal process. For each alternative sufficient basic design data have been developed in order to evaluate performance and capital cost. For some alternatives specific optimisation studies have been made in order to select the most convenient acid gas removal process and the best arrangement of the shift reactors.
The study is finally completed with a comparison of the various alternative designs, confronting for the various technology combinations cost and performance data.

FW like to acknowledge the following companies for their fruitful support to the preparation of this study:

- Dow (AGR)
- General Electric (Gas Turbine; CO_2 Compression)
- Shell (Gasification)
- Synetix (Shift)
- Sud-Chemie (Shift)
- Texaco (Gasification)
- UOP (AGR).

2.0 Project Design Bases

The IGCC Complex is designed to process, in an environmentally acceptable manner, an open-cut coal from eastern Australia and produce electric energy (800 MWe nominal capacity) to be delivered to the local grid.

For each of the alternative considered, the IGCC design capacity has been fixed to match the appetite of the selected gas turbines. The design capacity for each of the alternative considered is summarised in Table B.6.1, paragraph 6.0.

The Power Island inside the IGCC Complex is also able to process Natural Gas as back-up fuel.

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), kcal/kg (*)	6464
LHV (Air Dried Basis), kcal/kg (*)	6180
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/Nm3	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 IGCC Complex are listed here below with their specifications.

2.2.1 Electric Power

Net Power Output	:	800	MWe	nominal capacity
Voltage	:	380	kV	
Frequency	:	50	Hz	
Fault duty	:	50	kA	

2.2.2 Carbon Dioxide

For Alternatives where CO_2 capture is achieved (reference to be made to Section B, paragraph 6.0), the Carbon Dioxide characteristics at IGCC B.L. are the following:

Status	:	supercritical
Pressure	:	110 bar g
Temperature	:	30 °C
Purity	:	(1)
H_2S content	:	0.1 % wt (max) (2)
CO content	:	0.1 % wt (max)
Moisture	:	< 0.1 ppmvd
N_2 Contempt	:	to be minimized (3)

(1) Depending on the process alternative considered (see Section D – Basic information for each alternative).
(2) Except for cases with combined removal of CO_2 and H_2S
(3) High N_2 concentration in the product CO_2 stream has a negative impact for CO_2 storage, particularly if the CO_2 is used for Enhanced Oil Recovery. N_2 seriously degrades the performances of CO_2 in EOR, unlike H_2S which enhances it.

Minimum Capture level	:	80%
Preferred Capture level	:	85%

2.2.3 Sulphur

Sulphur is a by-product of the IGCC Complex for all the process alternatives considered other than where the combined removal of H_2S and CO_2 is required (reference to be made to Section B – paragraph B.6.1).

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 Complex produces solid by-products that are saleable, in particular:

Shell Technology	:	flyash	
		slag	(10% approx. water content)
Texaco Technology	:	slag	(50% approx water content)
		filter cake	(70% approx water content)

2.3 Environmental Limits

The environmental limits set up for the IGCC Complex are outlined hereinafter.

2.3.1 Gaseous Emissions

The overall gaseous emissions from the IGCC Complex 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
Particulate	:	≤	10	mg/Nm^3
CO	:	≤	50	mg/Nm^3

2.3.2 Liquid Effluent

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

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

The effluent from the Waste Water Treatment shall be generally recovered and recycled back to the Gasification Island as process water.

The only continuous liquid effluent from the IGCC Complex is the seawater return stream. Main characteristics of the water are listed in the following:

• Temperature	:	19	°C
• Cl_2	:	<0.05	ppm

2.3.3 Solid Wastes

The process does 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.

2.3.4 Noise

All the equipment of the IGCC Complex will be designed to obtain a sound pressure level of 85 dB(A) at 1 meter from the equipment.

2.4 IGCC Operation

2.4.1 Capacity

The gasification capacity, i.e. the coal flow rate of the IGCC Complex is shown in Table B.6.1. For each alternative considered, the IGCC design capacity has been fixed to match the appetite of the selected gas turbines which are two General Electric Frame 9FA.
The following Table B.2.1, “GE Syngas Experience”, summarizes the status and operating data of the GE gas turbines, fed with Syngas as of September 2002.

Table B.2.1 - GE Syngas Experience (September 2002)

Customer	Type	MW	Syngas start Date	Hours of operation
Cool Water	107FE	120	5/84	27,000
PSI	7FA	262	11/95	24,500
Tampa	107FA	250	9/96	33,500
Texaco El Dorado	6B	40	9/96	30,660
Sierra Pacific	106FA	100	-	0
Schwarze Pumpe	6B	40	9/96	37,600
Shell Pernis	2x6B	80	11/97	58,250
ISE / ILVA	3x109E	540	11/96	141,000
Fife Energy	6FA	80	-	0
Motiva Delaware	2x6FA	240	8/00	450
Sarlux	3x109E	550	10/00	33,100
Piombino	109E	150	10/00	12,400
Exxon Singapore	2x6FA	180	3/01	9,700

The list includes several “F” technology machines, in particular Frame 6FA which is very similar to the 9FA machine: GE is confident that operating experience of Frame 6FA can be entirely passed on Frame 9FA.
Therefore, this machine can be considered suitable to meet all the process requirements (environmental limits, performances, capability to burn fuels with relatively high hydrogen content, etc.) as well as to ensure a high degree of reliability and availability.

A minimum equivalent availability of 85% corresponding to 7446 hours of syngas operation in one year at 100% capacity is expected for all the alternatives starting from the second year of commercial operation.

The whole gasification train from the Gasification Unit to the Power Island is designed to operate at 100% of nominal design capacity, even though the single Units may have a design capacity selected on the basis of specific criteria.

The Air Separation Unit capacity is defined by oxygen requirements of the IGCC Complex (mainly the gasifiers requirement plus the marginal consumption of Sulphur Recovery Unit). ASU is also requested to produce nitrogen at different levels of pressure to be supplied to the IGCC complex. Nitrogen production is dependant on oxygen production, consequently nitrogen flowrate available for syngas dilution may be different case by case, based on the other requirements of the IGCC Complex (f..i. for Shell Alternatives nitrogen requirement of coal pneumatic transport).

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

2.4.2 Unit Arrangment

The IGCC Complex is in part a twin or multiple trains facility. due to constraints on equipment size and/or to reliability reasons. The arrangement of the process units is as follows:

Process Units		Trains
1000	Gasification	1 x 100%
	Texaco gasifiers	4 x 33 %
	Shell gasifiers	2 x 50 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	(*)
2300	AGR	(*)
2400	SRU	2 x 100%
	TGT	1 x 100%
2500	CO_2 Compression and Drying	2 x 50%

(*) Depending on the process alternative considered (see Section D – Basic information for each alternative).

Power Island (Unit 3000)

Gas Turbine	2 x 50%
HRSG	2 x 50%
Steam Turbine	1 x 100%

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 will be composed of multiple gasifiers, at least two, 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 allows to ensure a high power production by cofiring syngas and natural gas in the gas turbines.

The minimum turndown of each Gas Turbine on syngas is 20%, i.e. 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.

As a conclusion, even if the operation of the IGCC complex at 25% load is a necessary step of the start-up procedure, its duration is to be limited, being approx. 35% load the expected turn down capacity for the entire IGCC Complex, compatible with a prolonged continuous operation.

2.5 Location

The site is a green field located on the NE coast of The Netherlands.
Despite of the dutch location no special civil works implication shall be assumed. The plant area is assumed to be close to a deep sea, thus limiting the length of the sea water lines (both the submarine line and the sea water pumps discharge line). The site is also close to an existing harbour equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

2.6 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

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

2.7 Economic/Financial Factors

2.7.1 Design and Construction Period

IGCC design and construction will be completed in 34 months starting from issue of Notice to Proceed to the EPC contractor. Overnight construction will be applied.
The curve of capital expenditure during construction is assumed to be:

Year	Investment Cost %
1	20
2	45
3	35

2.7.2 Capital Charges

Discounted cash flow calculations will be expressed at a discount rate of 10% and to illustrate sensitivity at 5%.

2.7.3 Cost of Debt

All capital requirements will be treated as debt at the same discount rate used to derive capital charges. This is equivalent to assume a 100% equity. No interest during construction is applied.

2.7.4 Inflation

No inflation shall be applied to the economical analysis.

2.7.5 Commissioning

IGCC commissioning will take a 6 month period during the last two months of the third year of construction and the first four months of first year of IGCC operation.

2.7.6 Working Capital

Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables. No allowance will be made for receipts from sales in this period.

2.7.7 Land purchase, surveys, general site preparation

5% of the installed plant cost is assumed.

2.7.8 Taxation and Insurance

1% of the installed plant cost is assumed to cover local taxation. Taxation on profits is not included. The same percentage of the installed plant cost is assumed for insurance.

2.7.9 Fees

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

2.7.10 Operation and Maintenance

Labour and Maintenance data used for the economical evaluation are summarized in Section E, para 4.0.

2.7.11 Fuel Costs

Cost of coal delivered to site is 1.5 $/GJ.
Cost of natural gas delivered by a pipeline to site is 2 $/GJ.

2.7.12 By-Products Price

Sulphur Price is 103.3 €/t.
No selling price is attributed to CO_2.

2.8 Software Codes

For the development of the Study, two software codes have been mainly used:

- HYSYS v3.0.1 (by Hyprotech Ltd.): Process Simulator used for syngas treatment and conditioning line simulation of the Process Units downstream the Gasification Island.
- Gate Cycle v5.40.0 (by General Electric): Simulator of Power Island used for Combined Cycle Unit simulation.

3.0 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 Integrated Gasification Combined Cycle (IGCC) Complex to be built on the east coast area of Netherlands.

The IGCC Plant is constituted by the following groups of units:

Process Units (Unit 900 to 2500) including:
- Coal Handling and Storage (Unit 900);
- Gasification Island (Unit 1000);
- Air Separation Unit (Unit 2100);
- Syngas Treatment and Conditioning Line (Unit 2200);
- Acid Gas Removal Unit (Unit 2300);
- Sulphur Recovery and Tail Gas Treatment (Unit 2400);
- CO_2 Compression and Drying (Unit 2500).

Power Island including:
- Gas Turbines (Unit 3100);
- Heat Recovery Steam Generators (Unit 3200);
- Steam Turbine (Unit 3300);
- Electrical Power Generation (Unit 3400).

Utility and Offsite Units providing services and utility fluids to all the units of the plant; including:
- Sea Cooling Water/Machinery Cooling Water Systems (Unit 4100);
- Demineralized, Condensate Recovery, Plant and Potable Water Systems (Unit 4200);
- Natural Gas System (Unit 4300);
- Plant/Instrument Air Systems (Unit 4400);
- Waste Water Treatment (Unit 4600);
- Fire fighting System (Unit 4700);
- Flare (Unit 4800);
- Chemicals (Unit 4900);
- Solid (Slag & Flyash or Filtercake) Handling (Unit 5000);
- Sulphur Storage and Handling (Unit 5100);
- Interconnecting (instrumentation, DCS, piping, electrical, 400 kV substation) (Unit 5200).

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 Site conditions

- site elevation
  IGCC complex area : 6 m above mean sea level.

- atmosphere type : coastal area with salt pollution.

3.3 Climatic and Meteorological Information

Reference is made to para. 2.6 for main data.

Other data:

- rainfall
  design : 25 mm/h
  50 mm/day

- wind
  maximum speed : 35 km/h

- snow
  : 50 kg/m^2

- winterization
  winterization is required.

- sea water supply temperature and salinity
  average (on yearly basis) : 12 °C
  maximum average (summer) : 14 °C
  minimum average (winter) : 9 °C

  salinity : 22 g/l

3.4 Soil data

- earthquake
  earthquake factor : negligible

- geology
  green field site with no special civil works implications.

3.5 Project Battery Limits design basis

3.5.1 Electric Power

High voltage grid connection: 380 kV

Frequency: 50 Hz

Fault duty : 50 kA

3.5.2 Process and Utility Fluids

The streams available at plant battery limits are the following:

- Coal;
- Natural Gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- Sulphur product;
- CO_2 rich stream.

3.6 Utility and Service fluids characteristics/conditions

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

3.6.1 Cooling Water

The IGCC 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, ASU exchangers, CO_2 compression and drying exchangers, fresh 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

Fresh Cooling Water (secondary system)

Service : for machinery cooling and for all IGCC users other than steam turbine condenser, ASU and CO_2 compression and drying exchangers.
Type : demi water stabilized and conditioned.

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	: 60	°C
Fouling Factor	: 0.0002 h °C m^2/kcal	

3.6.2 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	: Ambient	

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	:	70 °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

3.6.3 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 Units (see INTRODUCTION-List of units).

Table B.3.1 – Process Units steam conditions.

	Pressure, barg			**Temperature, °C**	
	Max	**Min**	**Design**	**Norm**	**Design**
High Pressure (1) **(HP)** Nominal Pressure: 160 barg	170	160	187	353	370
High Pressure (2) **(HP)** Nominal Pressure: 126 barg	134	126	147	334	350
Medium Pressure (1) **(MP)** Nominal Pressure: 40 barg	43	40	47	256	270
Medium Pressure (2) **(MP)** Nominal Pressure: 42 barg	45	42	49	259	280
Medium Pressure (3) **(MP)** Nominal Pressure: 59 barg	63	59	69	280	310
Low Pressure **(LP)** Nominal Pressure: 6.5 barg	8.0	6.5	12	175	250
Very Low Pressure **(VLP)** Nominal Pressure: 3.2 barg	4.0	3.2	12	152	250

Notes: (1) Texaco alternatives (see paragraph 6.0).
(2) Shell alternatives (see paragraph 6.0).
(3) Shell Case B.2 (see paragraph 6.0).

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 m^2/kcal

(*) Depending on the process alternative considered (see Section D – Basic information for each 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. is 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 (1) **(BWH)**	195	160
Boiler Feed Water, High Pressure (2) **(BWH)**	153	160

Notes: (1) Texaco alternatives (see paragraph 6.0).
(2) Shell alternatives (see paragraph 6.0).

3.6.4 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

3.6.5 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.

High Pressure Nitrogen

Supply pressure	:	(*)
Supply temperature	:	15 °C min
Design pressure	:	(*)
Design temperature	:	(*)
Min Nitrogen content	:	99.9 % vol.

(*) Depending on the process alternative considered (see Section D – Basic information for each alternative).

3.6.6 Natural Gas

Characteristics of Natural Gas are listed at para 2.1.2, Project Design Bases.

High Pressure

Type : natural gas.
Service : gas turbine start-up and back-up fuel.

Operating pressure at Users	:	27.0 barg
Operating temperature at Users	:	30°C above natural gas dew point
Design pressure	:	33.0 barg
Design temperature	:	70 °C

Low Pressure

Type : natural gas.
Service : distribution.

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

Characteristics: as for High Pressure Natural Gas.

3.6.7 Oxygen

The Oxygen for the gasification unit has the following characteristics:

Supply pressure	:	(*)
Supply temperature	:	(*)
Design pressure	:	(*)
Design temperature	:	(*)

(*) Depending on the process alternative considered (see Section D – Basic information for each alternative).

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

3.6.8 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 IGCC 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 hdrochloric 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

3.6.9 Electrical System Distribution

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

	Voltage level (V)	***Electric Wire***	***Frequency (Hz)***	***Fault current duty (kA)***
Primary distribution	66000 ± 5%	3	50 ± 0.2%	31.5 kA
MV distribution and utilization	11000 ± 5% 6000 ± 5%	3 3	50 ± 0.2% 50 ± 0.2%	31.5 kA 25 kA
Emergency power souce	6000 ± 5%	3	50 ± 0.2%	31.5 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	-	-

3.7 Plant Life

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

- Design life of vessels, equipment, component 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.

3.8 Economical data

Economic evaluation shall be made to choose among different alternative process solutions. The techno-economical evaluation shall be based on a simple pay-out period of 6 years for the extra investment, as well as for energy saving.

The economical factors to be used are:

- Coal : 1.5 $/GJ
- Steam :
  High Pressure : 10.2 Euro/t
  Medium Pressure : 8.5 Euro/t
  Low Pressure : 6.0 Euro/t
- Electric Power : 0.03 Euro/kWh

3.9 Codes and standards

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

4.0 General Description of the IGCC Complex

The IGCC Complex of the study is a very large power production facility, converting coal to electric energy with a minimum impact to the environment.
The key process step of the IGCC Complex is the gasification of coal. Gasification is the partial oxidation of coal, or any other fossil fuel, to a gas, often identified as syngas, in which the major components are hydrogen and carbon monoxide.
The partial oxidation agent used is oxygen, or air, supplemented usually by steam. The choice of oxygen or air depends on the type of gasifier, the final use of the syngas and the reactivity of the feed material. For this study the gasification technologies selected are based on oxygen blown gasifier.
The syngas generated by gasification can be cleaned and then used in a combined cycle which is today the most efficient thermal cycle for power generation. The gasification therefore acts as a bridge between a low quality fossil fuel, coal, and the gas turbine with the target of high energy efficiency and minimum emissions to the environment.
The nominal production capacity of the IGCC Complex of the study is 800 MWe. However the various alternative designs investigated by the study have a production capacity which is somewhat greater or smaller than 800 MWe, depending on the performance efficiency of each alternative.
The IGCC Complex is a combination of several process units, different for each alternative. However the main process blocks of the Complex are:

- Coal milling and gasifier feed preparation;
- Air separation;
- Gasification;
- Syngas treatment and conditioning;
- Combined Cycle power generation.

These basic blocks, depending on the alternative, may be supported by other ancillary units, such as Sulphur recovery, Tail gas treatment, and a number of utility and offsite units, such as cooling water, flare, plant/instrument air, machinery cooling water, demineralized water, auxiliary fuels, etc. For alternatives with CO_2 capture an additional unit dedicated to CO_2 compression and drying is also present.
Each process unit of the Complex may be a single train for the total capacity or split in two, three or more parallel trains, depending on the maximum capacity of the equipment involved or on the necessity to assure, through the use of multiple parallel trains, a superior degree of reliability.
In Section C of this report more details about technology and configuration of each unit are provided.
In Section D each alternative design of the IGCC Complex is described with the support of schematic flow diagrams, equipment data, material and energy balances.

5.0 Selection of the Gasification Technology

The Gasification technology was developed in the past century to meet the demand of synthesis gas, first of the chemical industry, to make ammonia, methanol and hydrogen, and more recently, in the past 25 years, of the power industry to generate electric energy. Today a large number of gasification processes are available to the industry. Several of those processes have already a solid background of operating experience in large scale production plants. Section H of this report reviews the most important commercial gasification processes and attempts to assess the merits of these processes.

For this Study IEA GHG requested to confront two gasification technologies and to follow these rules in the selection of the two technologies:

- type of gasifier : entrained flow
- feed preparation : compare dry feed vs. slurry feed
- heat recovery : compare waste heat boiler vs. quench

These requirements are best matched by the two most proven gasification technologies available today: Shell and Texaco. In fact both gasifiers are entrained flow, oxygen blown. The feed to the Shell gasifier is pulverized coal, transported pneumatically in a stream of pressurized nitrogen, thus representing the dry feed option. The feed to the Texaco gasifier is a slurry of pulverized coal in water.
Finally Texaco can offer the two types of heat recovery, quench and waste heat boiler, while Shell process employs only the waste heat boiler type.
Based on the above considerations the 13 alternative designs of the IGCC Complex of the Study employ either the Texaco or the Shell coal gasification process. A detailed description of these two gasifiers is given in Section C, para 1, and Section H of this report, including the reference list of the commercial experience of Texaco and Shell.

6.0 Process Alternatives

Several design alternatives of the IGCC Complex have been developed in the Study. The contemplated alternatives attempt to compare the following key process aspects:

- Two gasification technologies: Texaco and Shell;
- Two levels of gasification pressure;
- Syngas utilization in the gas turbine without and with prior conversion of CO to H_2;
- Performance penalties for the capture of CO_2 to reduce environmental impact;
- Performance penalties for the simultaneous capture of CO_2 and H_2S;
- Different arrangements of the CO conversion reactors: number of reactors and dirty shift vs. clean shift;

Cases identified with A and B are based on Shell gasification; the first group, A, is without CO_2 capture, while the second group, B, is with CO_2 capture. The same is applicable to groups C and D, except that Texaco gasification is used in place of the Shell gasification.

- Case A.1 employs the Shell gasification, a low pressure of gasification and no CO shift and capture of CO_2.
- Case A.2 employs the Shell gasification, a high pressure of gasification and no CO shift and capture of CO_2.
- Case B.1 employs the Shell gasification, a low pressure of gasification, sour shift (2 stages) and capture of CO_2.
- Case B.2 employs the Shell gasification, a low pressure of gasification, clean shift (3 stages) and capture of CO_2.
- Case B.3 employs the Shell gasification, a low pressure of gasification, sour shift and capture of CO_2 and H_2S together.
- Case B.4 employs the Shell gasification, a high pressure of gasification, sour shift and capture of CO_2.
- Case C.1 employs the Texaco gasification, a high pressure of gasification, and no CO shift and capture of CO_2.
- Case C.2 employs the Texaco gasification, a high pressure of gasification, sour shift and no CO_2 capture.
- Case C.3 employs the Texaco gasification, a low pressure of gasification, no CO shift and capture of CO_2.
- Case D.1 employs the Texaco gasification, a high pressure of gasification, sour shift (1 stage) and capture of CO_2.

- Case D.2 employs the Texaco gasification, a high pressure of gasification, sour shift and simultaneous capture of CO_2 and H_2S.
- Case D.3 employs the Texaco gasification, a high pressure of gasification, sour shift and a somewhat reduced capture of CO_2.
- Case D.4 employs the Texaco gasification, a low pressure of gasification, sour shift and capture of CO_2.

The following Table B.6.1 provides a summary of the 13 cases with some of the most significant performance data:

Table B.6.1 – Most significant performance data for all the process alternatives

CASE	Gasification Process	Gasification Pressure Bar g	Shift	Coal t/h	NPO MWe	Net Electric Efficiency %	CO_2 Capture	AGR Process
A.1	Shell	36	NO	250.6	776	43.1	NO	MDEA
A.2	Shell	61	NO	252.1	748	41.3	NO	MDEA
B.1	Shell	39	Sour S.	273.1	676 (1)	34.5 (1)	YES	Selexol
B.2	Shell	39	Clean S.	274.6	651 (1)	33.0 (1)	YES	Selexol
B.3	Shell	39	Sour S.	271.4	683 (1)	35.0 (1)	YES	MDEA
B.4	Shell	61	Sour S.	271.9	639 (1)	32.7 (1)	YES	Selexol
C.1	Texaco	65	NO	303.0	827	38.0	NO	Selexol
C.2	Texaco	65	Sour S.	327.6	861	36.6	NO	Selexol
C.3	Texaco	38	NO	300.9	800	37.0	NO	MDEA + AGE
D.1	Texaco	65	Sour S.	323.1	730 (1)	31.5 (1)	YES	Selexol
D.2	Texaco	65	Sour S.	323.2	742 (1)	32.0 (1)	YES	Selexol
D.3	Texaco	65	Sour S.	323.1	744 (1)	32.1 (1)	YES	Selexol
D.4	Texaco	38	Sour S.	320.4	705 (1)	30.6 (1)	YES	Selexol

Note (1) : Including energy consumed for CO_2 compression
(2) : Combined removal of CO_2 and H_2S (3) : Lower Capture rate

7.0 Selection of the Gasification Pressure

The Gasification processes, originally developed for the chemical industry, were medium/high pressure processes because most of the subsequent uses of syngas are in high pressure processes: synthesis or hydrogenation reactors. For this reason currently available gasification technologies can operate at high pressure, 40 to 80 bar. However the final destination of the syngas in an IGCC is the combustion chamber of the gas turbine. Gas turbines commercially available today require a lower gas feed pressure, within the range of 20-30 bar. So there is an ample range of pressure, within which the gasification pressure can be selected by the designer of the plant.
For a given capacity an increase of the gasification pressure will reduce the size of the equipment but will increase the operating costs. This extra cost of operation can be compensated if a gas expander is installed between the gasification and the gas turbine.
In conclusion the gasification pressure is an important design parameter to optimize investment and operating costs of the plant.
For this Study two alternative levels of gasification pressure have been selected:

- high pressure : 60-65 bar
- low pressure : 36-39 bar

In this way the effect of pressure on cost and performance can be identified.
Texaco coal gasification process has been commercially proven up to 65-70 bar pressure. The type of feed chosen, coal water slurry, permits to operate the gasifier at high pressure because well proven coal-water slurry pumps are available for high delivery pressure.
The Shell process on the contrary, has been commercially tested for a pressure of the gasifier equal to 32 bar. The limit on pressure is imposed by the use of the dry type of feed, which is based on lock hoppers. These devices, and their associated block valves, are proven for pressure up to 40 bar. For higher pressures it will be necessary to extend the field of application of the current technology, therefore some developmental effort will be required. Shell is confident that this limit on pressure can be removed in the future, so design data on the process have been provided by Shell for the high pressure alternatives considered in the Study.

The results of the comparison between high and low pressure alternative for the two technologies are listed in the following tables B.7.1 and B.7.2, for Shell and Texaco technologies respectively.

Table B.7.1 -Shell Technology

	Low Pressure (36 bar g) w/o CO_2 capture Alt. A.1	**High Pressure (61 bar g) w/o CO_2 capture Alt. A.2**	**Low Pressure (39 bar g) w CO_2 capture Alt. B.1**	**High Pressure (61 bar g) w CO_2 capture Alt. B.4**
Coal Flowrate, t/h	250.6	252.1	273.1	271.9
Net Electrical Efficiency, %	43.1	41.3	34.5	32.7
Net Power Output, MWe	775.9	748.3	676.2	638.9
Total Investment Cost, MM Euro	1064.1	1143.2	1257.6	1314.0

As both the performances and the Investment Cost are better for the low pressure case, no advantage is expected for the state of the art Shell Technology by a pressure increase. Therefore for each Shell alternatives the gasification pressure is selected based on the requirement of the gas turbine and the pressure drop of the upstream units.

Table B.7.2 -Texaco Technology

	High Pressure (65 bar g) w/o CO_2 capture Alt. C.1	**Low Pressure (38 bar g) w/o CO_2 capture Alt. C.3**	**High Pressure (65 bar g) w CO_2 capture Alt. D.1**	**Low Pressure (38 bar g) w CO_2 capture Alt. D.4**
Coal Flowrate, t/h	303.0	300.9	323.1	320.4
Net Electrical Efficiency, %	38.0	37.0	31.5	30.6
Net Power Output, MWe	826.5	799.9	730.3	705.0
Total Investment Cost, MM Euro	981.4	959.9	1091.5	1117.1

The comparison of the alternatives without CO_2 capture shows better performances but a higher installed investment cost for the high pressure case (Alt. C.1). Based on an electric power cost 0.03 €/kWh (assumed conservatively low with respect to evaluations made in Section E) and 7446 operating hours per year, the simple payout time 3.2 as shown in Table B.7.3. As the payout time is significantly lower than 6 (reference to para. 3.8 of this Section B), the high pressure is selected for Texaco alternative without CO_2 capture.

Table B.7.3 –Simple Payout Time of Alternative C.1 vs Alternative C.3

Difference of coal consumption, t/h	2.1
Difference of electric power production, MWe	26.6
Yearly difference of coal cost, MM Euro	0.607
Yearly difference of electric power revenue, MM Euro	5.942
Net yearly saving, MM Euro	5.335
Investment Cost difference, MM Euro	21.5
Simple payout time, years	4

For Texaco alternatives with CO_2 capture both the performances and the Investment Cost are better for the high pressure case, so confirming that Texaco Technology takes advantage from a further pressure increase that may be expected to be feasible in the next years.

As a conclusion for Texaco alternatives high pressure (65 bar g) is selected.

8.0 Definition of the Degree of Integration between gas turbines and ASU

An important area of IGCC technology improvement in the optmization of the integration amongst the various components of the complex. Integration means recovery of the waste energy available, improvement of the efficiency and reduction of investment cost, but also a possible reduction of operating flexibility that can affect the IGCC availability.
The integration between two major components of the IGCC, i.e. the gas turbine and the Air Separation Unit represents an important potential benefit that has been investigated in this Study.

There are several possible degrees of integration between the air separation plant and the gas turbine.
In the case of total integration, 100% of the air required by the air separation is supplied by bleeding some of the air from the discharge of the gas turbine compressor.
Depending on the gas turbine frame this air is available at 10-15 bar, therefore the air separation plant is a high pressure type, delivering oxygen and nitrogen at 3-4 bar. Oxygen is recompressed and used in gasification, while nitrogen is recompressed and reinjected in the syngas to replenish the mass deficit, caused by the air bleeding, and, at the same time, reduce NOx formation during combustion by lowering the flame peak temperature.

Alternatively the air separation plant can be "stand alone", not integrated. In this case a low pressure air separation plant is chosen, with its own air compressor delivering air to the cryogenic process at the minimum pressure required to meet the energy demand of the unit. Oxygen and nitrogen are produced at 1 bar, so required large compression energy to feed respectively the gasifier and the gas turbine.
In the "stand alone" case, syngas humidification is generally preferred to nitrogen addition for NOx control, because of the large nitrogen compression energy consumption. In most of the "stand alone" cases, to achieve the desired NOx level it is necessary to throttle the gas turbine compressor inlet guide vanes, to create space for the diluent.

A design, which is intermediate between these two cases, is the partially integrated air separation. Air is partly supplied by the gas turbine and partly by a separated air compressor. The % of air required by the air separation, which is supplied by the gas turbine, is taken as the degree of integration. Also in this case the air separation plant operates at high pressure, thus reducing the compression energy of oxygen and nitrogen.
The selection of the optimum degree of integration is important to improve plant performance and reduce capital outlay, still maintaining a high operating flexibility and plant availability.
The best degree of integration changes with the characteristics of the gas turbine, so it is not the same for different gas turbines: its identification is a complex design effort.

Commercially available gas turbines have been developed for the use of natural gas, i.e. a fuel with high calorific value (LHV). With the advent of IGCC these turbines have been adapted to the use of syngas, a low LHV fuel, but their design features are not generally the optimum for syngas. Infact when passing from natural gas to syngas the gas turbine encounters two major changes:

1. For the same fuel heat input (MWt) the fuel mass flow is 4-5 times greater than for natural gas, due to the lower LHV.
2. While, with natural gas, premix burners have become common practice for NOx control, premix burners are not used with syngas due to the high content of H2 (flash back risk). Diffusion burners are used with syngas and control of NOx is achieved by diluting the syngas with nitrogen, steam or carbon dioxide, thus reducing the flame peak temperature and consequently the rate of formation of NOx.

These two factors, greater fuel flow and addition of diluent for NOx control, increase substantially the overall mass flow (air + fuel + diluent) through the turbine expander. This creates a back pressure to the air compressor discharge, which may bring the air compressor operation at or close to surge conditions, and sometimes overload the turbine blades up to their mechanical limit.
Some turbines frames, although designed for natural gas, are better suited to accept syngas operation. These frames have, in general a generously designed expander, compared to the air compressor, so that the extra mass flow of syngas + diluent can be easily accomodated without surge or mechanical problems.
But the majority of the gas turbine frames available do not have similar expander overcapacity, and, when passing from natural gas operation to syngas, they can accept only limited quantities of diluent before incurring in surge problems, thus limiting the reduction of NOx.

With the first group of gas turbines the integration (partial or total) does not make sense, as long as the NO_X level required can be achieved with a N_2 dilution rate acceptable by the generously sized gas turbine expander. The increased power output of the gas turbines operating with syngas and full rate of dilution more than compensate the extra power consumed by the “stand one” oxygen plant air compressor.

On the contrary, with the second group of gas turbines integration is advantageous because some compressed air must be bled off to permit sufficient diluent addition for NO_x so the use of this air in the air separation plant reduces or eliminate the air compressor.
The gas turbine selected for this study, the GE 9001 FA, is an example of this second group. As mentioned above it is important to develop a specific study to define the best degree of integration for a selected gas turbine.

A study of this type was developed by Foster Wheeler for an IGCC based on Texaco gasification and the same gas turbine used in the present study. A paper on this subject was presented by G.L. Farina and L. Bressan at the 1998 Power Gen in Milano. According to this paper the best degree of integration for GE 9001 FA falls in the range 45-50%. This result has been confirmed by the investigation made for the Gasification Power Generation Study.
For this study GE was requested to provide for various alternatives the power output of the gas turbine at two levels of integration, 30% and 50%. The difference between the gas turbine power output and the power consumption of ASU was used as a parameter for the optimization of the degree of integration. As shown in the attached Table B.7.1 the optimum degree of integration (maximum value of the parameter) is for all cases 50%, except for the alternative with Shell gasification and CO shift for which the best degree of integration is 30%, and for the alternative with Texaco gasification, CO shift, no CO_2, capture for which the best degree of integration selected by GE is 43.2%. In Shell alternative the nitrogen available for reintegration in the gas turbine is less, because the O_2 demand is lower, and, therefore the net power output decreases when the integration increases beyond 30%. In Texaco alternative with shift and no CO_2 capture, the optimization parameters are affected by the large amount of CO_2 that, only in this case, flows through the gas turbine.

An important advantage of partial integration vs. full integration (100%) is an easier operability of the plant at start-up, because the ASU, equipped with its own air compressor, permits to start-up ASU, at reduced capacity, and have it ready for the subsequent gasification start-up independently from the gas turbine operation.

When partial or full integration is used, the ASU operating pressure is linked to the delivery pressure of air coming from the gas turbine. Since the pressure changes with the load changes of the gas turbine, it is preferable, in an integrated design, to select the ASU air feed pressure at the level corresponding to the pressure of air from the gas turbine when operating at 50% load. In this way the ASU can operate at constant pressure between 50% and 100% of gas turbine load.

Table B.8.1 – Optimum degree of integration for all the process alternatives [(1)].

	30 % Integration			50 % Integration		
Case[(1)]	GT Pow Output, MWe	Air Comp Cons, Mwe	Δ, MWe	GT Pow Output, MWe	Air Comp Cons, MWe	Δ, MWe
A.1	286,0	48,4	237,6	276,8	34,6	242,2[(2)]
A.2	286,0	49,0	237,0	276,8	35,0	241,8[(2)]
B.1	286,0	52,7	233,3	268,0	37,7	230,3
B.2	286,0	53,0	233,0	268,0	37,9	230,1
B.3	286,0	52,4	233,6	268,0	37,5	230,5
B.4	286,0	53,0	233,0	268,0	37,9	230,1
C.1	286,0	61,7	224,3	286,0	44,0	242,0
C.2	286,0	66,1	219,9	286,0	54,0[(3)]	232,0
C.3	286,0	62,0	224,0	286,0	44,3	241,7
D.1	286,0	65,8	220,2	281,7	47,0	234,7
D.2	286,0	65,8	220,2	286,0	47,0	239,0
D.3	286,0	65,8	220,2	283,7	47,0	236,7
D.4	286,0	65,9	220,1	281,7	47,1	234,6

Notes:
(1) Process alternatives as per paragraph B.6.1.
(2) Additional gain is expected because of the different degree of nitrogen moisturisation to control the NOx emissions.
(3) A higher degree of moisturisation requires a higher LP steam consumption, thus decreasing the ST Power production.
(4) Value correspondent to 43,2 % integration. 50% integration was also investigated, but no advantage was found out.

9.0 Selection of the Shift Catalyst Type

The shift of CO to H_2 and CO_2 is a catalytic step necessary when the IGCC must reduce the CO_2 discharged to the atmosphere (reference to Shell alternatives B.1 to B.3, and to Texaco alternatives D.1 to D.4). However CO shift may also be considered for quench IGCC not recovering CO_2 (reference to Texaco alternative C.2). In fact when the reference of the comparison is a quench gasifier (reference to Texaco alternatives), the addition of CO shift brings the following benefits:

- CO shift reaction is exothermic and eliminates part of the syngas water coming from the quench. This results, downstream, in more availability of high temperature heat, for HP steam production, and less low temperature heat for LP steam production.
  With a quench gasifier without shift, heat can only be recovered as MP and LP steam.
- CO shift catalyst also hydrolyses COS to H_2S and there is no need of a separate COS hydrolysis system.
- The greater mass flow of syngas, due to CO_2, increases the energy recoverable from the expander.
- More CO_2 in the gas turbine reduces the quantity of H_2O to be added to saturate the expander and, at the same time, contributes to NO_x reduction.

In the case of a gasifier followed by a syngas cooler (no quench) (reference to Shell alternatives) the CO shift step would be negative because the large majority of heat from gasification is recovered as HP steam and the exothermic heat of the shift reaction is a net loss of syngas chemical energy to the gas turbine. Further to operate the shift, downstream a non quench gasifier, requires the addition to the syngas of a large quantity of steam, degrading the IGCC efficiency.

Two catalyst types have been investigated for this study:
- the sour shift catalyst, based on Co-Mo, operating at medium/high temperature and requiring a steam/dry gas volume ratio in the range of 1.2-1.6.
  The shift catalyst can withstand high concentration of sulphur in the syngas;
- the clean shift catalyst, based on Fe-Cr, operating at high temperature and requiring a lower steam/dry gas volume ratio equal to 1.
  The total S content of syngas entering the catalyst shall be 10 ppm max.

For Texaco quench gasification, advantages of sour shift are so large that a comparison between the two options is meaningless. Syngas at scrubber outlet has all the characteristics required by the shift reaction (high water content and high temperature). Installation of the sour shift section at the Scrubber outlet allows to avoid COS Hydrolysis section and to recover efficiently heat made available by the exothermic reaction.

For Shell gasification the water content at the scrubber outlet is not enough to satisfy the sour shift requirements and a large amount of MP steam shall be added. Due to the lower steam amount required by the clean shift catalyst, the two options (alternatives B.1 and B.2) have been compared from a techno-economical point of view. For the sour shift alternative the temperature at the scrubber outlet is maximized in order to reduce the steam amount to be added.
For clean shift alternative the process scheme up to first section the AGR removal is the same of cases without shift, and includes the COS Hydrolysis section. After H_2S removal, the clean shift reaction is achieved, followed by heat recovery and finally by the second section of AGR where CO_2 is captured.

Table B.9.1 – Shell Alternatives B.1 and B.2

	Sour Shift	Clean Shift
<u>Process Configuration</u>		
Temperature @ Scrubber Outlet, °C	161	126
Syngas H_2O content @ Scrubber Outlet, % vol	18	7
COS Hydrolysis Section	NO	YES
AGR split into two separate sections	NO	YES
<u>Process Performances</u>		
Coal Flowrate, t/h	273.1	274.6
Net Electrical Efficiency, %	34.5	33.0
Net Power Output, MWe	676.2	651.3
Installed Investment Cost, MM Euro	1257.6	1261.6

As both the performances and the Investment Cost are worst for the clean shift alternative, sour shift catalyst is selected even for Shell alternatives.

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DOCUMENT NAME : BASIC INFORMATION FOR THE IGCC COMPLEX

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SECTION C

BASIC INFORMATION FOR THE IGCC COMPLEX

I N D E X

SECTION C

1.0 Gasification Island

1.1 Shell Technology

Purpose of the attached document "Shell Gasification Island" is to summarize the information received from Shell for the Gasification Power Generation Study.
In particular these data were the basis in the first step of the study for the selection of the gasification pressure for the IGCC configurations with and without CO_2 capture.
Furtherly in the evaluation of the IGCC perfomances of all the Shell alternative some minor modifications of these data were made in order to adjust performances and investment cost to a slightly different coal flowrate as detailed per each alternative in Sections D and E.

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CONTRACT NO. : 1-BD-0119A
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SHELL GASIFICATION ISLAND

I N D E X

1.0 INTRODUCTION

Purpose of this document is to summarize the information received from SHELL for the first step of the Gasification Power Generation Study.
They are the basis for the selection of the gasification pressure for the IGCC configurations with and without CO_2 capture.

2.0 GASIFICATION ISLAND PROCESS DESCRIPTION AND BLOCK FLOW DIAGRAM

2.1 General description of the Shell Coal Gasification Process

The basic concepts selected for the Shell Coal Gasification Process (SCGP) are:
- Pressurised: compact equipment;
- Entrained flow: compact gasifier;
- Oxygen blown: compact equipment, high gasification efficiency;
- Membrane wall, slagging gasifier: robustness, high temperature, insulation by slag layer;
- Opposed burners: good mixing, high conversion, scale-up possibility;
- Dry feed of pulverised coal: high gasification efficiency, high feed flexibility.

The process can handle a wide variety of solid fuels, ranging from bituminous to lignite, as well as petroleum coke (petcoke) in an environmentally acceptable way and produces a high purity, medium-calorific gas as a fuel for power generation, as a chemical feedstock or as a source of hydrogen.

Raw coal or petcoke is crushed and fed to a pulveriser, a conventional bowl mill, similar to those used in a pulverised coal boiler. This mill grinds the coal to a size range suitable for efficient gasification (90% wt less than 100 microns). As the coal is being ground, it is simultaneously dried utilising a heated inert gas stream that carries the evaporated water from the system as it sweeps the pulverised coal through an internal classifier to collection in a bag house.

The oxygen required in the SCGP gasification step is supplied by an air separation plant. Nitrogen from the air separation unit provides low-pressure and high-pressure nitrogen for use in the gasification plant, e.g., for transporting coal in the feed system.

Milled and dried coal from the coal milling and drying area is pneumatically transported to the coal pressurisation and feeding system. Pressurised coal, oxygen and steam enter the gasifier through pairs of opposed burners. “Flux” can be added to a coal feed to ensure an appropriate slag flow from the gasifier, if it is required.

The gasifier operates at a pressure of 20 to 40 bar. Operation at pressure higher than 40 bar is not presently commercially proven. The gasifier consists of a pressure vessel with a gasification chamber inside. The inner gasifier wall temperature is controlled by circulating water through the membrane wall to generate saturated steam. The membrane wall encloses the gasification zone from which two outlets are provided. One opening at the bottom of the gasifier is used for the removal of slag. The other outlet allows hot raw gas and fly slag to exit from the top of the gasifier.

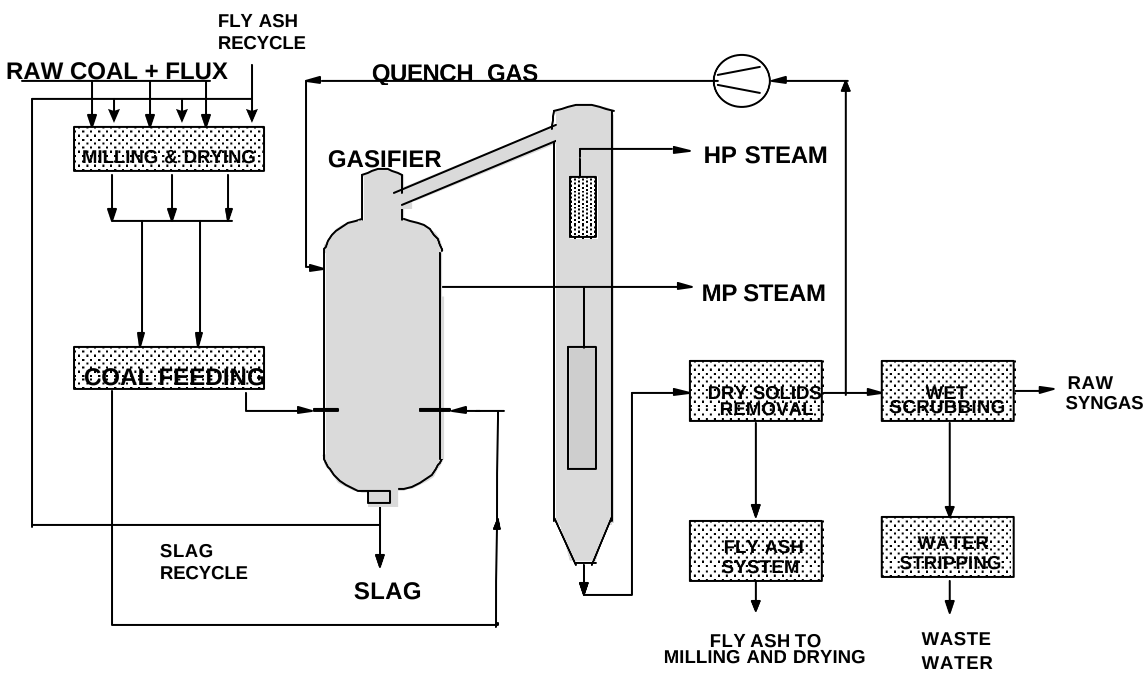
Most of the mineral content of the feed leaves the gasification zone in the form of molten slag. The high gasifier temperature (over 1500°C) ensures that the molten slag flows freely down the membrane wall into a water-filled compartment at the bottom of the gasifier. High carbon conversions (above 99%) are obtained, and the high temperature ensures that no organic components heavier than methane are in the raw syngas. The insulation provided by the slag layer in the gasifier inner membrane wall minimises heat losses, such that cold gas efficiencies are high and CO_2 levels in the syngas are low.

As the molten slag contacts the water bath, the slag solidifies into dense, glassy granules. The slag is washed, de-pressurised and then fed to intermediate storage for recycle and disposal.

The hot raw product gas leaving the gasification zone is quenched with cooled, recycled product gas to convert any entrained molten slag to a hardened solid material prior to entering the syngas cooler. The syngas cooler recovers high-level heat from the quenched raw gas by generating high-pressure steam, and steam at other desired pressure levels.

The bulk of the fly slag contained in the raw gas leaving the syngas cooler is removed from the gas using commercially available equipment such as filters or cyclones. The recovered fly slag can be recycled back to the gasifier via the coal feeding system. The syngas then goes to a scrubbing system, where the remaining traces of solids and water soluble contaminants are removed.

A bleed from the scrubbing system is sent to a sour slurry stripper. The water is then clarified and can be partially recycled to minimise the volume of effluent water.



THE SHELL COAL GASIFICATION PROCESS

2.2 Brief description of various process blocks

Reference is made to the attached Block Flow Diagram.

Coal milling - Unit 1100

The coal milling and drying unit includes a conventional mill, similar to those used in a pulverised coal boiler. The mill grinds the coal to a size range suitable for efficient gasification. As the coal is being ground, it is simultaneously dried utilising a heated inert gas stream. The gas stream carries the evaporated water from the system as it sweeps the pulverised coal through an internal classifier to collection in a bag house.
The heat required for drying the coal is supplied by burning LPG. Any other available fuel gas can be used, such as clean syngas downstream of the Acid Gas Removal unit at OSBL.

Coal Pressurisation and Feeding - Unit 1200

Milled and dried coal from the coal milling and drying area is pneumatically transported to the coal pressurisation and feeding system. This system consists of lock hoppers and feed hoppers. Once a lock hopper has been charged with coal, it is pressurised with nitrogen and its contents discharged into a feed hopper.
Pressurised coal is withdrawn from the feed hoppers and pneumatically conveyed with nitrogen to the gasifier's coal burners.
Lock hoppers are widely utilised in materials handling applications. They have proven to be a safe and reliable method for transferring solids under pressure.
The valves required for commercial scale lock hopper systems have been extensively demonstrated.

Gasification, Gas Quench and Slag Removal - Unit 1300/1400

A line-up of a single-train gasifier, hot-gas quench has been proposed.
In the top part of the gasifier, a solid-free cold syngas stream is injected to the hot product syngas, so that the product syngas is quenched to a temperature at which the flyash solidifies. The recycle quench gas is withdrawn from downstream of the dry solids removal unit. A recycle gas compressor is applied for this service.
At the bottom of the gasifier, as the molten slag contacts the water bath, the slag solidifies into dense, glassy granules. These slag granules fall into a collecting vessel located beneath the slag bath and are transferred to a lock hopper which operates on a timed cycle to receive the slag. After the lock hopper is filled, the slag is washed with clean make-up water to remove entrained gas and any surface impurities. After washing, the lock hopper is de-pressurised and the slag is fed to a de-watering bin. Commercially sized slag sluicing valves have been applied for this service.

This dewatering bin is equipped with a mechanical conveyor (drag chain) to lift the settled solids off the bottom of the vessel and deposit them on a conveyor belt for delivery to intermediate storage (conveyor belt and storage outside scope of this proposal).

High Temperature Gas Cooling - Unit 1300

The hot raw product gas leaving the gasification zone is quenched with cooled, recycled product gas to convert any entrained molten slag to a hardened solid material prior to entering the syngas cooler. The syngas cooler recovers high-level heat from the quenched raw gas by generating steam. The gasifier and syngas cooler included in the SCGP plant are similar to the water wall boilers which are widely used in other utility processes.
A syngas cooler liner-up has been selected for this proposal to maximise the heat recovery while maintaining operatability. The steam system has been designed bearing efficiency and intrinsic safety in mind. The choice for three steam levels (HP, MP and LP) ensures a high efficiency. The MP steam pressure level has been selected higher than the syngas pressure in order to maximise safety and integrity. LP steam is not produced inside the SGC for this reason but via a separate boiler. An economiser is installed to booster the efficiency further.

Dry Solids Removal - Unit 1500

The bulk of the flyash contained in the raw gas leaving the syngas cooler is removed from the gas using a commercially demonstrated high pressure, high temperature (HPHT) filter. The flyash leaving the process is conveyed to a flyash lock hopper. After the lock hopper is filled, the flyash is purged with high-pressure nitrogen to remove any entrained raw gas. After purging the lock hopper, the flyash is pneumatically conveyed to a silo for intermediate storage. All vent gases from the flyash lock hopper and the storage silo are filtered of particles. Flyash is recycled and added to the coal feed.

Wet Scrubbing - Unit 1600

The gas leaving the dry solids removal is further purified by passing through a wet scrubbing unit where any residual flyash is removed to a level of less than 1 ppm. This wet scrubbing system also removes other minor contaminants such as soluble alkali salts and hydrogen halides.
Make-up water is continuously added to the wet scrubbing unit to control the concentration of contaminants. To minimise the water use for the plant, recycle water from the sour water stripper unit is used for this make-up and this comprises the majority of the make-up water stream. A small bleed flow of the contaminated water is sent to the sour slurry stripping unit to recover the contaminants.
A scrubber outlet temperature of 128 °C has been generally selected. Other exit temperatures are however possible. For the study alternatives with CO_2 capture and sour shift reaction, the temperature is increased up to 160 °C, with the conseguent elimination of

LP steam production in Unit 1300.

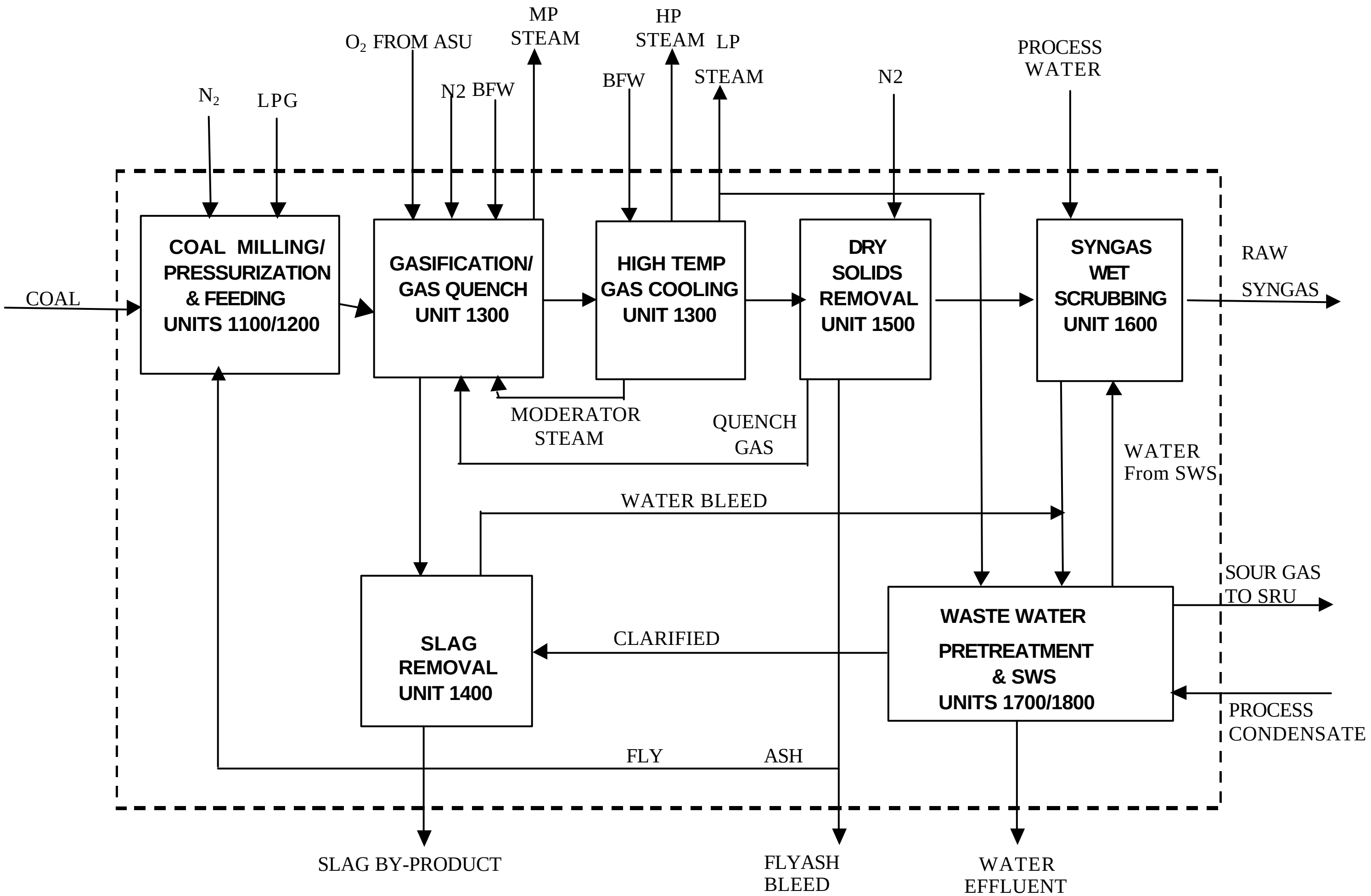
Sour Slurry Stripper (Waste Water Pretreatment) - Unit 1700

The blow-down water from the wet scrubbing unit and a bleed from the slag bath are fed to a stripper for the removal of hydrogen sulphide, dissolved raw gases and to reduce the ammonia level in the water to an environmentally acceptable level. In this unit, low-pressure steam provides the necessary heat and stripping medium. A large portion of the effluent water from the stripper is recycled after clarification to the slag bath as make-up water. Only a small effluent water stream is sent to the OSBL Effluent Treating facilities (e.g. biotreater). In this way, the consumption of process water has been minimised.

Sour Water Stripper – Unit 1800

Sour water streams from several sources in downstream OSBL units are stripped in this unit. Since we have no insight in all downstream units, we have assumed that any water condensed out of the syngas prior to the Acid Gas Removal unit will be supplied to this unit. In actual practice we expect a slightly higher volume of water to be treated. Since the column operates under non fouling conditions, the necessary stripping steam is supplied via a LP steam re-boiler. The vapour leaving the SWS column is sent to an overhead system. In this overhead system the overhead vapours are condensed and the sour gases are separated from the condensate in the gas/liquid separator. The condensed water is routed back to the SWS column as reflux, above the rectifying bed. The sour gases are routed to the battery limit. The SWS effluent has been used as make-up water in the wet scrubbing systems.

FIGURE 1
GASIFICATION ISLAND BLOCK FLOW DIAGRAM



3.0 PROCESS FLOW DIAGRAMS

The preliminary Process Flow Diagrams provided by SHELL are attached.

4.0 CHARACTERISTICS OF STREAMS AT GASIFICATION ISLAND BATTERY LIMITS.

The following Tables summarize the characteristics of Streams at Gasification Island Battery Limits for the cases 1, 2, 3, 4 and 5.

The Cases differ for plant configuration and gasification pressure as follows:

1 Low Gasification pressure, IGCC w/o CO_2 capture
2 High Gasification pressure, IGCC w/o CO_2 capture
3 Low Gasification pressure, IGCC with CO_2 capture (Outlet Scrubber T: 160°C)
4 High Gasification pressure, IGCC with CO_2 capture (Outlet Scrubber T:180°C)
5 Low Gasification pressure, IGCC with CO_2 capture (Outlet Scrubber T: 126°C)

Shell consider cases 1,3 and 5 as entirely proven concept. Cases 2 and 4 (High pressure cases) do contain elements that require confirmation during a feasibility study.

Cases 3 and 5 differ for the temperature at Scrubber Outlet. In case 3 this temperature is higher in order to maximize the syngas water content, thus limiting the steam flowrate to be added upstream of the sour shift section.

TABLE 1

	Case 1	Case 2	Case 3	Case 4	Case 5
Fresh Coal to Coal Grinding					
Flowrate (fresh, Air Dried Basis), t/h	254.9	256	271.8	272.9	271.8
Ultimate Analysis (%wt) (dry, ash free)					
Carbon	82.5	82.5	82.5	82.5	82.5
Hydrogen	5.6	5.6	5.6	5.6	5.6
Nitrogen	1.77	1.77	1.77	1.77	1.77
Sulphur	1.1	1.1	1.1	1.1	1.1
Oxygen	9	9	9	9	9
Chlorine	0.03	0.03	0.03	0.03	0.03
Total	100.00	100.00	100.00	100.00	100.00
Coal HHV (Air Dried Basis), kcal/kg	6464	6464	6464	6464	6464
Coal LHV (A.D.B.), kcal/kg	6180	6180	6180	6180	6180
Thermal Pow, MWt (HHV)	1915.9	1924.2	2042.9	2051.2	2042.9
Thermal Pow, MWt (LHV)	1831.6	1839.3	1953.1	1960.9	1953.1
Charge to Gasifiers (Total)					
Total (Coal + flux), t/h	262.8	263.9	280.1	281.2	280.1
Flux Flowrate, t/h	7.9	7.9	8.3	8.3	8.3
95% O_2 Flowrate, t/h	191.5	193.7	204.1	206.6	204.1
O_2 Pressure @ B.L., bar g	39.4	65.7	39.4	65.7	39.4
O_2 Temperature @ B.L., °C	100	100	100	100	100

TABLE 1 (c'd)

	Case 1	Case 2	Case 3	Case 4	Case 5
Gasifier/Syngas Cooler Outlet Cond.s					
Pressure, bar g	34.5	59.5	37.5	59.5	37.5
Temperature, °C	250	250	350	350	250
Gasification Temp, °C	> 1500	>1500	>1500	>1500	>1500
Characteristics of Syngas Ex Scrubber (Total)					
Composition, % mol					
CO	56.4	53.3	49.6	47.1	56.4
H_2	29.7	28	26.3	24.7	29.7
CO_2	1.4	1.5	1.3	1.3	1.4
H_2O	7.0	7.0	18.1	18.2	7.0
Ar	0.7	0.7	0.6	0.6	0.7
N_2	4.53	9.25	3.86	7.9	4.53
H_2S	0.24	0.22	0.21	0.2	0.24
COS	0.02	0.02	0.02	0.02	0.02
HCN	0.01	0.01	0.01	0.00	0.01
	100.00	100.00	100.00	100.00	100.00
Flowrate, kmol/h (1)	23,672.4	24,997.7	28,850	30,070	25,192.8
t/h	471.2	508	568.2	603.7	501.8
Pressure @ B.L., bar g	33	58	36	58	36
Temperature @ B.L., °C	126	145	160	180	126
Raw Syngas HHV, dry kcal/kg	3150.4	2903.3	2632.1	2918.5	2632.1
Raw Syngas LHV, dry kcal/kg	2981.6	2748	2490.6	2762.4	2490.6
Raw Syngas Thermal Power (LHV), MWt	1531.4	1527	1453.5	1630.4	1453.5
Gasification eff. (HHV), %	84.5	83.8	84.5	84.0	84.5
Gasification eff. (LHV), %	83.6	83.0	83.6	83.1	83.6
Nitrogen Consumptions					
HP N_2 Flowrate, t/h	81.4	234	84.6	239.8	84.6
HP N_2 Press @ B.L., barg	68	93	68	93	68
HP N_2 Temp @ B.L., °C	80	80	80	80	80
LP N_2 Flowrate, t/h	31.7	66.6	32.8	67.7	32.8
LP N_2 Press @ B.L., barg	6.5	6.5	6.5	6.5	6.5
LP N_2 Temp @ B.L., °C	70	70	70	70	70

Note (1): Net of clean syngas consumption for coal drying (approx 1% of total syngas production).

TABLE 2

STEAM PRODUCTIONS/BFW CONSUMPTIONS

	Case 1	Case 2	Case 3	Case 4	Case 5
HP Steam Production					
Flowrate, t/h	306	319.7	326.2	340.6	326.2
Pressure @ Unit B.L, barg	127	165	127	165	127
Temperature, °C	380	380	380	380	380
MP Steam Production					
Flowrate, t/h	7.2	0.36	7.6	1.08	7.6
Pressure @ Unit B.L, barg	43.3	72.2	43.3	72.2	43.3
Temperature, °C	315	315	315	315	315
LP Steam Production					
Flowrate, t/h	58	71.3	-	-	61.5
Pressure @ Unit B.L, barg	6.5	6.5	-	-	6.5
Temperature, °C	168	168	-	-	168
HP BFW Consumption					
Flowrate, t/h	348.5	363.2	371.5	387	371.5
Pressure @ Unit B.L., barg	179	179	179	179	179
Temperature, °C	160	160	160	160	160
MP BFW Consumption					
Flowrate, t/h	79.6	95	35.6	38.1	85
Pressure @ Unit B.L, barg	59	59	59	59	59
Temperature, °C	160	160	160	160	160
LP BFW Consumption					
Flowrate, t/h	11.5	11.9	-	-	12.2
Pressure @ Unit B.L, barg	17	17	-	-	17
Temperature, °C	160	160	-	-	160
Steam Condensate					
Flowrate, t/h	38.9	49	41.4	51.5	41.4

TABLE 3

	Case 1	Case 2	Case 3	Case 4	Case 5
Slag					
Total Dry, kg/h	37,800	38,160	40,320	40,680	40,320
Water, % wt	10	10	10	10	10
Total Wet, kg/h	42,000	42,400	44,800	45,200	44,800
Temperature, °C	50	50	50	50	50
Fly ash					
Flowrate, kg/h	1260	1260	1330	1330	1330
Temperature, °C	80	80	80	80	80
Process Water Make-up					
Flowrate, t/h	126.7	126	-113.1	-114.6	135
Pressure, barg	50	50	50	50	50
Temperature, °C	50	50	50	50	50
Sour Gas to SRU					
Flowrate	N/A	N/A	N/A	N/A	N/A
Composition	N/A	N/A	N/A	N/A	N/A
Liquid Effluent from Clarifier					
Flowrate, t/h	39.6	40	42.1	42.8	42.1
Pressure, barg	ATM	ATM	ATM	ATM	ATM
Temperature, °C	50	50	50	50	50

Note: (1) Total make-up calculated by FW to close the water balance of the overall Process Units.

5.0 UTILITY AND CHEMICAL CONSUMPTIONS.

Table 4.1 summarizes the utility continuous consumptions (other than steam and Nitrogen) estimated for the four cases.

TABLE 4.1

	Case 1	Case 2	Case 3	Case 4	Case 5
Fresh Cooling Water, m^3/h	233	234	248	249	248
Absorbed Electric Pow, kW	12000	13000	12700	13700	12700
Instrument Air, Nm^3/h	700	700	700	700	700

Caustic solution is injected to the wet scrubbing unit to maintain the pH value of the circulating water slightly above neutral. For the same reason, HCl is added to the primary water treatment unit to prevent fouling. The consumption of these materials are summarised in Table 4.2.

TABLE 4.2

Estimated chemical consumption

Item	Specifications	Unit	Quantity
NaOH	20%	t/h	0.6
HCl	15%	t/h	0.45

6.0 EQUIPMENT LIST

Major Equipment related to the SHELL Gasification Island are presented in the attached Equipment List.

The main process units consist of two 50% trains as detailed in the Equipment List. Even if the capacity of each gasifier is significantly higher than the Buggenum capacity, the required scale up (approx. + 60%) is not seen by Shell as a risk. They have designed and offered gasifiers at even higher throughput.
For IGCC generating electric power only, Shell do not recommend to install overcapacity in the Gasification Island, but only to have natural gas available as back-up for the Combined Cycle.

MAIN EQUIPMENT LIST

The first numbers give the number of systems, the second number gives the fraction of the total plant capacity.

Unit 1100 - Coal Milling and Drying (4 x 33% trains)

4	33.3%	Raw Coal Bunker
4	33.3%	Raw Coal Bunker Bag Filter and Exhaust Fan
4	33.3%	Gravimetric Coal Weigh Feeder
4	33.3%	Flux Bunker(*)
4	33.3%	Flux Bunker Bag Filter and Exhaust Fan (*)
4	33.3%	Gravimetric Flux Weigh Feeder
4	33.3%	Coal Mill
4	33.3%	Rotary Classifier
4	33.3%	Inert Gas Generator
4	33.3%	Circulation Gas Fan
4	33.3%	Combustion Air Blower
4	33.3%	Seal Air Fan
4	33.3%	Dilution Air Fan
4	33.3%	Pulverised Coal Bag Filter
8	17%	Pulverised Coal Bag Filter Discharge Screws
8	17%	Pulverised Coal Rotary Feeders
8	17%	Pulverised Coal Screw Conveyors

(*) These are required when gasifying coals need fluxing, as in the present case.

Unit 1200 - Coal Pressurisation & Feeding (6 x 20% trains)

6	20%	Pulverised Coal Storage Vessel
6	20%	Pulverised Coal Storage Vessel Bag Filter
6	20%	Pulverised Coal Storage Bag Filter Discharge Screw
6	20%	Pulverised Coal Storage Bag Filter Rotary Feeder
6	20%	Coal Sluice Vessel
6	20%	Coal Sluice Vessel HP Filter
6	20%	Coal Feed Vessel
2	50%	Flyash Buffer Vessel
6	20%	Flyash Buffer Vessel Rotary Feeder

Unit 1300 - Gasification, Quenching, Syngas Cooling (2 x 50 trains)

2	50 %	Gasifier, which includes
		MP evaporator membrane wall
		Quench section with HP evaporator
		Duct between gasifier and SGC with HP evaporator
		Slag bath
2	50%	Syngas Cooler (SGC) which includes
		HP/MP superheater
		HP evaporator
		MP economiser
2	50%	LP Steam Generator
4	50%	HP Circulation Pump for syngas cooler and syngas duct sections
6	25%	MP Circulation Pump for gasifier membrane wall
4	50%	MP Circulation Pump for syngas cooler economiser
2	50%	HP Steam Drum
2	25%	MP Steam Drum
6	16.7%	Coal Burners per each gasifier
1	100%	Start up Burner per each gasifier
1	100%	Ignition Burner per each gasifier
2	50%	Oxygen Preheater
2	130%	Quench Gas Compressor
4	50%	Burner Cooling Water Circulation Pump
2	50%	Burner Cooling Water Buffer Vessel
2	50%	Burner Cooling Water Circulation Heater

Unit 1400 - Slag Removal (2 x 50% trains)

2	50%	Slag Crusher
2	50%	Slag Accumulator
2	50%	Slag Sluice Vessel
2	50%	Slag De-watering Silo with Drag Chain
2	50%	Slag Conveyor (outside Shell scope)
4	50%	Slag Bath Circulation Pump
4	25%	Slag Bath Circulation Cooler
2	50%	Slag Sluice Water Clarifier
4	50%	Clarifier Overflow Pump
4	50%	Clarifier Bottom Pump
2	50%	Slag Sluice Water Buffer Tank
4	50%	Slag Sluice Vessel Fill Pump
4	50%	Slag Sluice Support Pump

4	50%	Slag De-watering Silo Slurry Pump
4	50%	Slag Sludge Pump

Unit 1500 - Dry Solids Removal (2 x 50% trains)

2	50%	HPHT Ceramic Candle Filter includes Cleaning system with buffer volume
2	50%	Flyash Sluice Vessel
2	50%	Flyash Sluice Vessel Vent Filter
1	100%	Flyash Sluice Vessel Nitrogen Buffer Vessel
1	100%	Flyash Stripping/cooling Vessel
1	100%	Flyash Stripping/cooling Vessel filter
1	100%	Flyash Stripping/cooling Vessel Nitrogen Buffer Vessel
1	100%	LP Nitrogen Buffer Stripper Filter
1	100%	LP Nitrogen Buffer Storage Filter
1	100%	LP Nitrogen Heater
1	100%	Flyash Intermediate Storage Silo
1	100%	Flyash Intermediate Storage Silo Filter
1	100%	Flyash Blow Egg
1	100%	Flyash Pick-up
1	100%	Flyash Storage Silo
1	100%	Flyash Storage Silo Filter
1	100%	Rotary Ash Feeder
4	50%	Flyash Recycle or Disposal System

Unit 1600 - Wet Scrubbing (2 x 50% trains)

2	50%	Scrubber Column
2	50%	Scrubber Circulation Cooler
4	50%	Scrubber Top Circulation Pump
4	50%	Scrubber Bottom Circulation Pump
2	50%	Start up Steam Ejector
4	50%	Caustic Dosing Pump

Unit 1700 - Sour Slurry Stripper (1 x 100% train)

1	100%	Sour Slurry Stripper (SSS) column
1	100%	SSS Feed Vessel
3	50%	SSS Effluent Cooler
2	100%	SSS Feed Pump
2	100%	SSS Effluent Pump
2	100%	Acid Dosing Pump
1	100%	Drains Collection Vessel
2	100%	Drain Pump
1	100%	SSS Effluent Clarifier
2	100%	SSS Effluent Clarifier Bottom Pump
2	100%	SSS Effluent Clarifier Overflow Pump
1	100%	Sludge Storage Tank
2	100%	Sludge Storage Tank Bottom Pump
1	100%	Vacuum Belt Filter
2	100%	Filtrate Recycle Pump
1	100%	Filtrate Vacuum Pump

Unit 1800 - Sour Water Stripper (1 x 100% train)

2	100%	Feed/Effluent Heat Exchanger
1	100%	Sour Water Stripper
1	100%	SWS Overhead Condenser
1	100%	SWS Reflux Vessel
2	100%	Reflux SWS Pump
1	100%	SWS Reboiler
2	100%	SWS Effluent Pump
1	100%	SWS Effluent Cooler

7.0 REFERENCES

The following Table 5 “Overview of reference SCGP Projects” summarizes the status and operating data of all the plants adopting the Shell Coal Gasification Process, i.e. the pilot plants (Amsterdam and Hamburg), the demonstration plant (SCGP – Germany, Houston (USA), the operating plant (Demkolec, Buggenum (the Netherlands)) and the plants under design/engineering/development which Shell are allowed to refer to.

TABLE 5

OVERVIEW OF REFERENCE SCGP PROJECTS

PROJECT	Units	GASCO	Harburg	SCGP-1	Demkolec	Sulcis	Paradip	Dongting
Location	-	Amsterdam, Netherlands	Harburg, Germany	Houston, USA	Buggenum, Netherlands	Sardinia, Italy	IOCL India	Dongting, China
Status	D/P/C/O/S (*)	S	S	S	O	D	D	D
type of project	I/R/P/O (**)	P	P	P	O	I	O	O
year of license	-	N.A.	N.A.	N.A.	1989	1999	1999	2000
first operating year	-	1976	1978	1986	1993	-	-	-
type of feedstock	-	coal + petcoke	coal	coal + petcoke	coal	coal	Petcoke	coal
capacity	t/d	6	150	220-360	2,000	2 x 2,500	8 x 960	2,000
gasifier pressure	Barg	25	25	24	27	34	40	40
sulphur range	%wt moisture free	-	-	0.3 - 5.2	0.3 - 1.5	4.3 - 7.3	<=8.3	3.9 - 4.3
total runhours	-	19,000	6,000	15,000	30,000	-	-	-
longest run	-	-	1,000	1,528	2,070	-	-	-
overall plant availability	-	-	-	-	85% (****)	-	-	-
gasification unit availability	-	-	-	80% (***)	90% (****)	-	-	-

Notes:

*	D/PC/O/S	-	Design / Pending Project Approval / Construction / Operation / Shut-down
**	I/R/P/O	-	IPP with project financing / Refinery / Pilot or demonstration plant / Other
***	During Demonstration Phase		
****	Excluding scheduled shut downs		

8.0 INVESTMENT COSTS

Table 6 summarizes the estimated total FOB costs provided by SHELL for the Gasification Island, as defined in para 2.0 for the four cases, based on 2002 costs in the Netherlands. Excluded are Coal Yard and Handling/Conveying facilities and general facilities (i.e. building, control room, DCS utilities etc.).

TABLE 6

	Case 1 MM Euro	Case 2 MM Euro	Case 3 MM Euro	Case 4 MM Euro	Case 5 MM Euro
Gasification Island	152	185	161	196	161

9.0 AVAILABILITY DATA

SHELL expect the following plant availability including scheduled maintenance, for the first operating years:

1st year 55%
2nd year 75%
3rd year 85%
4th year 90%

SHELL communicate that Demkolec had excellent operation last year; gasification availability is considerably above 90%. Including gas treating the gasification plant has 8% planned outages and 7% unplanned outages. Demkolec's yearly production rate was about 60% of design capacity due to favorable commercial circumstances (load balancing with 15 min. notice) and planned shutdown for GT overhaul.

1.2 Texaco Technology

Purpose of the attached document “Texaco Gasification Island” is to summarize the information received from Texaco for the Gasification Power Generation Study.
Texaco provided a set of information provided pursuant to the non-disclosure agreement between FW and Texaco. As a consequence this chapter contains only the data that Texaco allows to be disclosed to IEA GHG R&D without a non-disclosure agreement between IEA and Texaco.
In particular these data were the basis in the first step of the study for the selection of the gasification pressure for the IGCC configurations with and without CO_2 capture.
Furtherly in the evaluation of the IGCC perfomances of all the Shell alternative some minor modifications of these data were made in order to adjust performances and investment cost to a slightly different coal flowrate as detailed per each alternative in Sections D and E.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
CONTRACT NO. : 1-BD-0119A
UNIT NO. :
DOCUMENT NAME : TEXACO GASIFICATION ISLAND

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CHECKED BY : S. ANDREOLA
APPROVED BY : R. DOMENICHINI

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TEXACO GASIFICATION ISLAND

I N D E X

1.0 <u>Introduction</u>

Purpose of this chapter is to summarize the information received from Texaco for the Gasification Power Generation Study that Texaco allows to be disclosed to IEA GHG R&D without a non-disclosure agreement between IEA and Texaco.

2.0 Gasification Island Process Description And Block Flow Diagram

2.1 Overall Texaco Gasification Process Description

The Gasification Unit employs the Texaco Gasification Process (TGP) to convert feedstock coal into syngas. Facilities are included for scrubbing particulates from the syngas as well as removing the coarse and fine slag from the quench and scrubbing water.

The Gasification Unit includes the following sections, which are described briefly hereinafter:

Section	**Description**
1	Coal Grinding/Slurry Preparation
2	Gasification
3	Slag Handling
4	Black Water Flash
5	Black Water Filtration

The following description refers to a single train.

2.1.1 Coal Grinding/Slurry Preparation (PFD-01)

The Coal Grinding & Slurry Preparation System provides a means to prepare the coal as a slurry feed for the gasifier. Coal is continuously fed to the Coal Weigh Feeder, which regulates and weighs the coal fed to the Grinding Mill. Grey water from Black Water Filtration is used for slurrying the coal feed. Slurrying water is added to the grinding mill with a feed ratio controller to control the desired slurry concentration. The Grinding Mill may also utilize coal dust recovered by dust collection systems in the coal storage areas. The Grinding Mill is either a rod-type or ball-type with an overflow discharge. The Grinding Mill reduces the feed coal to the design particle size distribution.

Slurry discharged from the Grinding Mill passes through a coarse screen and into the Mill Discharge Tank, and is then pumped into the Slurry Run Tank. The Slurry Run Tank holds enough capacity to sustain full rate operation of the gasifier train during routine maintenance of the Grinding Mill. Coal slurry is pumped from the Slurry Run Tank to the Gasifier by the Slurry Charge Pumps, which are high pressure metering pumps. These pumps supply a steady, controlled flow of slurry to the Gasifier Feed Injector.

A below grade Grinding Area Sump is located centrally within the Coal Grinding and Slurry Preparation section to allow for handling of drains and spills in this area.

2.1.2 Gasification (PFD-02)

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.

2.1.3 Slag Handling (PFD-03)

The Slag Handling System removes the majority of solids from the gasification process equipment. These solids are made up from the coal ash and unconverted coal components that exit the gasifier in the solid phase.

Coarse slag and some of the fine solids flow by gravity from the Gasifier quench chamber into the Lockhopper. Flow into the Lockhopper is assisted by the Lockhopper Circulation Pump which takes water from the top of the Lockhopper and returns it to the Gasifier quench chamber. After the solids enter the Lockhopper, the particles settle to the bottom. Thus, the Lockhopper acts as a clarifier, separating solids from the water. Solids are collected in this manner for a set period of time, typically about 30 minutes.

When the solids collection time is over, the Lockhopper is isolated from the quench chamber and depressured. Then, the solids, which have accumulated in the Lockhopper, are flushed with water into the Slag Sump. The water flush is then discontinued and the Lockhopper is filled with water and repressured, and the next solids collection period begins.

In the Slag Sump, slag settles onto a submerged conveyor, which drags the slag out of the water. It is passed over a screen, which allows surface water to drain. The slag is then transported by trucks to offsite for disposal. The water removed from the slag is pumped by the Slag Sump Overflow Pump to the Vacuum Flash Drum in the Black Water Flash Section.

Water used to flush the Lockhopper of collected solids is supplied to the Lockhopper Flush Drum from the Grey Water Tank in the Black Water Filtration Section. The water is cooled in the Lockhopper Flush Water Cooler so that the water in the Lockhopper will be cool at the start of the solids collection period and not get excessively hot during the solids collection period.

2.1.4 Black Water Flash (PFD-04)

The purpose of the Black Water Flash Section is to recover heat from the black water, as well as to remove dissolved syngas. Gas evolved from the flashes is routed to the Sulfur Recovery Unit, since it contains traces of hydrogen sulfide and ammonia. The cooled and flashed black water is sent to Black Water Filtration.

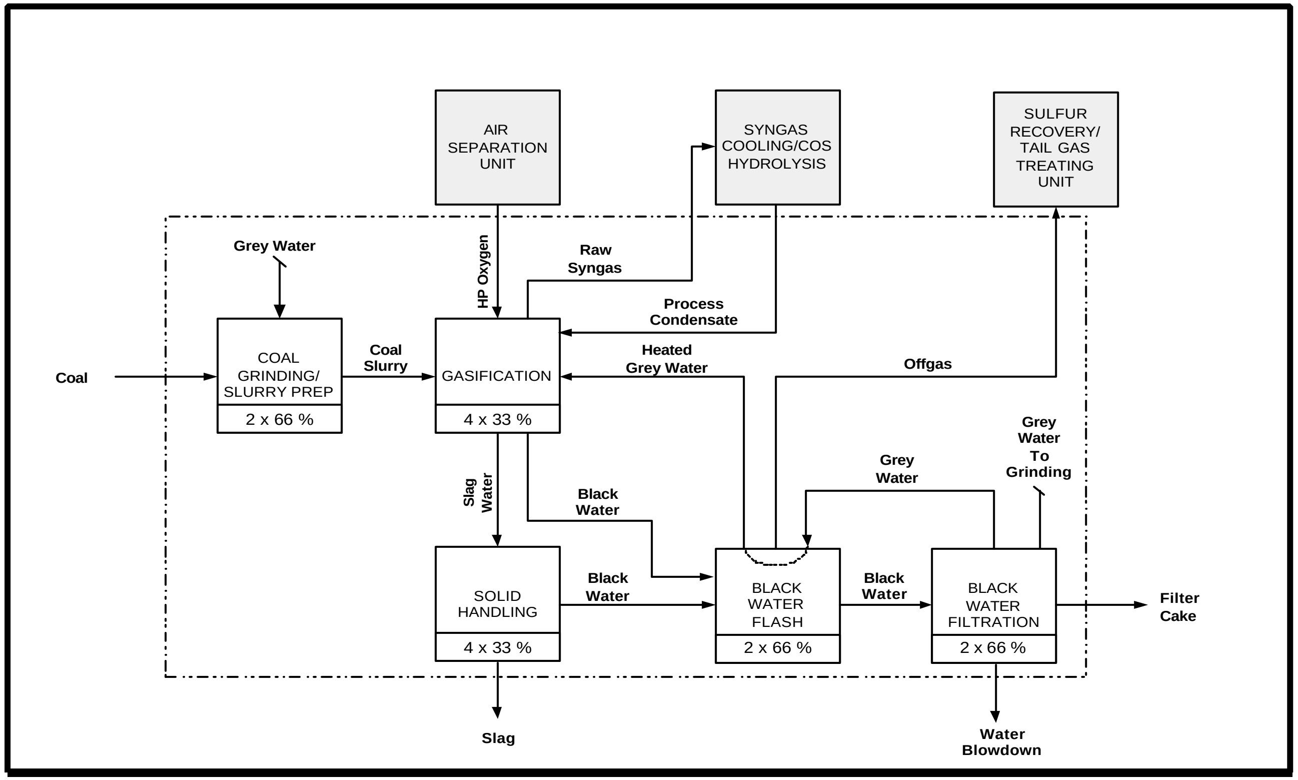
Black Water from the Gasifier quench chamber and the Syngas Scrubber is first routed to the LP Flash Drum. The overhead vapor is first used to heat the grey water return from the Black Water Filtration Section before it is condensed by the LP Flash Condenser. Then, both of the vapor and condensate are routed to the Vacuum Pump Knockout Drum. From the LP Flash Drum, the black water stream goes to the Vacuum Flash Drum along with the black water from the Overflow Slag Sump. The Vacuum Flash Drum flashes out additional dissolve gases and liquid of which most of the liquid is condensed by the Vacuum Flash OH Condenser and separated in the Vacuum KO Drum. Then, both of the vapor and condensate are routed to the Vacuum Pump Knockout Drum. Most of entrained gas in the black water is removed in the Vacuum Pump Knockout Drum and flows to the Sulfur Recovery Unit. Any liquid condensed in this vapor stream is also removed in Vacuum Pump Knockout Drum and flows to the Grey Water Tank.

2.1.5 Black Water Filtration (PFD-05)

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.

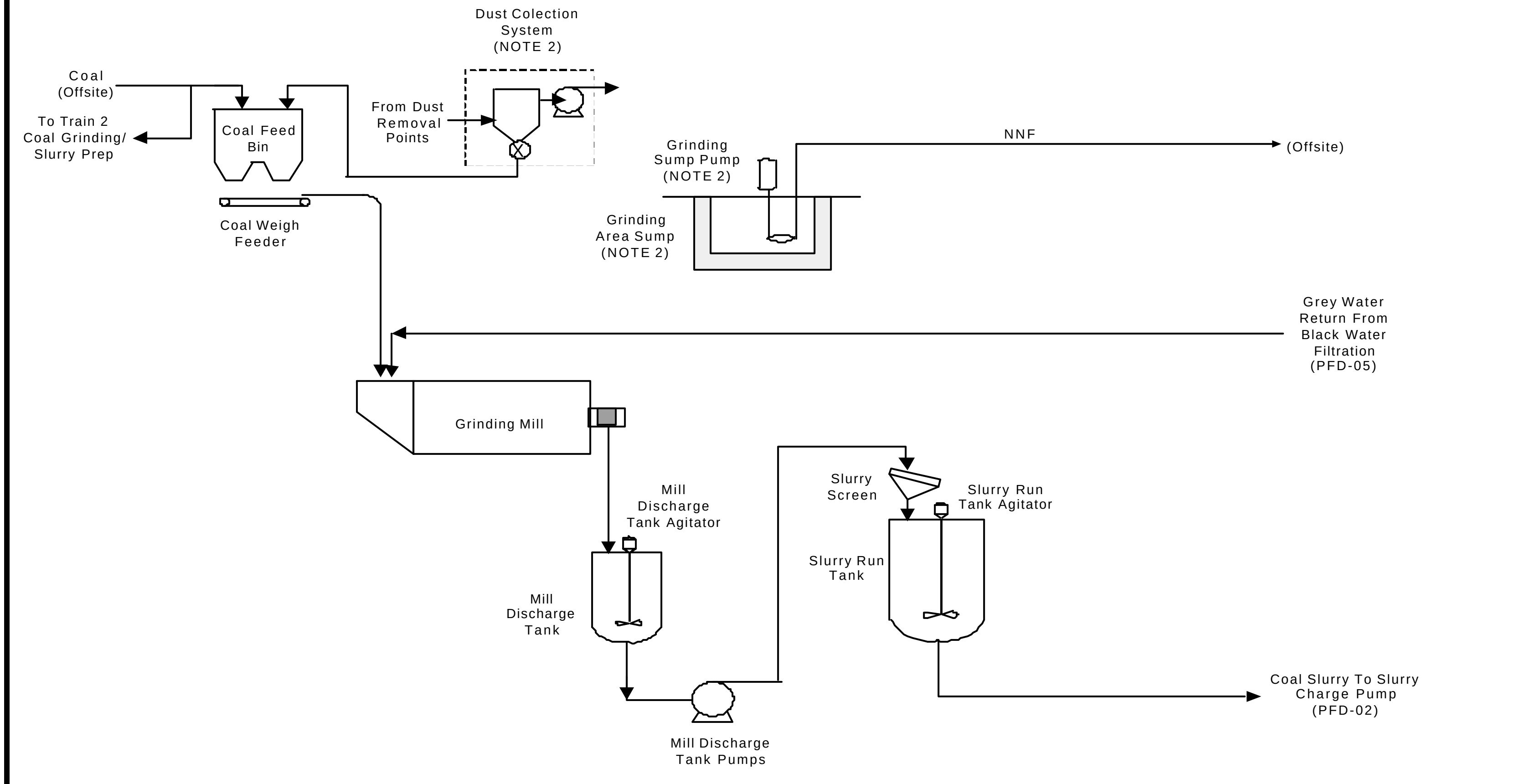
The water in the Grey Water Tank is essentially free of particulates. Some portion of the grey water is pumped by the LP Grey Water Return Pump to the Lockhopper Flush Drum, to the Coal Grinding Section and to offsite. The HP Grey Water Return Pump pumps grey water to the Grey Water Heater and then to the Syngas Scrubber.

FIGURE 1
PROCESS SCHEME FOR ALTERNATIVES W/O CO_2 CAPTURE



3.0 Process Flow Diagrams

The simplified Process Flow Diagrams provided by Texaco are attached.



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

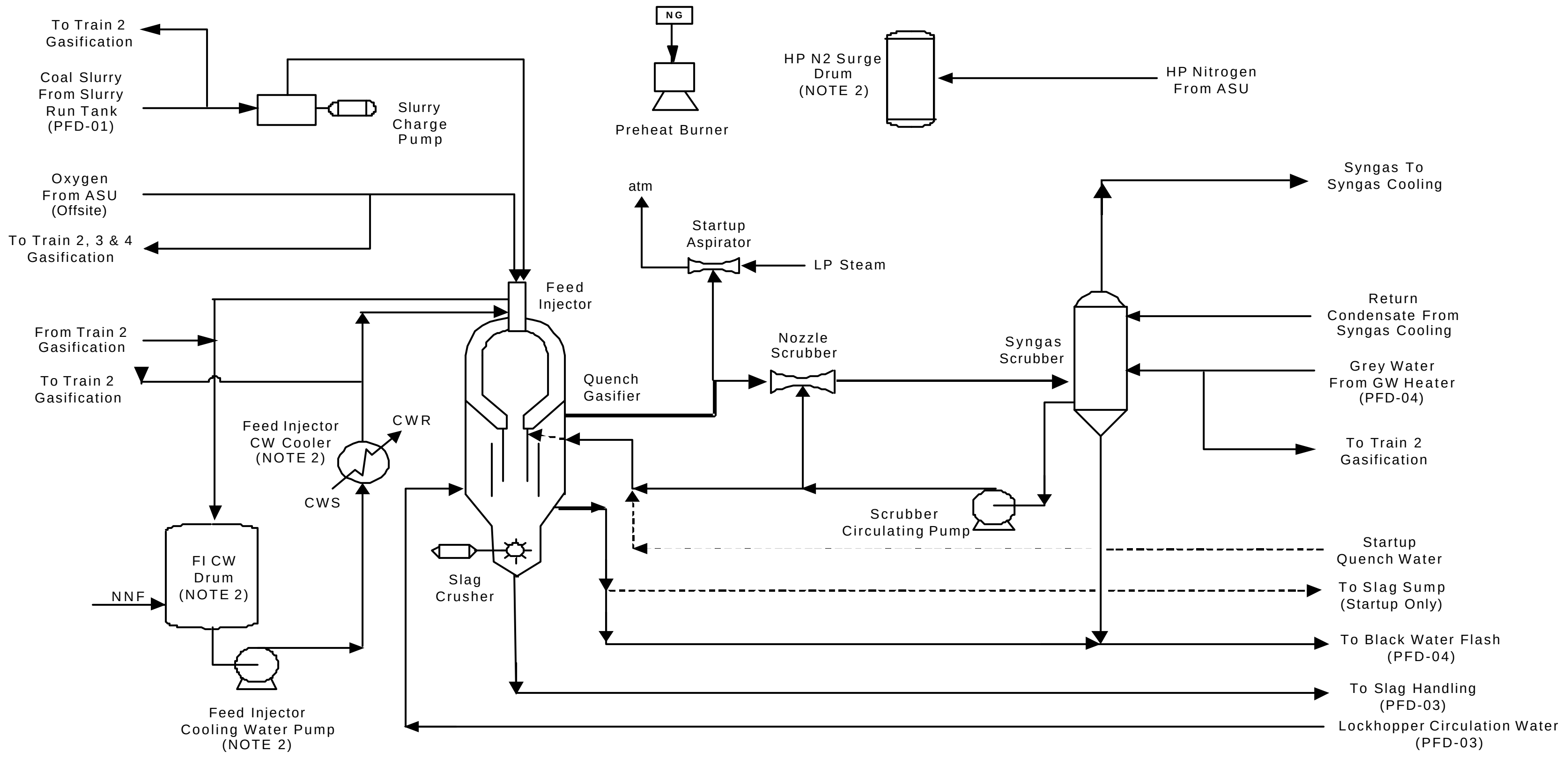
COAL GRINDING/SLURRY PREP SECTION

DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-01	
APPROVED	DATE		

IEA GHG

Gasification Power Generation Study

Revision no.: 3
Date: March 2003
Sheet: 11 of 23



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. FOUR TRAINS AT 33.3% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

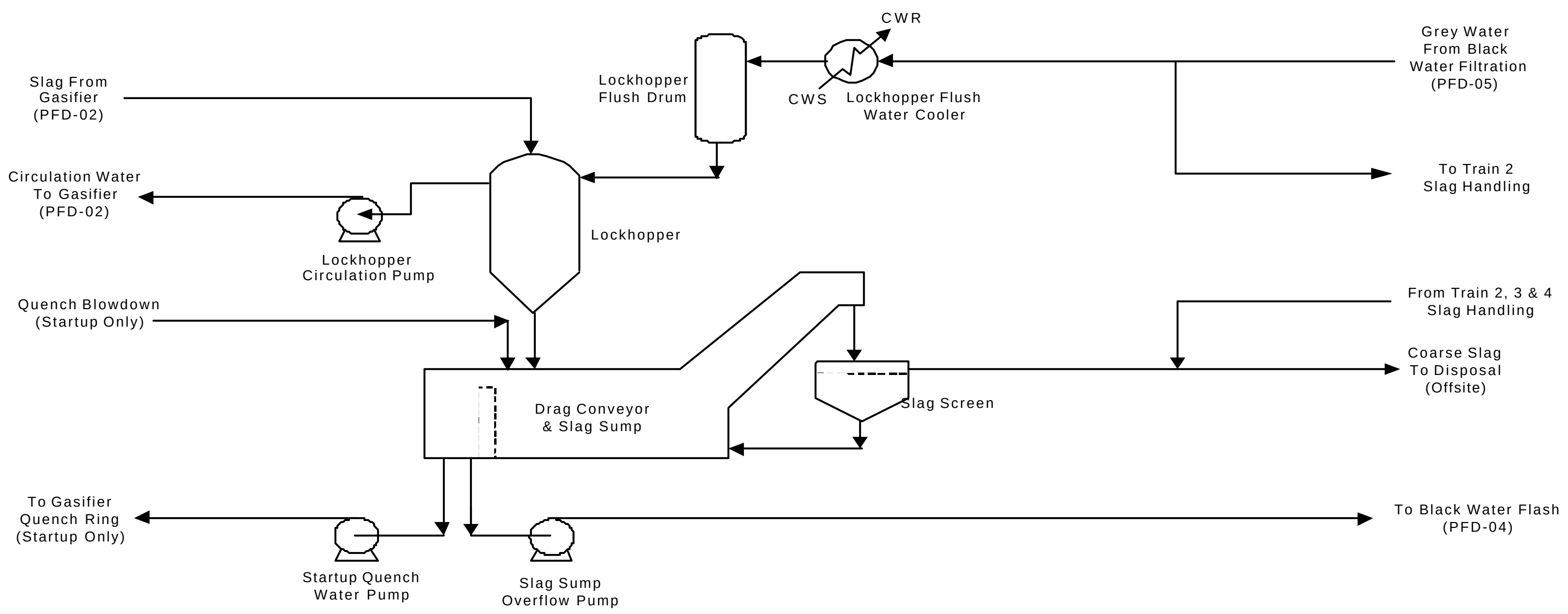
2. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED FOR HP N2 SURGE DRUM, FI CW DRUM, FI CW PUMP, AND FI CW COOLER.

TEXACO GASIFICATION POWER SYSTEMS			
GASIFICATION SECTION			
DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-02	
APPROVED	DATE		

IEA GHG

Gasification Power Generation Study

Revision no.: 3
Date: March 2003
Sheet: 12 of 23



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. FOUR TRAINS AT 33.3% CAPACITY ARE REQUIRED.

TEXACO GASIFICATION POWER SYSTEMS

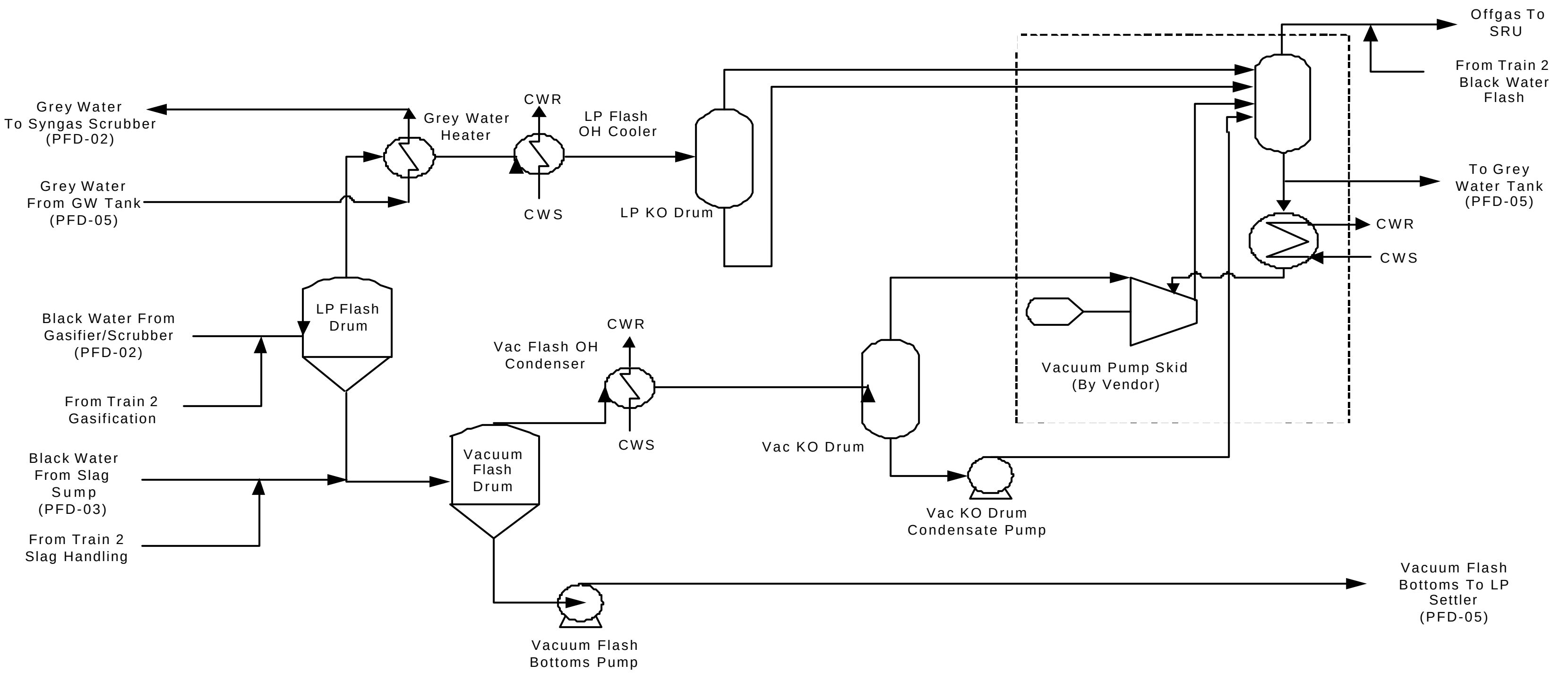
SLAG HANDLING SYSTEM

DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-03	
APPROVED	DATE		

IEA GHG

Gasification Power Generation Study

Revision no.: 3
Date: March 2003
Sheet: 13 of 23



TEXACO DEVELOPMENT CORPORATION
HOUSTON, TEXAS

NOTES:

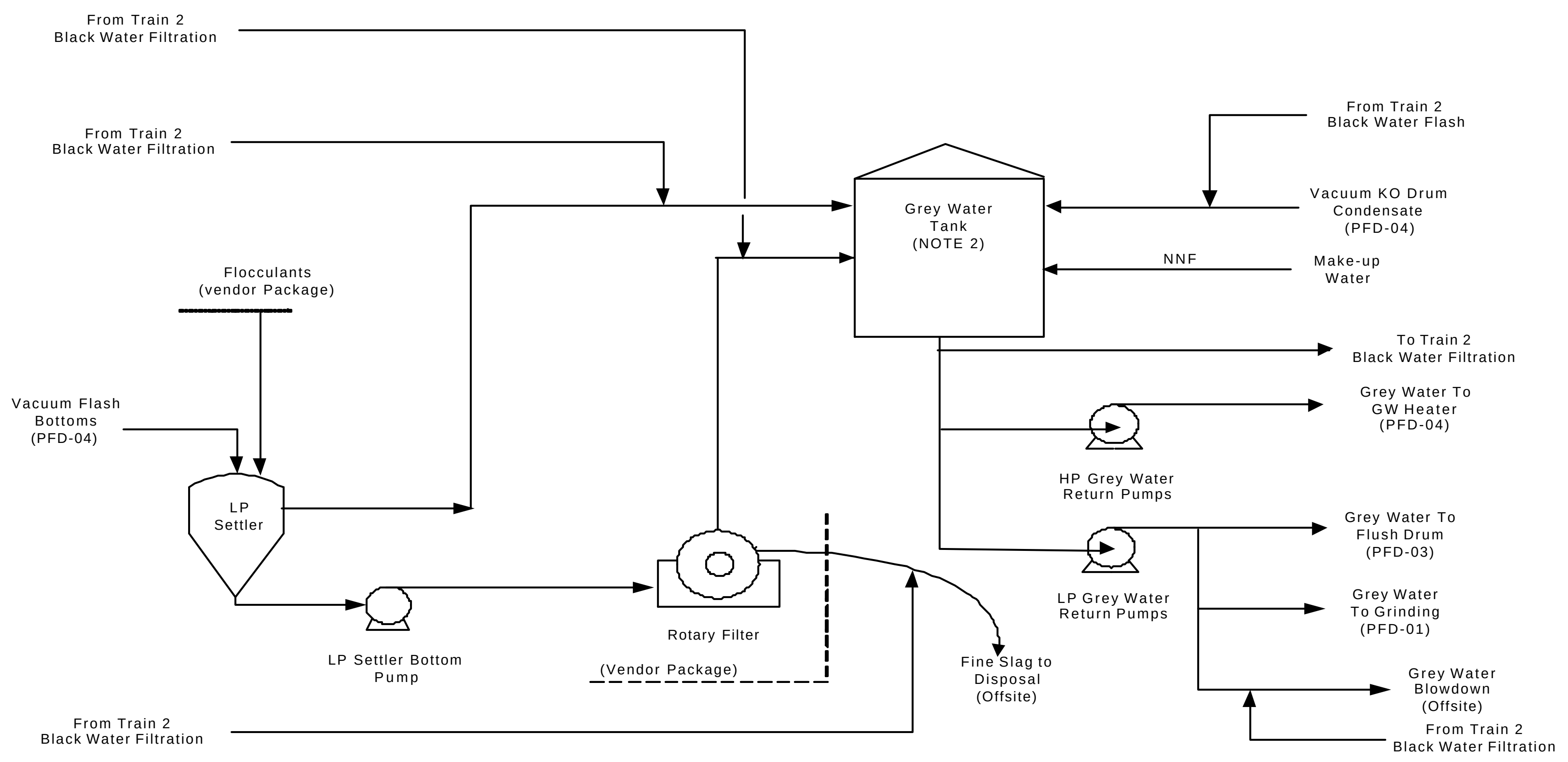
1. THE EQUIPMENT SHOWN IS FOR ONE TRAIN. TWO TRAINS AT 66.6% CAPACITY ARE REQUIRED UNLESS NOTED OTHERWISE.

TEXACO GASIFICATION POWER SYSTEMS			
BLACK WATER FLASH SECTION			
DRAWN	DATE	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-04	
APPROVED	DATE		

IEA GHG

Gasification Power Generation Study

Revision no.: 3
Date: March 2003
Sheet: 14 of 23



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	PROJECT NO.	REV.
DESIGNER	DATE		
CHECKED	DATE	DRAWING NO. PFD-05	
APPROVED	DATE		

4.0 Characteristics of Streams at Gasification Island Battery Limits.

The following Tables summarize the characteristics of Streams at Gasification Island Battery Limits for the cases 1, 2, 3 and 4, as well as the Estimate of Operation for the Gasifiers.
The Cases differ for plant configuration and gasification pressure as follows:

1 High Gasification pressure, IGCC w/o CO_2 capture
2 Low Gasification pressure, IGCC w/o CO_2 capture
3. High Gasification pressure, IGCC with CO_2 capture
4. Low Gasification pressure, IGCC with CO_2 capture

TABLE 1

	Case 1	Case 2	Case 3	Case 4
Fresh Coal to Coal Grinding				
Flowrate (fresh, dry), t/h	273.5	272.2	289.1	287.7
Flowrate (fresh, Air Dried Basis), t/h	302.2	300.7	319.4	317.9
Ultimate Analysis (%wt) (Moisture free)				
Carbon	71.4	71.4	71.4	71.4
Hydrogen	4.8	4.8	4.8	4.8
Nitrogen	1.5	1.5	1.5	1.5
Sulphur	1.0	1.0	1.0	1.0
Oxygen	7.8	7.8	7.8	7.8
Ash	13.5	13.5	13.5	13.5
Total	100.0	100.0	100.0	100.0
Coal HHV (Air Dried Basis), kcal/kg	6464	6464	6464	6464
Total Thermal Power (HHV), MWt	2271.3	2260.3	2400.8	2389.1
Charge to Gasifiers (Total)				
Slurry, t/h	427.3	425.2	427.3	425.2
Solids Slurry Percentage, %	64	64	64	64
95% Oxygen Flowrate, t/h	260.6	261.7	275.5	276.6
Oxygen Pressure @ B.L., bar g	79	52	79	52
Oxygen Temperature @ B.L., °C	149	149	149	149
Gasification Conditions				
Pressure, bar g	65	38	65	38
Temperature, °C	~ 1400	~ 1400	~ 1400	~ 1400

TABLE 1 (c'd)

	Case A.1	Case A.2	Case B.1	Case B.2
Characteristics of Syngas Ex Gasification Chamber (Total)				
Composition, % mol				
CO	34.0	34.2	34.0	34.2
H_2	33.0	32.9	33.0	32.9
CO_2	16.0	15.9	16.0	15.9
H_2O	14.9	14.9	14.9	14.9
$Ar + N_2$	1.8	1.8	1.8	1.8
H_2S + COS	0.27	0.27	0.27	0.27
Others	0.03	0.03	0.03	0.03
Syngas Flowrate, kmol/h	31,200	31,200	33,000	33,000
Characteristics of Syngas Ex Scrubber (Total)				
Composition, % mol				
CO	15.6	15.5	15.6	15.5
H_2	15.1	14.8	15.1	14.8
CO_2	7.3	7.2	7.3	7.2
H_2O	61.0	61.4	61.0	61.4
$Ar + N_2$	0.8	0.8	0.8	0.8
H_2S + COS	0.12	0.12	0.12	0.12
Others	0.08	0.18	0.08	0.18
Flowrate, kmol/h	67,600	68,700	71,400	72,600
Pressure @ B.L., bar g	62	35	62	35
Temperature @ B.L., °C	243	215	243	215
Raw Syngas, HHV, kcal/kg	2564	2558	2564	2558
Raw Syngas LHV, kcal/kg	2369	2364	2369	2364
Gasification Efficiency (HHV), %	73.0	73.5	73.0	73.5
Gasification Efficiency (LHV), %	70.5	71.0	70.5	71.0

TABLE 2

	Case A.1	Case A.2	Case B.1	Case B.2
Coarse Slag				
Dry Solids, % wt				
Char	12.5	12.5	12.5	12.5
Ash	87.5	87.5	87.5	87.5
Total Dry, kg/h	35,700	34,400	37,725	36,350
Water, % wt	50	50	50	50
Total Wet, kg/h	71,400	68,800	75,450	72700
Filter Cake				
Dry Solids, % wt				
Char	37.57	37.57	37.57	37.57
Ash	62.43	62.43	62.43	63.43
Total Dry, kg/h	8,900	8,600	9,400	9,100
Water, % wt	70	70	70	70
Total Wet, kg/h	29,750	28,650	31450	30300
Raw Water Make-up				
Flowrate, t/h	100.7	97.5	107.8	105.7
Sour Gas to SRU				
Flowrate, kg/h	4000	2900	4200	3000
Molecular weight	21.2	20.6	21.2	20.6

Note: (1) Total make-up calculated by FW to close the water balance of the overall Process Units.

5.0 Utility Consumptions

Table 3 summarizes the utility continuous consumptions estimated for the four cases.

TABLE 3

	Case 1	Case 2	Case 3	Case 4
HP Steam, t/h	5	5	5	5
MP Steam, t/h	0	0	0	0
LP Steam, t/h	0	0	0	0
Fresh Cooling Water, m^3/h	2933	3021	3087	3180
Absorbed Electric Power, kW	13020	12960	13760	13700

6.0 Equipment list

Only major equipment in TGP's Battery Limit are presented.

Coal Handling/Slurry Preparation

Coal Weigh Feeder	2 x	66%
Coal Feed Bin	2 x	66%
Dust Collection System	1 x	100%
Grinding Area Sump	1 x	100%
Grinding Sump Pump	1 x	100%
Grinding Mill	2 x	66%
Mill Disch Tank Agitator	2 x	66%
Mill Discharge Tank	2 x	66%
Mill Discharge Tank Pump	2 x	66%
Slurry Screen	2 x	66%
Slurry Run Tank Agitator	2 x	66%
Slurry Run Tank	2 x	66%

Gasification

Slurry Charge Pump	4 x	33%
Feed Injector CW Drum	2 x	66%
Feed Injector CW Cooler	2 x	66%
Feed Injector CW Pump	2 x	66%
Feed Injectors	9	Total
Preheat Burner	4	Total
Quench-type Gasifier	4 x	33%
Gasifier – Refractory	4	Total
Slag Crusher	4 x	33%
Syngas Scrubber	4 x	33%
Nozzle Scrubber	4 x	33%
Scrubber Circulation Pump	4 x	33%
HP Nitrogen Surge Drum	2 x	66%
Safety System PLC	1	
Start-Up Aspirator	4 x	33%

Slag Handling

Lockhopper	4 x	33%
Lockhopper Circ Pump	4 x	33%
Lockhopper Flush Drum	4 x	33%
Lockhopper Flush Water Cooler	4 x	33%
Start Up Quench Water Pump	4 x	33%
Drag Conveyor/Slag Sump	4 x	33%
Slag Screen	4 x	33%
Slag Sump Overflow Pump	4 x	33%

Black Water Flash

Grey Water Heater	2 x	66%
LP Flash OH Cooler	2 x	66%
LP Knockout Drum	2 x	66%
LP Flash Drum	2 x	66%
Vacuum Flash Drum	2 x	66%
Vacuum Flash OH Condenser	2 x	66%
Vacuum KO Drum	2 x	66%
Vacuum KO Drum Condensate Pump	2 x	66%
Vacuum Flash Bottoms Pump	2 x	66%
Vacuum Pump Skid	2 x	66%

Black Water Filtration

LP Settler	2 x	66%
LP Settler Bottoms Pump	2 x	66%
Rotary Filter	2 x	66%
Grey Water Tank	1 x	100%
HP Grey Water Return Pump	2 x	66%
LP Grey Water Return Pump	2 x	66%

7.0 References

As of January 2001 the total plants licensed by Texaco are 127, with a total of 69 plants in operation and engineering, construction or start-up phases.
Table 4 shows the split among different feedstocks.

TABLE 4

Feedstock	Plants in operation	Plants in Eng./ Constr./Start-up Phases	Total
Coal/Petcoke	13	2	15
Liquid	20	12	32
Natural Gas	19	3	22
TOTAL	49	20	69

Table 5 lists coal gasification plants presently in operation.

TABLE 5

Texaco Coal/Petcoke Gasification Process

Customer	Location	No. of Gasifiers Op/spare	Type Quench (Q) WHB (FHR)	Solid Feedstock	Product	Start Date
Eastman Chemical	Kingsport, TN – USA	1/1	Q	Bituminous Coal	Oxochemicals	1983
Ube Ammonia Industry	Ube City – Japan	3/1	Q	Coal/Petcoke	Ammonia	1984
Rheinbraun	Ville – Germany	3/0	Q/FHR	Coal/oil	Methanol	1986
Lu Nan Chemical Industry	Tengxian, Shandong – China	2/0	Q	Bituminous Coal	Ammonia	1993
Shanghai Pacific Chemical	Wujing, Shanghai – China	3/1	Q	Anthracite Coal	Methanol/ Town gas	1995
Tampa Electric	Lakeland, FL – USA	1/0	FHR	Coal	Electricity	1996
Texaco Gasification Power Systems	El Dorado, KS – USA	1/0	Q	Petcoke	Electricity/ Steam	2000
Weihe Fertilizer	Xian, Shaanxi – China	2/1	Q	Coal	Acetic Acid	1996
Farmland Industries	Coffeyville, KS – USA	1/0	Q	Petcoke	Ammonia/ UAN	2000
Huainan	Anhui – China	2/1	Q	Coal	Ammonia	2000
Motiva Enterprises	Delaware City, DE – USA	2/0	Q	Petcoke	Electricity/ Steam	2000

8.0 Investment costs

Table 6 summarizes the estimated Investment Cost provided by Texaco for the Gasification Island for the four cases, split into the main sections. This cost includes materials and construction only.

All dollar figures in $000

SECTION NAME	CASE 1	CASE 2	CASE 3	CASE 4
Coal Grinding and Slurry Preparation	37,575	37,575	38,846	38,846
Gasification	63,563	57,207	65,713	59,141
Slag Handling	18,662	18,662	19,293	19,293
Black Water Flash	10,090	10,090	10,431	10,431
Black Water Filtration	10,771	10,771	11,135	11,135
TOTAL (*)	**140,661**	**134,305**	**145,418**	**138,847**

* These costs include bulk materials, equipment and labor costs only and some adjustments to reflect the difference in pressure and gasifier size.

2.0 Coal Handling and Storage

Coal Handling and Storage consists of one dome with a coal storage capacity equivalent to approx. 21 days at IGCC full capacity, one conveyor connecting the pier with the dome sized for 1200 t/h, and one conveyor connecting the dome with the milling system in the Gasification Island sized for the actual coal flowrate. Due to the similar coal consumption of some alternatives four different designs of this Unit are assumed:

1. for alternatives A.1, A.2;
2. for alternatives B.1, B.2, B.3, B.4;
3. for alternatives C.1, C.3;
4. for alternatives C.2, D.1, D.2, D.3, D.4.

The Unit is designed in order to minimize particulate emissions, with both closed storage (dome) and closed conveyors.

3.0 Air Separation Unit

The Air Separation Unit (ASU, Unit 2100) 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:

- for Texaco alternatives nitrogen is almost integrally routed to the gas turbines of the combined cycle for power augmentation and NO_x control;
- for Shell alternatives nitrogen is used for the pneumatic transport of dried pulverized coal to the gasifiers; the excess is routed to the gas turbines for power augmentation and NO_x 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. Reference is made to Section B, para. 8, for details about optimization of the integration degree.
The streams listed in Table C.2.1 are produced according to the requirement of each gasification technology.

Table C.2.1

	Product	Use	Details	Gasification Technology
1	Oxygen	C	High Pressure Gaseous Oxygen for Gasifiers	S/T
2	Oxygen	C	Low Pressure Gaseous Oxygen for Sulphur Recovery Claus Units	S/T
3	Nitrogen	C	Medium Pressure Gaseous Nitrogen for Syngas Dilution at Gas Turbines	S/T
4	Nitrogen	C	Very High Purity High Pressure Gaseous Nitrogen for dried coal transport	S
5	Nitrogen	C	Very High Purity Low Pressure Gaseous Nitrogen for died coal transports	S
6	Nitrogen	C	Very High Purity Low Pressure Gaseous Nitrogen for blanketing, equipment purging, etc	S/T
7	Nitrogen	D	Very High Purity High/Low Pressure Gaseous Nitrogen for Purging under Gasifiers and Gas Turbine Shutdown	S/T
8	Air	C	Low Pressure Dry Gaseous Air to Plant and Instrument Air System	S/T

Notes (1): S = Shell (2) C = Continuous
T = Texaco D = Discontinuous

3.1 Capacity

The Air Separation Unit capacity is defined per each alternative by the required oxygen production (sum of flowrates to the gasification island and to the sulphur plant).

3.2 Compressed Air

When the gasification operates at full load, 50% (or 30% for one Shell case, or 43.2% for one Texaco case) 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% (or 70%/56.8% whichever is the case) 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.

3.3 Product Characteristics

Oxygen For Gasifiers and Sulphur Plant

Purity

O_2	95 mol%
Ar	3.5 mol%
N_2	1.5 mol%
H_2O	1 ppm (max)
CO_2	1 ppm (max)

Nitrogen For Syngas Dilution at Gas Turbines

The gas turbines require a continuous gaseous nitrogen supply to dilute Syngas and maximise power output. The maximum oxygen content of nitrogen stream is 2% mol.

Other Nitrogen Streams

Purity	
N_2	99.99 mol% (1)
Cl_2	Absent
Ar	300 ppm (max)
CO_2	5 ppm (max)
HC	5 ppm (max)
Oxygenated Compounds	100 ppm (max)
Dew Point	-50 °C @ 7 barg
CO (No. of times the content in ambient air)	1.5 max

Note (1): including Argon

These streams perform the following functions:

a. Nitrogen For Pneumatic Transport of dried coal transport

b. Nitrogen For Blanketing and Purging

The IGCC plant requires a continuous supply of gaseous nitrogen for tank blanketing and other small purging.

c. Nitrogen For Purging Under Gasifier and Gas Turbine Shutdown

The instantaneous shutdown of one gasifier or of one gas turbine requires a purging supply of gaseous nitrogen. To ensure a secure supply the Gasifiers, as well as the two gas turbines require a dedicated high pressure local storage of gaseous nitrogen, to be fed by the ASU. The refilling of these storage vessels is intermittent. A vaporiser, two pumps and/or compressors are to be provided if required to meet this demand.

Dry Air For Plant and Instrument Air System

All plant and instrument air requirements for the IGCC are met by extracting air from each main air compressor of ASU. An air receiver will be provided common to both trains, sized for 10 minutes hold up at the flow given below. Each air compressor is sized for the extraction of 5,000 Nm^3/hr, however under normal circumstances the compressors shall share the duty equally.

Flow	5,000 Nm^3/h
Dew Point	- 20°C @ 7.0 bar g

3.4 Product Storage

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.
Also the nitrogen system is provided with a liquid storage designed to ensure for Shell case 12 hours of a single ASU train continuous nitrogen requirements of the Gasification Island. In addition for both technologies 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.

4.0 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.

Depending on the design alternative under consideration, amongst the 13 cases listed in paragraph 6.0 of Section B, this unit may include the following processing steps:

- catalytic conversion of CO to H_2 and CO_2 (shift reaction; based on a catalyst that can be suitable to process either sulphur containing syngas (sour shift) or only sulphur free syngas (clean shift);
- syngas cooling in waste heat boilers, recovering MP, LP and VLP steam;
- further cooling of syngas by preheating process condensate;
- catalytic conversion of COS to H_2S and CO_2;
- reduction of pressure from the gasification pressure to the pressure required by the gas turbine. This pressure reduction may be achieved by an expansion turbine, recovering energy, or by control valve;
- preheating of clean syngas, and possibly humidification, before entering the gas turbine combustion chamber.

Each of the cases examined in the study has a different combination and sequence of the above listed processing steps.
Section D of the study provides for each case a description of this unit, with the support of process flow diagrams.
For Catalytic Conversion of CO to H_2 and CO_2 Synetix and Süd Chemie provided Shift Reactors data.

5.0 Acid Gas Removal

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.
The selection of the acid gas removal process for each of the 13 alternatives examined in the study was done with a dedicated optimization study reported in Section H of this report. A summary of the acid gas removal processes selected for each case is given in the Table B.6.1, attached to paragraph 6.0 of Section B.

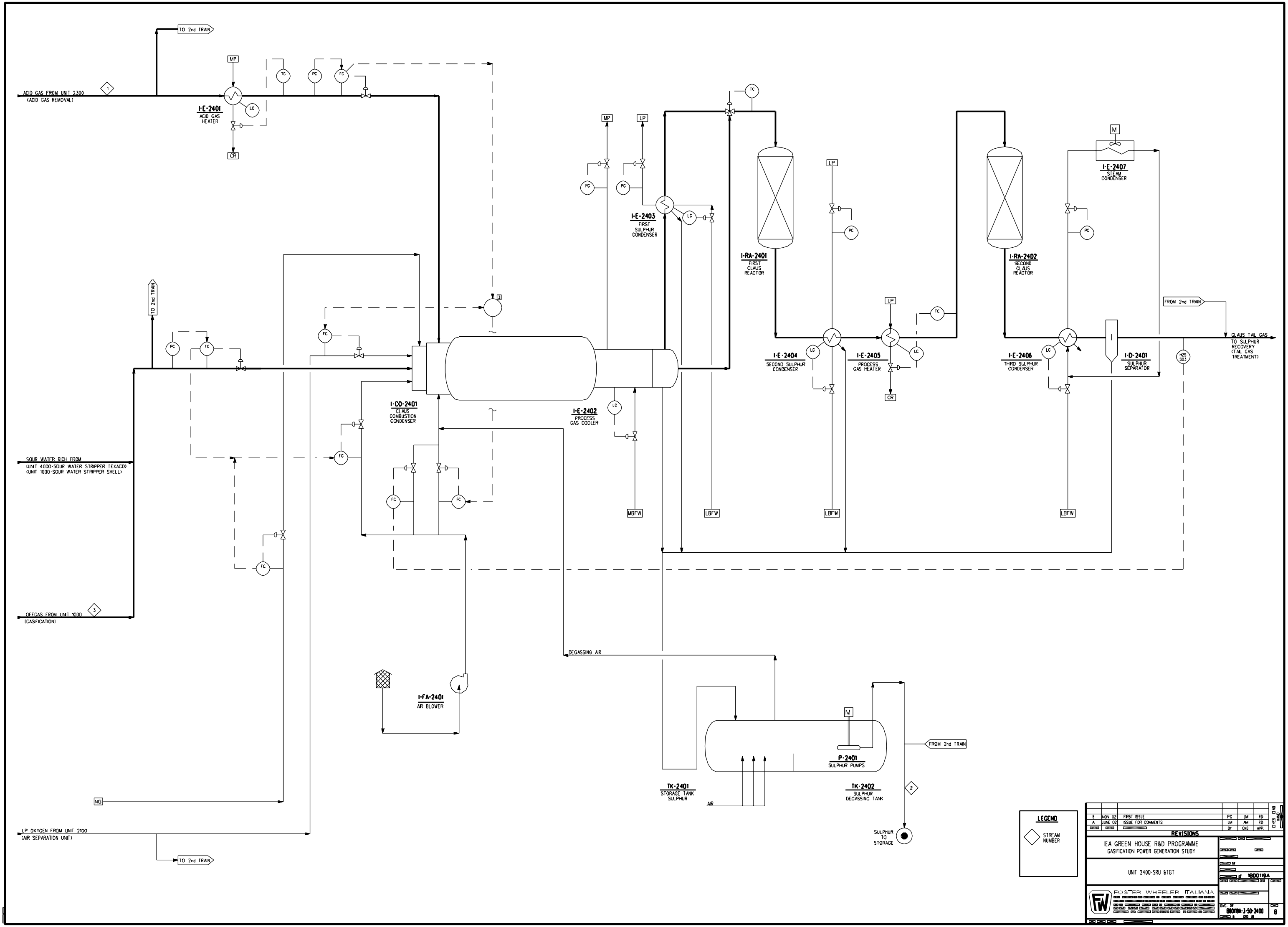
The process description of the AGR used in each of the alternative cases is given in Section D. This description is limited to the information which the Licensor (UOP and DOW) of the process has authorized for disclosure, without a secrecy agreement by IEA.

6.0 Sulphur Recovery Unit and Tail Gas Treatment

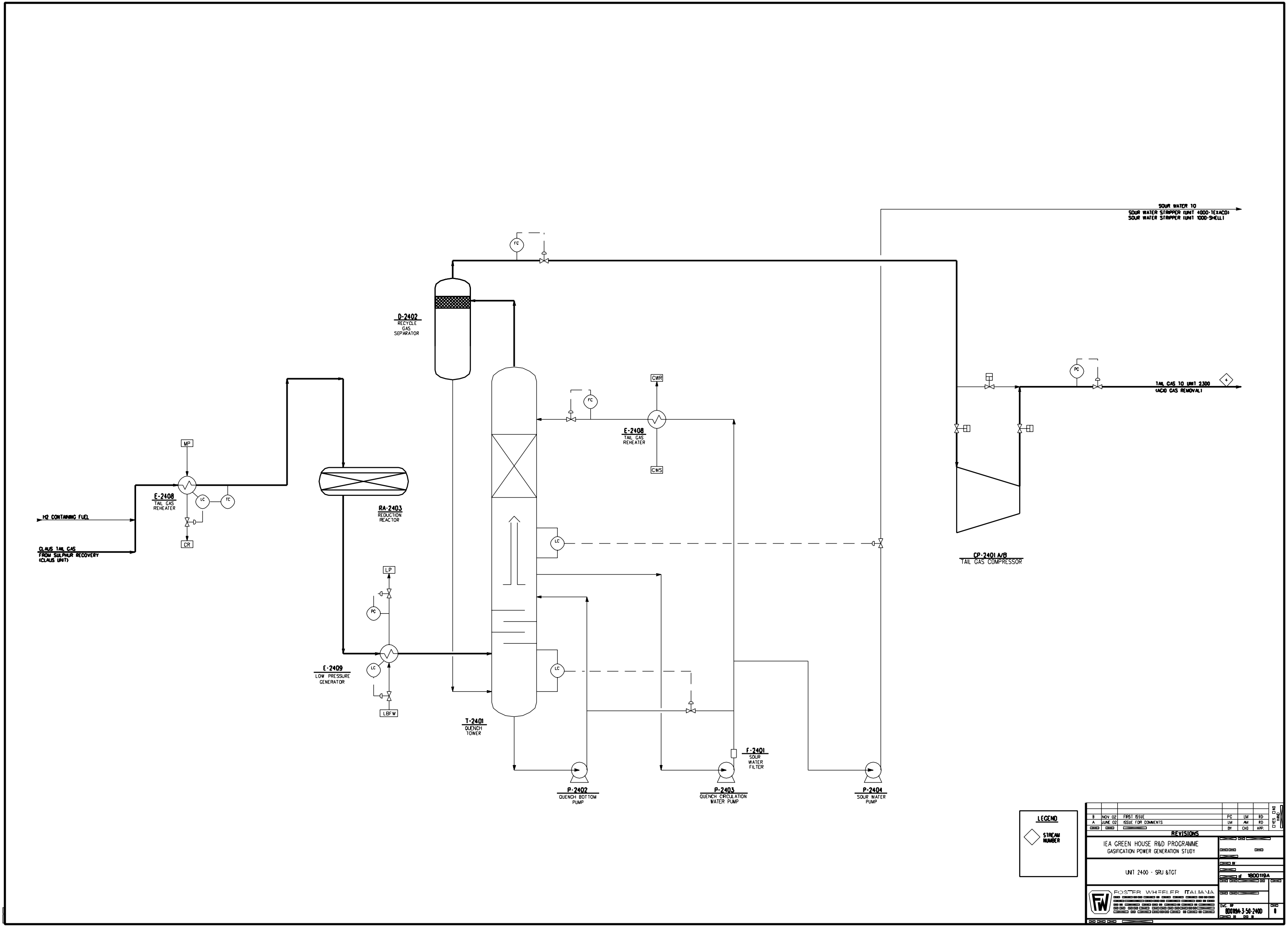
For the process description of this Unit reference should be made to the Process Flow Diagrams attached to the end of this paragraph.

The Sulphur Recovery Unit (SRU) processes the main acid gas from the Acid Gas Removal, together with other small flash gas and ammonia containing offgas streams coming from other units SRU consists of two Claus Units, each sized for approx. 100% of the max sulphur production in order to assure a satisfactory service factor. Low pressure oxygen from ASU may be used as oxidant of Claus reaction.
The required recovery of sulphur from the entering streams is 95% minimum @ EOR, (95.5% minimum @ SOR); it is obtained by means of thermal reactor plus two Claus catalytic reactors.
Each train is equipped with its own liquid sulphur product degassing facilities whereby each train sulphur pit (48 h minimum total hold up) is divided into separate zones for collection from condensers etc. in the unit and for degassing (24 h hold up) plus transfer to liquid sulphur storage.
The Tail Gas Treatment Unit (TGT), is designed as a single train, capable of processing 100% tail gas resulting from the possible SRU operating modes.
A complete hydrogenation of SO_2, residual COS, CS_2 and elemental sulphur is achieved. After quenching tail gas is recycled back to the Acid Gas Removal (Unit 2300) by means of two tail gas recycle compressors (one operating, one spare).
In case a small quantity of hydrogen is needed for tail gas hydrogenation, back-up hydrogen containing gas (syngas) is available at SRU/TGT battery limit.

The catalyst selection shall be adequate to convert HCN and COS, in order not to accumulate them through the tail gas recycle to the solvent wash unit.
Ammonia contained in the feed gas streams to the Unit shall be completely destroyed.



TO 2nd TRAIN
ACID GAS FROM UNIT 2300
(ACID GAS REMOVAL)
1
MP
TC
PC
FC
LC
I-E-2401
ACID GAS HEATER
CR
TO 2nd TRAIN
3
SOUR WATER RICH FROM
(UNIT 4000-SOUR WATER STRIPPER TEXACO)
(UNIT 1000-SOUR WATER STRIPPER SHELL)
OFFGAS FROM UNIT 1000
(GASIFICATION)
3
NG
LP OXYGEN FROM UNIT 2100
(AIR SEPARATION UNIT)
TO 2nd TRAIN
I-CO-2401
CLAUS COMBUSTION CONDENSER
I-E-2402
PROCESS GAS COOLER
I-FA-2401
AIR BLOWER
MP
LP
I-E-2403
FIRST SULPHUR CONDENSER
MBFW
LBFW
I-RA-2401
FIRST CLAUS REACTOR
I-E-2404
SECOND SULPHUR CONDENSER
I-E-2405
PROCESS GAS HEATER
I-RA-2402
SECOND CLAUS REACTOR
M
I-E-2407
STEAM CONDENSER
FROM 2nd TRAIN
CLAUS TAIL GAS TO SULPHUR RECOVERY (TAIL GAS TREATMENT)
I-E-2406
THIRD SULPHUR CONDENSER
I-D-2401
SULPHUR SEPARATOR
H2S SO2
DEGASSING AIR
P-2401
SULPHUR PUMPS
FROM 2nd TRAIN
TK-2401
STORAGE TANK SULPHUR
TK-2402
SULPHUR DEGASSING TANK
AIR
2
SULPHUR TO STORAGE
LEGEND
STREAM NUMBER
B NOV 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
UNIT 2400-SRU &TGT
1BD0119A
FOSTER WHEELER ITALIANA
DWG. Nº
BD0119A-3-50-2400
B



SOUR WATER TO
SOUR WATER STRIPPER (UNIT 4000-TEXACO)
SOUR WATER STRIPPER (UNIT 1000-SHELL)
FC
D-2402
RECYCLE GAS SEPARATOR
TAIL GAS TO UNIT 2300
(ACID GAS REMOVAL)
4
PC
CWR
FC
E-2408
TAIL GAS REHEATER
CWS
MP
E-2408
TAIL GAS REHEATER
LC
TC
CR
H2 CONTAINING FUEL
CLAUS TAIL GAS
FROM SULPHUR RECOVERY
(CLAUS UNIT)
RA-2403
REDUCTION REACTOR
LC
LC
CP-2401 A/B
TAIL GAS COMPRESSOR
LP
PC
E-2409
LOW PRESSURE GENERATOR
LC
LBFW
T-2401
QUENCH TOWER
F-2401
SOUR WATER FILTER
P-2402
QUENCH BOTTOM PUMP
P-2403
QUENCH CIRCULATION WATER PUMP
P-2404
SOUR WATER PUMP
LEGEND
STREAM NUMBER
B NOV 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
YES NO
HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
UNIT 2400 - SRU &TGT
1BD0119A
FOSTER WHEELER ITALIANA
DWG. Nº
BD0119A-3-50-2400
B

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 %).

Product Characteristics

Liquid Sulphur

State		liquid	
Colour		bright yellow	(at ambient temperature)
Sulphur content	wt %	99.9	min. (dry basis)
H_2S content	wt ppm	10	max.
Ash content	wt %	0.05	max.
Carbonaceous material	wt %	0.05	max.

7.0 CO_2 Compression and Drying

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.

Depending on the alternative considered (see Section D), the incoming streams to CO_2 Compression and Drying Unit are two or three, at different pressures of between 1 and 30 bar g. All of these streams require treating to remove water and compression. These requirements therefore present some alternatives:

- Provide separate dryers and compress the streams either with individual machines or a single machine;
- Use a pass-out compression system where the drier is operated at the highest pressure of the streams, and the compressor passes-out the remaining streams at the required pressure for drying in a single drier;
- Let down the higher pressure streams to the lowest pressure, dry at the low pressure and compress the combined LP stream to 110 bar g;
- Dry after compression at 110barg.

The flow rates of the streams are approx. similar, making the letdown option expensive, as this would add nearly 10% to the total compression duty compared against the first option. For this reason, the flowscheme described below has been adopted, based on the relative costs of the equipment involved and metallurgy considerations.

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.

8.0 Power Island

The power island for all the alternatives is based on two General Electric gas turbines, frame 9001 FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.
The power island is integrated with the other process units. The following interfaces generally exist, even if power island schemes may present some differences alternative by alternative:

- Compressed Air to Unit 2100 – Air Separation Unit;
- HP steam generated in the gasification is superheated and processed in the steam turbine;
- Steam to moderate gasification temperature is supplied by the power island (for Texaco alternatives only);
- MP and LP steam generated in the process unit are routed to the power island;
- BFW is supplied by the power island to the process units for steam generation;
- Process condensate recovered from the process units is recycled to the power island, after polishing.

The power island configuration relevant to Case C.1 (Texaco Gasification, High Pressure, no CO_2 capture) is described referring to the Process Flow Diagrams attached to the end of this paragraph. This case is selected because it depicts the general criteria followed for the power island design.

For each alternative in Section D, the main differences of Power Island configuration with respect to Case C.1 are listed.

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 Section B, para 8.0)
MP nitrogen coming from ASU is injected into the Gas Turbines for NO_x 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 Economizer (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 (1/2-D-3204) 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 stand-by), 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.

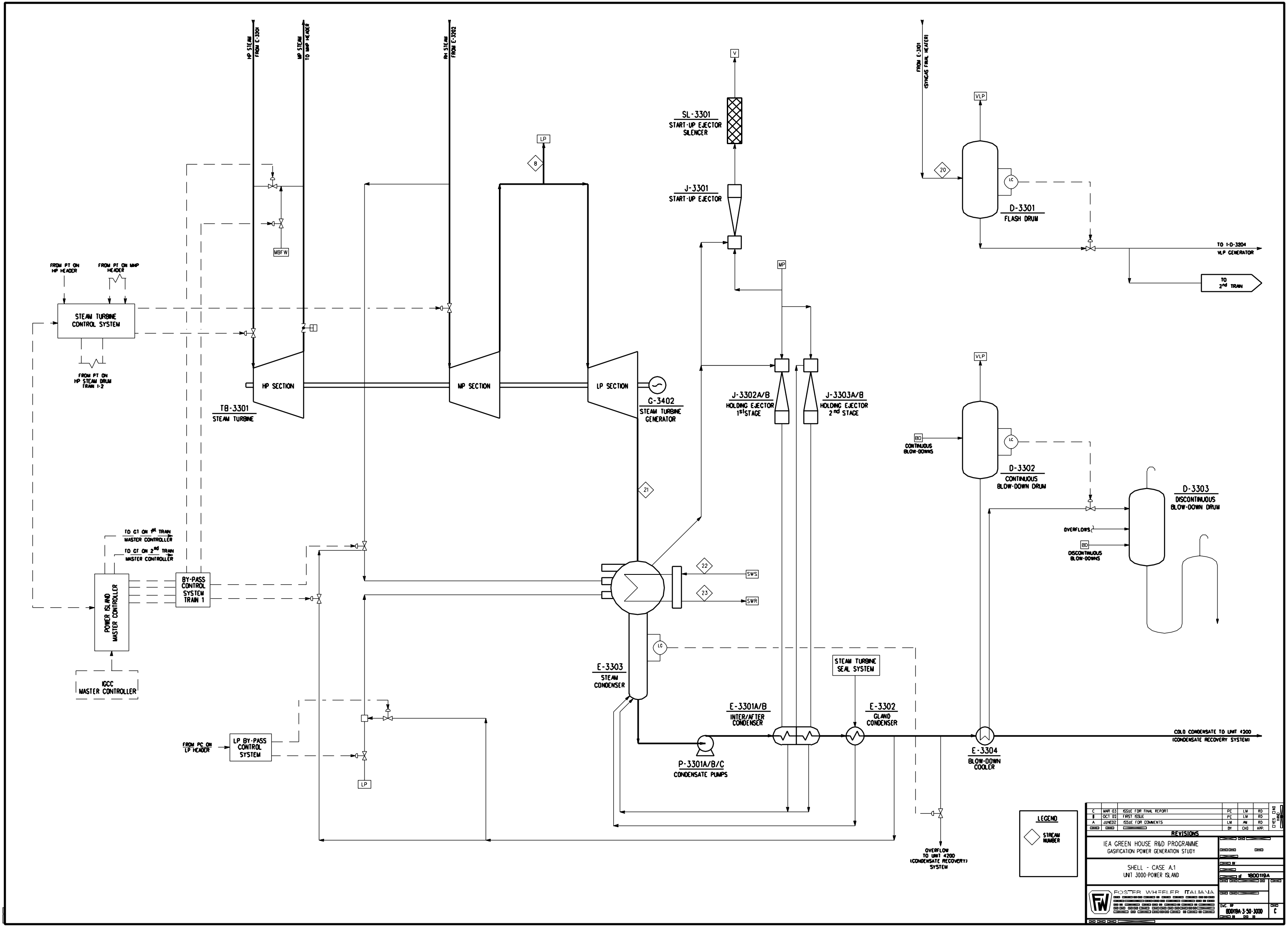
In case of Steam Turbine trip, live HP Steam is bypassed to MP manifold by means of dedicated letdown stations, while Reheated Steam and excess of LP steam are also let down and then sent directly into the condenser neck.

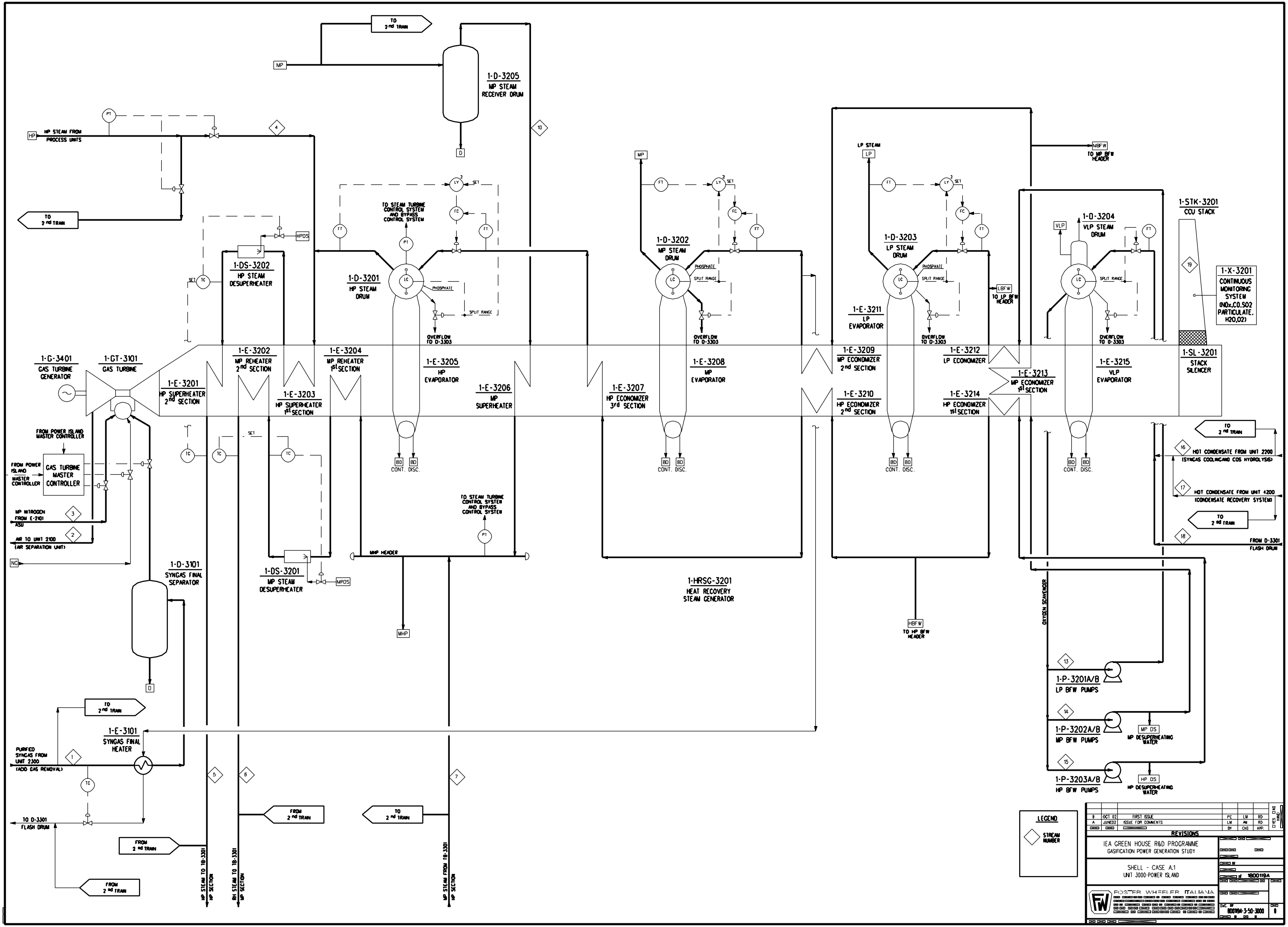
When the clean syngas production is not sufficient to satisfy the appetite of both Gas Turbines it is possible to cofire natural gas or to switch to natural gas one or both Gas Turbines.
This could happen in case of partial or total failure of the Gasification/Gas Treatment units of the IGCC and during start-up.
The selected machines are suitable to cofire syngas and natural gas from 20% to 100% load.

During Natural Gas Operation no air extraction is foreseen, while a stream of MP Steam has to be injected into the combustion chambers of the Gas Turbines to reduce the NO_x emissions.

During normal operation on Natural Gas, the Power Island does not export/import to/from IGCC Process Units any steam/water stream and no low temperature heat can be recovered in Process Units. Then all cold condensate coming from Steam Condenser can be directly sent to the deaerator after polishing.

In this situation, the degassing steam demand of the deaerator is very high, more than VLP steam produced by HRSG's that needs to be integrated with steam coming from LP and MP headers.


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
FROM E-3101 (SYNGAS FINAL HEATER)
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM TRAIN 1-2
MBFW
HP SECTION
MP 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
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
P-3301A/B/C
CONDENSATE PUMPS
E-3304
BLOW-DOWN COOLER
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
LEGEND
STREAM NUMBER
C MAR 03 ISSUE FOR FINAL REPORT
B OCT 02 FIRST ISSUE
A JUNE02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.1
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1800119A
BDD19A-3-50-3000



TO 2nd TRAIN
MP
1-D-3205
MP STEAM RECEIVER DRUM
D
10
HP STEAM FROM PROCESS UNITS
HP
PT
4
TO 2nd TRAIN
HPDS
1-DS-3202
HP STEAM DESUPERHEATER
TC
SET
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
LY
FC
FT
LC
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
LP
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
1-D-3204
VLP STEAM DRUM
VLP
1-STK-3201
CCU STACK
19
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
MP SUPERHEATER
1-E-3207
HP ECONOMIZER 3rd SECTION
1-E-3208
MP EVAPORATOR
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3211
LP EVAPORATOR
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
3
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
2
NG
BD
CONT. DISC.
TO 2nd TRAIN
16
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING AND COS HYDROLYSIS)
17
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
TO 2nd TRAIN
18
FROM D-3301 FLASH DRUM
MHP HEADER
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
MHP
1-D-3101
SYNGAS FINAL SEPARATOR
1-HRSG-3201
HEAT RECOVERY STEAM GENERATOR
HBFW
TO HP BFW HEADER
OXYGEN SCAVENGER
13
1-P-3201A/B
LP BFW PUMPS
14
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
15
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
TO 2nd TRAIN
1-E-3101
SYNGAS FINAL HEATER
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
1
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
FROM 2nd TRAIN
5
6
FROM 2nd TRAIN
TO 2nd TRAIN
7
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 HP SECTION
MP STEAM FROM TB-3301 HP SECTION
LEGEND
STREAM NUMBER
B OCT 02 FIRST ISSUE
A JUNE02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.1
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA

9.0 Utility and Offsite Units

For the process description of these Units reference is made to the Process Flow Diagrams attached to the end of this paragraph. The main Units only are described as the other ones are typical units designed according to general standards.

9.1 Sour Water Stripper (Unit 4000 – Only for Texaco Cases)

In order to avoid accumulation of H_2S and NH_3 in the water circulating, Sour Water Stripper processes contaminated condensate from the last separator of the Syngas Treatment, at 38 °C (plus a portion of condensate from the upstream separator, if necessary) together with Blowdown from Gasification Island and Sour Water from Sulphur Recovery Unit and Tail Gas Treatment.

The feed to the stripper is heated against treated column bottoms in Sour Water Stripper Feed/Bottoms Exchanger and enters via a distributor at the top of the column. Overhead vapour from the top of the column is condensed in SWS Overhead Condenser and sent to SWS Reflux Drum, where sour gas and condensed liquid are separated. The sour gas is sent to Sulphur Recovery and Tail Gas Treatment, Unit 2400 or to CO_2 Compression if SRU is not provided, while the liquid is refluxed back to the column.
The bottom from the column is pumped to Stripper Feed/Bottoms Exchangers and furtherly sent to the Waste Water Treatment.

This Unit is considered for the Texaco case only, because for Shell based cases, it is already included in the Gasification Island.

9.2 Cooling Water/Fresh Cooling Water System (Unit 4100)

Unit 4100 includes the IGCC primary cooling system, sea water in once through circuit, and the IGCC secondary cooling system, fresh cooling water in closed circuit with relevant distribution system.

Five electric driven operating pumps are provided to pump sea water from the Sea Water Basin, located on the beach, to the IGCC site, and back to the sea. The sea water intake and the discharge to the sea connected to the beach facilities by means of submarine lines, are located at suitable distance in order not to mix the two streams, supply and return.

Inside the IGCC plant, sea water is directly used to condense steam in the steam turbine condenser, as cooling medium of ASU and of CO_2 compression and drying Unit when foreseen, and in a separate branch, after further pumping, to cool the

Fresh Cooling Water. The machinery cooling water system produces fresh cooling water, circulating in a closed circuit, used as cooling medium for all IGCC users other than steam turbine condenser, CO_2 compression and ASU users.

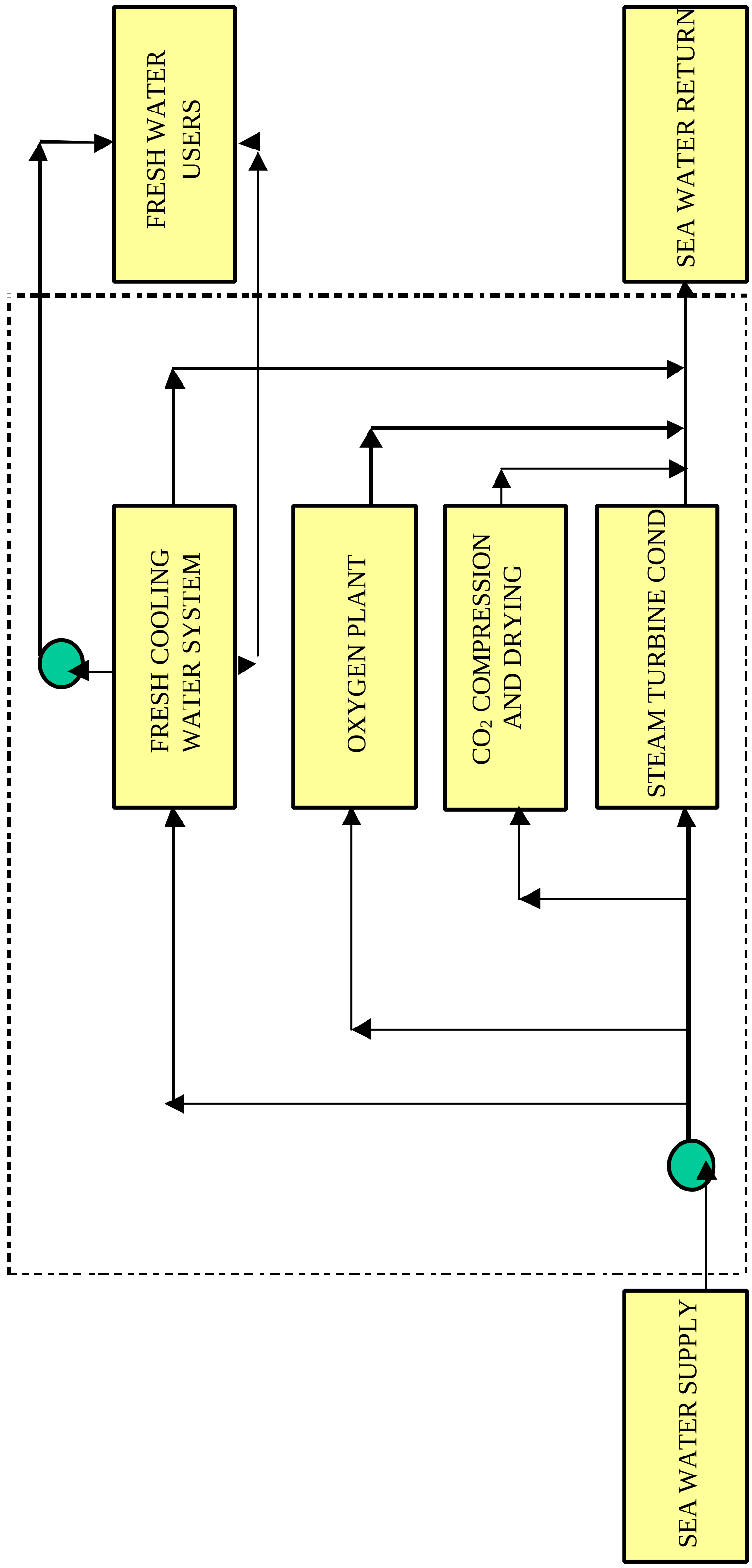
The max allowed sea water temperature increase is 7°C.

A plate heat exchanger type is selected to cool the machinery cooling water by means of sea water, in order to minimize the plot area, surface and pressure drop.

Self cleaning backflushing filters will be provided to protect plate exchangers from excessive sea water fouling.

A machinery cooling water expansion drum is installed to compensate the fluctuation of the water volume, due to the temperature variations.
Three electric driven pumps are provided to keep the machinery cooling water circulation, two operating and one spare.
Demineralized water is used as first filling of the machinery cooling water circuit and to compensate water losses.
A chemical injection system is provided in order to add the oxygen scavanger to the machinery cooling water circuit.

COOLING WATER/ FRESH COOLING WATER SYSTEM



9.3 Demi Water / Condensate recovery System (Unit 4200)

Raw water is used to produce Demineralized Water and as make-up water in Gasification Island to close the Gasification water balance.

For the Shell cases with shift reaction, a large quantity of water is added to syngas to keep the reaction active. As a consequence, a large amount of condensate is recovered and sent to the Waste Water Treatment after stripping. Part of the effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island as process water, closing the Gasification water balance. The other part is sent to a dedicated treatment where the Reverse Osmosis process, allows to recover almost 60% of the treated water. This recovered water is recycled back to the Demi Water System, Unit 4200, reducing the raw water to be fed to the Demineralized water plant. The remaining 40% of water is discharged together with the sea cooling water return stream.

Raw water flows through the Demineralized Water Plant, and is collected in the Demineralized Water Storage Tank. The Demi Water is pumped by the Demineralized Water Pump, taking suction from Demineralized Water Storage Tank and then fed to the combined cycle as make-up.

Condensate recovered from Process Unit is collected in a Condensate Recovery Drum, where the condensate is cooled down with cold reflux. Output stream is then pumped by the Recovered Condensate Pump, cooled in the Condensate/Cold Condensate Exchanger, and divided in cold reflux and condensate streams. In the Condensate Recovery Drum temperature is controlled by the reflux steam flow and level is controlled by the condensate stream flow.
Condensate is cooled in the air cooler and then stored in the Condensate Storage Tank. After polishing in the condensate polishing Unit, this condensate is then pumped by the Condensate Pumps, taking suction from the tank, under level control, and fed to the Power Island via the Condensate/Cold Condensate Exchanger.
Cold condensate from Power Island (Steam Turbine condensate) enters Unit 2400 for polishing in the cold condensate polishing unit. Furtherly it flows to the Syngas Treatment and Conditioning Line for heating.

9.4 Waste Water Treatment (Unit 4600)

The Effluents from Unit 1000 - Gasification Island (Shell Cases), and from Unit 4000 - Sour Water Stripper (Texaco Cases), flow to the anaerobic section, where a phosphoric acid solution is added to the waste water to support the bacterial growth.

In the Anaerobic Reactor the organic pollutants are biodegraded with production of biological gas and biological sludge. The biogas produced in the reactor is routed to the local flare to be burned.

The biological mass exits the anaerobic reactor and enters the Anaerobic Clarifier where the biomass is separated by gravity from the supernatant.

Effluent from anaerobic section is subject to a further aerobic treatment for the complete removal of ammonia and organic contaminants. The effluent from the anaerobic clarifier is pumped to the denitrification/oxidation tanks where is mixed with the rainwater bleed-off and drainage coming from the deoiling section.

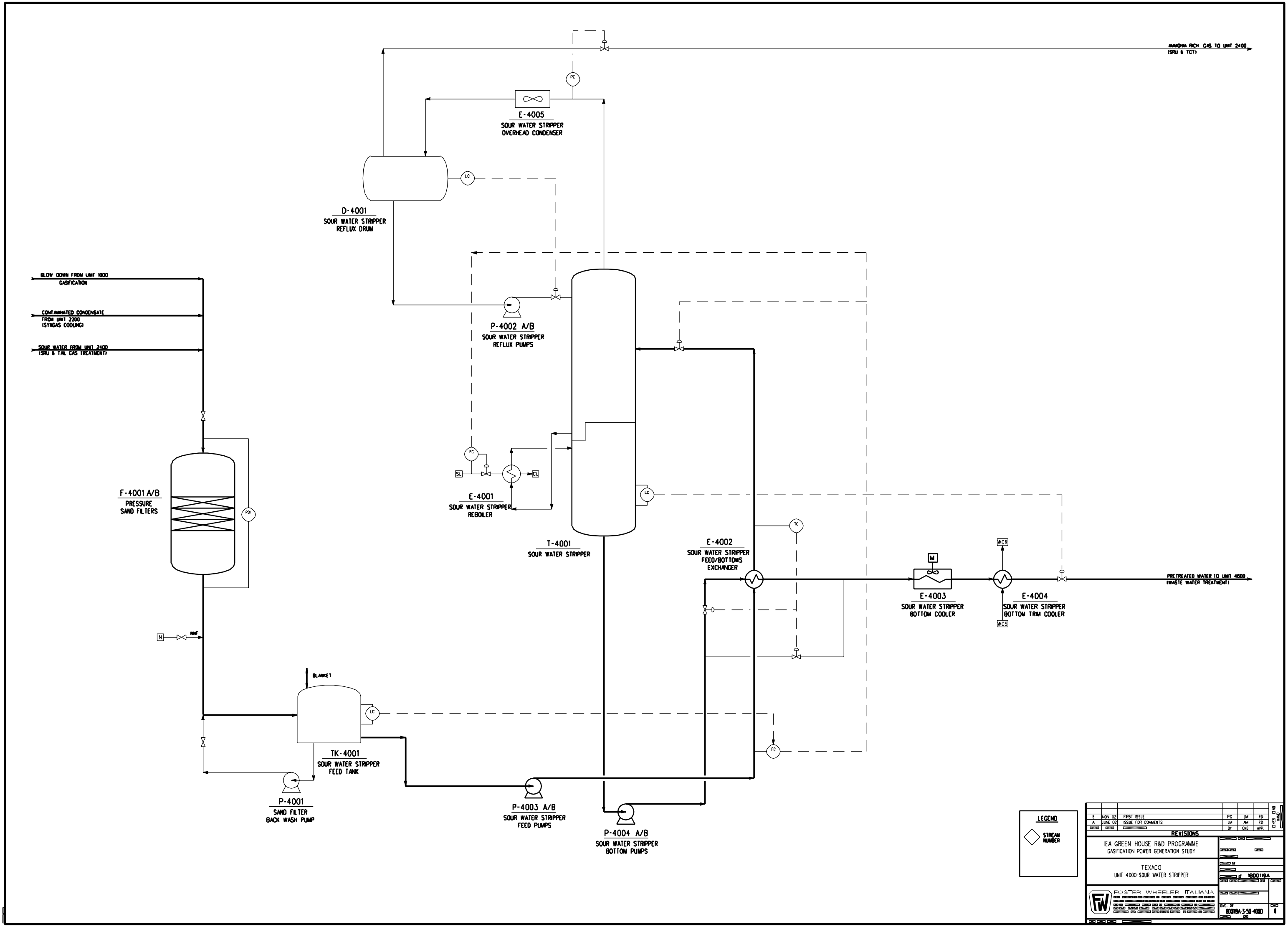
In this deoiling section, the oily drainage mixed with contaminated rainwater is fed by means of pumps from the oil water storage tank to the primary deoiling section, consisting of a Corrugate Plate Interceptor, witch provides gravity separation of free oil and suspended solids carried in the waste water.

The effluent from the separator cells is dosed with polyelectrolyte and is routed by gravity to a secondary deoiling step, consisting of Induced Air Flotation. Air induced by motors driven self aerating rotors mechanism removes the oil and suspended solids, which are collected in a dense froth to be recycled back to the CPI.
The deoiled water is then pumped to the denitrification/oxidation tanks, where it is mixed with the section from the anaerobic treatment effluent and where the organic contaminants are removed and ammonia is oxidized to nitrates which are further reduced to nitrogen gas in the denitrification section.

The effluent from the oxidation tank enters the aerobic clarifier, where the biomass separates by gravity from the supernatant. The sludge from the bottom of the clarifier is recycled to the anaerobic reactor by the Sludge Pump.

The supernatant from the clarifier is dosed with polyelectrolyte and pumped into Dual Media Filter, which uses sand and anthracite as filter media for the removal of residual hydrocarbons and suspended solids, and into Activated Carbon Filters, for the complete removal of organic contaminants.

From the filters the waer is sent to the Revers Osmosis process (Unit 4200 – Shell Cases) or to the Gasification Island (Unit 1000 – Texaco Cases) as make-up water.


AMMONIA RICH GAS TO UNIT 2400
(SRU & TGT)
PC
E-4005
SOUR WATER STRIPPER
OVERHEAD CONDENSER
LC
D-4001
SOUR WATER STRIPPER
REFLUX DRUM
BLOW DOWN FROM UNIT 1000
GASIFICATION
CONTAMINATED CONDENSATE
FROM UNIT 2200
(SYNGAS COOLING)
SOUR WATER FROM UNIT 2400
(SRU & TAIL GAS TREATMENT)
P-4002 A/B
SOUR WATER STRIPPER
REFLUX PUMPS
F-4001 A/B
PRESSURE
SAND FILTERS
PDI
FC
SL
CL
E-4001
SOUR WATER STRIPPER
REBOILER
LC
T-4001
SOUR WATER STRIPPER
TC
E-4002
SOUR WATER STRIPPER
FEED/BOTTOMS
EXCHANGER
M
E-4003
SOUR WATER STRIPPER
BOTTOM COOLER
WCR
WCS
E-4004
SOUR WATER STRIPPER
BOTTOM TRIM COOLER
PRETREATED WATER TO UNIT 4600
(WASTE WATER TREATMENT)
N
BLANKET
LC
TK-4001
SOUR WATER STRIPPER
FEED TANK
FC
P-4001
SAND FILTER
BACK WASH PUMP
P-4003 A/B
SOUR WATER STRIPPER
FEED PUMPS
P-4004 A/B
SOUR WATER STRIPPER
BOTTOM PUMPS
LEGEND
STREAM
NUMBER
B NOV 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
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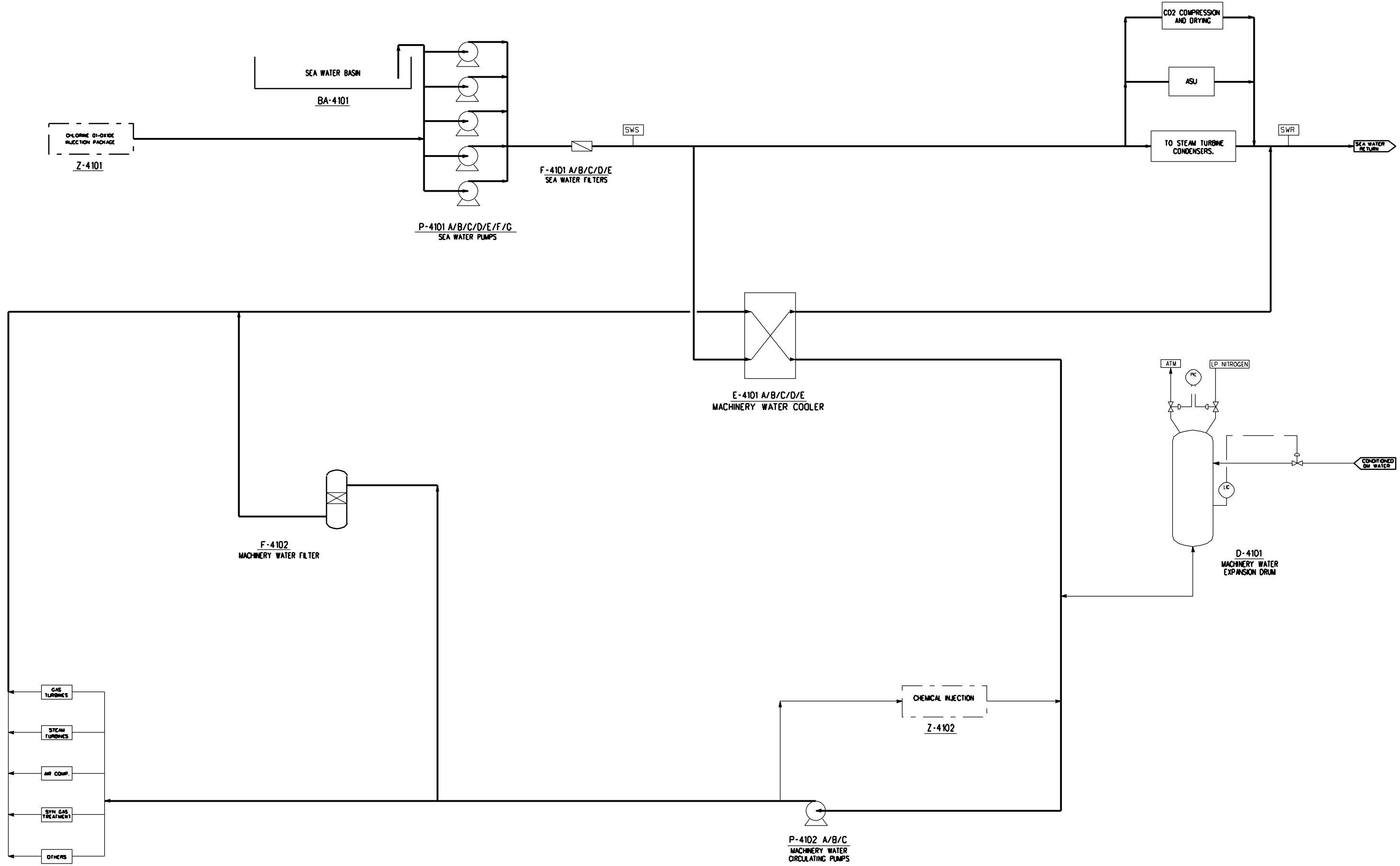
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO
UNIT 4000-SOUR WATER STRIPPER
1BD0119A
FOSTER WHEELER ITALIANA
DWG. Nº
800119A-3-50-4000



B	NOV 02	FIRST ISSUE	PC	LM	RD	
A	JUNE 02	ISSUE FOR COMMENTS	LM	AM	RD	
			BY	CHD	APP.	YES NO HAND

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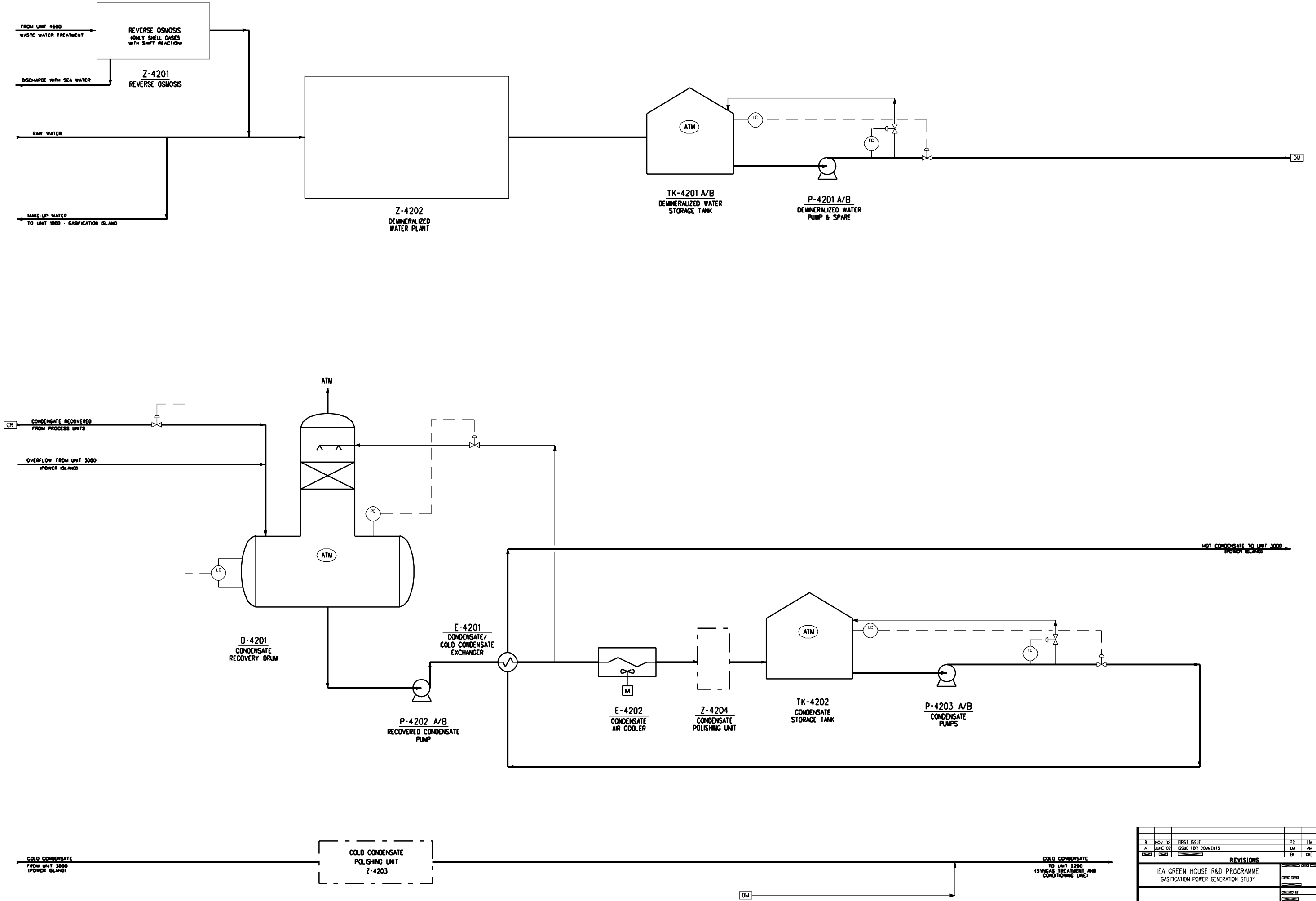
GASFICATION POWER GENERATION STUDY

UNIT 4100-COOLING WATER (SEA WATER/MACHINERY WATER)

1800119A

FOSTER WHEELER ITALIANA

DWG.
BOO119A-3-50-4100
B



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A	JUNE 02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

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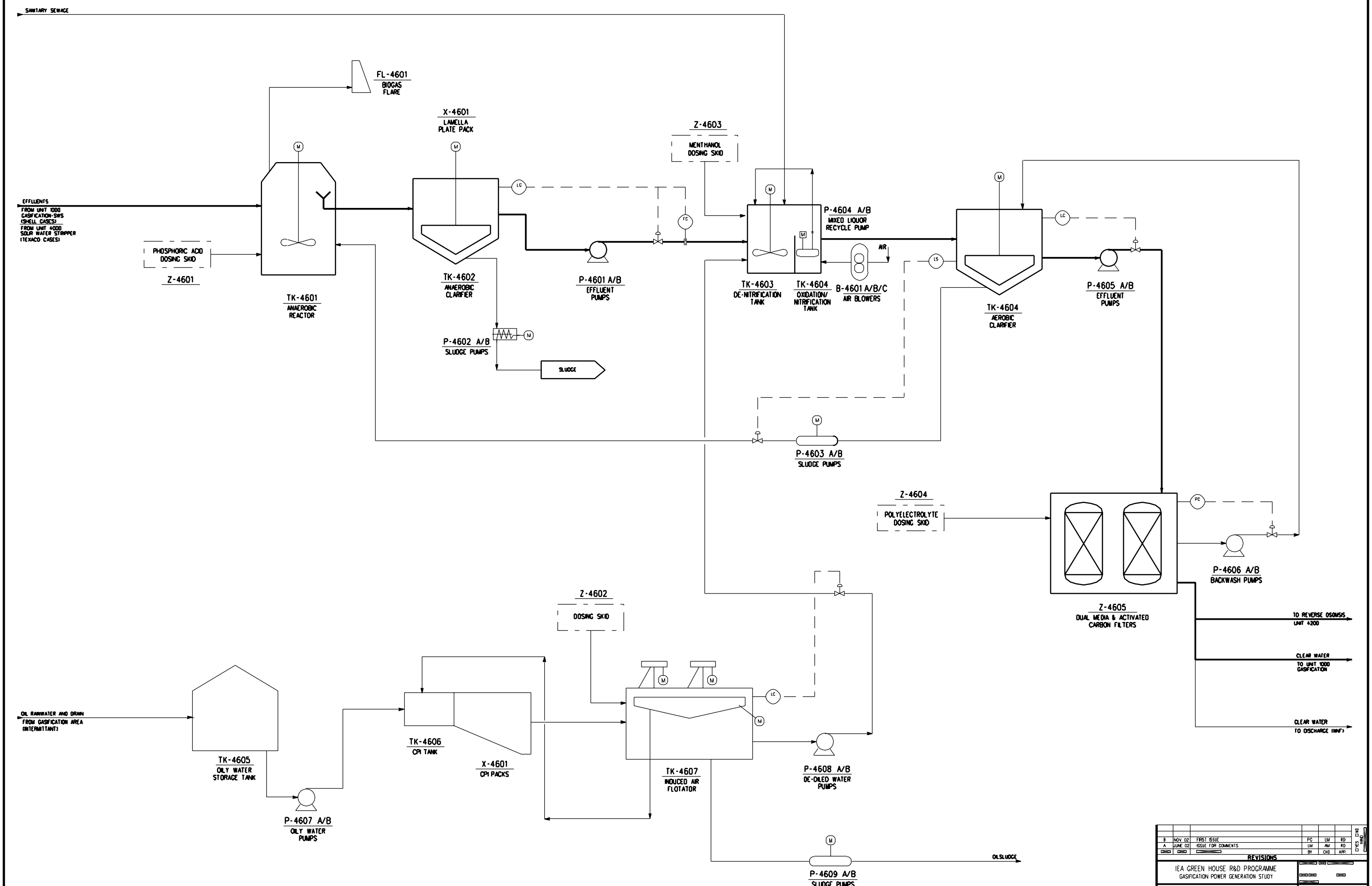
UNIT 4200-DM WATER / CONDENSATE RECOVERY SYSTEM

FOSTER WHEELER ITALIANA

1800119A

DWG.
1800119A-3-50-4200

B



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			BY	CHD	APP.

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UNIT 4600 - WASTE WATER TREATMENT

1BD0119A

FOSTER WHEELER ITALIANA

DWG. Nº 1BD0119A-3-50-4600 B

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : BASIC INFORMATION FOR EACH ALTERNATIVE

ISSUED BY : R. DOMENICHINI
CHECKED BY : R. DOMENICHINI
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	R. Domenichini	R. Domenichini	R. Domenichini
March 2003	General Revision	R. Domenichini	R. Domenichini	R. Domenichini

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

INDEX

SECTION D

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE A.1

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.1

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.1 BASIC INFORMATION FOR EACH ALTERNATIVE

1.0 Case A.1

1.1 Introduction

The main features of the Case A.1 configuration of the IGCC Complex are:

- Low pressure (36 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- No Shift and CO_2 removal.

The removal of acid gas (AGR) is based on DOW-UCARSOL process (activated MDEA solvent).
The degree of integration between the Air Separation Unit (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and syngas dilution, for NO_x control, is achieved with injection of compressed moisturised 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.

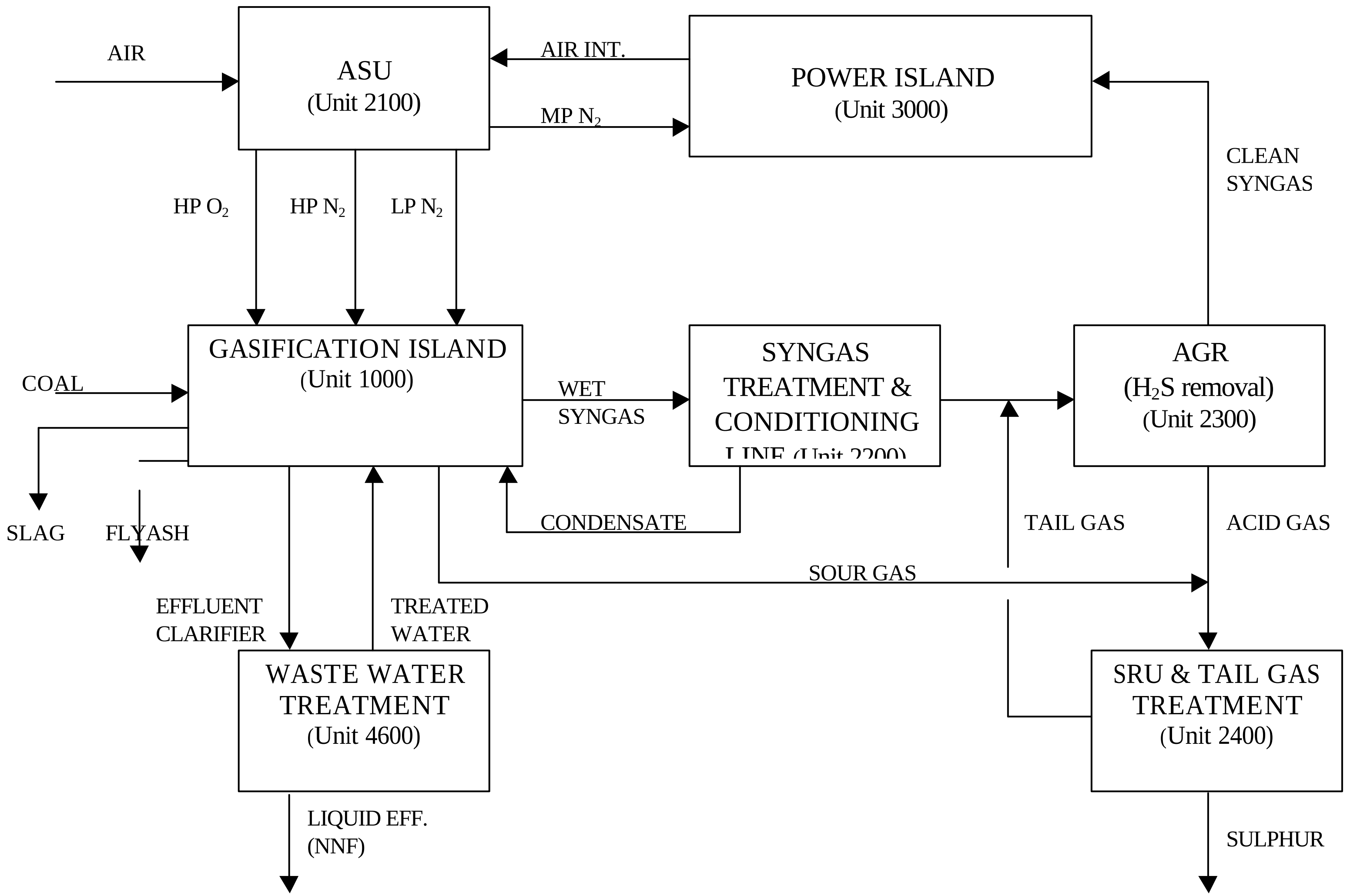
The arrangement of the process units is :

Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurization/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
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%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

SHELL A.1 – IGCC COMPLEX BLOCK FLOW DIAGRAM



1.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	80	80	70	126
Pressure (bar)		40	69	7.5	34
TOTAL FLOW					
Mass flow (kg/h)	250,600	196,980	82,000	31,800	463,500
Molar flow (kmol/h)			2,920	1,132	23,260
Composition (% vol)					
H_2					29.70
CO					56.40
CO_2					1.40
N_2		3.5	99.88	99.88	4.53
Ar		1.5	0.08	0.08	0.70
O_2		95	0.04	0.04	0.00
H_2S + COS					0.26
H2O					7.00
Others					0.01

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 1.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 1.4.

The capacity is approximately 20% smaller than the correspondent Unit for Texaco, case C.1, reflecting the lower O_2 demand of the Shell process compared to the Texaco one.

The degree of integration with the gas turbines is 50% and the N_2 used to augment the power of the gas turbine and control the NOx is moisturised by direct contact with hot water in order to increase the syngas diluent mass flow.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 1.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 33 barg and 126°C enters Unit 2200. The syngas is first preheated in E-2201, with the hydrolysis effluent, and then in E-2202 with MP steam, before entering the hydrolysis reactor R-2201, which converts COS to H_2S. The effluent is cooled in E-2201 and in E-2203 against cold condensate. Process condensate separated in D-2201 is recycled to Unit 1000 Gasification while cold syngas is sent to Unit 2300 AGR.
Up to this point Unit 2220 is split in two parallel lines, each sized for 50% capacity.
Clean syngas, returning from Unit 2300, after removal of H_2S, is preheated with LP steam in E-2204 and sent to the gas turbines of Unit 3000.

Unit 2300: Acid Gas Removal (AGR)

For this Unit, reference can be made to the Process Flow Diagram attached to paragraph 1.3. Unit 2300 utilises the DOW-UCARSOL solvent (activated MDEA) as acid gas solvent.

Unit 2300 is characterised by a low syngas pressure (29 barg), and a low CO_2/H_2S ratio (5.5/1). As UOP/DOW see this separation as relatively easy, only an UCARSOL chemical wash has been proposed.

A single-stage absorption is suitable to accomplish all objectives, i.e. no acid gas enrichment is required. Therefore the tail gas coming from the Sulphur Recovery Unit is mixed with the raw syngas before entering the AGR section.

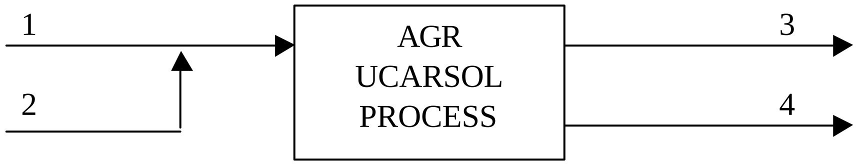
The interfaces of the Ucarsol process with the other Units are the following, as shown in the Process Flow Diagram attached to para 1.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Unit
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

Exit Streams

3. Treated Gas to Gas Turbines
4. Acid Gas to Sulphur Recovery Unit



The MDEA solvent consumption, to make-up losses, is 60 m^3/year.
The proposed process matches the process specifications with reference to H_2S+COS concentration of the treated gas exiting the Unit and fed to the Combined Cycle Unit. The treated gas feeding the gas turbines has an H_2S+COS concentration of 18 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.

The acid gas H_2S concentration is 49% dry basis, more than suitable to feed the oxygen blown Claus process.

Additional technical information are shown in the report “AGR Technical Comparison and Optimisation” attached to Section H.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each having a normal sulphur production of 51.5 t/d normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 30 barg.

Unit 3000: Power Island

The Process Flow Diagram is attached to paragraph 1.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island.
- MP steam (42 barg) : steam exported to Syngas Treatment and Conditioning Line. Part of the required steam is also generated in the Sulphur Recovery Unit and in the Gasification Island.
- LP steam (6,5 barg) : steam exported to the following Process Units: Syngas Treatment and Conditioning Line, AGR, ASU, Utility and Offsite Unit. Most of the steam is used to heat the recirculation of the Saturator Tower to moisturise the nitrogen fed to the gas turbine.
- BFW : HP, MP, LP 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 1.5, Utilities Consumption.

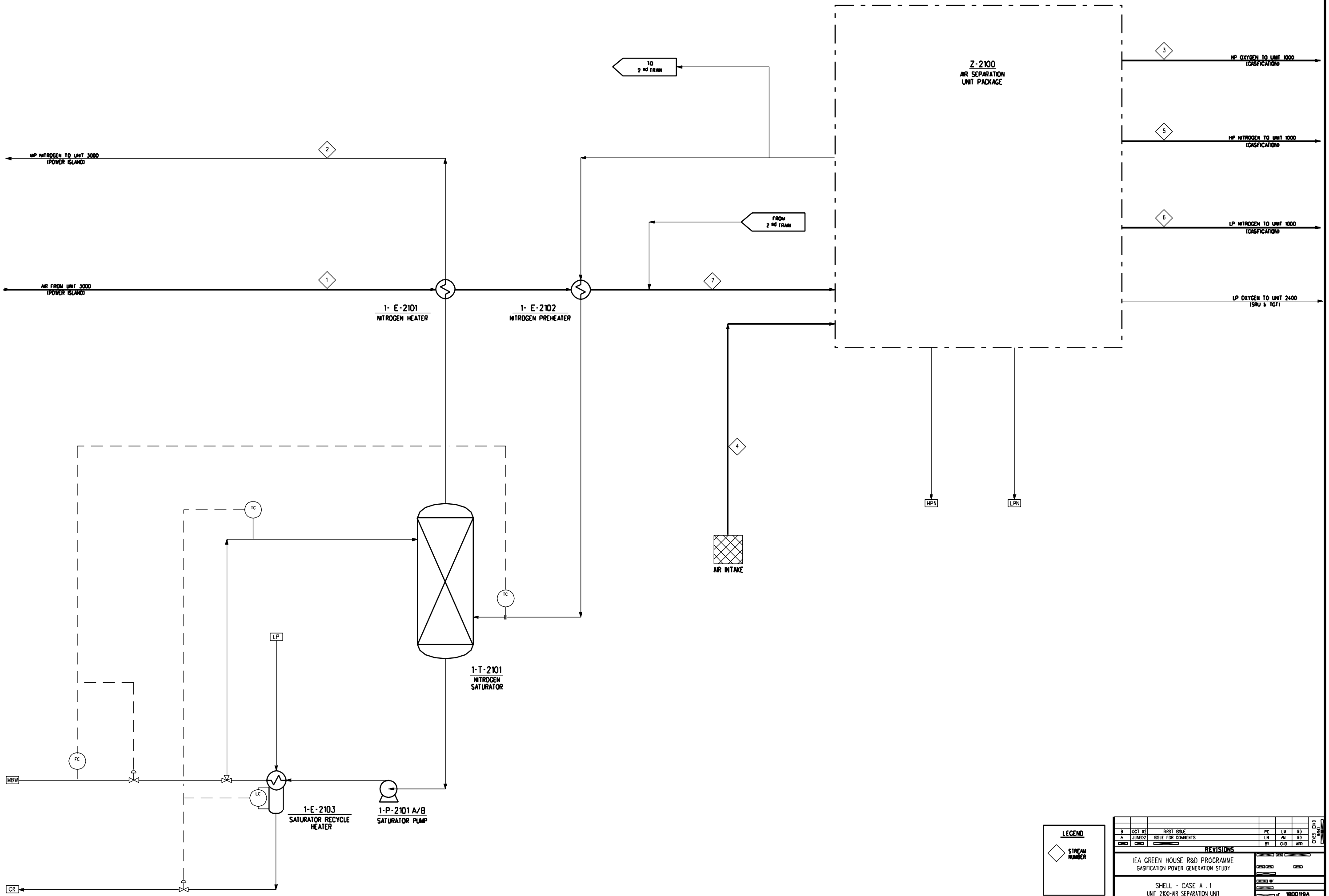
The only steam imported from the Power Island is the superheated steam generated in the Gasification Island; all other steams are exported. As a consequence, the generation levels are the same of the Process Units.

1.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0 and 9.0.



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STREAM NUMBER

B	OCT 02	FIRST ISSUE	PC	LM	RD	
A	JUNE02	ISSUE FOR COMMENTS	LM	AM	RD	
			BY	CHD	APP.	YES NO HAND

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GASIFICATION POWER GENERATION STUDY

SHELL - CASE A .1
UNIT 2100-AIR SEPARATION UNIT

1BD0119A

FOSTER WHEELER ITALIANA

DWG. Nº 1BD0119A-3-50-2100

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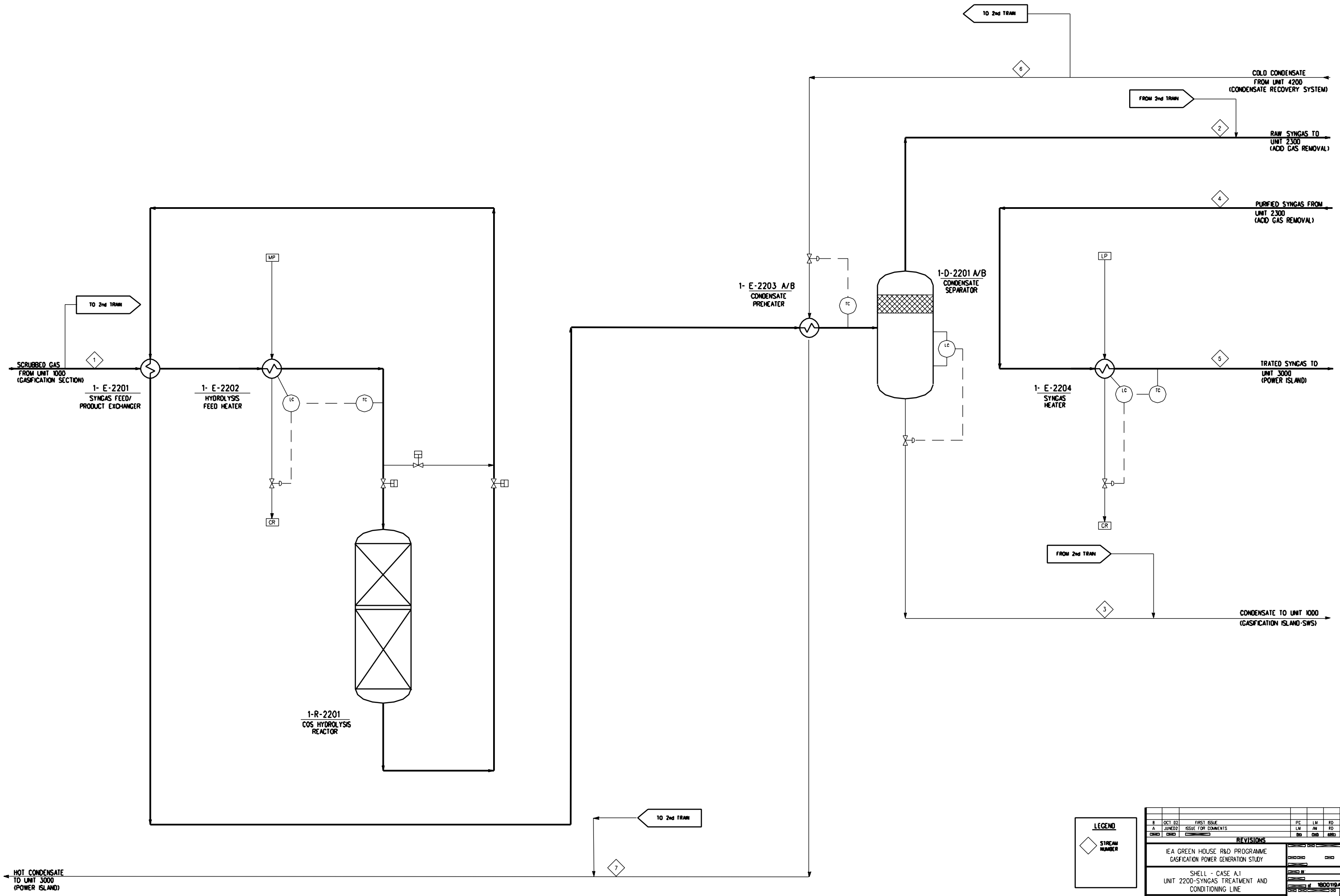

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SHELL - CASE A.1
UNIT 2200-SYNGAS TREATMENT AND
CONDITIONING LINE

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº
1BD0119A-3-50-2200

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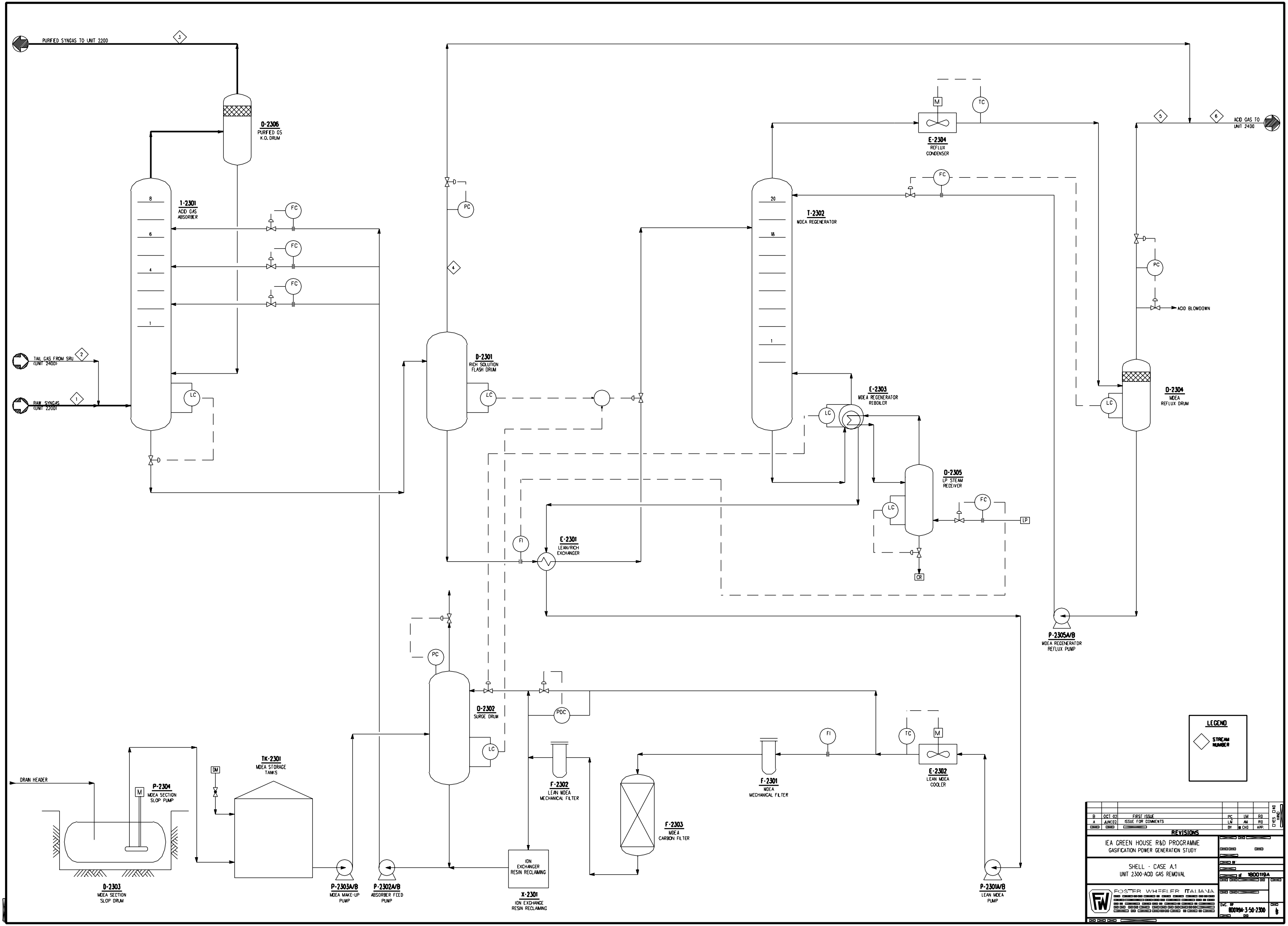

PURIFED SYNGAS TO UNIT 2200
D-2306
PURIFED GS
K.O. DRUM
T-2301
ACID GAS
ABSORBER
TAIL GAS FROM SRU
(UNIT 2400)
RAW SYNGAS
(UNIT 2200)
D-2301
RICH SOLUTION
FLASH DRUM
E-2304
REFLUX
CONDENSER
T-2302
MDEA REGENERATOR
E-2303
MDEA REGENERATOR
REBOILER
ACID GAS TO
UNIT 2400
ACID BLOWDOWN
D-2304
MDEA
REFLUX DRUM
D-2305
LP STEAM
RECEIVER
E-2301
LEAN/RICH
EXCHANGER
P-2305A/B
MDEA REGENERATOR
REFLUX PUMP
D-2302
SURGE DRUM
LEGEND
STREAM
NUMBER
DRAIN HEADER
P-2304
MDEA SECTION
SLOP PUMP
TK-2301
MDEA STORAGE
TANKS
F-2302
LEAN MDEA
MECHANICAL FILTER
F-2301
MDEA
MECHANICAL FILTER
E-2302
LEAN MDEA
COOLER
F-2303
MDEA
CARBON FILTER
D-2303
MDEA SECTION
SLOP DRUM
P-2303A/B
MDEA MAKE-UP
PUMP
P-2302A/B
ABSORBER FEED
PUMP
ION
EXCHANGER
RESIN RECLAMING
X-2301
ION EXCHANGE
RESIN RECLAMING
P-2301A/B
LEAN MDEA
PUMP
B OCT 02 FIRST ISSUE PC LM RO
A JUNE02 ISSUE FOR COMMENTS LM AN RO
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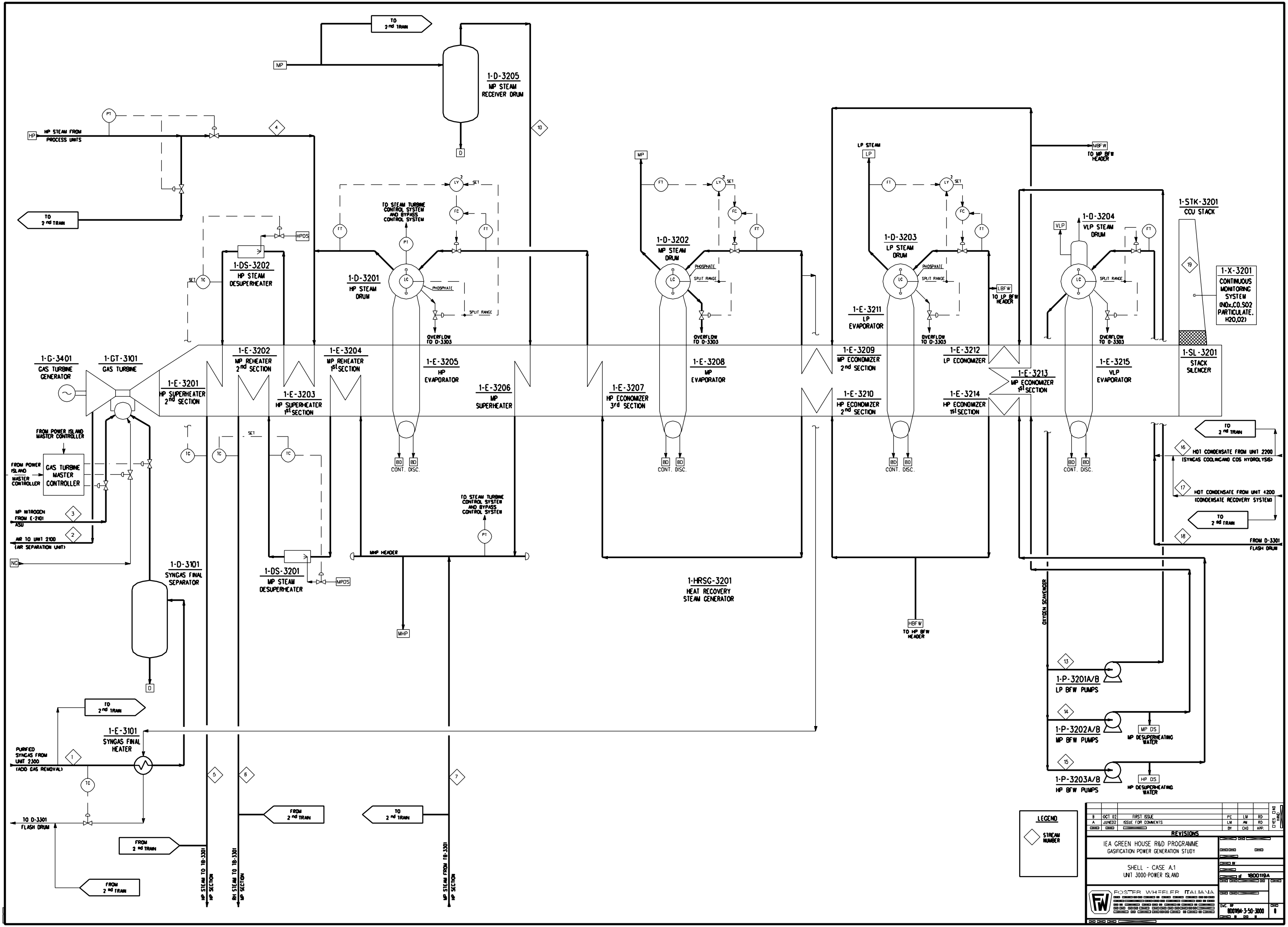
GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.1
UNIT 2300-ACID GAS REMOVAL
1BD0119A
FOSTER WHEELER ITALIANA
DWG.
BD0119A-3-50-2300


1-D-3205
MP STEAM RECEIVER DRUM
TO 2nd TRAIN
MP
HP STEAM FROM PROCESS UNITS
HP
TO 2nd TRAIN
HPDS
1-DS-3202
HP STEAM DESUPERHEATER
1-D-3201
HP STEAM DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
LP
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
1-D-3204
VLP STEAM DRUM
VLP
1-STK-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
MP SUPERHEATER
1-E-3207
HP ECONOMIZER 3rd SECTION
1-E-3208
MP EVAPORATOR
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3211
LP EVAPORATOR
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
BD BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
1-D-3101
SYNGAS FINAL SEPARATOR
D
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
MHP HEADER
MHP
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-HRSG-3201
HEAT RECOVERY STEAM GENERATOR
HBFW
TO HP BFW HEADER
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING AND COS HYDROLYSIS)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
TO 2nd TRAIN
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
TO 2nd TRAIN
1-E-3101
SYNGAS FINAL HEATER
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 HP SECTION
FROM 2nd TRAIN
TO 2nd TRAIN
MP STEAM FROM TB-3301 HP SECTION
LEGEND
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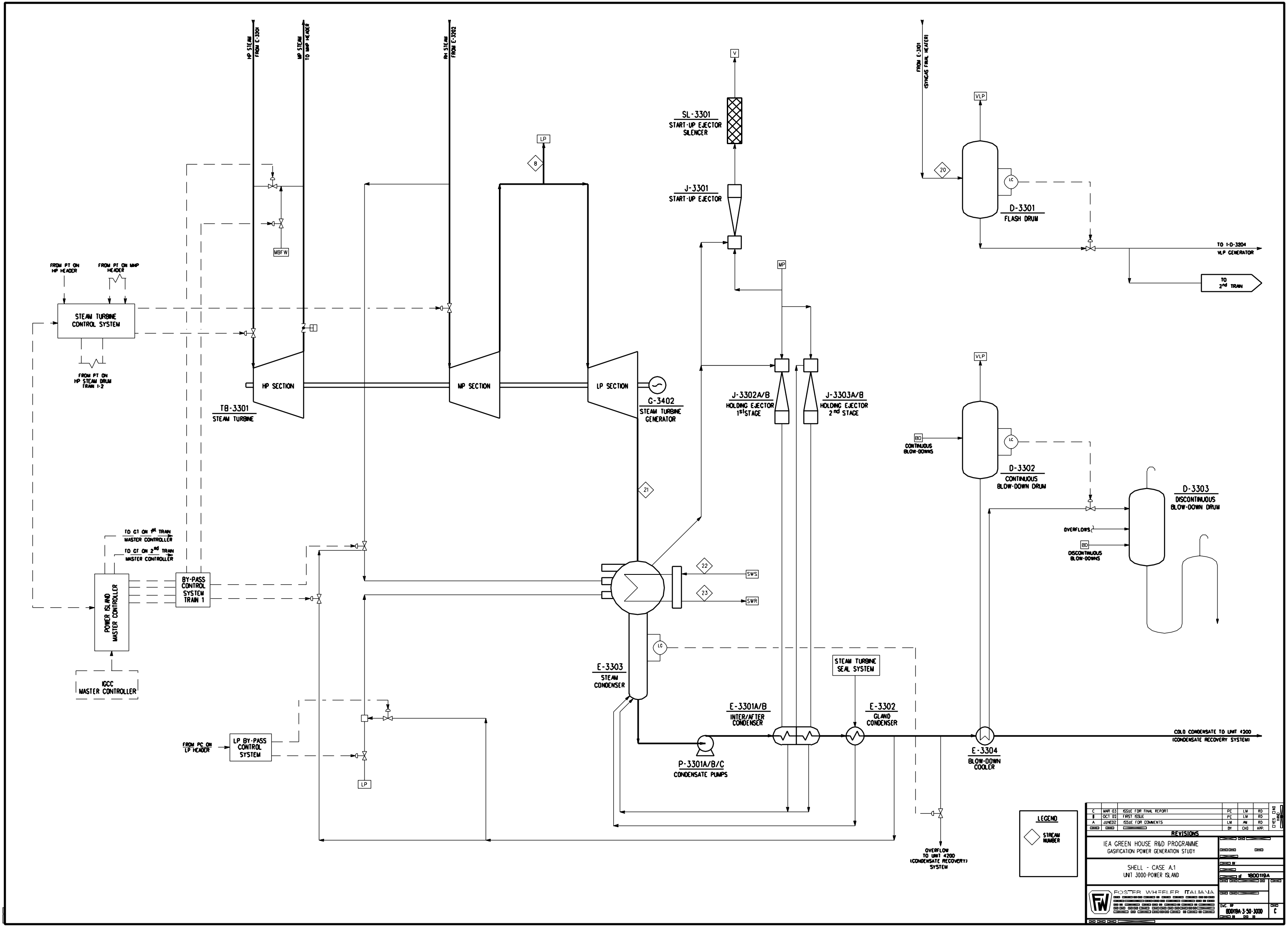
B OCT 02 FIRST ISSUE
A JUNE02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.1
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
1BD0119A-3-50-3000


HP STEAM FROM E-3201
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
FROM E-3101 (SYNGAS FINAL HEATER)
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
LP
8
MBFW
MP
VLP
20
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
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
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
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
21
TO GT ON 1st TRAIN MASTER CONTROLLER
TO GT ON 2nd TRAIN MASTER CONTROLLER
POWER ISLAND MASTER CONTROLLER
BY-PASS CONTROL SYSTEM TRAIN 1
22
23
SWS
SWR
IGCC MASTER CONTROLLER
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
P-3301A/B/C
CONDENSATE PUMPS
E-3304
BLOW-DOWN COOLER
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
LEGEND
STREAM NUMBER
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B OCT 02 FIRST ISSUE PC LM RD
A JUNE02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.1
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
DWG.
BD0119A-3-50-3000
C

1.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 2400: Sulphur Recovery Unit & Tail Gas Treatment;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE A.1	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	Oct-02	Mar-03	

STREAM	1	2	3	4	5	6	7			
	AIR EXTRACTED FROM EACH GAS TURBINE	MP NITROGEN TO EACH GAS TURBINE	HP OXYGEN TO GASIFICATION	AMBIENT AIR INTAKE	HP NITROGEN	LP NITROGEN	TOTAL Air from GTs			
Temperature (°C)	406	213	80	AMB.	80	70	190			
Pressure (bar)	14,3	22	40,4	AMB.	69,0	7,5	13,8			
TOTAL FLOW										
Mass flow (kg/h)	218720	281200	196982	437440	81860	31870	437440			
Molar flow (kgmole/h)	7555	10010	6161	15110	2924	1138	7555			
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	218720	281200	196982	437440	81860	31870	437440			
Molar flow (kgmole/h)	7555	10010	6160	15110	2924	1138	7555			
Molecular Weight	28,87	28,00	32	28,87	28,01	28,01	28,87			
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	77,57	97,50	3,50	77,57	99,88	99,88	77,57			
O_2	20,86	2,15	95,00	20,86	0,04	0,04	20,86			
CH_4										
H_2S										
COS										
Ar	0,89	0,26	1,50	0,89	0,08	0,08	0,89			
H2O	0,68	0,09		0,68			0,68			

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0		Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.		of 1
	CASE : SHELL CASE A.1	APPROVED	R.D.		
	UNIT : 2200 SYNGAS Treatment and conditioning line	DATE	Oct-02		

STREAM	1	2	3	4	5	6	7			
	SYNGAS at Scrubber Outlet (2 Trains)	Raw SYNGAS to AGR (2 Trains)	Condensate Return to Gasification (2 Trains)	Purified Syngas from AGR	Treated Syngas to Power Island	Cold Condensate from CRS	Hot Condensate to Power Island			
Temperature (°C)	126	38	70	41	150	21	58			
Pressure (bar)	34	30,5	30	30	29,5	15,0	14,5			
TOTAL FLOW										
Mass flow (kg/h)	231750	217530	14050	435770	435770	484500	484500			
Molar flow (kgmole/h)	11632	10850		21726	21726					
LIQUID PHASE										
Mass flow (kg/h)			14050			484500	484500			
GASEOUS PHASE										
Mass flow (kg/h)	463500	217530		435770	435770					
Molar flow (kgmole/h)	23263,5	10850		21726	21726					
Molecular Weight	19,9	20,0		20,1	20,1					
Composition (vol %)										
H_2	29,70	31,82		31,83	31,83					
CO	56,40	60,42		60,35	60,35					
CO_2	1,40	1,52		1,62	1,62					
N_2	4,53	4,92		5,17	5,17					
O_2	0,00	0,00		0,00	0,00					
CH_4	0,00	0,00		0,00	0,00					
H_2S	0,24	0,28		0,00	0,00					
COS	0,02	0,00		0,00	0,00					
Ar	0,70	0,75		0,75	0,75					
H2O	7,00	0,29		0,28	0,28					

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0		Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.		of 1
	CASE : SHELL CASE A.1						APPROVED	R.D.		
	UNIT : 2300 Acid Gas Removal						DATE	Oct-02		
STREAM	1	2	3	4	5	6				
	Raw SYNGAS from Syngas Cooling	Recycle gas	Purified Syngas to Syngas Cooling	Flash gas	Acid gas from reflux drum	Acid gas to SRU				
Temperature (°C)	38	38	41	46	49	49				
Pressure (bar)	30,5	30,5	30,0	4,4	1,7	1,7				
TOTAL FLOW										
Mass flow (kg/h)	435060	5385	435770	104	5175	5279				
Molar flow (kgmole/h)	21700	161	21726	4	138	143				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	435060	5385	435770	104	5175	5279				
Molar flow (kgmole/h)	21700	161	21726	4	138	143				
Molecular Weight	20,0	33,5	20,1	23,8	37,4	37,0				
Composition (vol %)										
H_2	31,82	7,80	31,83		0,03	0,12				
CO	60,42	1,07	60,35		0,01	1,32				
CO_2	1,52	55,49	1,62		46,81	46,98				
N_2	4,92	33,84	5,17		0,00	0,11				
O_2	0,00	0,00	0,00		0,00	0,00				
CH_4	0,00	0,00	0,00		0,00	0,00				
H_2S	0,28	1,37	0,00		45,36	44,05				
COS	0,00	0,00	0,00		0,00	0,00				
Ar	0,75	0,37	0,75		0,07	0,11				
H2O	0,29	0,06	0,28		7,45	7,31				

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0		Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.		of 1
	CASE : SHELL CASE A.1						APPROVED	R.D.		
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	Oct-02		

STREAM	1	2	3	4	5	6	7	8	9	10
	Acid Gas from AGR Unit	Product Sulphur	Sour Gas from Gasification	Recycle Tail Gas to AGR Unit						
Temperature (°C)	49	AMB.	100	38						
Pressure (bar)	1,7	AMB.	1,5	30,5						
TOTAL FLOW										
Mass flow (kg/h)	5279	51.5 t/d	1200	5385						
Molar flow (kgmole/h)	143			161						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	5279		1200	5385						
Molar flow (kgmole/h)	142,7			161						
Molecular Weight	37,0			33,5						
Composition (vol %)										
H_2	0,12			7,80						
CO	1,32			1,07						
CO_2	46,98		16,00	55,49						
N_2	0,11			33,84						
O_2	0,00			0,00						
CH_4	0,00			0,00						
H_2S + COS	44,05		18,00	1,37						
COS	0,00			0,00						
NH3 + HCN	0,00		31,00	0,00						
Ar	0,11		0,00	0,37						
H2O	7,31		35,00	0,06						

	IGCC HEAT & MATERIAL BALANCE				
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME CASE : SHELL CASE A.1 UNIT : 3000 POWER ISLAND				
Stream	**Description**	**Flowrate t/h**	**Temperature °C**	**Pressure bar a**	**Entalphy kJ/kg**
1	Treated SYNGAS from Syngas Cooling (*) (1)	217,89	150	29,5	174,3
2	Extraction Air to Air Separation Unit (*)	218,72	406	15,0	-
3	MP Nitrogen from ASU (*)	281,20	213	22,00	-
4	HP Steam from Process Units	150,45	380	128,0	2958,7
5	HP Steam to Steam Turbine (*)	381,36	552	122,5	3482
6	Hot RH Steam to Steam Turbine (*)	446,91	525	38,7	3503
7	MP Steam from Steam Turbine (*)	381,36	386	41,7	3179
8	LP steam to process	108,96	172	7,3	2776
9	- - NOT USED - -				
10	MP Steam to MP -Superheater (*)	62,00	254,7	43,0	2799
11	- - NOT USED - -				
12	- - NOT USED - -				
13	BFW to LP BFW Pumps (*)	69,16	119	1,9	499
14	BFW to MP BFW Pumps (*)	185,36	119	1,9	499
15	BFW to HP BFW Pumps (*)	403,40	119	1,9	499
16	Hot Condensate returned from Unit 2200 (*)	484,50	65	2,5	275
17	Hot Condensate returned from CR (*)	119,05	94	2,5	394
18	Water from Flash Drum (*)	32,50	119	2,5	499
19	FLUE GAS AT STACK (*) (2)	2682,10	129	AMB.	117
20	Condensate from Syngas Final Heater (*)	36,18	170	52,0	722
21	LP Steam Turbine Exhaust	823,30	21,7	0,026	2220
22	Sea Water Supply to Steam Condenser	60168	12	3,0	50,5
23	Sea Water Return from Steam Condenser	60168	19	2,1	79,8

(*) Flowrate for one train
(1) Syngas composition as per stream 4 of Material Balance for Unit 2200 .
(2) Flues gas molar composition: N_2: 74.2%; H_2O: 6.2%; O_2: 11.5%; CO_2: 7.3%; Ar: 0.8%.

1.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

				REVISION	Rev.0	Rev.1	Rev.2
FOSTER WHEELER	CLIENT:	IEA GHG		DATE	25-mar-02	20-june-02	15-july-02
	PROJECT:	GASIFICATION POWER GENERATION STUDY		ISSUED BY	S.T.	L.M.	P.C.
	LOCATION:	Netherlands		CHECKED BY	S.A.	A.M.	L.M.
	FWI Nº:	1- BD 0119A		APPROVED BY	R.D.	R.D.	R.D.

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE A.1 - LP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 42 barg [t/h]	LP Steam 6.5 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS									
1000	**Gasification Section**		**-300,9**	**-7,1**	**-57,0**	**342,7**	**78,2**	**11,3**	**38,2**	**29,0**
2100	**Air Separation Unit**				**124,4**		**113,2**		**124,4**	**113,2**
2200	**Syngas Treatment and COS Hydrolysis**			**15,1**	**35,6**				**50,7**	
2300	**Acid Gas Removal**				**12,5**				**12,5**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-0,7**	**-0,9**		**4,1**	**0,9**	**3,4**	
3000	**POWER ISLANDS UNITS**		**300,9**	**-7,3**	**-123,5**	**-342,7**	**-195,5**	**-12,2**		
4100 to 5300	**UTILITY and OFFSITE UNITS**				**9,0**				**9,0**	
	BALANCE		**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**238,1**	**142,2**

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG		Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY		set-02
	LOCATION:	Netherlands		ISSUED BY: PC.
	FWI Nº:	1- BD 0119A		CHECKED BY: LM
				APPR. BY: RM

WATER CONSUMPTION SUMMARY - SHELL - CASE A1 - LP w/o 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				
1000	**Gasification Section**	58	29	2361	
2100	**Air Separation Unit**		113		19228
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**			648	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			20	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		4	1648	60168
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4100/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				8654
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	166	-166		
	Other Units		20	361	
	BALANCE	224	0	5038	88050

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	**CLIENT:** **PROJECT:** **LOCATION:** **FWI Nº:**	IEA GHG GASIFICATION POWER GENERATION STUDY Netherlands 1- BD 0119A	Rev 0 nov-02 ISSUED BY: PC. CHECKED BY: LM APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE A1 - LP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**280**
1000	**Gasification Section**	**11800**
2100	**Air Separation Unit**	**100423**
2200	**Syngas treatment and conditioning line**	**-**
2300	**Acid Gas Removal**	**240**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**972**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4741**
3200	**Heat Recovery Steam Generator**	**5759**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1889**
3500	**Miscellanea**	**490**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**6079**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**559**
	Other Units	**639**
	BALANCE	**133871**

1.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

SHELL

Case A.1 - LOW PRESSURE without CO2 capture - Rev. 2

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	250.6
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1800.8**
Thermal Power of Raw Syn exit Scrubber (dry, based on LHV) (E)	MWt	1504.4
Thermal Power of Clean Syngas to GT (based on LHV) (F)	MWt	1496.6
Syngas treatment efficiency (F/E*100)	%	99.5
Gas turbines total power output	MWe	553.6
Steam turbine power output	MWe	356.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**909.8**
ASU power consumption	MWe	100.4
Process Units consumption	MWe	13.0
Utility Units consumption	MWe	1.5
Offsite Units consumption (including sea cooling water system)	MWe	6.0
Power Islands consumption	MWe	12.9
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**133.9**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**775.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**50.5**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**43.1**

1.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristics are shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

1.7.1 Gaseous Emissions

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, and emission from the coal Drying process.

Table 1.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 1.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	745,0
Flow, $Nm^3/h^{(1)}$	2.835.070
Temperature, °C	129
Composition	(%vol)
Ar	0,82
N_2	74,23
O_2	11,48
CO_2	7,30
H_2O	6,17
Emissions	$mg/Nm^{3\ (1)}$
NOx	80
SOx	5
CO	31
Particulate	5

(1) Dry gas, O2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 1.2.

Table 1.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1490,0
Flow, $Nm^3/h^{(1)}$	5.670.140
Temperature, °C	129
Emissions	kg/h
NOx	453,6
SOx	28,3
CO	176,0
Particulate	28,0

(1) Dry gas, O2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate	:	35	t/h
N2	:	80	% vol.
$H_2O+O_2+CO_2$	:	20	% vol.
Particulate	:	<10	mg/Nm^3, wet basis.

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

1.7.2 Liquid Effluent

The effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island.

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	:	85.500	m^3/h
• Temperature	:	19	°C
• Cl_2	:	<0.05	ppm

1.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

Slag from Slag Removal Unit

Flow rate	:	37,2	t/h
Water content	:	10	%wt

Slag product can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

Flyash from Dry Solids Removal Unit

Flow rate	:	1,2	t/h

Flyash can be dispatched to cement industries.

1.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A			REVISION	Rev.0	Rev.1	Rev.2	Rev.3
					DATE				
					ISSUED BY	L.M.			
					CHECKED BY	R.D.			
					APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		TOWERS		D,mm x TT,mm					
1	**T-2101**	**Nitrogen Saturator**	Packed			26	190		
2	**T-2101**	**Nitrogen Saturator**	Packed			26	190		
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
1	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 26	320 / 190		DUTY = 6710 kW
2	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 26	320 / 190		DUTY = 6710 kW
1	**E-2102**	**Nitrogen preheater**	Shell & Tube			19 / 26	435 / 180		DUTY = 7350 kW
2	**E-2102**	**Nitrogen preheater**	Shell & Tube			19 / 26	435 / 180		DUTY = 7350 kW
1	**E-2103**	**Saturator recycle heater**	Shell & Tube			12 / 26	200 / 190		DUTY = 32440 kW
2	**E-2103**	**Saturator recycle heater**	Shell & Tube			12 / 26	200 / 190		DUTY = 32440 kW
		PUMPS		$Q,m^3/h$ x H,m					
1	**P-2101 A/B**	**Saturator pump**	centrifugal						One operating, one spare
2	**P-2101 A/B**	**Saturator pump**	centrifugal						One operating, one spare
		PACKAGES							
	Z-2100	**Air Separation Unit Package** (two parallel trains, each sized for 50% of the capacity)		HP O_2 flow rate to Gasifier = 207 t/h		45			Oxigen purity = 95 %
				HP N_2 flow rate to Gasifier = 86 t/h		74			Nitrogen purity = 98 %
				LP N_2 flow rate to Gasifier = 34 t/h		11			Nitrogen purity = 98 %
				MP N_2 flow rate to GTs = 591 t/h		26			Nitrogen purity = 98 %
				LP N_2 flow rate to Proc Unit = 1.8 t/h		14			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 460 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE				
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling & COS hydrolisys - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**Syngas Feed/ Product Exchanger**	Shell & Tube			39 / 39	230 / 193		DUTY = 3690 kW H2 service H2/Wet H2S service on
2	**E-2201**	**Syngas Feed/ Product Exchanger**	Shell & Tube			39 / 39	230 / 193		DUTY = 3690 kW H2 service H2/Wet H2S service on
1	**E-2202**	**Hydrolysis Feed Heater**	Shell & Tube			50 +FV / 39	285 / 230		DUTY = 3670 kW H2/Wet H2S service on channel side
2	**E-2202**	**Hydrolysis Feed Heater**	Shell & Tube			50 +FV / 39	285 / 230		DUTY = 3670 kW H2/Wet H2S service on channel side
1	**E-2203 A/B**	**Condensate Preheater**	Shell & Tube			26 / 39	185 / 105		DUTY = 21174 kW H2/Wet H2S service on channel side
2	**E-2203 A/B**	**Condensate Preheater**	Shell & Tube			26 / 39	185 / 105		DUTY = 21174 kW H2/Wet H2S service on channel side
	E-2204	**Syngas Heater**	Shell & Tube			12 / 39	200 / 180		DUTY = 19730 kW H2/Wet H2S service on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE				
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling & COS hydrolisys - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS		D,mm x TT,mm					
1	D-2201 A/B	Condensate Separator	Vertical			39	80		Equipped with demister Wet H2S service/H2 service
2	D-2201 A/B	Condensate Separator	Vertical			39	80		Equipped with demister Wet H2S service/H2 service
		REACTOR		D,mm x TT,mm					
1	R-2201	COS Hydrolysis Reactor	vertical			39	230		H2 service Wet H2S service
2	R-2201	COS Hydrolysis Reactor	vertical			39	230		H2 service Wet H2S service
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	COS Hydrolysis Catalyst							Catalyst volume: 230 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE				
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2300 - Acid Gas Removal - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		TOWERS		D,mm x N° Trays					
	T-2301	Acid Gas Absorber	Tray Column			38	80		H2/Amine/wet H2S service
	T-2302	UCARSOL regenerator	Tray Column			3,5	180		Amine/wet H2S service
		HEAT EXCHANGERS		S, m2		Shell/tube	Shell/tube		
	E-2301	Lean/Rich Exchanger	Shell & Tube			3,5 / 3,5	155 / 80		DUTY = 11670 kw Wet H2S/ Amine service
	E-2302	Lean Solvent Cooler	Air Cooler						DUTY = 6150 kW Wet H2S/ Amine service
	E-2303	Reboiler	Shell & Tube			12 / 3,5	190 / 155		DUTY = 10020 kW Wet H2S/ Amine service
	E-2304	Reflux Condenser	Air Cooler						DUTY = 3060 kW Wet H2S service
		DRUMS		D,mm x TT,mm					
	D-2301	Flash Drum	horizontal			8	80		Wet H2S/ Amine service
	D-2302	Surge Drum	horizontal			12	80		Wet H2S/ Amine service
	D-2303	UCARSOL Section Slop Drum	horizontal			3,5	160		Wet H2S/ Amine service
	D-2304	UCARSOL Regenerator Reflux Drum	vertical			3,5	80		Wet H2S service
	D-2305	LP Steam Receiver	vertical			12	190		
	D-2306	Purified Gas K.O. Drum	vertical			38	80		Wet H2S/ H2 service

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE				
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2300 - Acid Gas Removal - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		W,m^3/h x H,m					
	P-2301 A/B	Lean UCARSOL Pump	centrifugal						One operating, one spare.
	P-2302 A/B	Absorber Feed Pump	centrifugal						One operating, one spare.
	P-2303 A/B	UCARSOL Make-up Pump	centrifugal						One operating, one spare.
	P-2304	UCARSOL Section Slop Pump	vertical submerged						Intermittent .
	P-2305 A/B	UCARSOL Regenerator Reflux Pump	centrifugal						One operating, one spare.
		TANKS		D,mm x TT,mm					
	TK-2301	Ucarsol Storage Tank	Fixed Roof				160		Wet H2S service
		MISCELLANEA							
	F-2301	1st UCARSOL Mechanical Filter	Basket						
	F-2302	2nd UCARSOL Mechanical Filter	Basket						
	F-2303	Lean UCARSOL Mechanical Filter	Basket						
	F-2304	UCARSOL Carbon Filter	Act. Carb. Bed						
		PACKAGES							
	Z-2301	Ion Exchange Resin Reclaiming	Regen. Resin Package	7 m3/h					

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		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment- SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=51.5 t/d					Sulphur content = 99,9 wt min (dry basis)
				Acid Gas from AGR = 143 kmol/h		3,5	80		Sulphur content = 44% (wet basis) Hydrogen content = 0,12 % (wet basis)
				Sour gas from Gasif. = 45 kmol/h					Sulphur content = 18,00 % (wet basis)
				Expected Treated Tail Gas=160 kmol/h		35	70		Major components (wet basis): CO_2 = 55.5%, H_2=7.8%, N_2 = 33.8%

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EQUIPMENT LIST

Unit 3100 - Gas Turbine - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 39	280 / 200		DUTY = 890 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			70 / 39	280 / 200		DUTY = 890 kW Tubes: H2 service
		DRUMS		D,mm x TT,mm					
1	**D-3101**	**Syngas Final Separator**	vertical			39	200		H2 service
2	**D-3101**	**Syngas Final Separator**	vertical			39	200		H2 service
		PACKAGES							
1	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	277 MW					 Included in 1-Z- 3101 Included in 1-Z- 3101
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	277 MW					 Included in 2-Z- 3101 Included in 2-Z- 3101

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		Q,m^3/h x H,m					
1	P-3201 A/B	LP BFW Pumps	centrifugal						One operating, one spare
2	P-3201 A/B	LP BFW Pumps	centrifugal						One operating, one spare
1	P-3202 A/B	MP BFW Pumps	centrifugal						One operating, one spare
2	P-3202 A/B	MP BFW Pumps	centrifugal						One operating, one spare
1	P-3203 A/B	HP BFW Pumps	centrifugal						One operating, one spare
2	P-3203 A/B	HP BFW Pumps	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	D-3205	MP Steam Receiver Drum	horizontal			50 + FV	285		
2	D-3205	MP Steam Receiver Drum	horizontal			50 + FV	285		
		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 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

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**MP Superheater**							Included in 1-HRS-3201
1	E-3207	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3208	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3210	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**LP Evaporator**							Included in 1-HRS-3201
1	E-3212	**LP Economizer**							Included in 1-HRS-3201
1	E-3213	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3214	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**VLP Evaporator**							Included in 1-HRS-3201

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**MP Superheater**							Included in 2-HRS-3201
2	E-3207	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3208	**MP Evaporator**							Included in 2-HRS-3201
2	E-3209	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3210	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**LP Evaporator**							Included in 2-HRS-3201
2	E-3212	**LP Economizer**							Included in 2-HRS-3201
2	E-3213	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3214	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**VLP Evaporator**							Included in 2-HRS-3201

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EQUIPMENT LIST

Unit 3300 - Steam Turbine & Blow Down System - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			19 / 4	55 / 140		DUTY = 1044 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		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	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

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		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - SHELL Case A.1 - Low Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	**G-3401**	**Gas Turbine Generator**							Included in 1 -Z- 3101
2	**G-3401**	**Gas Turbine Generator**							Included in 2 -Z- 3101
	G-3402	**Steam Turbine Generator**							Included in Z- 3301

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE A.2

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
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SECTION D.2

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.2 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.2 BASIC INFORMATION FOR EACH ALTERNATIVE

2.0 Case A.2

2.1 Introduction

The main features of the Case A.2 configuration of the IGCC Complex are:

- High pressure (61 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- No Shift and CO_2 removal.

The removal of acid gas (AGR) is based on DOW-UCARSOL process (activated MDEA solvent).
The degree of integration between the Air Separation Unit (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and NO_x control are achieved with injection of compressed moisturised 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.

The arrangement of the process units is :

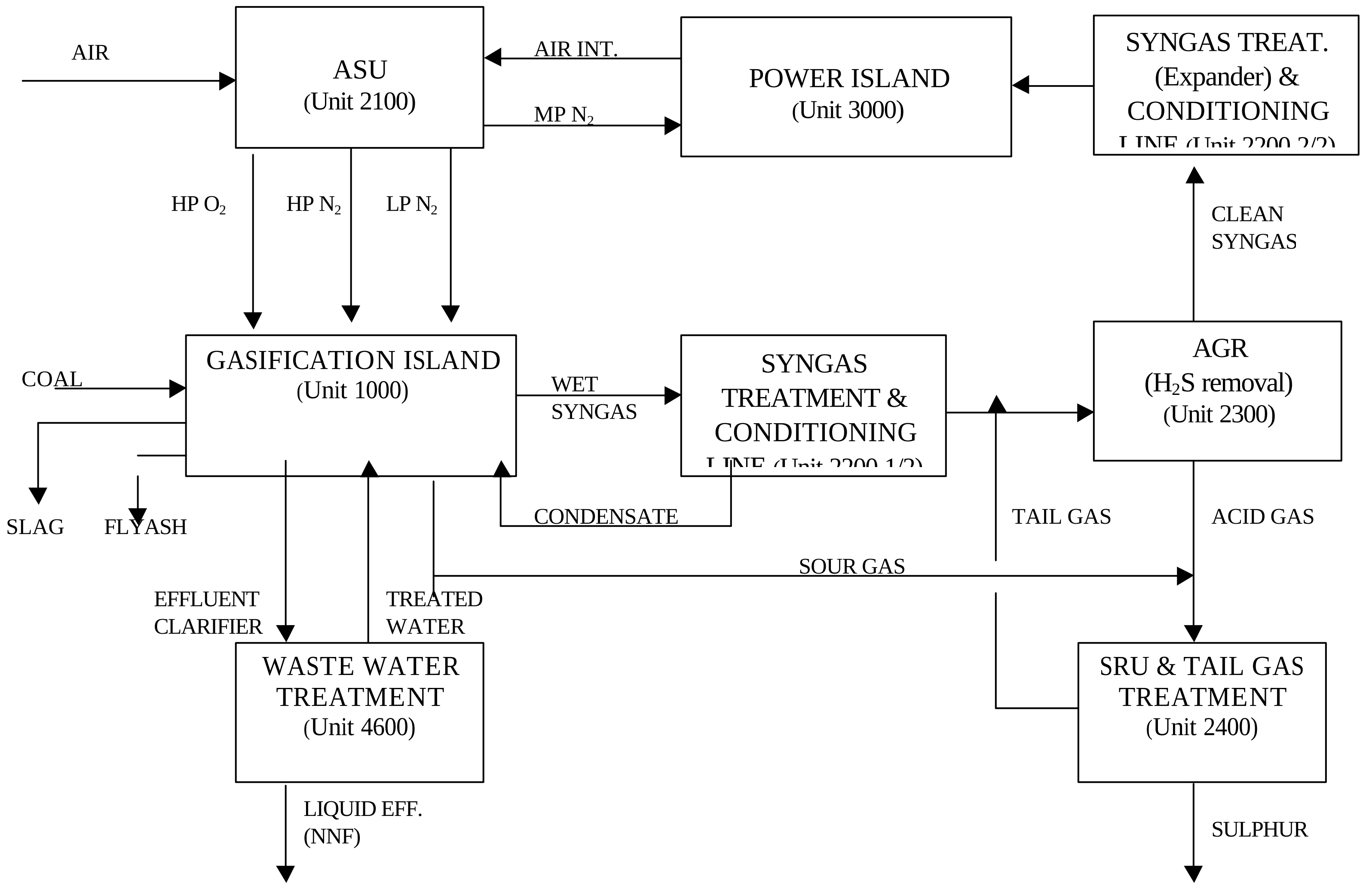
Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurization/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
		1 x 100%
2200	Syngas Treatment and 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-9351FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

During the 1st phase of the project, the low pressure was selected as the optimum pressure for the Shell Technology. As a consequence, Vendors were not required to provide data for this high pressure alternative and all the process calculation of the 1st phase, based on in-house data, were revised in order to meet the new Gas turbine requirement (GE data).

SHELL A.2 – IGCC COMPLEX BLOCK FLOW DIAGRAM



2.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB	100	80	70	145
Pressure (bar)		66.7	94	7.5	59
TOTAL FLOW					
Mass flow (kg/h)	252,100	199,550	235,840	67,120	501,282
Molar flow (kmol/h)			8,393	2,389	24,610
Composition (% vol)					
H_2					28.00
CO					53.33
CO_2					1.50
N_2		3.5	99.88	99.88	9.20
Ar		1.5	0.08	0.08	0.70
O_2		95	0.04	0.04	0.00
H_2S + COS					0.24
H2O					7.00
Others					0.03

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 2.3 indicates the interconnections of ASU with the other units of the IGCC.

The degree of integration with the gas turbines is 50% and the N_2 used to augment the power of the gas turbine is moisturised by direct contact with hot water in order to increase the syngas diluent mass flow. As for this alternative General Electric was not required to provide data concerning the performance of the Gas turbine, a further investigation on the NOx emissions shall be done in order to understand if a SCR system to be installed in the Heat Recovery Steam Generator is needed.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the process flow diagram attached to paragraph 2.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 58 barg and 145°C enters Unit 2200. The syngas is first preheated in E-2201, with the hydrolysis effluent, and then in E-2202 with MP steam, before entering the hydrolysis reactor R-2201, which converts COS to H_2S. The effluent is cooled in E-2202 and in E-2203 against cold condensate. Process condensate separated in D-2201 is recycled to Unit 1000 Gasification while cold syngas is sent to Unit 2300 AGR.
Up to this point Unit 2220 is split in two parallel lines, each sized for 50% capacity. Downstream D-2201 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-2204 with LP steam and then reduced in pressure, down to 25 bar g in the Expander EX-2201, generating electric energy.
Expanded clean syngas is preheated with LP steam in E-2205 before flowing to Unit 3000, gas turbines.

Unit 2300: Acid Gas Removal (AGR)

In the absence of licensor data for this alternative, an open-art DOW-UCARSOL process (activated MDEA solvent) was considered, based on data provided by DOW with reference to Case A1 (Shell Low Pressure, no shift reaction).

Unit 2300 is characterised by a high syngas pressure (53 barg), and a low CO_2/H_2S ratio (6,3/1). A single-stage absorption is suitable to accomplish all objectives, i.e. no acid gas enrichment is required. Therefore the tail gas coming from the Sulphur Recovery Unit is mixed with the raw syngas before entering the AGR section.

The interfaces of the Ucarsol process with the other Units are the following, as shown in the Process Flow Diagram attached to para 2.3:

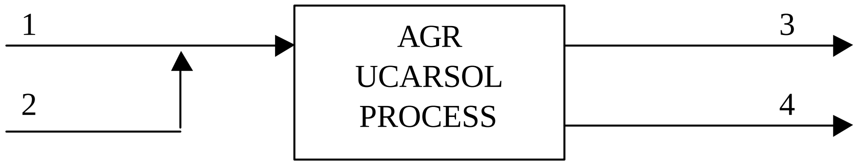
Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Unit

2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

Exit Streams

3. Treated Gas to Gas Turbines
4. Acid Gas to Sulphur Recovery Unit



The MDEA solvent consumption, to make-up losses, is 60 m^3/year.

The proposed process matches the process specifications with reference to H_2S+COS concentration of the treated gas exiting the Unit and fed to the Combined Cycle Unit. The treated gas feeding the gas turbines has an H_2S+COS concentration of 16 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.

The acid gas H_2S concentration is 45% dry basis, more than suitable to feed the oxygen blown Claus process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 51.8 t/day and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 53 barg.

Unit 3000: Power Island

The process flow diagram is attached to paragraph 2.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island.
- MP steam (42 barg) : steam exported to Syngas Treatment and Conditioning Line. Part of the required steam is also generated in the Sulphur Recovery Unit and in the Gasification Island.
- LP steam (6,5 barg) : steam exported to the following Process Units: Syngas Treatment and Conditioning Line, AGR, ASU, Utility and Offsite Unit. Most of the steam is used to heat the recirculation of the Saturator Tower to moisturise the nitrogen fed to the gas turbine.
- BFW : HP, MP, LP Boiler Feed Water is exported to the Process Units to generate the above mentioned steam production. Part of the MP BFW is added to the nitrogen in the Saturator Tower.
- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 2.4, Utilities Consumption.

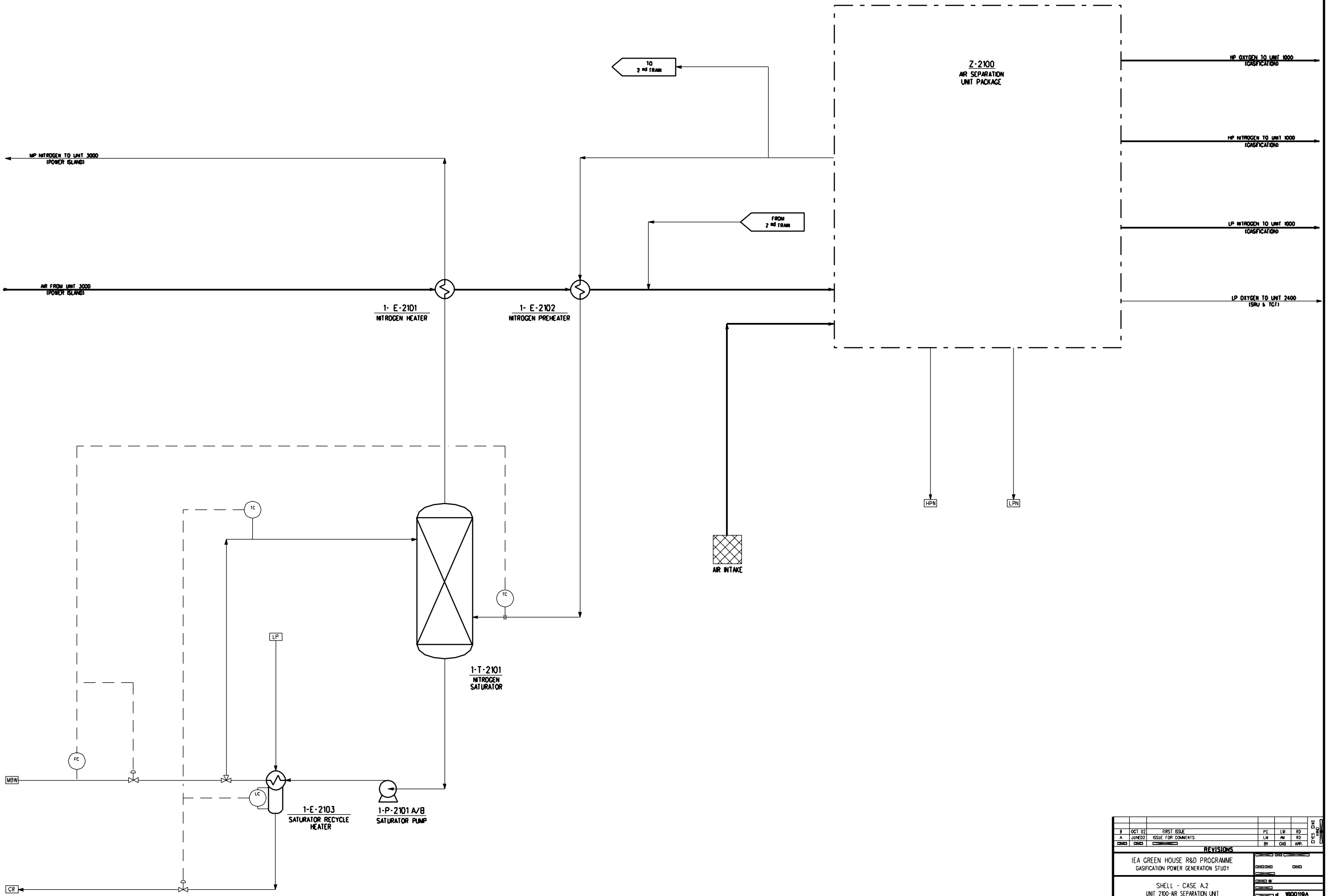
The only steam imported from the Power Island is the superheated steam generated in the Gasification Island; all other steams are exported. As a consequence, the generation levels are the same of the Process Units.

2.3 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0 and 9.0.



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A	JUNE02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

SHELL - CASE A.2
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

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DWG. Nº 1800119A-3-50-2100

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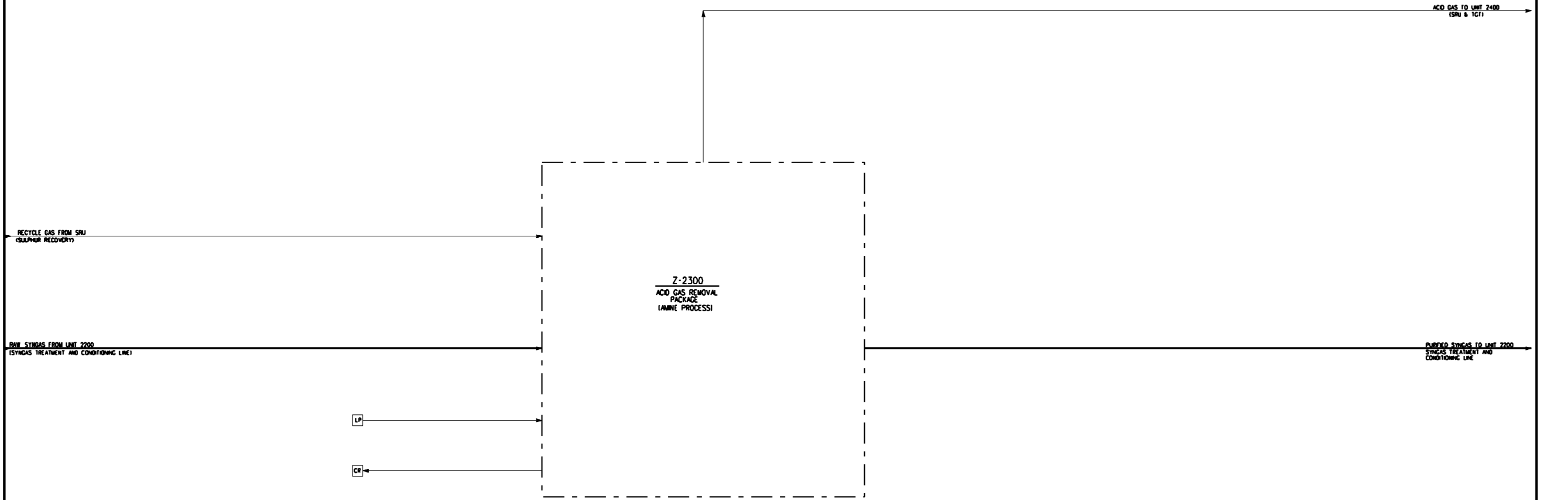

0	OCT. 07	FIRST ISSUE	P.C.	L.M.	R.D.
A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

YES NO HAND

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

SHELL - CASE A.2
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

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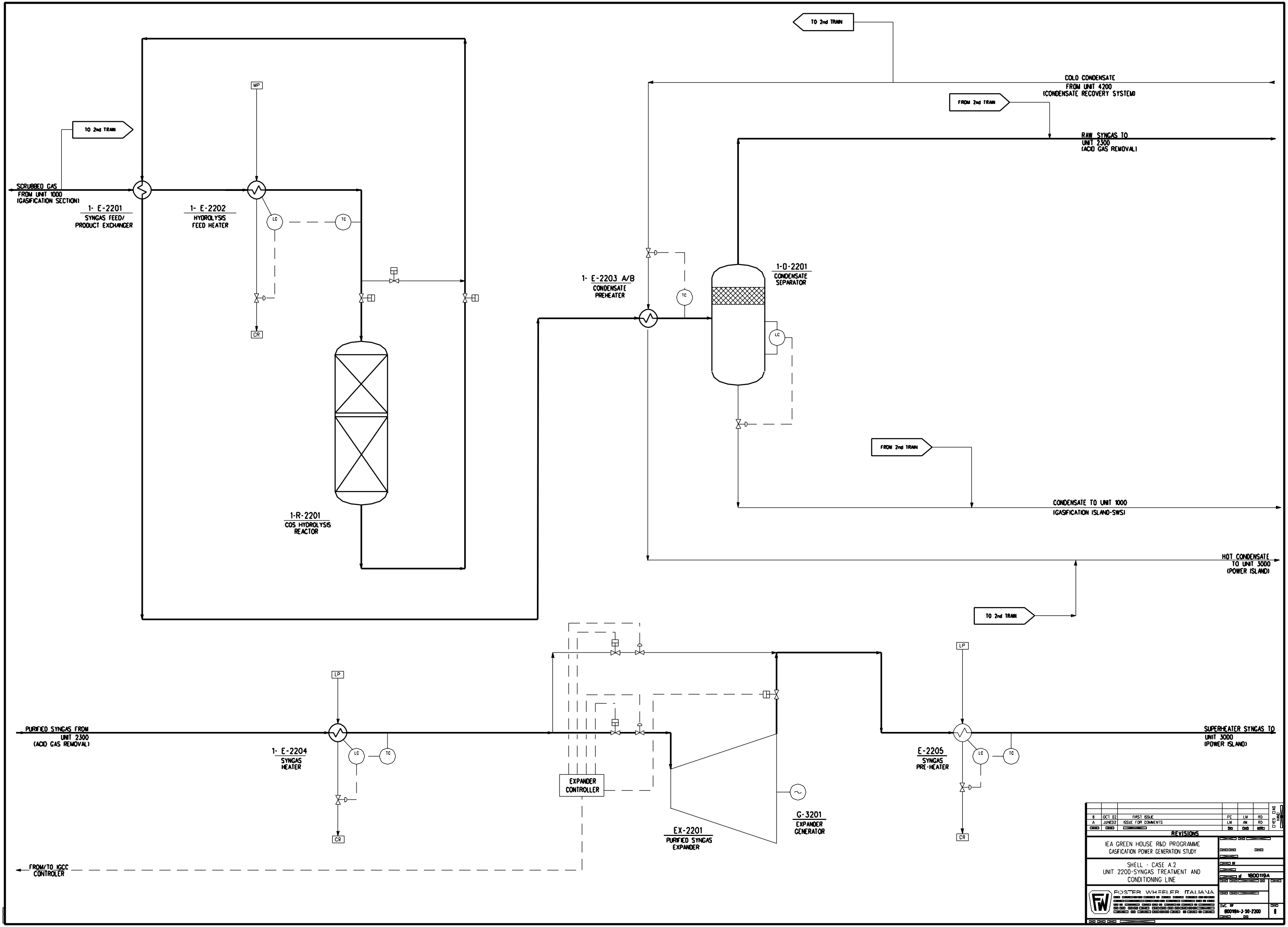
TO 2nd TRAIN
COLD CONDENSATE
FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
FROM 2nd TRAIN
RAW SYNGAS TO
UNIT 2300
(ACID GAS REMOVAL)
MP
TO 2nd TRAIN
SCRUBBED GAS
FROM UNIT 1000
(GASIFICATION SECTION)
1- E-2201
SYNGAS FEED/
PRODUCT EXCHANGER
1- E-2202
HYDROLYSIS
FEED HEATER
LC
TC
CR
1- E-2203 A/B
CONDENSATE
PREHEATER
TC
1-D-2201
CONDENSATE
SEPARATOR
LC
FROM 2nd TRAIN
1-R-2201
COS HYDROLYSIS
REACTOR
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND-SWS)
HOT CONDENSATE
TO UNIT 3000
(POWER ISLAND)
TO 2nd TRAIN
LP
PURIFIED SYNGAS FROM
UNIT 2300
(ACID GAS REMOVAL)
1- E-2204
SYNGAS
HEATER
LC
TC
CR
EXPANDER
CONTROLLER
EX-2201
PURIFIED SYNGAS
EXPANDER
G-3201
EXPANDER
GENERATOR
LP
E-2205
SYNGAS
PRE-HEATER
LC
TC
CR
SUPERHEATER SYNGAS TO
UNIT 3000
(POWER ISLAND)
FROM/TO IGCC
CONTROLER
B OCT 02 FIRST ISSUE PC LM RD
A JUNE02 ISSUE FOR COMMENTS LM AM RD
REVISIONS
YES NO
HAND
IEA GREEN HOUSE R&D PROGRAMME
GASFICATION POWER GENERATION STUDY
SHELL - CASE A.2
UNIT 2200-SYNGAS TREATMENT AND
CONDITIONING LINE
FOSTER WHEELER ITALIANA
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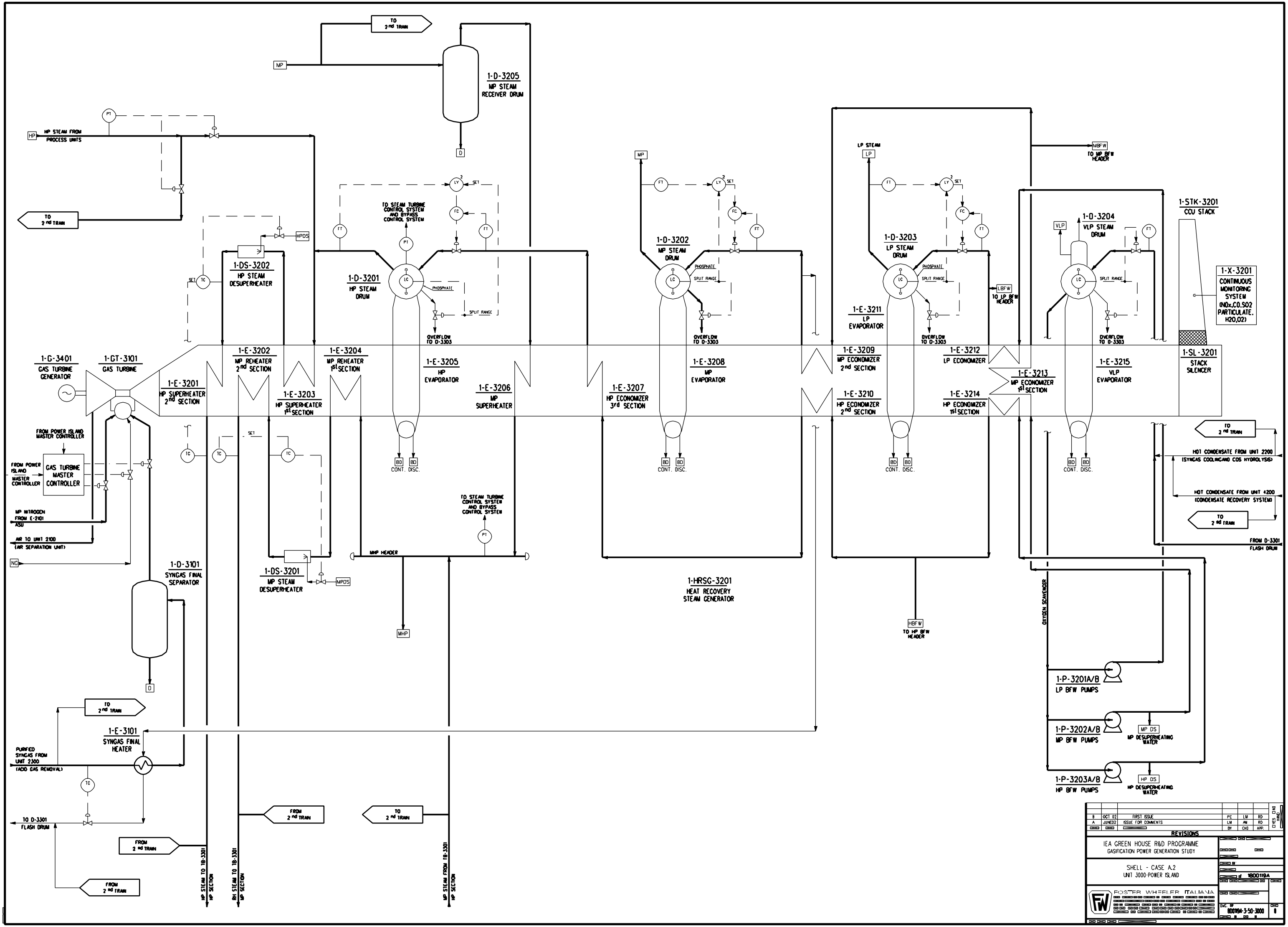
1-D-3205
MP STEAM RECEIVER DRUM
HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
1-DS-3202
HP STEAM DESUPERHEATER
1-D-3201
HP STEAM DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
TO MP BFW HEADER
1-D-3204
VLP STEAM DRUM
1-STK-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-E-3211
LP EVAPORATOR
TO LP BFW HEADER
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
MP SUPERHEATER
1-E-3207
HP ECONOMIZER 3rd SECTION
1-E-3208
MP EVAPORATOR
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
CONT. DISC.
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING AND COS HYDROLYSIS)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
MHP HEADER
1-D-3101
SYNGAS FINAL SEPARATOR
1-DS-3201
MP STEAM DESUPERHEATER
1-HRSG-3201
HEAT RECOVERY STEAM GENERATOR
TO HP BFW HEADER
OXYGEN SCAVENGER
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DESUPERHEATING WATER
1-E-3101
SYNGAS FINAL HEATER
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 HP SECTION
MP STEAM FROM TB-3301 HP SECTION
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GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.2
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
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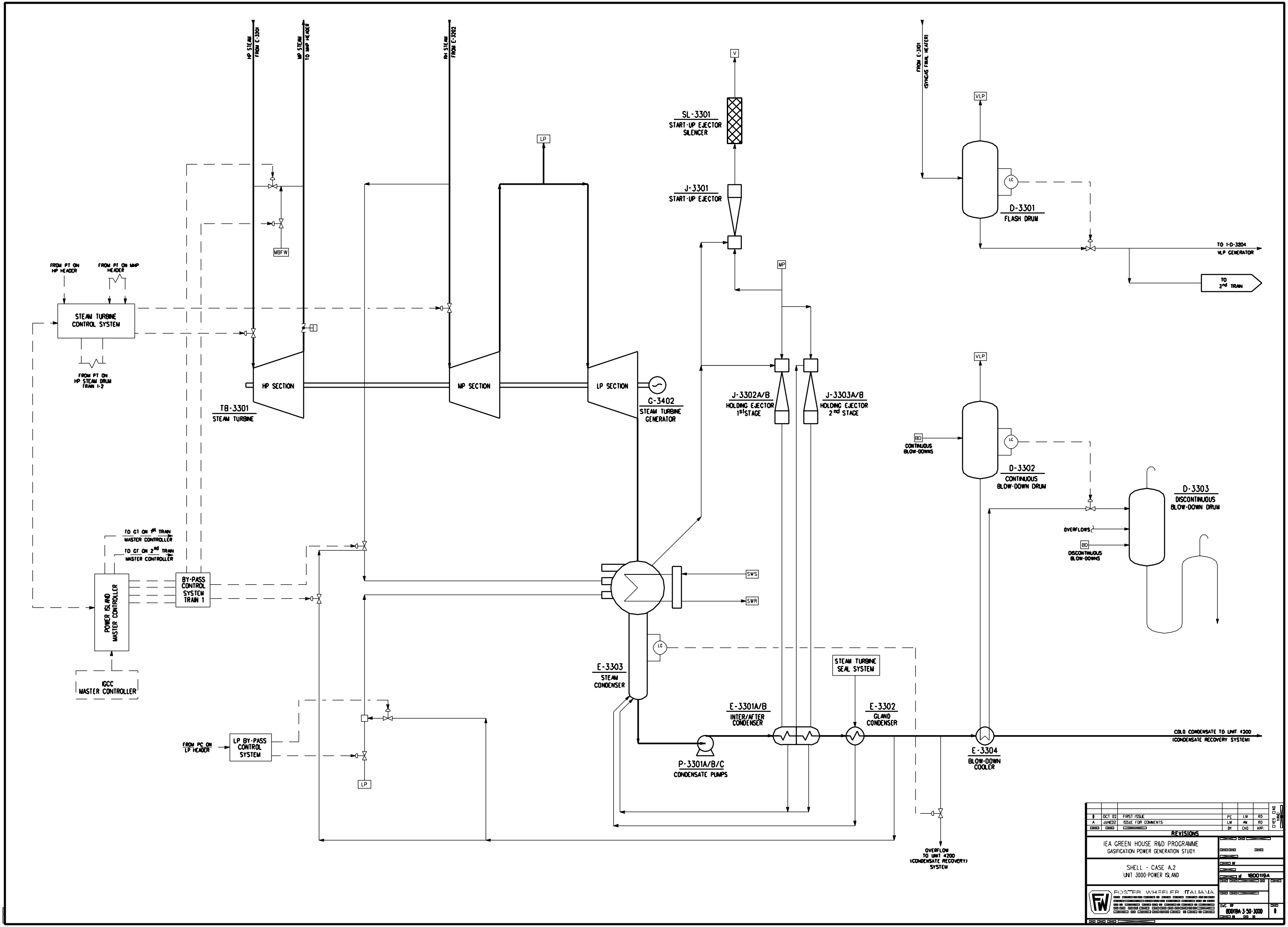
HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
FROM E-3301 (SYNGAS FINAL HEATER)
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
LP
VLP
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
MBFW
MP
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM TRAIN 1-2
HP SECTION
MP SECTION
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
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
E-3304
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
P-3301A/B/C
CONDENSATE PUMPS
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
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GASIFICATION POWER GENERATION STUDY
SHELL - CASE A.2
UNIT 3000-POWER ISLAND
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FOSTER WHEELER ITALIANA
DWG. Nº
BD0119A-3-50-3000
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2.4 Steam and Electrical Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.0	Rev.0
	PROJECT: GASIFICATION POWER GENERATION STUDY	DATE	25-mar-02	25-mar-02
	LOCATION: Netherlands	ISSUED BY	S.T.	S.T.
	FWI Nº: 1- BD 0119A	CHECKED BY	S.A.	S.A.
		APPROVED BY	R.D.	R.D.

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE A.2 - HP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 42 barg [t/h]	LP Steam 6.5 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS									
1000	**Gasification Section**		**-314,8**	**-0,4**	**-70,2**	**357,7**	**93,6**	**11,7**	**48,2**	**29,4**
2100	**Air Separation Unit**				**220,8**		**233,2**		**220,8**	**233,2**
2200	**Syngas Treatment and Conditioning Line**			**12,1**	**57,2**				**69,3**	
2300	**Acid Gas Removal**				**15,6**				**15,6**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-0,7**	**-0,9**		**4,1**	**0,9**	**3,4**	
3000	**POWER ISLANDS UNITS**		**314,8**	**-11,1**	**-231,5**	**-357,7**	**-330,9**	**-12,6**		
4100 to 5300	**UTILITY and OFFSITE UNITS**				**9,1**				**9,1**	
	BALANCE		**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**366,4**	**262,6**

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	**CLIENT:** IEA GHG **PROJECT:** GASIFICATION POWER GENERATION STUDY **LOCATION:** Netherlands **FWI Nº:** 1- BD 0119A		Rev 0 nov-02 ISSUED BY: PC. CHECKED BY: LM APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE A2 - HP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**281**
1000	**Gasification Section**	**12804**
2100	**Air Separation Unit**	**111344**
2200	**Syngas treatment and conditioning line**	**0**
2300	**Acid Gas Removal**	**588**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**1984**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4691**
3200	**Heat Recovery Steam Generator**	**6114**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1832**
3500	**Miscellanea**	**476**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**5389**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**556**
	Other Units	**642**
	BALANCE	**146702**

2.5 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

SHELL

Case A.2 - High Pressure without CO_2 capture - Rev. 1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	252.1
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1811.6**
Thermal Power of Raw Syn exit Scrubber (dry, based on LHV) (E)	MWt	1503.3
Thermal Power of Clean Syngas to GT (based on LHV) (F)	MWt	1496.6
Syngas treatment efficiency (F/E*100)	%	99.6
Gas turbines total power output	MWe	553.6
Steam turbine power output	MWe	330.5
Expander Power Output	MWe	10.9
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**895.0**
ASU power consumption	MWe	111.3
Process Units consumption	MWe	15.4
Utility Units consumption	MWe	1.5
Offsite Units consumption (including sea cooling water system)	MWe	5.4
Power Islands consumption	MWe	13.1
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**146.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**748.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**49.4**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**41.3**

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE B.1

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.3

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.3 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.3 BASIC INFORMATION FOR EACH ALTERNATIVE

3.0 Case B.1

3.1 Introduction

The main features of the Case B.1 configuration of the IGCC Complex are:

- Low pressure (39 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- Double 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 Unit (ASU) and the Gas Turbines is 30%. Gas Turbine power augmentation and syngas dilution, for NO_x control, is 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.

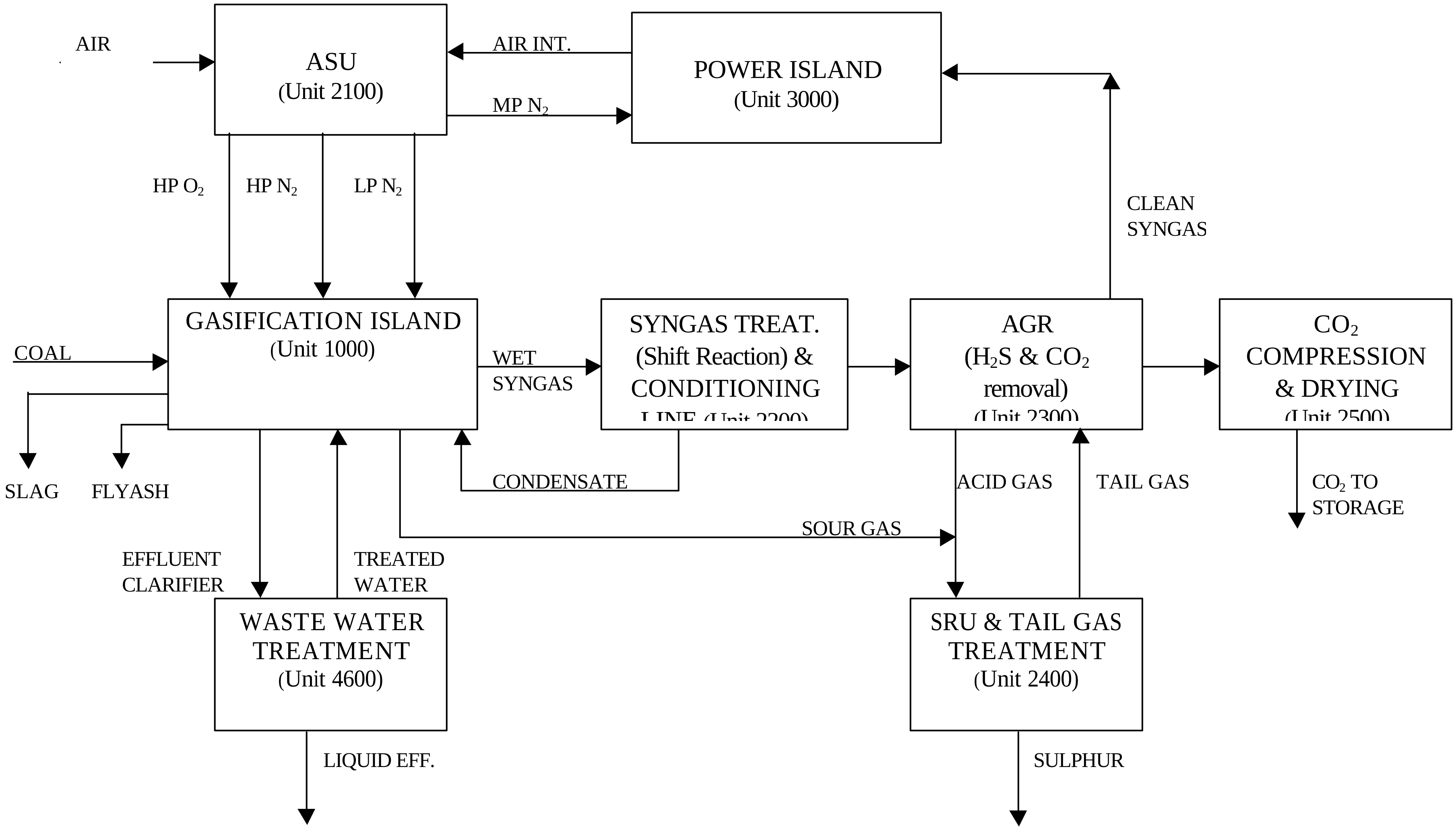
The arrangement of the process units is :

Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurization/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	2 x 50%
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%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO B.1 – IGCC COMPLEX BLOCK FLOW DIAGRAM



3.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	80	80	70	160
Pressure (bar)		40	69	7.5	37
TOTAL FLOW					
Mass flow (kg/h)	273,100	214,550	87,000	33,680	568,200
Molar flow (kmol/h)			3,100	1,200	28,850
Composition (% vol)					
H_2					26.25
CO					49.60
CO_2					1.24
N_2		3.5	99.88	99.88	4.00
Ar		1.5	0.08	0.08	0.62
O_2		95	0.04	0.04	0.00
H_2S + COS					0.23
H_2O					18.05
Others					0.01

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 3.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 3.4.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 3.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 36 barg and 160°C, 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 451°C. Due to the low water content of the syngas, the injection of MP steam to the syngas is required before entering the shift reactor. In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. The hot shifted syngas outlet from the first stage is cooled in a series of heat exchangers:

E-2201 Shift feed product exchanger
E-2202 HP Steam Generator
E-2203 MP Steam Generator

Inlet temperature to the second stage shift is controlled to 250 °C. Outlet temperature from second shift is 331°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:

E-2204	MP Steam Generator
E-2205	LP Steam Generator
E-2206	VLP Steam Generator
E-2207 A/B	Condensate Preheater

The final cooling step of the syngas takes place in E-2208, where syngas is cooled with cooling water. Process condensate separated in Separator Drums D2201/3 is recycled back to the Sour Water Stripper of the Gasification Island.
The first stage of the shift reactor is split in three parallel trains. Downstream 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.
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-2210 with VLP steam and then sent to the gas turbines, Unit 3000.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a low syngas pressure (26 bar g) and an extremely high CO_2/H_2S ratio (205/1). The following two alternatives, both based on a Selexol Solvent, have been considered:

- **Option 1 – with nitrogen stripping**: a single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit.

- **Option 2 – without nitrogen stripping**: a single train configuration, adopting a more complicated and electric power consuming process scheme.

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment and Operating costs of the two options (reference is made to the report "AGR Technical Comparison and Optimisation" attached to Section H for all the details).
Option 2 without nitrogen stripping was finally selected because of the lower investment and operating costs.

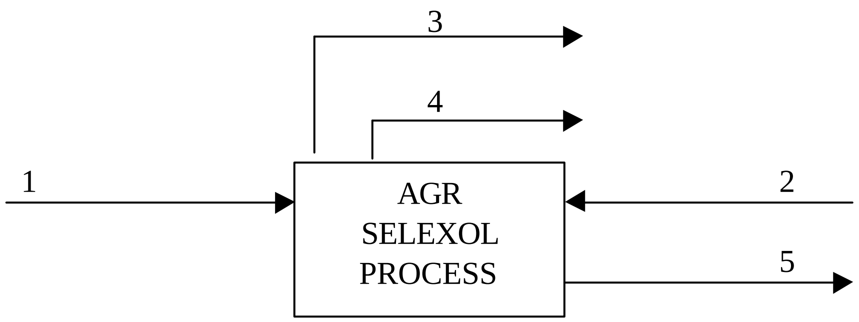
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 3.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit.

Exit Streams

3. Treated Gas to Gas Turbines
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 H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is 3 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 = 41% of the overall AGR Power requirement) before flowing to the CO_2 absorber.

The CO_2 removal rate is 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 large power consumption.

The acid gas H_2S concentration is 22% dry basis, 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:

- 221 kmol/h of Hydrogen, corresponding to 1,7% vol and to an overall thermal power of 14,9 MWt, i.e. almost 5 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 100 ppmvd.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each having a normal sulphur production of 56.4 t/day, and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 28 barg.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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 : 29,9 barg
- LP stream : 13,4 barg
- VLP stream : 10,2 barg

The product stream sent to final storage is mainly composed of CO_2 and CO. The main properties of the stream are as follows:

- Product stream: 550 t/h.
- Product stream: 110 bar.
- Composition :

	%wt
CO_2	99,8
CO	0,1
Others	0,1
TOTAL	100,0

Unit 3000: Power Island

The Process Flow diagram is attached to paragraph 3.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island and Syngas Treatment and Conditioning Line.
- MP steam (42 barg) : steam exported to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction. A small quantity of steam is also generated in the Gasification Island and in the Sulphur Recovery Unit.
- LP steam (6,5 barg) : steam exported to the following Process Units: AGR, ASU, Utility and Offsite Unit. LP steam is also generated in the Syngas Treatment and Conditioning Line.
- 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 Treatment and Conditioning Line and recycled back to the HRSG.

Flow rate of the above interfaces of the Plant are shown in table attached to para 3.5, Utilities Consumption.

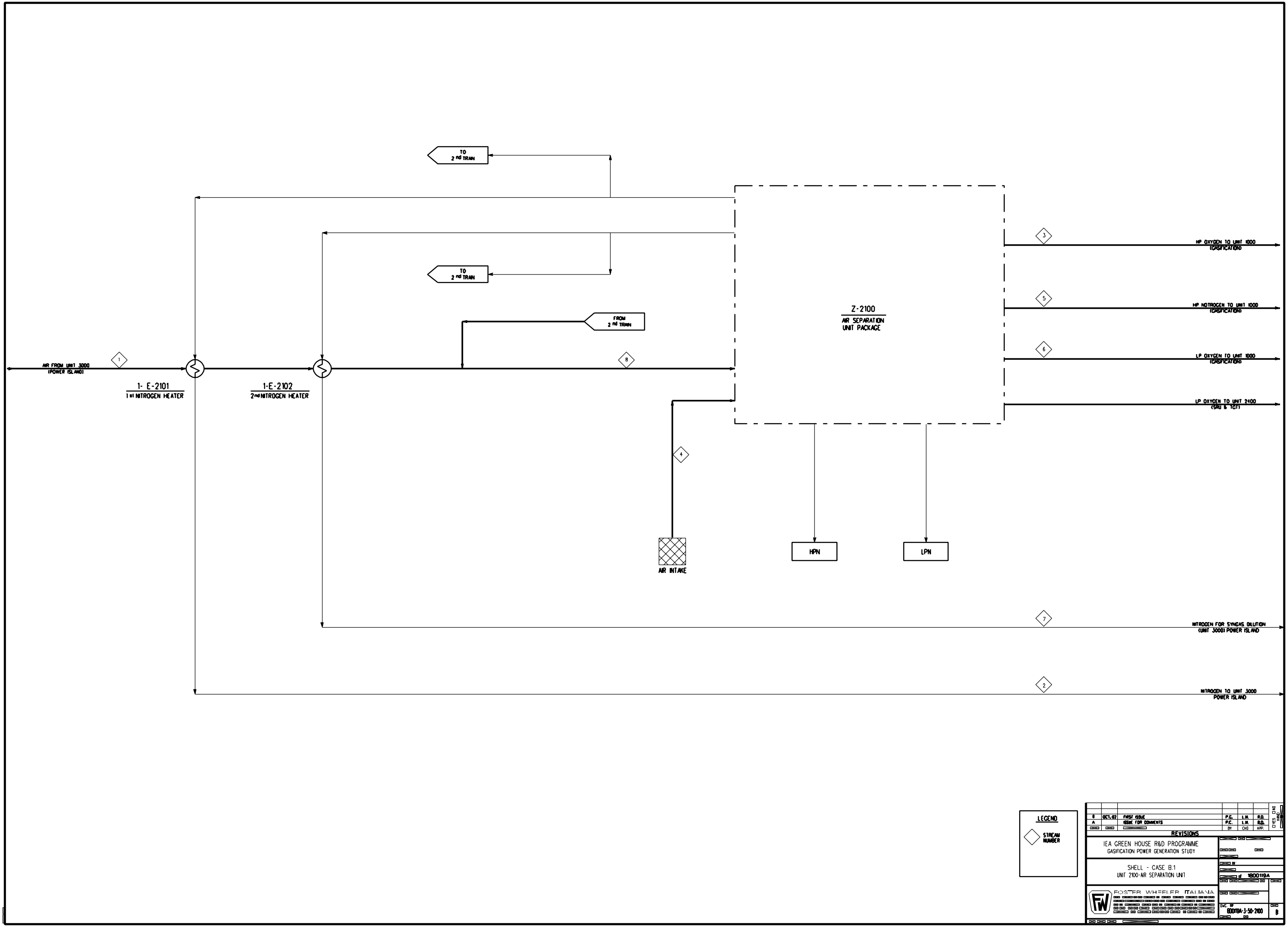
Steam imported to the Power Island are HP and VLP steam; all other streams are exported. As a consequence, the generation levels are the same of the Process Units.

3.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



TO
2 nd TRAIN
TO
2 nd TRAIN
FROM
2 nd TRAIN
Z-2100
AIR SEPARATION
UNIT PACKAGE
HP OXYGEN TO UNIT 1000
(GASIFICATION)
HP NOTROGEN TO UNIT 1000
(GASIFICATION)
LP OXYGEN TO UNIT 1000
(GASIFICATION)
LP OXYGEN TO UNIT 2400
(SRU & TGT)
AIR FROM UNIT 3000
(POWER ISLAND)
1
2
3
4
5
6
7
8
1- E-2101
1 st NITROGEN HEATER
1-E-2102
2 nd NITROGEN HEATER
AIR INTAKE
HPN
LPN
NITROGEN FOR SYNGAS DILUTION
(UNIT 3000) POWER ISLAND
NITROGEN TO UNIT 3000
POWER ISLAND
LEGEND
STREAM
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UNIT 2100-AIR SEPARATION UNIT
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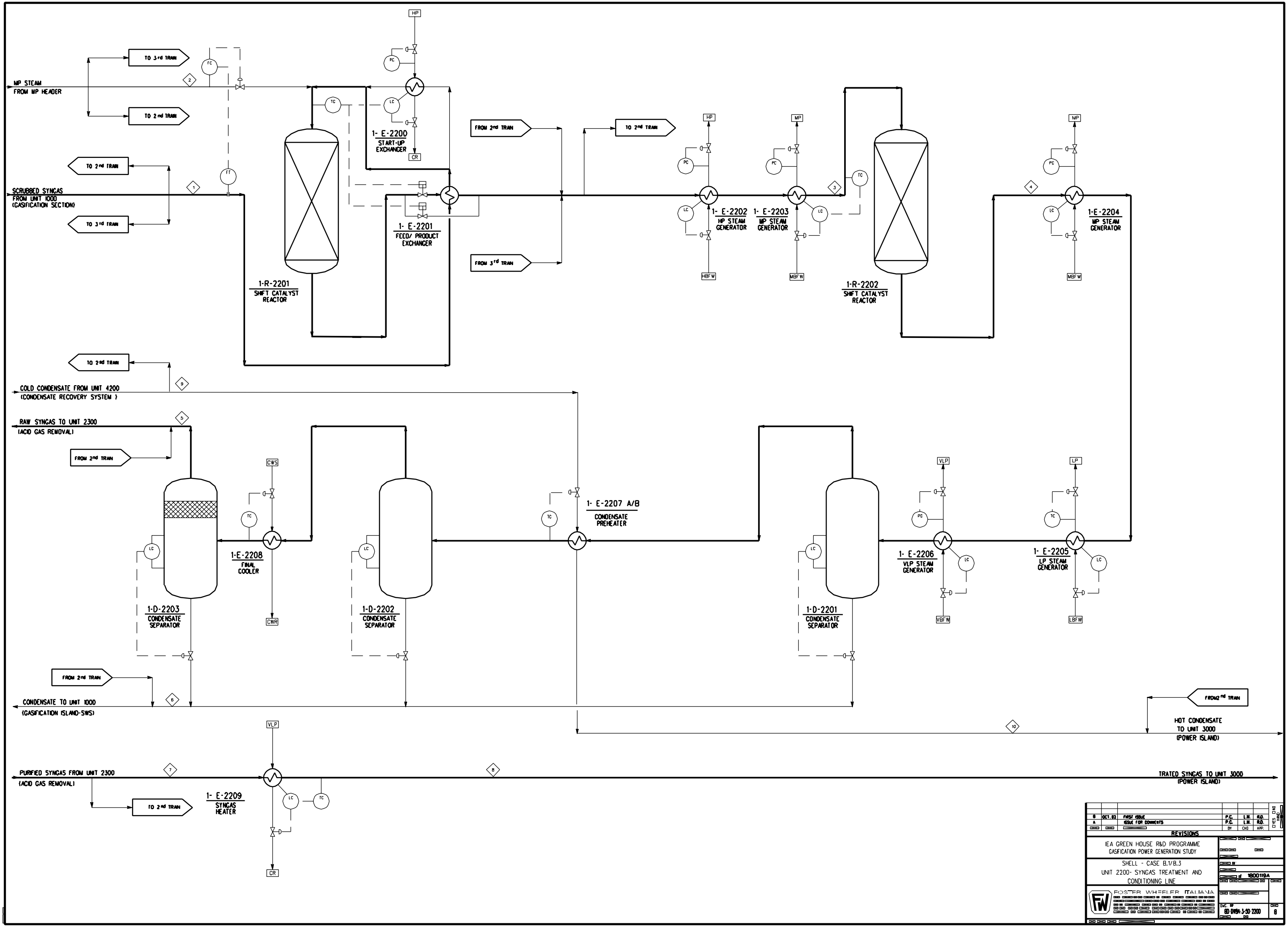
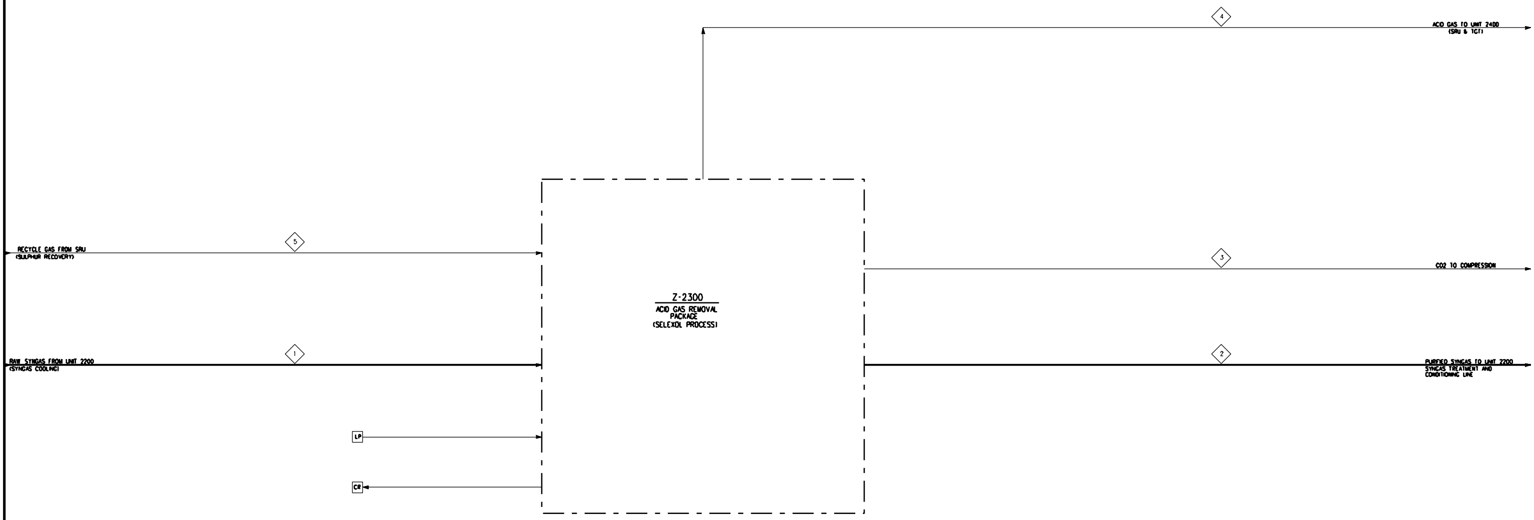

MP STEAM
FROM MP HEADER
TO 3rd TRAIN
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
TO 2nd TRAIN
TO 3rd TRAIN
1- E-2200
START-UP
EXCHANGER
1- E-2201
FEED/ PRODUCT
EXCHANGER
1-R-2201
SHIFT CATALYST
REACTOR
FROM 2nd TRAIN
FROM 3rd TRAIN
TO 2nd TRAIN
1- E-2202
HP STEAM
GENERATOR
1- E-2203
MP STEAM
GENERATOR
1-R-2202
SHIFT CATALYST
REACTOR
1-E-2204
MP STEAM
GENERATOR
TO 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
FROM 2nd TRAIN
1- E-2207 A/B
CONDENSATE
PREHEATER
1-E-2208
FINAL
COOLER
1-D-2203
CONDENSATE
SEPARATOR
1-D-2202
CONDENSATE
SEPARATOR
1-D-2201
CONDENSATE
SEPARATOR
1- E-2206
VLP STEAM
GENERATOR
1- E-2205
LP STEAM
GENERATOR
FROM 2nd TRAIN
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND-SWS)
FROM2nd TRAIN
HOT CONDENSATE
TO UNIT 3000
(POWER ISLAND)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
TO 2nd TRAIN
1- E-2209
SYNGAS
HEATER
TRATED SYNGAS TO UNIT 3000
(POWER ISLAND)
B OCT.02 FIRST ISSUE P.C. L.M. R.D.
A ISSUE FOR COMMENTS P.C. L.M. R.D.
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASFICATION POWER GENERATION STUDY
SHELL - CASE B.1/B.3
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
FOSTER WHEELER ITALIANA
1800119A
80-DW9A-3-50-2200
B



LEGEND

◇ STREAM NUMBER

0	OCT. 07	FIRST ISSUE	P.C.	L.M.	R.D.
A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

SHELL - CASE B.1
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2300

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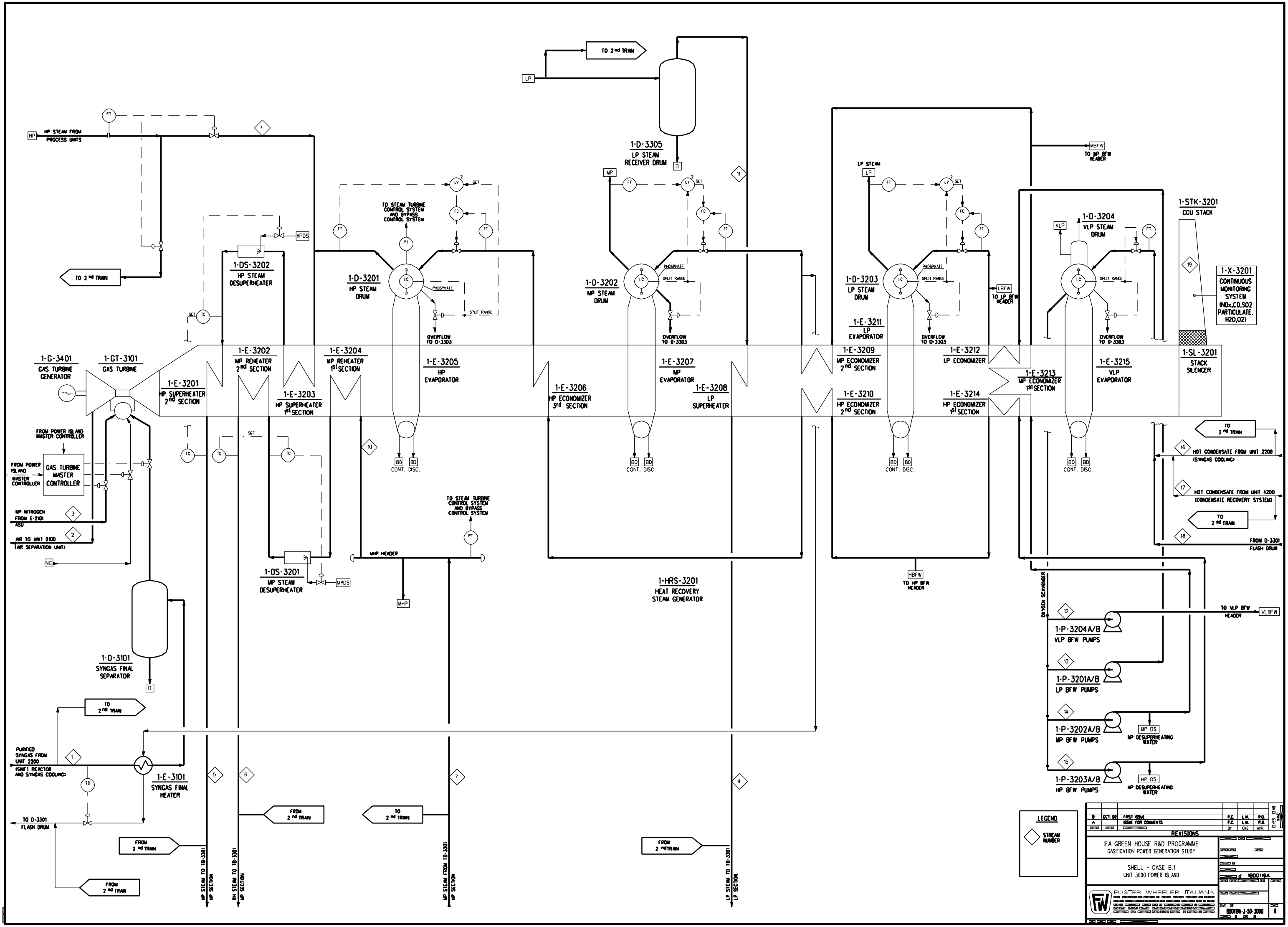
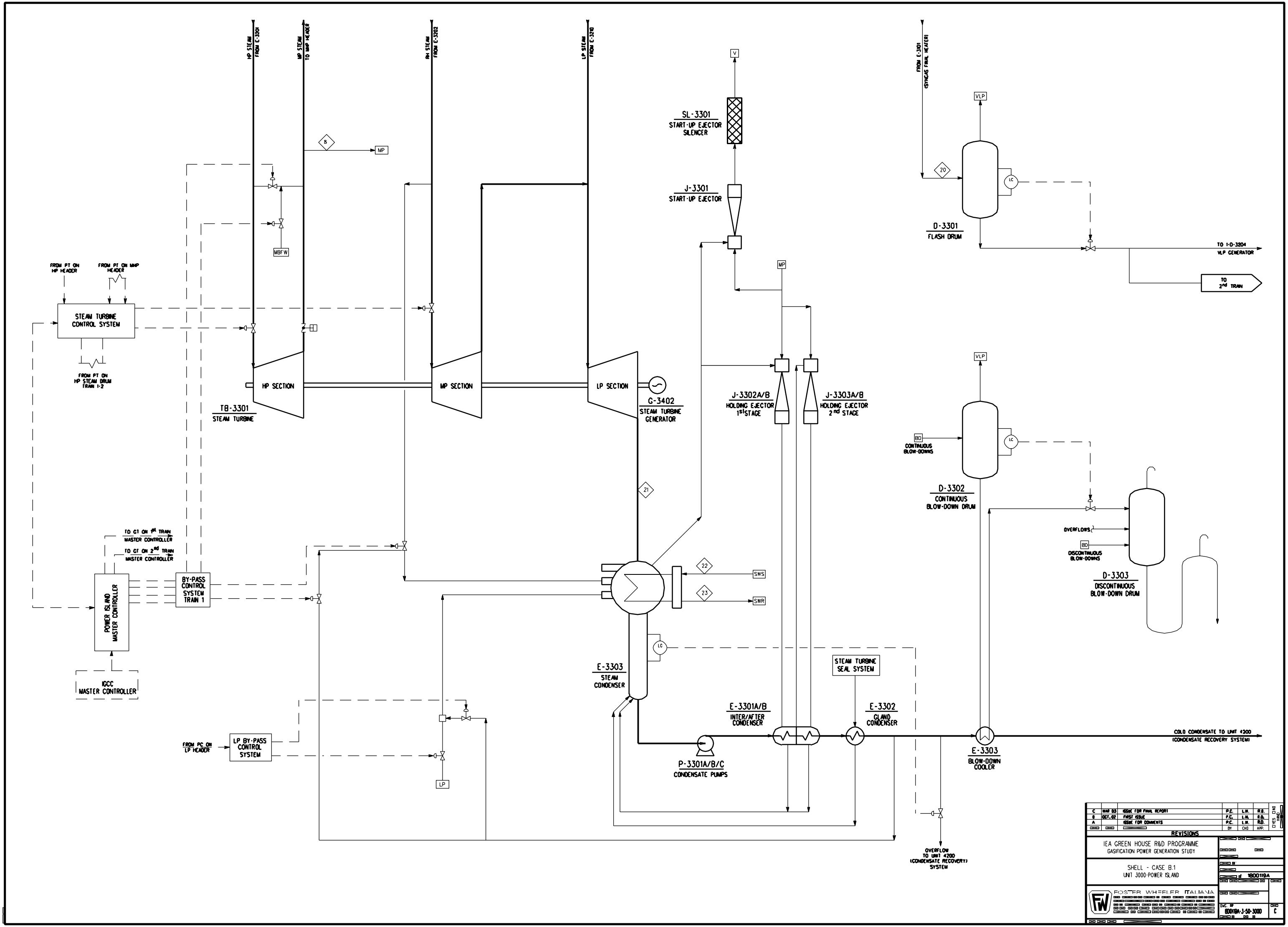


1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
GAS TURBINE MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
1-DS-3202
HP STEAM DESUPERHEATER
1-D-3201
HP STEAM DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3305
LP STEAM RECEIVER DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
TO MP BFW HEADER
TO LP BFW HEADER
1-D-3204
VLP STEAM DRUM
1-STK-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP EVAPORATOR
1-E-3208
LP SUPERHEATER
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3211
LP EVAPORATOR
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
CONT. DISC.
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
1-DS-3201
MP STEAM DESUPERHEATER
MHP HEADER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
OXYGEN SCAVENGER
TO VLP BFW HEADER
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DESUPERHEATING WATER
TO HP BFW HEADER
1-D-3101
SYNGAS FINAL SEPARATOR
PURIFIED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
LEGEND
STREAM NUMBER
B OCT.02 FIRST ISSUE P.C. L.M. R.D.
A ISSUE FOR COMMENTS P.C. L.M. R.B.
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE B.1
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1BD0119A
DWG. Nº
BD0119A-3-50-3000



HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
MP
MBFW
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
FROM PT ON HP STEAM DRUM TRAIN 1-2
HP SECTION
MP SECTION
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
P-3301A/B/C
CONDENSATE PUMPS
E-3301A/B
INTER/AFTER CONDENSER
STEAM TURBINE SEAL SYSTEM
E-3302
GLAND CONDENSER
E-3303
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
C MAR 03 ISSUE FOR FINAL REPORT P.C. L.M. R.B.
B OCT.02 FIRST ISSUE P.C. L.M. R.D.
A ISSUE FOR COMMENTS P.C. L.M. R.D.
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE B.1
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
DWG.
BD0119A-3-50-3000
C

3.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 2400: Sulphur Recovery Unit & Tail Gas Treatment;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	
	CASE : SHELL CASE B.1	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	oct 02	Mar 03	

STREAM	1	2	3	4	5	6	7	8		
	AIR EXTRACTED FROM EACH GAS TURBINE	MP NITROGEN TO EACH GAS TURBINE	HP OXYGEN TO GASIFICATION	AMBIENT AIR INTAKE	HP NITROGEN	LP NITROGEN	NITROGEN FOR SYNGAS DILUTION	TOTAL AIR FROM GTs		
Temperature (°C)	396	213	80	AMB.	80	70	216	136		
Pressure (bar)	14,3	22,6	40,4	AMB.	69,0	7,5	25,7	13,3		
TOTAL FLOW										
Mass flow (kg/h)	142935	200906	214548	667030	86986	33684	107000	285870		
Molar flow (kgmole/h)	4951	7175	6837	23121	3108	1203	3808	9902		
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	142935	200906	214548	667030	86986	33684	107000	285870		
Molar flow (kgmole/h)	4951	7175	6837	23121	3108	1203	3808	9902		
Molecular Weight	28,87	28,00	31,4	28,87	28,0	28,0	28,1	28,9		
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	77,57	97,50	3,50	77,57	99,88	99,88	97,50	77,57		
O_2	20,86	2,15	95,00	20,86	0,08	0,08	2,15	20,86		
CH_4										
H_2S										
COS										
Ar	0,89	0,26	1,50	0,89	0,90	0,90	0,26	0,89		
H2O	0,68	0,09		0,68			0,09	0,68		

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE B.1	APPROVED	R.D.	R.D.	
	UNIT : 2200 SYNGAS treatment and conditioning line	DATE	oct 02	Mar 03	

STREAM	1	2	3	4	5	6	7	8	9	10
	SYNGAS at Scrubber Outlet (3 Trains)	MP STEAM from MP Header (3 Trains)	SYNGAS to 2nd Shift Catalyst Reactor (2 Trains)	SYNGAS from 2nd Shift Catalyst Reactor (2 Trains)	Raw SYNGAS to AGR (2 Trains)	Condensate Return to Gasification (2 Trains)	Purified Syngas from AGR (2 Trains)	Treated Syngas to Power Island (2 Trains)	Cold Condensate from CRS (2 Trains)	Hot Condensate to Power Island (2 Trains)
Temperature (°C)	160	248	250	331	38	121	34	135	21	75
Pressure (bar)	37	38,5	33,2	31,8	27,8	27,8	27,0	26,5	4,0	2,6
TOTAL FLOW										
Mass flow (kg/h)	188589	139140	491818	491818	357216	133975	82419	82419	613950	613950
Molar flow (kgmole/h)	9593	7730	25985	25985	18556	7430	12240	12240		
LIQUID PHASE										
Mass flow (kg/h)						133975			613950	613950
GASEOUS PHASE										
Mass flow (kg/h)	188589	139140	491818	491818	357216		82419	82419		
Molar flow (kgmole/h)	9593	7730	25985	25985	18556		12240	12240		
Molecular Weight	19,7	18,0	18,9	18,9	19,3		6,7	6,7		
Composition (vol %)										
H_2	26,25		33,00	40,29	56,51		85,35	85,35		
CO	49,60		9,08	1,79	2,51		3,74	3,74		
CO_2	1,24		19,17	26,46	36,91		5,24	5,24		
N_2	4,00		2,21	2,21	3,10		4,93	4,93		
HCN + NH3	0,00		0,01	0,01	0,00		0,00	0,00		
CH_4	0,00		0,00	0,00	0,00		0,00	0,00		
H_2S	0,21		0,13	0,13	0,18		0,00	0,00		
COS	0,02		0,00	0,00	0,00		0,00	0,00		
Ar	0,62		0,34	0,34	0,48		0,72	0,72		
H2O	18,05		36,06	28,77	0,31		0,03	0,03		

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE B.1	APPROVED	R.D.	R.D.	
	UNIT : 2300 Acid Gas Removal	DATE	oct 02	Mar 03	

STREAM	1	2	3	4	5					
	Raw SYNGAS from Syngas Cooling to AGR	Purified Syngas to Syngas Treatment	CO_2 to compression	Acid gas to SRU	Recycle Gas from SRU to AGR					
Temperature (°C)	38	34	-	49	38					
Pressure (bar)	27,8	27,0	-	1,8	27,0					
TOTAL FLOW										
Mass flow (kg/h)	714433	164839	549273	13419	13011					
Molar flow (kgmole/h)	37113	24480	12728	336	332					
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	714433	82419	549273	13419	13011					
Molar flow (kgmole/h)	37113	12240	12728	336	332					
Molecular Weight	19,3	6,7	43,2	39,9	39,2					
Composition (vol %)										
H_2	56,51	85,35	1,74	0,28	4,10					
CO	2,51	3,74	0,19	0,03	0,15					
CO_2	36,91	5,24	97,69	72,41	76,63					
N_2	3,10	4,93	0,06	0,01	17,78					
O_2	0,00	0,00	0,00	0,00	0,00					
CH_4	0,00	0,00	0,00	0,00	0,00					
H_2S	0,18	0,00	0,01	20,25	0,72					
COS	0,00	0,00	0,00	0,02	0,01					
Ar	0,48	0,72	0,03	0,01	0,19					
H2O	0,31	0,03	0,28	6,46	0,42					

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE B.1	APPROVED	R.D.	R.D.	
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)	DATE	oct 02	Mar 03	

STREAM	1	2	3	4	5	6	7	8	9	10
	Acid Gas from AGR Unit	Product Sulphur	Sour Gas from Gasification	Recycle Tail Gas to AGR Unit						
Temperature (°C)	49	AMB.	100	38						
Pressure (bar)	1,8	AMB.	1,5	27,0						
TOTAL FLOW										
Mass flow (kg/h)	13419	56.4 t/d	1280	13011						
Molar flow (kgmole/h)	336			332						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	13419		1280	13011						
Molar flow (kgmole/h)	336			332						
Molecular Weight	39,9			39,2						
Composition (vol %)										
H_2	0,28			4,10						
CO	0,03			0,15						
CO_2	72,41		16,00	76,63						
N_2	0,01			17,78						
O_2	0,00			0,00						
CH_4	0,00			0,00						
H_2S	20,25		18,00	0,72						
COS	0,00			0,01						
NH3 + HCN	0,00		31,00	0,00						
Ar	0,01			0,19						
H2O	6,46		35,00	0,42						

	IGCC HEAT & MATERIAL BALANCE
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME
	CASE : SHELL CASE B.1
	UNIT : 3000 POWER ISLAND

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	Treated SYNGAS from Syngas Cooling (*) (1)	189,99	150	26,0	332,6
2	Extraction Air to Air Separation Unit (*)	142,94	396	15,0	-
3	MP Nitrogen from ASU (*)	200,91	213	22,60	-
4	HP Steam from Process Units	193,45	330	127,0	2674,0
5	HP Steam to Steam Turbine (*)	406,70	552	122,5	3482,1
6	Hot RH Steam to MP Steam Turbine (*)	353,03	517	38,7	3485,0
7	MP Steam from Steam Turbine (*)	349,23	386	41,7	3179,2
8	MP steam to process	284,70	253	42,0	2799,4
9	LP steam to LP Steam Turbine (*)	34,21	237	6,1	2928,8
10	MP Steam to MP Reheater (*)	353,03	382	41,0	3171,0
11	LP Steam to LP superheater	34,21	167	7,2	2764,8
12	BFW to VLP BFW Pumps (*)	61,05	119	1,9	499,2
13	BFW to LP BFW Pumps (*)	89,24	119	1,9	499,2
14	BFW to MP BFW Pumps (*)	198,01	119	1,9	499,2
15	BFW to HP BFW Pumps (*)	430,56	119	1,9	499,2
16	Hot Condensate returned from Unit 2200 (*)	613,95	75	5,0	310,0
17	Hot Condensate returned from CR (*)	93,85	94	2,5	393,9
18	Water from Flash Drum (*)	23,87	119	1,9	499,2
19	FLUE GAS AT STACK (*) (2)	2511,50	129	AMB.	122,8
20	Condensate from Syngas Final Heater (*)	53,00	169	52,3	718,0
21	LP Steam Turbine Exhaust	774,50	21,7	0,026	2220,0
22	Sea Water Supply to Steam Condenser	56382,90	12	3,0	50,5
23	Sea Water Return from Steam Condenser	56382,90	19	2,1	79,8

(*) flowrate for one train

(1) Syngas composition as per stream 8 of Material Balance for Unit 2200 .

(2) Flues gas molar composition: N_2: 75.0%; H_2O: 11.8%; O_2: 11.2%; CO_2: 1.2%; Ar: 0.8%.

3.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER

CLIENT: IEA GHG
PROJECT: GASIFICATION POWER GENERATION STUDY
LOCATION: Netherlands
FWI N°: 1- BD 0119A

REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
DATE	20-June-02	Oct-02		
ISSUED BY	L.M.	L.M.		
CHECKED BY	A.M.	P.C.		
APPROVED BY	R.D.	R.D.		

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE B.1 - LP with CO_2 capture, separated removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 42 barg [t/h]	LP Steam 6.5 barg [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**		-327,7	-7,6			373,3	35,8			41,6	32,2
2100	**Air Separation Unit**				16,8						16,8	
2200	**Syngas Treatment and Conditioning line**		-59,2	284,5	-76,9	-88,2	59,2	133,3	76,9	122,1	33,9	417,8
2300	**Acid Gas Removal**				82,4						82,4	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			-0,7	-1,0			4,3	1,0		3,6	
3000	**POWER ISLANDS UNITS**		386,9	-276,2	-30,7	88,2	-432,5	-173,4	-77,9	-122,1		
4100 to 5300	**UTILITY and OFFSITE UNITS**				9,4						9,4	
	BALANCE		0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	187,7	450,0

Note: Minus prior to figure means figure is generated

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	oct 02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RM

WATER CONSUMPTION SUMMARY - SHELL - CASE B1 - LP with CO_2 capture, separated removal of H_2S and CO_2

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**		32	2569	
2100	**Air Separation Unit**				20944
2200	**Syngas Treatment and Conditioning line**		418	4813	
2300	**Acid Gas Removal**			4369	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			52	
2500	**CO_2 Compression and Drying**				(5800)
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1623	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		4		56383
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4100/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				23649
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	474	-474		
4600	**Waste Water Treatment**	-68			
	Other Units		20	361	
	BALANCE excluding CO_2 compression	406	0	13787	100976
	BALANCE including CO_2 compression	406	0	13787	106776

Note: Minus prior to figure means figure is generated

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	oct 02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE B1
LP with CO_2 capture, separated removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**305**
1000	**Gasification Section**	**12761**
2100	**Air Separation Unit**	**113620**
2200	**Syngas treatment and conditioning line**	**0**
2300	**Acid Gas Removal**	**32785**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2420**
2500	**CO_2 Compression and Drying**	**(32600)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4706**
3200	**Heat Recovery Steam Generator**	**6293**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1817**
3500	**Miscellanea**	**483**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10201**
	Additional consumption including CO_2 Compression and Drying	**(400)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**708**
4600	**Waste Water Treatment**	**476**
	Other Units	**385**
	BALANCE excluding CO_2 compression	**186959**
	BALANCE including CO_2 compression	**219959**

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

3.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

SHELL

Case B.1 - Low pressure with CO_2 capture, separated H_2S and CO_2 removal - Rev.2

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	273.1
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1962.5**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1638.2
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1467.2
Syngas treatment efficiency (F/E*100)	%	89.6
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	324.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**896.2**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	113.6
Process Units consumption	MWe	48.0
Utility Units consumption	MWe	2.5
Offsite Units consumption (including sea cooling water system)	MWe	9.6
Power Islands consumption	MWe	13.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**187.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**709.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**36.1**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	32.6
Offsite Units consumption (sea cooling water system)	MWe	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**220.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**676.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.5**

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)	14701
Slag (Carbon =~0,4% wt) *	61
Net Carbon flowing to Process Units (A)	14640
Liquid Storage	
CO	24,0
CO_2	12434,0
Total to storage (B)	12458,0
Emission	
CO_2	2177,4
CO	5,6
Total Emission	2183,0
Overall CO_2 removal efficiency, % (B/A)	85,1

* The percentage of unreacted C stated by Shell is 0.2%. However, the carbon mass balance of the whole IGCC results in a 0.4% carbon less. This value is conservatively assumed.

3.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic is shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

3.7.1 Gaseous Emissions

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, and emission from the coal Drying process.

Table 3.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 3.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	697,6
Flow, $Nm^3/h^{(1)}$	2.507.890
Temperature, °C	129
Composition	(%vol)
Ar	0,91
N_2	74,95
O_2	11,17
CO_2	1,20
H_2O	11,77
Emissions	$mg/Nm^{3\ (1)}$
NOx	74
SOx	1
CO	31
Particulate	5

(1) Dry gas, O2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 3.2.

Table 3.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1395,2
Flow, $Nm^3/h^{(1)}$	5.015.780
Temperature, °C	129
Emissions	kg/h
NOx	371,2
SOx	5,0
CO	155,5
Particulate	25,1

(1) Dry gas, O2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate	:	39	t/h
N_2	:	80	% vol.
$H_2O+O_2+CO_2$	:	20	% vol.
Particulate	:	<10	mg/Nm^3, wet basis.

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

3.7.2 Liquid Effluent

Waste Water Treatment (Unit 4600)

Part of the effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island as process water, closing the Gasification water balance. The other part is sent to a dedicated treatment where the reverse osmosis process allows recovering almost 60% of the treated water. This recovered water is recycled back to the Demi Water System, Unit 4200, and used as raw water for the Demineralized water plant. The remaining 40% of water is discharged together with the sea cooling water return stream. The expected flow rate of this stream is as follows:

- Flow rate : 46 m^3/h

Sea Water System (Unit 4100)

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 : 103.700 m^3/h
- Temperature : 19 °C
- Cl_2 : <0.05 ppm

3.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

Slag from Slag Removal Unit

Flow rate	:	40,5	t/h
Water content	:	10	%wt

Slag product can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

Flyash from Dry Solids Removal Unit

Flow rate : 1,3 t/h

Flyash can be dispatched to cement industries.

3.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
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EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
1	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 28	430 / 243		DUTY = 7820 kW
2	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 28	430 / 243		DUTY = 7820 kW
1	**E-2102**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	250 / 250		DUTY = 3458 kW
2	**E-2102**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	250 / 250		DUTY = 3458 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 = 226 t/h		47,3			Oxigen purity = 95 %
				LP N_2 flow rate to Gasifier = 36 t/h		9,5			Nitrogen purity = 99.9 %
				MP N_2 flow rate to GTs = 422 t/h		24,9			Nitrogen purity = 98 %
				HP N_2 flow rate to Gasifier = 91 t/h		74,8			Nitrogen purity = 99.9 %
				MP N_2 flow rate to Proc Unit = 1945		28,6			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 300 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			42 / 42	300 / 480		DUTY = 8887 kW H2 service H2/Wet H2S serv. on channel
2	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			42 / 42	300 / 480		DUTY = 8887 kW H2 service H2/Wet H2S serv. on channel
3	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			42 / 42	300 / 480		DUTY = 8887 kW H2 service
1	**E-2202**	**HP Steam Generator**	Kettle			140 / 42	360 / 430		DUTY = 17360 kW H2 service H2/Wet H2S serv. on channel
2	**E-2202**	**HP Steam Generator**	Kettle			140 / 42	360 / 430		DUTY = 17360 kW H2 service H2/Wet H2S serv. on channel
1	**E-2203**	**MP Steam Generator**	Kettle			48 / 42	285 / 370		DUTY = 22415 kW H2 service H2/Wet H2S serv. on channel
2	**E-2203**	**MP Steam Generator**	Kettle			48 / 42	285 / 370		DUTY = 22415 kW H2 service H2/Wet H2S serv. on channel
1	**E-2204**	**MP Steam Generator**	Kettle			48 / 42	285 / 360		DUTY = 18175 kW H2 service H2/Wet H2S serv. on channel
2	**E-2204**	**MP Steam Generator**	Kettle			48 / 42	285 / 360		DUTY = 18175 kW H2 service H2/Wet H2S serv. on channel
1	**E-2205**	**LP Steam Generator**	Kettle			12 / 42	200 / 290		DUTY = 22610 kW H2 service H2/Wet H2S serv. on channel
2	**E-2205**	**LP Steam Generator**	Kettle			12 / 42	200 / 290		DUTY = 22610 kW H2 service H2/Wet H2S serv. on channel

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube		
1	E-2206	VLP Steam Generator	Kettle			12 / 42	175 / 205		DUTY = 38275 kW H2 service H2/Wet H2S serv. on channel
2	E-2206	VLP Steam Generator	Kettle			12 / 42	175 / 205		DUTY = 38275 kW H2 service H2/Wet H2S serv. on channel
1	E-2207 A/B	Condensate Preheater	Shell & Tube			5 / 42	105 / 180		DUTY = 37195 kW H2 service H2/Wet H2S serv. on channel
2	E-2207 A/B	Condensate Preheater	Shell & Tube			5 / 42	105 / 180		DUTY = 37195 kW H2 service H2/Wet H2S serv. on channel
1	E-2208	Final Cooler	Shell & Tube			12 / 42	60 / 150		DUTY = 32305 kW H2 service H2/Wet H2S serv. on channel
2	E-2208	Final Cooler	Shell & Tube			12 / 42	60 / 150		DUTY = 32305 kW H2 service H2/Wet H2S serv. on channel
1	E-2209	Syngas Heater	Shell & Tube			12 / 42	175 / 165		DUTY = 10105 kW H2 service H2/Wet H2S serv. on channel
2	E-2209	Syngas Heater	Shell & Tube			12 / 42	175 / 165		DUTY = 10105 kW H2 service H2/Wet H2S serv. on channel

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS		D,mm x TT,mm					
1	D-2201	Condensate Separator	Vertical			42	180		Wet H2S service/H2 service
2	D-2201	Condensate Separator	Vertical			42	180		Wet H2S service/H2 service
1	D-2202	Condensate Separator	Vertical			42	170		Wet H2S service/H2 service
2	D-2202	Condensate Separator	Vertical			42	170		Wet H2S service/H2 service
1	D-2203	Condensate Separator	Vertical			42	70		Equipped with demister Wet H2S service/H2 service
2	D-2203	Condensate Separator	Vertical			42	70		Equipped with demister Wet H2S service/H2 service

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		REACTOR		D,mm x TT,mm					
1	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
2	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
3	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
1	R-2202	Shift Catalyst Reactor - 2nd Bed	vertical			42	360		H2 service Wet H2S service
2	R-2201	Shift Catalyst Reactor - 2nd Bed	vertical			42	360		H2 service Wet H2S service
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	Shift Catalyst							Catalyst volume: 580 m^3

FOSTER WHEELER		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
			DATE	Oct. 02			
			ISSUED BY	P.C.			
			CHECKED BY	L.M.			
			APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment- Shell Case B.1 - Low Pressure with CO2 capture, dirty shift reaction, separated removal of H2S and CO2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=56.4 t/d					Sulphur content = 99,9 wt min (dry basis)
				Acid Gas from AGR = 336 kmol/h		3,5	80		Sulphur content = 20.25% (wet basis) Hydrogen content = 0.28 % (wet basis)
				Sour gas from Gasif. = 55 kmol/h					Sulphur content = 18,00 % (wet basis)
				Expected Treated Tail Gas=332 kmol/h		35	70		Major components (wet basis): CO_2 = 76.63%, H_2=4.1%, N_2 = 17.78%

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 3100 - Gas Turbine - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			57 / 35	280 / 200		DUTY= 2633 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			57 / 35	280 / 200		DUTY= 2633 kW Tubes: H2 service
		DRUMS		D,mm x TT,mm					
1	**D-3101**	**Syngas Final Separator**	vertical			35	200		H2 service
2	**D-3101**	**Syngas Final Separator**	vertical			35	200		H2 service
		PACKAGES							
1	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					 Included in 1-Z- 3101 Included in 1-Z- 3101
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					 Included in 2-Z- 3101 Included in 2-Z- 3101

FOSTER WHEELER		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A				REVISION	Rev.0	Rev.1	Rev.2	Rev.3
						DATE	Oct. 02			
						ISSUED BY	P.C.			
						CHECKED BY	L.M.			
						APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		Q,m^3/h x H,m					
1	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	**D-3205**	**LP Steam Receiver Drum**	horizontal			44	260		
2	**D-3205**	**LP Steam Receiver Drum**	horizontal			44	260		
		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	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Evaporator**							Included in 1-HRS-3201
1	E-3208	**LP Superheater**							Included in 1-HRS-3201
1	E-3209	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3210	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**LP Evaporator**							Included in 1-HRS-3201
1	E-3212	**LP Economizer**							Included in 1-HRS-3201
1	E-3213	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3214	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
2	D-3201	**HP steam Drum**							Included in 2-HRS-3201
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3207	**MP Evaporator**							Included in 2-HRS-3201
2	E-3208	**LP Superheater**							Included in 2-HRS-3201
2	E-3209	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3210	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**LP Evaporator**							Included in 2-HRS-3201
2	E-3212	**LP Economizer**							Included in 2-HRS-3201
2	E-3213	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3214	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**VLP Evaporator**							Included in 2-HRS-3201

FOSTER WHEELER

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LOCATION: Netherlands
PROJ. NAME: Gasification Power Generation Study
CONTRACT N. 1- BD- 0119 A

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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	58 / 150		DUTY = 990 kW
		DRUMS		D,mm x TT,mm					
	D-3301	**Flash Drum**	vertical			3,5	240		
	D-3302	**Continuous Blow-down Drum**	vertical			3,5	150		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	150		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	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

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		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Shell Case B.1 - Low Pressure with CO_2 capture, dirty shift reaction, separated removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	**G-3401**	**Gas Turbine Generator**							Included in 1 -Z- 3101
2	**G-3401**	**Gas Turbine Generator**							Included in 2 -Z- 3101
	G-3402	**Steam Turbine Generator**							Included in Z- 3301

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE B.2

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

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SECTION D.4

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.4 BASIC INFORMATION FOR EACH ALTERNATIVE

4.0 Case B.2

4.1 Introduction

The main features of the Case B.2 configuration of the IGCC Complex are:

- Low pressure (39 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- Clean Shift Reaction Section;
- Separate removal of H_2S and CO_2.

The separate removal of H_2S and CO_2 is based on the Selexol process. The H_2S content is lowered before entering the Clean Shift Reactors, while CO_2 is removed downstream them, before flowing to the gas turbines.
The degree of integration between the Air Separation Unit (ASU) and the Gas Turbines is 30%. Gas Turbine power augmentation and NO_x 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.

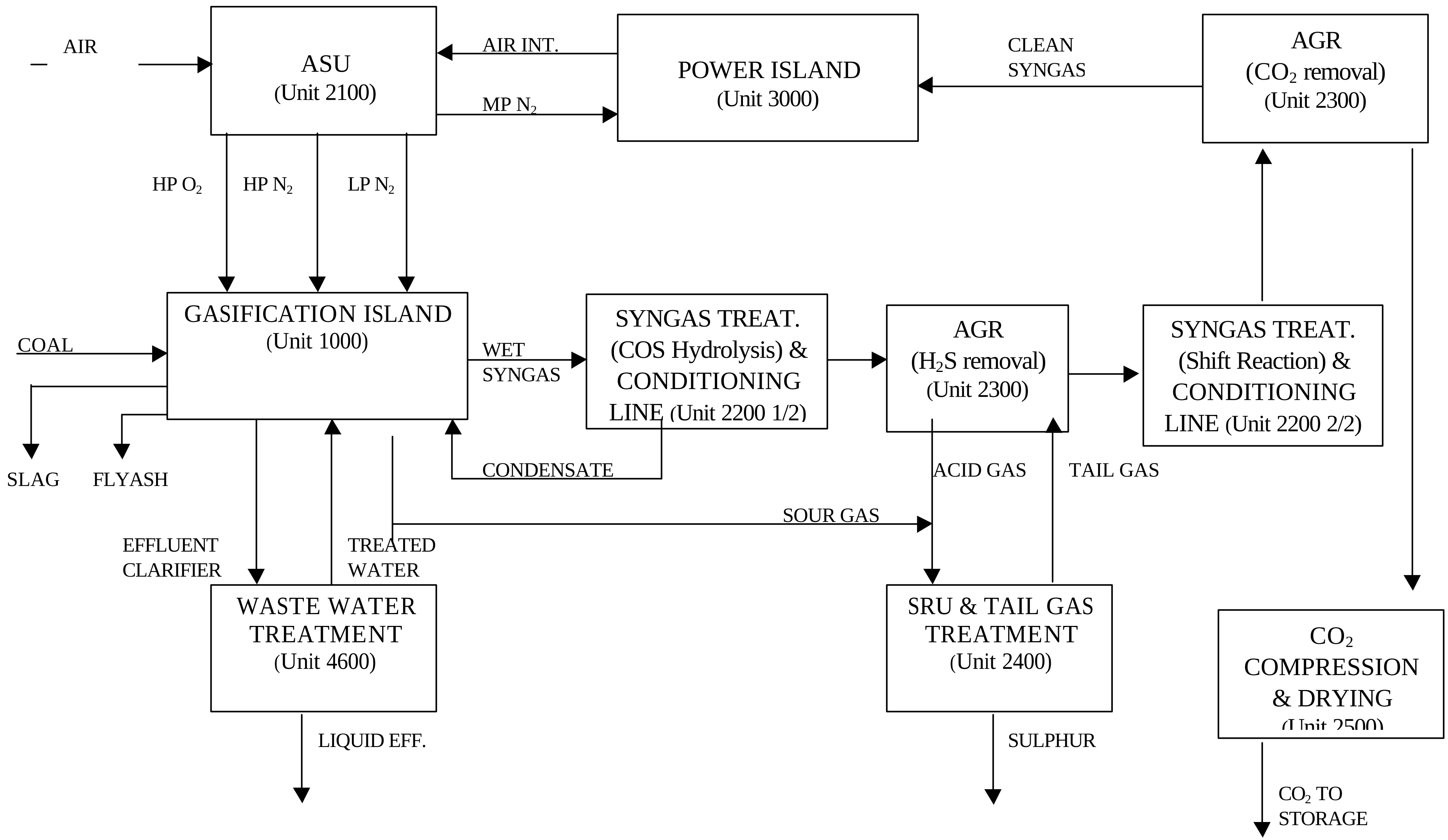
The arrangement of the process units is:

Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurisation/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	2 x 50%
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%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO B.2 – IGCC COMPLEX BLOCK FLOW DIAGRAM



4.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	80	80	70	126
Pressure (bar)		40	69	7.5	39
TOTAL FLOW					
Mass flow (kg/h)	274,600	215,730	87,450	33,860	507,050
Molar flow (kmol/h)			3,120	1,205	25,450
Composition (% vol)					
H_2					29.70
CO					56.40
CO_2					1.40
N_2		3.5	99.88	99.88	4.50
Ar		1.5	0.08	0.08	0.70
O_2		95	0.04	0.04	0.00
H_2S + COS					0.26
H_2O					7.00
Others					0.04

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 4.3 indicates the interconnections of ASU with the other units of the IGCC.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the Process Flow Diagrams attached to paragraph 4.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 38 barg and 126°C enters Unit 2200. The syngas is first preheated in E-2201, with the hydrolysis reactor effluent, and then in E-2202 with MP steam, before entering the hydrolysis reactor R-2201, which converts COS to H_2S. The degree of conversion of the hydrolysis reaction is higher than the other cases, 97% versus 95%, in order to lower the COS content down to 6.4 ppmvd outlet from the reactor allowing to reach after the H_2S absorptions in AGR the total S content requirement of the downstream clean shift catalyst (S less than 10 ppm). The higher syngas dewpoint and consequently the higher inlet temperature, 240°C versus 200 °C makes feasible this higher degree of conversion.
As the H_2S+COS content needs to be kept below 10 ppmvd in order to keep the catalyst active, the Acid Gas Removal Unit has to lower the H_2S content down to 3.6 ppmvd.
The effluent from the hydrolysis reactor is cooled in E-2201 and in E-2203 against cold condensate, before flowing to Unit 2300 AGR, H_2S Absorber, where the H_2S content is lowered down to 3 ppmvd. Overhead from H_2S Absorber returns Unit 2200, where is preheated in E-2204/5 respectively by MP steam and the hot shift effluent, before entering the Shift Reactor R-2202, where CO is shifted to H_2 and CO_2. The exothermic shift reaction brings the syngas temperature up to 540°C. Due to the low water content of the syngas, the injection of MP steam to the syngas is required before entering the shift reactor. In order to meet the required degree of CO conversion, three stages of clean shift catalyst are used. The hot shifted syngas outlet from the first and second stage is cooled respectively in E-2206/7, generating HP steam and controlling the inlet temperature of the downstream shift reactor. Syngas outlet from the third reactor is cooled in a series of heat exchangers:

E-2208 HP Steam Generator
E-2209 MP Steam Generator
E-2210 LP Steam Generator
E-2211 VLP Steam Generator
E-2212 Condensate Preheater

The final cooling step of the syngas takes place in E-2213, where syngas is cooled against cooling water.
Process condensate separated in Separator Drums D2201/4 is recycled back to the Sour Water Stripper of the Gasification Island.
Cold syngas goes to Unit 2300 for the removal of CO_2, then returns to Unit 2200 where syngas is preheated in E-2214 with VLP steam before going to Unit 3000, gas turbines.

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.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a low syngas pressure (35 bar g) and a low CO_2/H_2S ratio (5.5/1). The following two alternatives have been considered:

- **Option 1 – Ucarsol**: an Acid Gas Removal System composed of two independent removal sections, the first one for the H_2S removal and the last one for the CO_2 removal. The Clean Shift reaction is between the two removal packages.

- **Option 2 – Selexol**: a single removal sections, capable of first removing H_2S selectively and further removing the CO_2 downstream of the clean shift reaction. Data for this option were based on information provided by Vendors for other alternatives of the study.

Both the alternatives match all process requirements. Selexol was finally selected because of the more favourable steam consumption of the AGR section. In fact, the high steam requirement of Option 1 drastically reduces the ST power production, thus making this alternative less efficient.

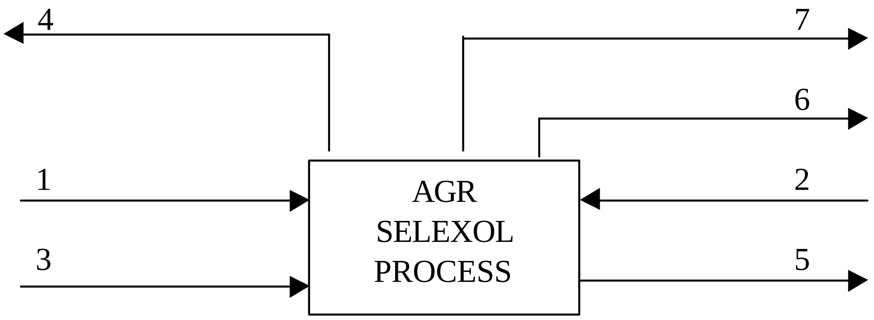
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 4.3:

Entering Streams

1. Hydrolysed Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit.
3. Shifted Gas from Shift Reactors

Exit Streams

4. H_2S purified Syngas to Shift Reactors
5. Purified Syngas to Gas Turbines
6. CO_2 to compression
7. Acid Gas to Sulphur Recovery Unit



The Selexol solvent consumption, to make-up losses, is 125 m^3/year.

The proposed process matches the process specification with reference to the H_2S+COS concentration of the treated gas exiting the Unit. In fact the outlet H_2S concentration of the treated gas is 3 ppmvd and the concentration of COS outlet from Hydrolysis reactor is 6.4 ppmvd, thus meeting the required overall concentration of 10 ppmvd inlet to the clean shift reactors. In addition, as Selexol is a physical solvent, a further removal of COS is expected; in fact, typical COS removal in the H_2S absorber ranges from 20 to 50 % of the incoming flow rate.
The low H_2S concentration achieved by the H_2S absorber does not cause an increase of the solvent circulation, because the downstream CO_2 removal already requires such a large circulation solvent that is cooled down by a refrigerant package (Power Consumption = 41% of the overall AGR Power requirement) before flowing to the CO_2 absorber.
The CO_2 removal rate is 93%, allowing reaching an overall CO_2 capture of almost 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 large power consumption.

The acid gas H_2S concentration is 26% dry basis, 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:

- 202 kmol/h of Hydrogen, corresponding to 1,6% vol and to an overall thermal power of 13,6 MWt, i.e. more then 4 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 80 ppmvd.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each having a normal sulphur production of 56.7 t/day, and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 35 barg.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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 : 29,9 barg
- LP stream : 13,4 barg
- VLP stream : 10,2 barg

The product stream sent to final storage is mainly composed of CO_2 and CO. The main properties of the stream are as follows:

- Product stream: 546 t/h.
- Product stream: 110 bar.
- Composition :

	%wt
CO_2	99,4
$CO+H_2$	0,5
Others	0,1
TOTAL	100,0

Unit 3000: Power Island

The Process Flow Diagrams of the Unit are attached to paragraph 4.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island and Syngas Treatment and Conditioning Line.
- MP steam (42 barg) : steam exported to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction. A small quantity of steam is also generated in the Gasification Island and in the Sulphur Recovery Unit.
- LP steam (6,5 barg) : steam imported from Gasification Island and Syngas Treatment and Conditioning Line. Most of the steam is used in the Acid Gas Removal.
- 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 Treatment and Conditioning Line and recycled back to the HRSG.

Flow rate of the above interfaces of the Plant are shown in table attached to para 4.4, Steam and Electrical Power Consumption.

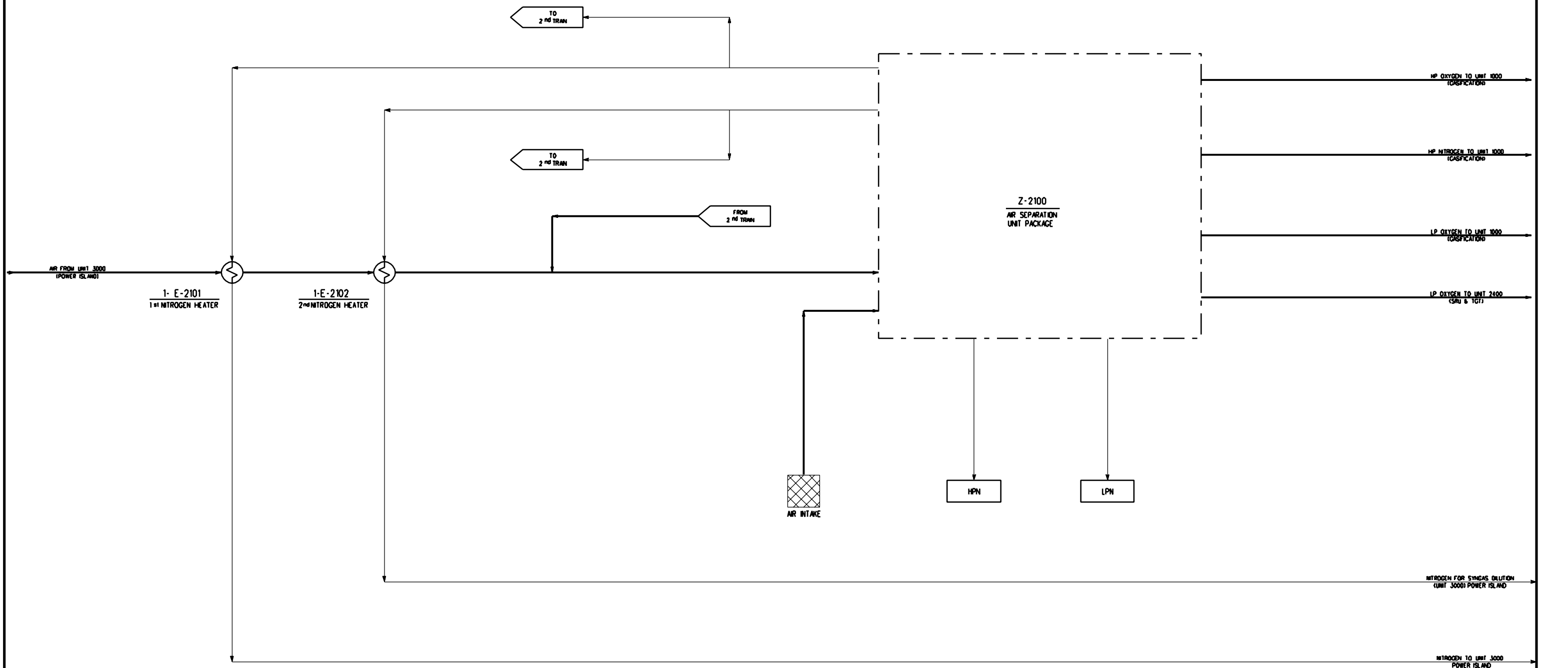
Steam exported to the Power Island is MP steam; all other streams are imported. The generation levels inside the Power Island are the same of the Process Units.

4.3 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200, sheet 1 and 2);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



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			BY	CHD	APP.

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SHELL - CASE B.2
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

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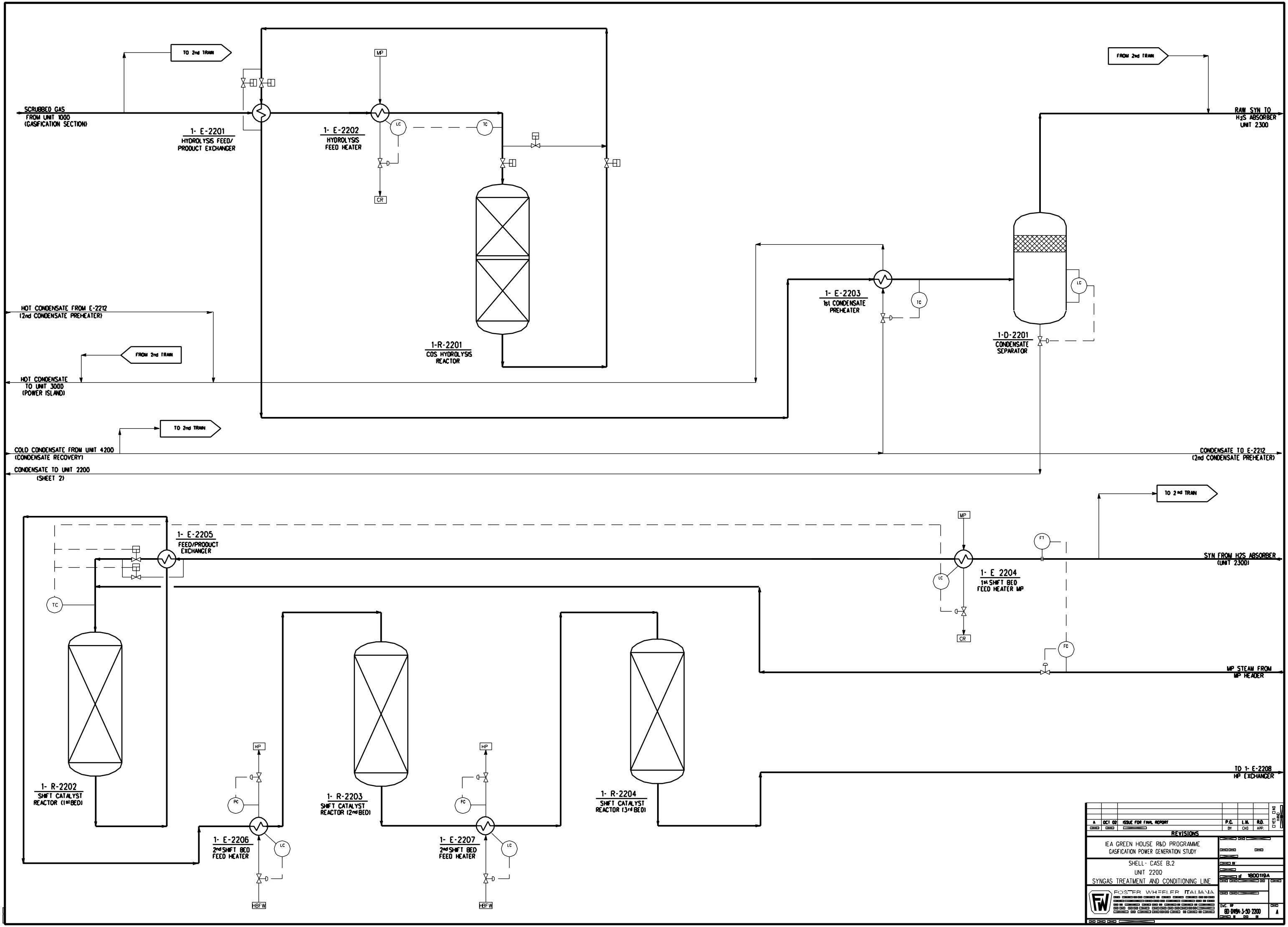
DWG. Nº 1800119A-3-50-2100 A


TO 2nd TRAIN
FROM 2nd TRAIN
SCRUBBED GAS
FROM UNIT 1000
(GASIFICATION SECTION)
1- E-2201
HYDROLYSIS FEED/
PRODUCT EXCHANGER
MP
LC
TC
1- E-2202
HYDROLYSIS
FEED HEATER
CR
1-R-2201
COS HYDROLYSIS
REACTOR
RAW SYN TO
H2S ABSORBER
UNIT 2300
1- E-2203
1st CONDENSATE
PREHEATER
1-D-2201
CONDENSATE
SEPARATOR
HOT CONDENSATE FROM E-2212
(2nd CONDENSATE PREHEATER)
FROM 2nd TRAIN
HOT CONDENSATE
TO UNIT 3000
(POWER ISLAND)
TO 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY)
CONDENSATE TO E-2212
(2nd CONDENSATE PREHEATER)
CONDENSATE TO UNIT 2200
(SHEET 2)
TO 2nd TRAIN
1- E-2205
FEED/PRODUCT
EXCHANGER
MP
FT
SYN FROM H2S ABSORBER
(UNIT 2300)
1- E 2204
1st SHIFT BED
FEED HEATER MP
CR
FC
MP STEAM FROM
MP HEADER
1- R-2202
SHIFT CATALYST
REACTOR (1st BED)
HP
PC
1- E-2206
2nd SHIFT BED
FEED HEATER
HBFW
1- R-2203
SHIFT CATALYST
REACTOR (2nd BED)
1- E-2207
2nd SHIFT BED
FEED HEATER
1- R-2204
SHIFT CATALYST
REACTOR (3rd BED)
TO 1- E-2208
HP EXCHANGER
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UNIT 2200
SYNGAS TREATMENT AND CONDITIONING LINE
FOSTER WHEELER ITALIANA
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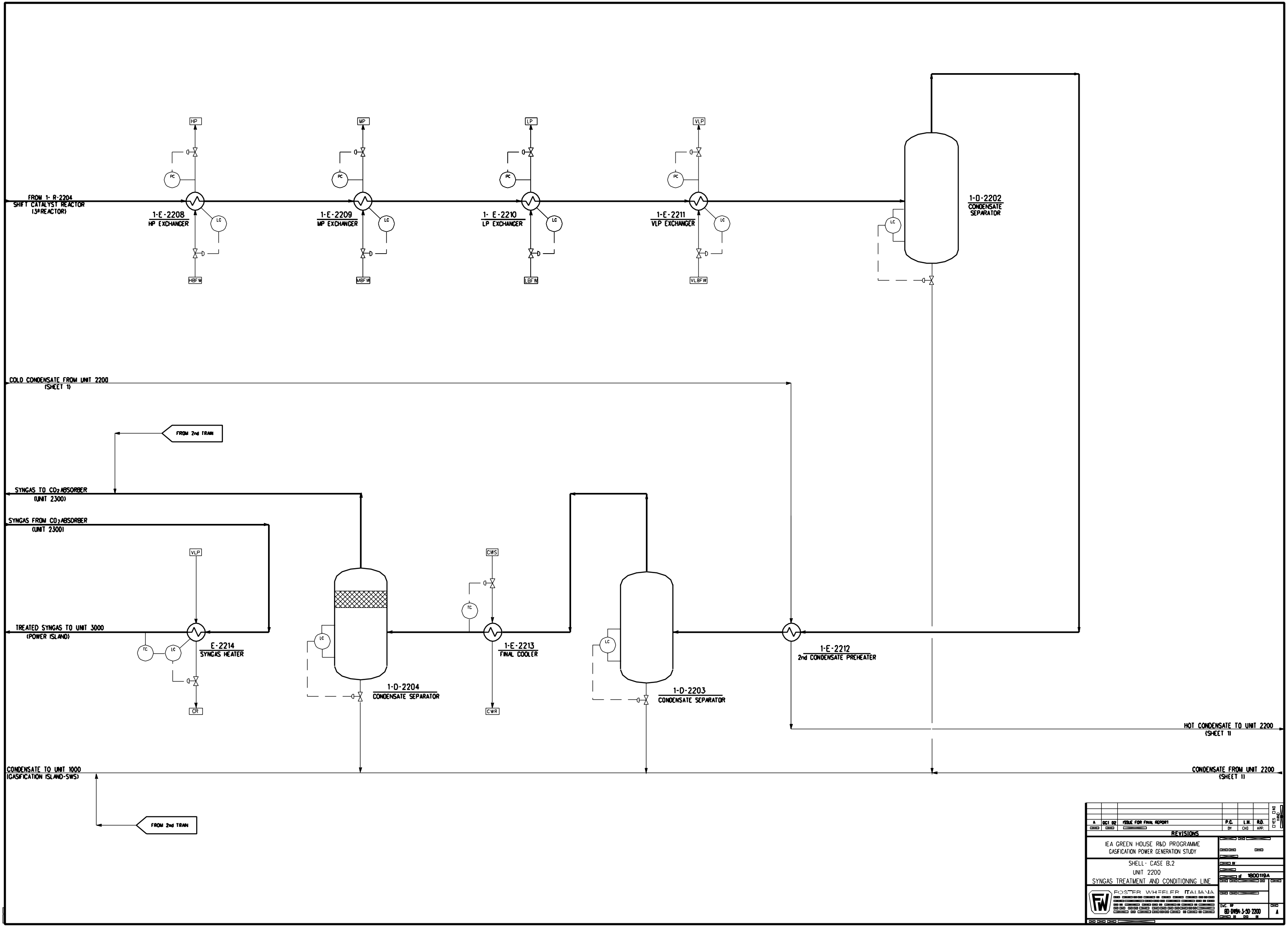

FROM 1- R-2204
SHIFT CATALYST REACTOR
(3rd REACTOR)
HP
MP
LP
VLP
PC
LC
1-E-2208
HP EXCHANGER
1-E-2209
MP EXCHANGER
1- E-2210
LP EXCHANGER
1-E-2211
VLP EXCHANGER
HBFW
MBFW
LBFW
VLBFW
1-D-2202
CONDENSATE
SEPARATOR
COLD CONDENSATE FROM UNIT 2200
(SHEET 1)
FROM 2nd TRAIN
SYNGAS TO CO2 ABSORBER
(UNIT 2300)
SYNGAS FROM CO2 ABSORBER
(UNIT 2300)
VLP
CWS
TC
TREATED SYNGAS TO UNIT 3000
(POWER ISLAND)
E-2214
SYNGAS HEATER
CR
1-D-2204
CONDENSATE SEPARATOR
1-E-2213
FINAL COOLER
CWR
1-D-2203
CONDENSATE SEPARATOR
1-E-2212
2nd CONDENSATE PREHEATER
HOT CONDENSATE TO UNIT 2200
(SHEET 1)
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND-SWS)
CONDENSATE FROM UNIT 2200
(SHEET 1)
FROM 2nd TRAIN
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SHELL- CASE B.2
UNIT 2200
SYNGAS TREATMENT AND CONDITIONING LINE
FOSTER WHEELER ITALIANA
1800119A
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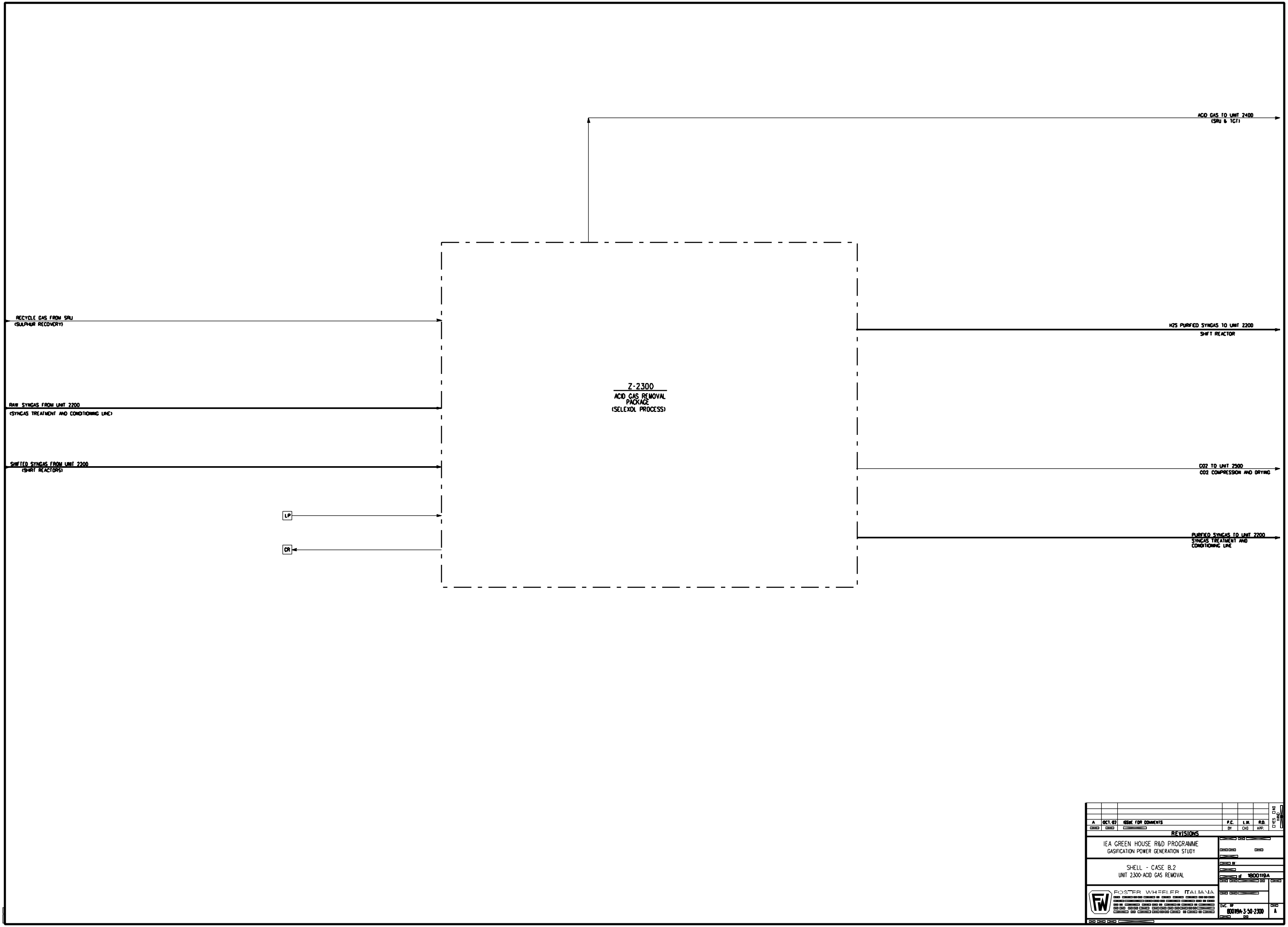
ACID GAS TO UNIT 2400
(SRU & TGT)
RECYCLE GAS FROM SRU
(SULPHUR RECOVERY)
H2S PURIFIED SYNGAS TO UNIT 2200
SHIFT REACTOR
Z-2300
ACID GAS REMOVAL
PACKAGE
(SELEXOL PROCESS)
RAW SYNGAS FROM UNIT 2200
(SYNGAS TREATMENT AND CONDITIONING LINE)
SHIFTED SYNGAS FROM UNIT 2200
(SHIFT REACTORS)
CO2 TO UNIT 2500
CO2 COMPRESSION AND DRYING
LP
PURIFIED SYNGAS TO UNIT 2200
SYNGAS TREATMENT AND
CONDITIONING LINE
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SHELL - CASE B.2
UNIT 2300-ACID GAS REMOVAL
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FOSTER WHEELER ITALIANA
DWG.
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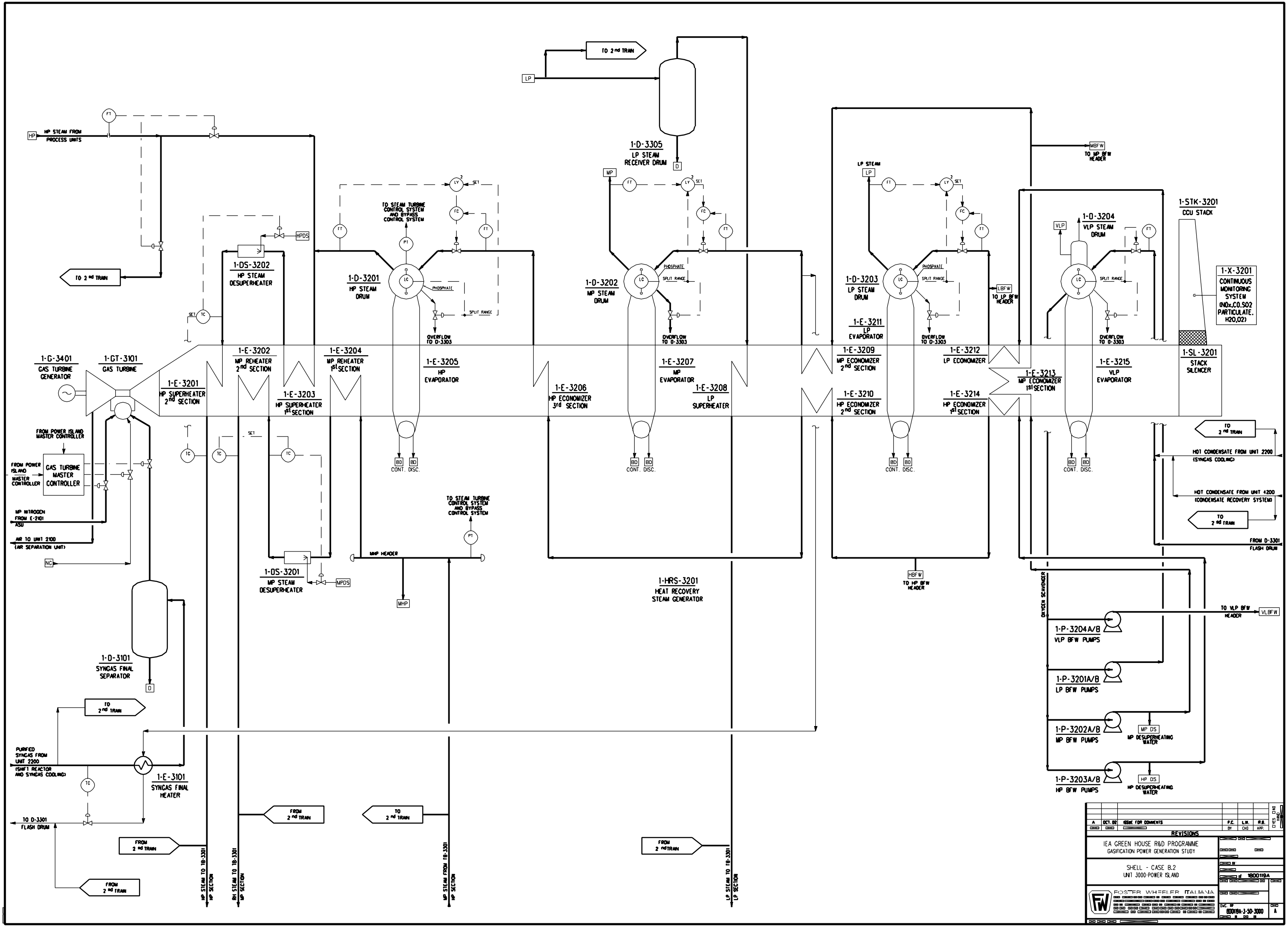

HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
LP
1-D-3305
LP STEAM RECEIVER DRUM
MP
1-DS-3202
HP STEAM DESUPERHEATER
HPDS
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
1-D-3204
VLP STEAM DRUM
VLP
1-STK-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP EVAPORATOR
1-E-3208
LP SUPERHEATER
1-E-3211
LP EVAPORATOR
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
BD BD
CONT. DISC.
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
MHP HEADER
MHP
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
HBFW
TO HP BFW HEADER
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
1-D-3101
SYNGAS FINAL SEPARATOR
D
PURIFIED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
A OCT. 02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
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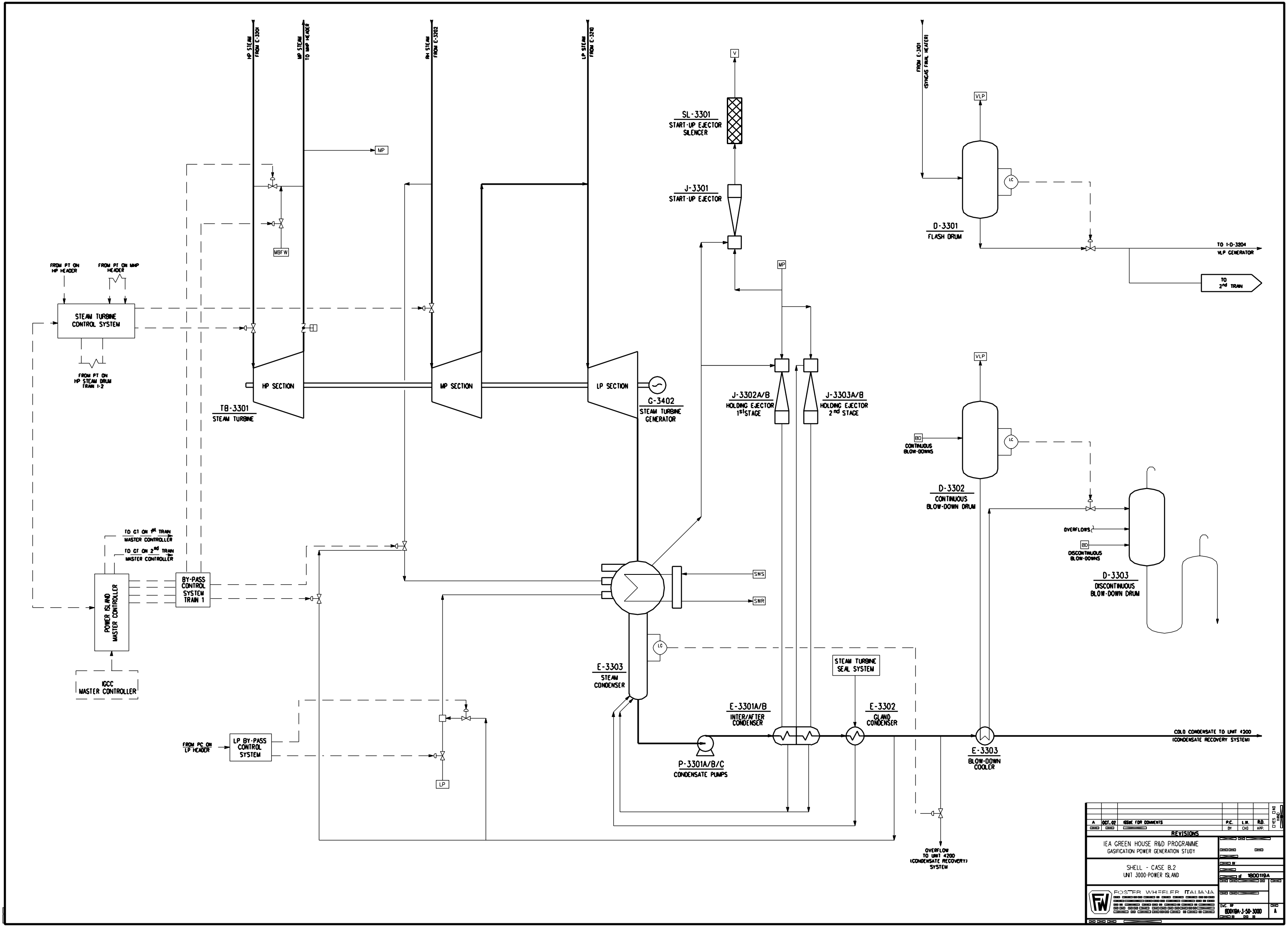
SHELL - CASE B.2
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1800119A



HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
MP
MBFW
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
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
VLP
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
BD
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
P-3301A/B/C
CONDENSATE PUMPS
E-3303
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
A
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P.C.
L.M.
R.D.
BY
CHD
APP.
YES
NO
HAND
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GASIFICATION POWER GENERATION STUDY
SHELL - CASE B.2
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
DWG.
BD0119A-3-50-3000
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4.4 Steam and Electric Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER	**CLIENT:**	IEA GHG	REVISION	Rev.0 / Rev.1 / Rev.2 / Rev. 3
	PROJECT:	GASIFICATION POWER GENERATION STUDY	DATE	Oct - 02
	LOCATION:	Netherlands	ISSUED BY	L.M.
	FWI Nº:	1- BD 0119-A	CHECKED BY	P.C.
			APPROVED BY	R.D.

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE B.2 - LP with Clean shift and CO_2 capture, separated removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 42 barg [t/h]	LP Steam 6.5 barg [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**		**-329,5**	**-7,6**	**-62,2**		**375,3**	**85,8**	**12,4**		**41,8**	**32,4**
2100	**Air Separation Unit**				**16,9**						**16,9**	
2200	**Syngas Cooling and COS Hydrolysis**		**-151,9**	**487,0**	**-69,6**	**-21,9**	**151,9**	**57,9**	**69,6**	**52,7**	**150,4**	**425,3**
2300	**Acid Gas Removal**				**84,0**						**84,0**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-0,7**	**-1,0**			**4,3**	**1,0**		**3,6**	
3000	**POWER ISLANDS UNITS**		**481,4**	**-478,7**	**22,3**	**21,9**	**-527,2**	**-148,0**	**-83,0**	**-52,7**		
4100 to 5300	**UTILITY and OFFSITE UNITS**				**9,6**						**9,6**	
	BALANCE		**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**306,3**	**457,7**

Note: Minus prior figure means figure is generated

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	oct 02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE B2
LP - Clean Shift with separated removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**306**
1000	**Gasification Section**	**12831**
2100	**Air Separation Unit**	**114207**
2200	**Syngas treatment and conditioning line**	**0**
2300	**Acid Gas Removal**	**33426**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2433**
2500	**CO_2 Compression and Drying**	**(35100)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4646**
3200	**Heat Recovery Steam Generator**	**6588**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1672**
3500	**Miscellanea**	**471**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10293**
	Additional consumption including CO_2 Compression and Drying	**(400)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**681**
4600	**Waste Water Treatment**	**279**
	Other Units	**375**
	BALANCE excluding CO_2 compression	**188209**
	BALANCE including CO_2 compression	**223709**

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

4.5 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

SHELL

Case B.2 - Low pressure, Clean Shift with CO_2 capture, separated H_2S and CO_2 removal - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	274.6
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1973.3**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1646.9
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1467.2
Syngas treatment efficiency (F/E*100)	%	89.1
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	303.0
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**875.0**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	114.2
Process Units consumption	MWe	48.7
Utility Units consumption	MWe	2.4
Offsite Units consumption (including sea cooling water system)	MWe	9.5
Power Islands consumption	MWe	13.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**188.2**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**686.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.8**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	35.1
Offsite Units consumption (sea cooling water system)	MWe	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**223.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**651.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.0**

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)	14780
Slag (Carbon =~0,4% wt) *	61
Net Carbon flowing to Process Units (A)	14719
Liquid Storage	
CO	107,0
CO_2	12331,0
Total to storage (B)	12438,0
Emission	
CO_2	2275,0
CO	6,0
Total Emission	2281,0
Overall CO_2 removal efficiency, % (B/A)	84,5

* The percentage of unreacted C stated by Shell is 0.2%. However, the carbon mass balance of the whole IGCC results in a 0.4% carbon less. This value is conservatively assumed.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE B.3

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
December 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.5

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.5 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.5 BASIC INFORMATION FOR EACH ALTERNATIVE

5.0 Case B.3

5.1 Introduction

The main features of the Case B.3 configuration of the IGCC Complex are:

- Low pressure (39 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- Double stage dirty shift;
- Combined removal of H_2S and CO_2.

The combined removal of acid gases, H_2S and CO_2, is based on the Amine Guard FS process. The product of this process is a single stream to be compressed and delivered to plant B.L.
The degree of integration between the Air Separation Unit (ASU) and the Gas Turbines is 30%. Gas Turbine power augmentation and syngas dilution, for NO_x control, is achieved with injection of compressed N_2 from ASU to the gas turbines.

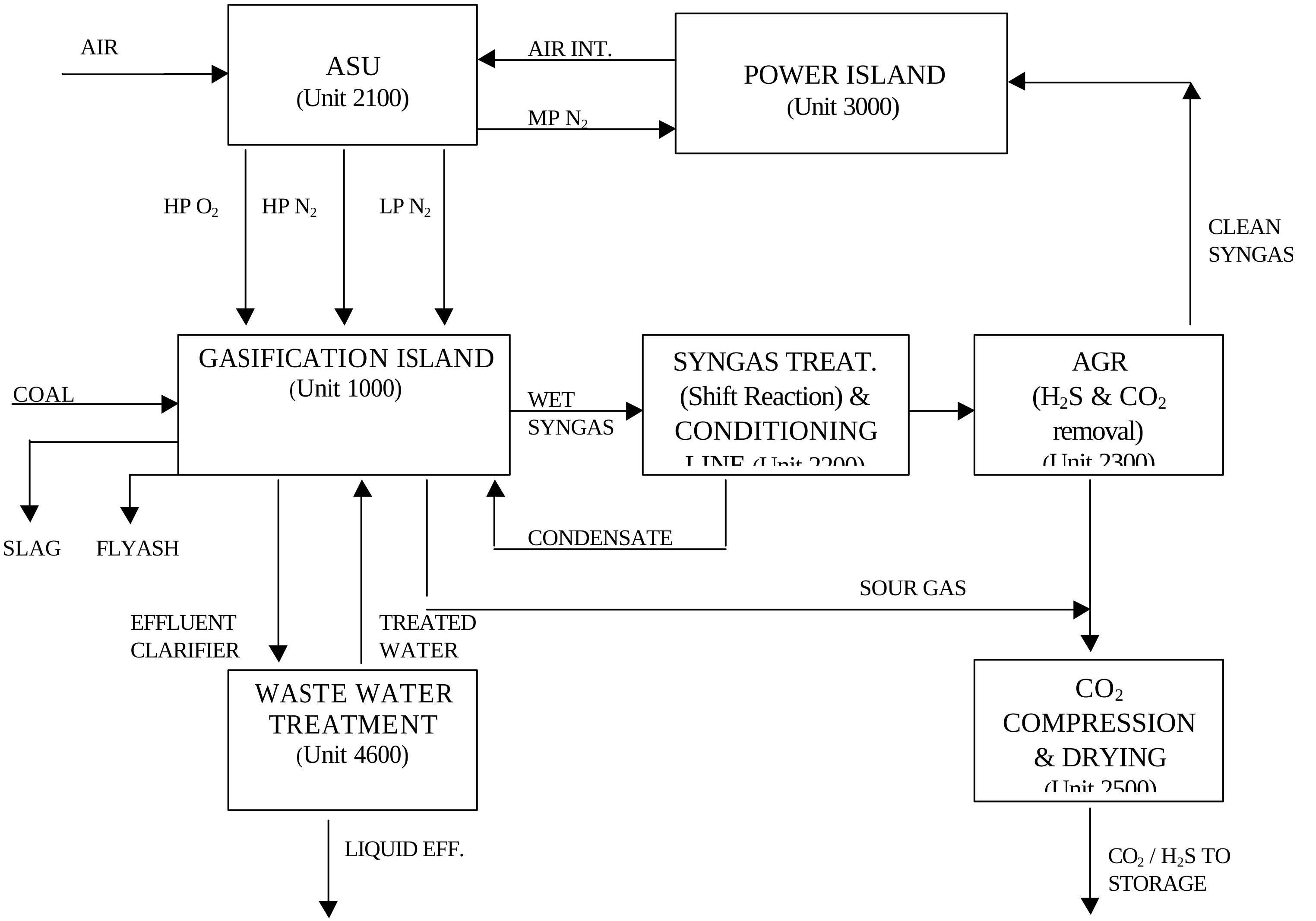
The arrangement of the process units is:

Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurization/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	3 x 33%

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%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO B.3 – IGCC COMPLEX BLOCK FLOW DIAGRAM



5.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	80	80	70	160
Pressure (bar)		40	69	7.5	37
TOTAL FLOW					
Mass flow (kg/h)	271,400	213,200	86,500	33,470	564,700
Molar flow (kmol/h)			3,080	1,190	28,670
Composition (% vol)					
H_2					26.25
CO					49.60
CO_2					1.24
N_2		3.5	99.88	99.88	4.00
Ar		1.5	0.08	0.08	0.62
O_2		95	0.04	0.04	0.00
H_2S + COS					0.23
H_2O					18.05
Others					0.01

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 3.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 5.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 5.4.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 5.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 36 barg and 160°C, 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 451°C. Due to the low water content of the syngas, the injection of MP steam to the syngas is required before entering the shift reactor. In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. The hot shifted syngas outlet from the first stage is cooled in a series of heat exchangers:

E-2201 Shift feed product exchanger
E-2202 HP Steam Generator
E-2203 MP Steam Generator

Inlet temperature to the second stage shift is controlled to 250 °C. Outlet temperature from second shift is 331°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:

E-2204 MP Steam Generator
E-2205 LP Steam Generator
E-2206 VLP Steam Generator
E-2207 A/B Condensate Preheater

The final cooling step of the syngas takes place in E-2208, where syngas is cooled with cooling water. Process condensate separated in Separator Drums D2201/3 is recycled back to the Sour Water Stripper of the Gasification Island.
The first stage of the shift reactor is split in three parallel trains. Downstream 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.
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-2209 with VLP steam and then sent to the gas turbines, Unit 3000.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises UOP/DOW-Amine Guard (MDEA) as acid gas solvent.

Unit 2300 is characterised by a low syngas pressure (26 bar g) and an extremely high CO_2/H_2S ratio (205/1). As UOP/DOW see this separation relatively easy, only an Amine Guard chemical wash has been proposed.

The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 5.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line

Exit Streams

2. Treated Gas to Gas Turbines
3. CO_2 /H_2S gas to compression

The Amine Guard FS solvent consumption, to make-up losses, is 60 m^3/year.

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 3 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.

The CO_2 removal rate is 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 large steam consumption.

Together with CO_2/H_2S exiting the Unit, the following quantity of hydrogen is sent to the final destination, after compression:

- 98 kmol/h of Hydrogen, corresponding to 0.72% vol and to an overall thermal power of 6.6 MWt, i.e. more than 2 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

<u>Unit 2500: CO_2 Compression and Drying</u>

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 7.0 for the general information about the technology.

The incoming stream of Unit 2500 flows from Unit 2300, Acid Gas Removal, and is delivered at 1.81 barg. A small quantity of Sour gas flowing from the Gasification Island is also fed to Unit 2500 for compression (Pressure=0.7 barg).

The product stream sent to final storage is mainly composed of CO_2 and H_2S. The main properties of the stream are as follows:

- Product stream: 550 t/h.
- Product stream: 110 bar.
- Composition :

	%wt
CO_2	99.52
H_2S	0.41
H_2	0.04
Others	0.03
TOTAL	100.00

Unit 3000: Power Island

The Process Flow diagram is attached to paragraph 5.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island and Syngas Treatment and Conditioning Line.
- MP steam (42 barg) : steam exported to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction. A small quantity of steam is also generated in the Gasification Island.
- LP steam (6.5 barg) : steam exported to the following Process Units: AGR, ASU, Utility and Offsite Unit. LP steam is also generated in the Syngas Treatment and Conditioning Line.
- 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 Treatment and Conditioning Line and recycled back to the HRSG.

Flow rate of the above interfaces of the Plant are shown in table attached to para 5.5, Utilities Consumption.

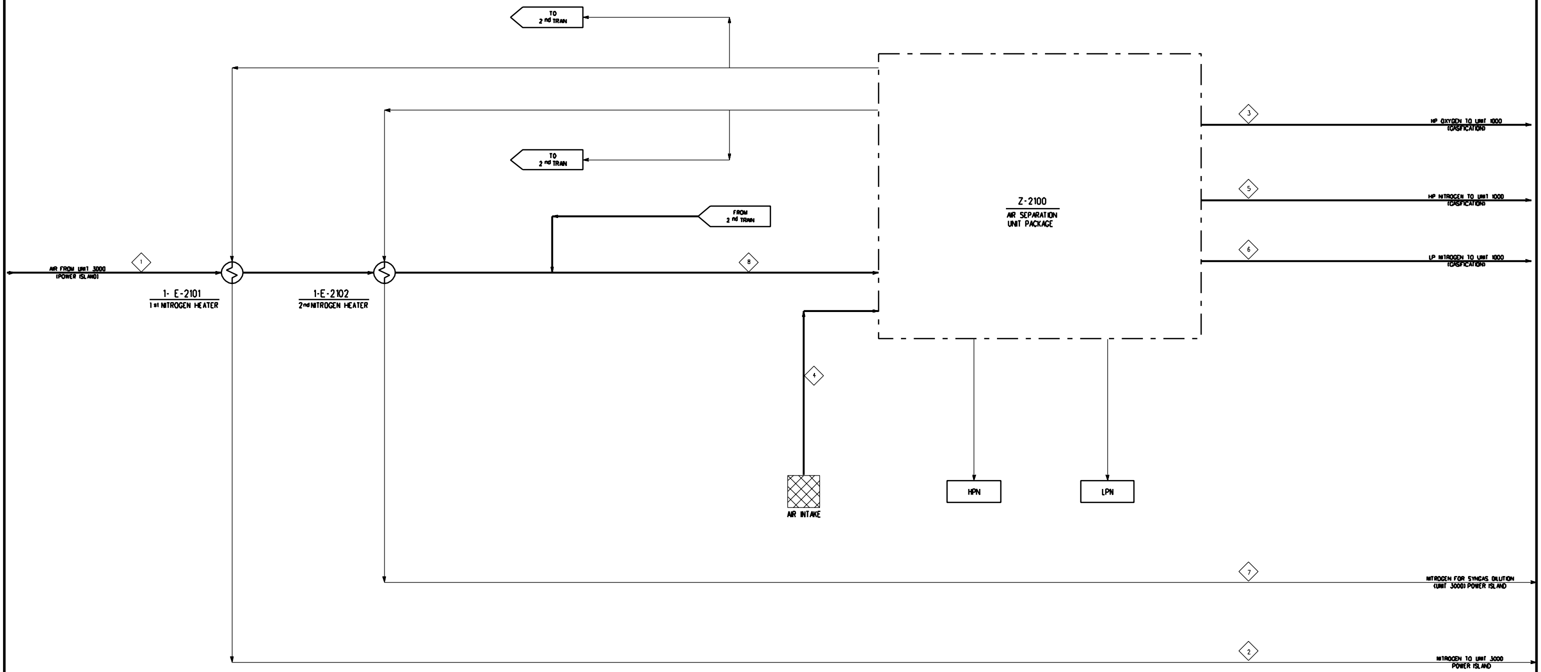
Steam imported to the Power Island are HP and VLP steam; all other streams are exported. As a consequence, the generation levels are the same of the Process Units.

5.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 7.0, and 9.0.



LEGEND

◇ STREAM NUMBER

B	OCT 07	FIRST ISSUE	P.C.	L.M.	R.D.
A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

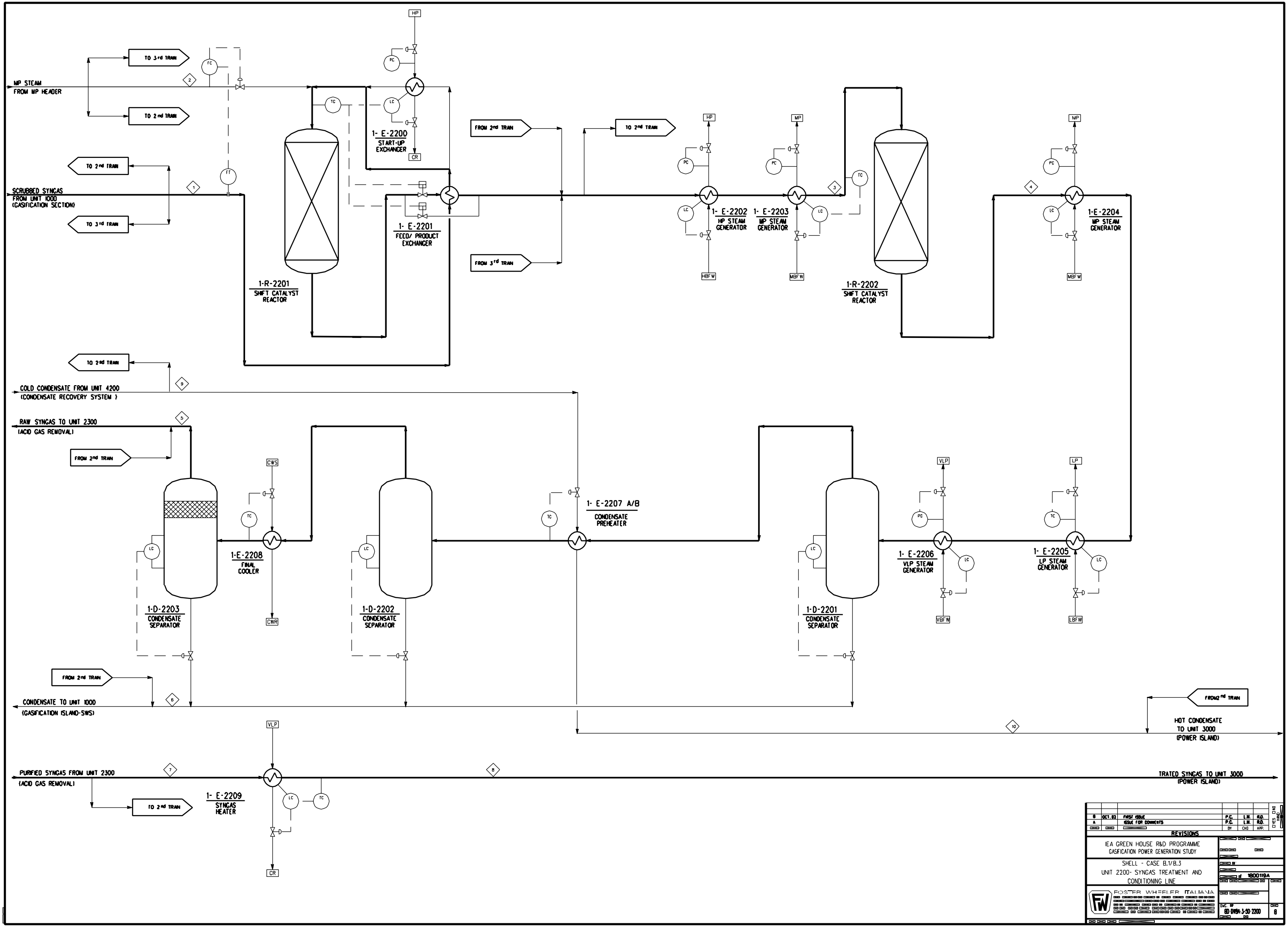
SHELL - CASE B.3
UNIT 2100-AIR SEPARATION UNIT

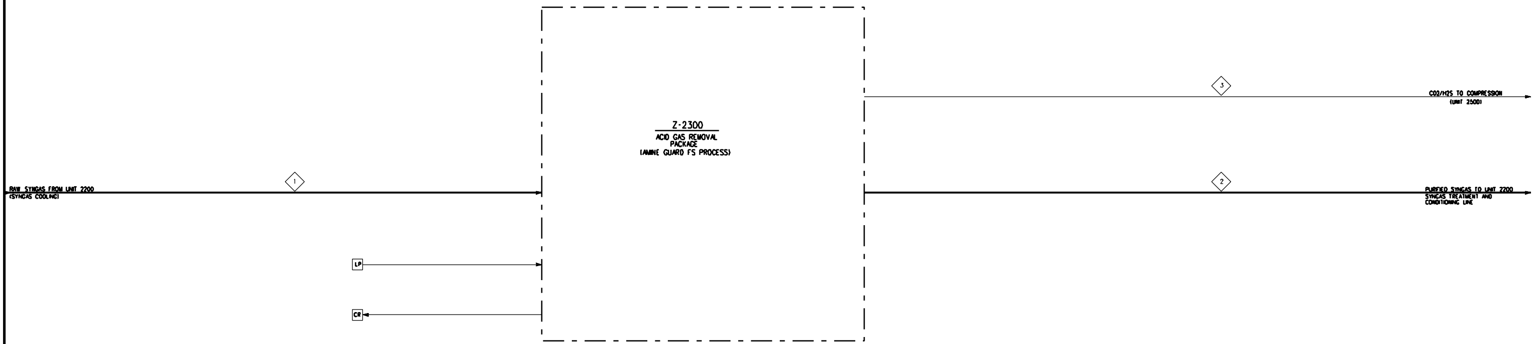
FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº
1BD0119A-3-50-2100

B


MP STEAM
FROM MP HEADER
TO 3rd TRAIN
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
TO 2nd TRAIN
TO 3rd TRAIN
HP
PC
LC
TC
FC
FT
1- E-2200
START-UP
EXCHANGER
CR
1- E-2201
FEED/ PRODUCT
EXCHANGER
1-R-2201
SHIFT CATALYST
REACTOR
FROM 2nd TRAIN
FROM 3rd TRAIN
TO 2nd TRAIN
1- E-2202
HP STEAM
GENERATOR
HBFW
MP
1- E-2203
MP STEAM
GENERATOR
MBFW
1-R-2202
SHIFT CATALYST
REACTOR
1-E-2204
MP STEAM
GENERATOR
TO 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
FROM 2nd TRAIN
CWS
1-E-2208
FINAL
COOLER
CWR
1-D-2203
CONDENSATE
SEPARATOR
1-D-2202
CONDENSATE
SEPARATOR
1- E-2207 A/B
CONDENSATE
PREHEATER
1-D-2201
CONDENSATE
SEPARATOR
VLP
1- E-2206
VLP STEAM
GENERATOR
VBFW
LP
1- E-2205
LP STEAM
GENERATOR
LBFW
FROM 2nd TRAIN
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND-SWS)
FROM2nd TRAIN
HOT CONDENSATE
TO UNIT 3000
(POWER ISLAND)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
TO 2nd TRAIN
1- E-2209
SYNGAS
HEATER
TRATED SYNGAS TO UNIT 3000
(POWER ISLAND)
B OCT.02 FIRST ISSUE P.C. L.M. R.D.
A ISSUE FOR COMMENTS P.C. L.M. R.D.
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASFICATION POWER GENERATION STUDY
SHELL - CASE B.1/B.3
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
FOSTER WHEELER ITALIANA
1800119A
DWG. Nº
BD-DW9A-3-50-2200
B



LEGEND

◇ STREAM NUMBER

0	OCT. 07	FIRST ISSUE	P.C.	L.M.	R.D.
A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

SHELL - CASE B.3
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2300

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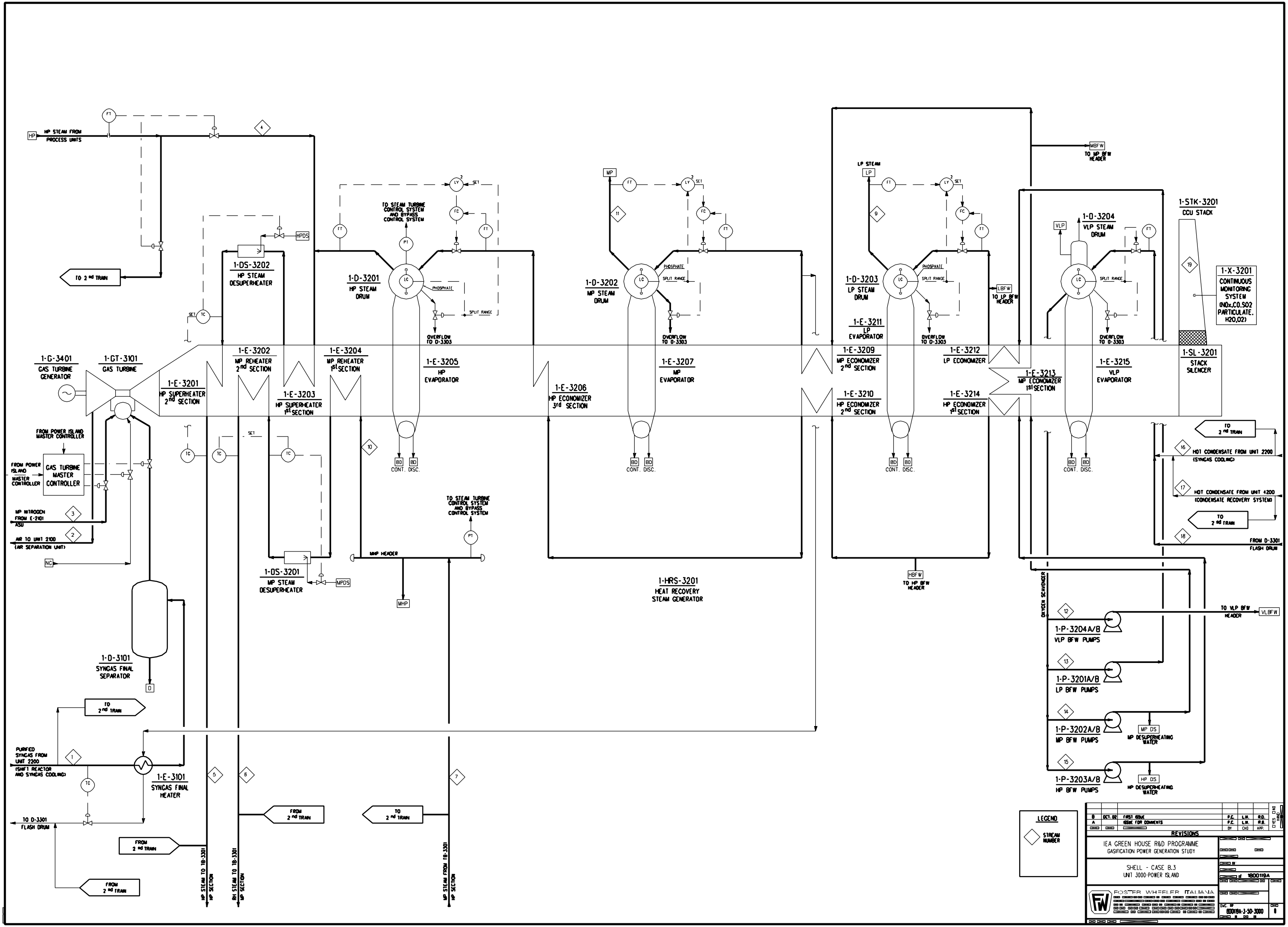
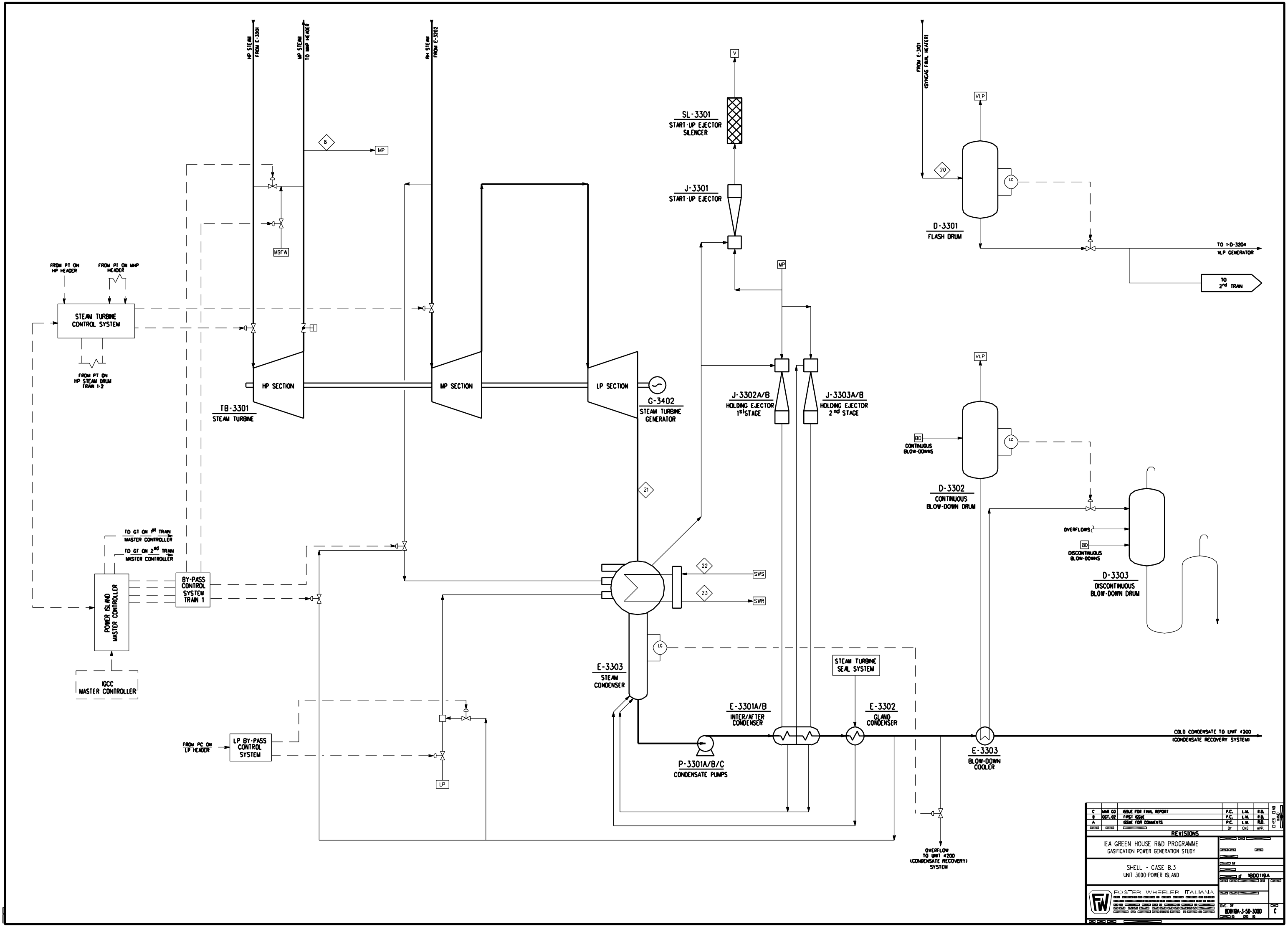

HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
1-DS-3202
HP STEAM DESUPERHEATER
HPDS
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
LP STEAM
1-D-3204
VLP STEAM DRUM
VLP
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
1-STK-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
HP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP EVAPORATOR
1-E-3211
LP EVAPORATOR
1-E-3209
MP ECONOMIZER 2nd SECTION
1-E-3210
HP ECONOMIZER 2nd SECTION
1-E-3212
LP ECONOMIZER
1-E-3213
MP ECONOMIZER 1st SECTION
1-E-3214
HP ECONOMIZER 1st SECTION
1-E-3215
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
BD BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
MHP HEADER
MHP
HBFW
TO HP BFW HEADER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
1-D-3101
SYNGAS FINAL SEPARATOR
PURIFIED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
LEGEND
STREAM NUMBER
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE B.3
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1BD0119A
BD0119A-3-50-3000


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
MP
MBFW
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
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
STEAM TURBINE SEAL SYSTEM
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
P-3301A/B/C
CONDENSATE PUMPS
E-3303
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
C MAR 03 ISSUE FOR FINAL REPORT
B OCT.02 FIRST ISSUE
A ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
SHELL - CASE B.3
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA

5.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	
	CASE : SHELL CASE B.3	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	Nov 02	Mar 03	

STREAM	1	2	3	4	5	6	7	8		
	AIR EXTRACTED FROM GAS TURBINE	MP NITROGEN TO ONE GAS TURBINE	HP OXYGEN TO GASIFICATION	AMBIENT AIR INTAKE	HP NITROGEN TO GASIFICATION	LP NITROGEN TO GASIFICATION	NITROGEN FOR SYNGAS DILUTION	TOTAL Air From GTs		
Temperature (°C)	396	213	80	AMB.	80	70	220			
Pressure (bar)	14,3	22,6	40,4	AMB.	69,0	7,5	26,2	13,3		
TOTAL FLOW										
Mass flow (kg/h)	142045	87406	213213	662877	86444	33474	218591	284090		
Molar flow (kgmole/h)	4920	3122	6667	22961	3078	1192	7785	9840		
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	142045	87406	213213	662877	86444	33474	218591	284090		
Molar flow (kgmole/h)	4920	3122	6667	22961	3078	1192	7785	9840		
Molecular Weight	28,87	28,00	31,98	28,87	28,08	28,08	28,08	28,87		
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	77,57	97,50	3,50	77,57	98,00	98,00	98,00	77,57		
O_2	20,86	2,15	95,00	20,86	2,00	2,00	2,00	20,86		
CH_4										
H_2S										
COS										
Ar	0,89	0,26	1,50	0,89				0,89		
H2O	0,68	0,09		0,68				0,68		

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE			REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME			PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE B.3			APPROVED	R.D.	R.D.	
	UNIT : 2300 Acid Gas Removal			DATE	Nov 02	Mar 03	

STREAM	1	2	3							
	Raw SYNGAS from Syngas Cooling to AGR	Purified Syngas to Syngas Cooling	Combined Acid gas and CO2 to compression							
Temperature (°C)	38	40	49							
Pressure (bar)	27,8	27,5	1,8							
TOTAL FLOW										
Mass flow (kg/h)	712814	159908	569821							
Molar flow (kgmole/h)	36952	24294	13589							
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	712814	159908	569821							
Molar flow (kgmole/h)	36952	24294	13589							
Molecular Weight	19,3	6,6	41,9							
Composition (vol %)										
H_2	56,41	85,39	0,72							
CO	2,51	3,80	0,03							
CO_2	37,02	4,75	92,17							
N_2	3,09	4,69	0,03							
O_2	0,00	0,00	0,00							
CH_4	0,00	0,00	0,00							
H_2S	0,18	0,00	0,49							
COS	0,00	0,00	0,00							
Ar	0,48	0,73	0,00							
H2O	0,31	0,64	6,56							

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : SHELL CASE B.3	APPROVED	R.D.	R.D.	
	UNIT : 2200 SYNGAS Cooling and COS Hydrolysis	DATE	Nov 02	Mar 03	

STREAM	1	2	3	4	5	6	7	8	9	10
	SYNGAS at Scrubber Outlet (3 Trains)	MP STEAM from MP Header (3 Trains)	SYNGAS to 2nd Shift Catalyst Reactor (2 Trains)	SYNGAS from 2nd Shift Catalyst Reactor (2 Trains)	Raw SYNGAS to AGR (2 Trains)	Condensate Return to Gasification (2 Trains)	Purified Syngas from AGR (2 Trains)	Treated Syngas to Power Island (2 Trains)	Cold Condensate from CRS (2 Trains)	Hot Condensate to Power Island (2 Trains)
Temperature (°C)	160	248	250	331	38	105	40	155	21	69
Pressure (bar)	37	38,5	33,2	31,8	27,8	27	27,5	27,0	4,0	2,6
TOTAL FLOW										
Mass flow (kg/h)	187418	137760	487603	487577	356407	132930	79954	79954	580577	580577
Molar flow (kgmole/h)	9533	7653	25780	25780	18476	7385	12147	12147		
LIQUID PHASE										
Mass flow (kg/h)						132930			580577	580577
GASEOUS PHASE										
Mass flow (kg/h)	187418	137760	487603	487577	356407		79954	79954		
Molar flow (kgmole/h)	9533	7653	25780	25780	18476		12147	12147		
Molecular Weight	19,7	18,0	18,9	18,9	19,3		6,6	6,6		
Composition (vol %)										
H_2	26,25		32,99	40,28	56,41		85,39	85,39		
CO	49,60		9,08	1,79	2,51		3,80	3,80		
CO_2	1,25		19,12	26,41	37,02		4,75	4,75		
N_2	4,00		2,22	2,21	3,09		4,69	4,69		
HCN + NH3	0,00		0,01	0,01	0,00		0,00	0,00		
CH_4	0,00		0,00	0,00	0,00		0,00	0,00		
H_2S	0,21		0,13	0,13	0,18		0,00	0,00		
COS	0,02		0,00	0,00	0,00		0,00	0,00		
Ar	0,62		0,34	0,34	0,48		0,73	0,73		
H2O	18,05		36,11	28,83	0,31		0,64	0,64		

	IGCC HEAT & MATERIAL BALANCE				
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME CASE : SHELL CASE B.3 UNIT : 3000 POWER ISLAND				
Stream	**Description**	**Flowrate t/h**	**Temperature °C**	**Pressure bar a**	**Entalphy kJ/kg**
1	Treated SYNGAS from Syngas Cooling (*) (1)	189,98	155	27,0	332,6
2	Extraction Air to Air Separation Unit (*)	142,05	396	15,0	-
3	MP Nitrogen from ASU (*)	87,41	213	22,60	-
4	HP Steam from Process Units	192,15	345	127,0	2789,0
5	HP Steam to Steam Turbine (*)	405,72	552	122,5	3482,1
6	Hot RH Steam to MP Steam Turbine (*)	352,91	517	38,7	3485,0
7	MP Steam from Steam Turbine (*)	349,11	386	41,7	3179,0
8	MP steam to process	113,23	396	42,0	3179,0
9	LP steam to process	173,70	168	7,5	2764,8
10	MP Steam to MP Reheater (*)	352,91	382	41,0	3171,0
11	Saturated MP steam to process	149,74	255	43,0	2799,0
12	BFW to VLP BFW Pumps (*)	61,20	119	1,9	499,2
13	BFW to LP BFW Pumps (*)	90,69	119	1,9	499,2
14	BFW to MP BFW Pumps (*)	194,91	119	1,9	499,2
15	BFW to HP BFW Pumps (*)	429,44	119	1,9	499,2
16	Hot Condensate returned from Unit 2200 (*)	580,55	69	39,5	289,2
17	Hot Condensate returned from CR (*)	120,90	94	2,5	393,9
18	Water from Flash Drum (*)	23,87	119	1,9	499,2
19	FLUE GAS AT STACK (*) (2)	2511,50	129	AMB.	122,8
20	Condensate from Syngas Final Heater (*)	53,00	170	52,3	721,6
21	LP Steam Turbine Exhaust	712,00	21,7	0,026	2220
22	Sea Water Supply to Steam Condenser	51898,76	12	3,0	50,5
23	Sea Water Return from Steam Condenser	51898,76	19	2,1	79,8

(*) flowrate for one train

5.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

	FOSTER WHEELER	CLIENT:	IEA GHG	REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
				DATE	oct-02			
		PROJECT:	GASIFICATION POWER GENERATION STUDY	ISSUED BY	P.C.			
		LOCATION:	Netherlands	CHECKED BY	L.M.			
		FWI Nº:	1- BD 0119-A	APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE B.3 - LP with CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 42 barg [t/h]	LP Steam 6.5 barg [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**		-325,7	-7,6			371,0	35,6			41,3	32,0
2100	**Air Separation Unit**				16,7						16,7	
2200	**Syngas Cooling and COS Hydrolysis**		-58,6	281,7	-75,3	-95,6	58,6	132,0	75,3	122,4	26,8	413,7
2300	**Acid Gas Removal**				147,7						147,7	
3000	**POWER ISLANDS UNITS**		384,3	-274,1	-98,4	95,6	-429,6	-167,6	-75,3	-122,4		
4100 to 5300	**UTILITY and OFFSITE UNITS**				9,3						9,3	
	BALANCE		0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	241,8	445,7

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Netherlands FWI Nº: 1- BD 0119A		Rev 0 oct 02 ISSUED BY: PC. CHECKED BY: LM APPR. BY: RM

WATER CONSUMPTION SUMMARY - SHELL - CASE B3 - LP with CO_2 capture, combined removal of H_2S and CO_2

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**		32	2553	
2100	**Air Separation Unit**				20819
2200	**Syngas Treatment and Conditioning line**		414	4799	
2300	**Acid Gas Removal**			5258	
2500	**CO_2 Compression and Drying**				(5000)
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1600	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		4		51898
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4100/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				24977
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	470	-470		
4600	**Waste Water Treatment**	-67			
	Other Units		20	352	
	BALANCE excluding CO_2 compression	403	0	14562	97694
	BALANCE including CO_2 compression	403	0	14562	102694

Note: Minus prior to figure means figure is generated

	FOSTER WHEELER			
		CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	oct 02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE B3
LP with CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**303**
1000	**Gasification Section**	**12681**
2100	**Air Separation Unit**	**112986**
2200	**Syngas treatment and conditioning line**	**0**
2300	**Acid Gas Removal**	**12539**
2500	**CO_2 Compression and Drying**	**(36600)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4618**
3200	**Heat Recovery Steam Generator**	**6148**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1719**
3500	**Miscellanea**	**475**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10169**
	Additional consumption including CO_2 Compression and Drying	**(400)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**669**
4600	**Waste Water Treatment**	**276**
	Other Units	**375**
	BALANCE excluding CO_2 compression	**162959**
	BALANCE including CO_2 compression	**199959**

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

5.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

SHELL

Case B.3 - Low pressure with CO_2 capture, combined H_2S and CO_2 removal - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	271.4
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1950.3**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1628.4
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1467.2
Syngas treatment efficiency (F/E*100)	%	90.1
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	311.3
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**883.3**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	113.0
Process Units consumption	MWe	25.2
Utility Units consumption	MWe	2.5
Offsite Units consumption (including sea cooling water system)	MWe	9.3
Power Islands consumption	MWe	13.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**163.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**720.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**36.9**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	36.6
Offsite Units consumption (sea cooling water system)	MWe	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**200.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**683.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.0**

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)	14609
Slag (Carbon =~0,4% wt) *	61
Net Carbon flowing to Process Units (A)	14548
Liquid Storage	
CO	3.7
CO_2	12459.3
Total to storage (B)	12463.0
Emission	
CO_2	2079.4
CO	5.6
Total Emission	2085.0
Overall CO_2 removal efficiency, % (B/A)	85.7

* The percentage of unreacted C stated by Shell is 0.2%. However, the carbon mass balance of the whole IGCC results in a 0.4% carbon less. This value is conservatively assumed.

5.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic is shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

5.7.1 Gaseous Emissions

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, and emission from the coal Drying process.

Table 5.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 5.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	697.6
Flow, $Nm^3/h^{(1)}$	2,507,824
Temperature, °C	129
Composition	(%vol)
Ar	0.91
N_2	75.01
O_2	11.17
CO_2	1.14
H_2O	11.77
Emissions	$mg/Nm^{3\ (1)}$
NOx	74
SOx	1
CO	31
Particulate	5

(1) Dry gas, O_2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 5.2.

Table 5.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1395.2
Flow, $Nm^3/h^{(1)}$	5,015,648
Temperature, °C	129
Emissions	kg/h
NOx	371,2
SOx	5,0
CO	155,5
Particulate	25,1

(1) Dry gas, O_2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate	:	39	t/h
N_2	:	80	% vol.
$H_2O+O_2+CO_2$	:	20	% vol.
Particulate	:	<10	mg/Nm^3, wet basis.

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

5.7.2 Liquid Effluent

Waste Water Treatment (Unit 4600)

Part of the effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island as process water, closing the Gasification water balance. The other part is sent to a dedicated treatment where the reverse osmosis process allows recovering almost 60% of the treated water. This recovered water is recycled back to the Demi Water System, Unit 4200, and used as raw water for the Demineralized water plant. The remaining 40% of water is discharged together with the sea cooling water return stream. The expected flow rate of this stream is as follows:

- Flow rate : 46 m^3/h

Sea Water System (Unit 4100)

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 : 100,600 m^3/h
- Temperature : 19 °C
- Cl_2 : <0.05 ppm

5.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

Slag from Slag Removal Unit

Flow rate	:	40.2	t/h
Water content	:	10	%wt

Slag product can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

<u>Flyash from Dry Solids Removal Unit</u>

Flow rate	:	1.3 t/h

Flyash can be dispatched to cement industries.

5.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
1	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 28	430 / 243		DUTY = 7500 kW
2	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 28	430 / 243		DUTY = 7500 kW
1	**E-2102**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	250 / 250		DUTY = 3550 kW
2	**E-2102**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	250 / 250		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 = 225 t/h		47,3			Oxigen purity = 95 %
				LP N_2 flow rate to Gasifier = 36 t/h		9,5			Nitrogen purity = 99.9 %
				MP N_2 flow rate to GTs = 420 t/h		24,9			Nitrogen purity = 98 %
				HP N_2 flow rate to Gasifier = 91 t/h		74,8			Nitrogen purity = 99.9 %
				MP N_2 flow rate to Proc Unit = 1935		28,6			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 298 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning LIne - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1	E-2201	Feed/ Product Exchanger	Shell & Tube			42 / 42	300 / 480		DUTY = 8850 kW H2 service H2/Wet H2S serv. on channel
2	E-2201	Feed/ Product Exchanger	Shell & Tube			42 / 42	300 / 480		DUTY = 8850 kW H2 service H2/Wet H2S serv. on channel
3	E-2201	Feed/ Product Exchanger	Shell & Tube			42 / 42	300 / 480		DUTY = 8850 kW H2 service H2/Wet H2S serv. on channel
1	E-2202	HP Steam Generator	Kettle			140 / 42	360 / 430		DUTY = 17270 kW H2 service H2/Wet H2S serv. on channel
2	E-2202	HP Steam Generator	Kettle			140 / 42	360 / 430		DUTY = 17270 kW H2 service H2/Wet H2S serv. on channel
1	E-2203	MP Steam Generator	Kettle			48 / 42	285 / 370		DUTY = 22300 kW H2 service H2/Wet H2S serv. on channel
2	E-2203	MP Steam Generator	Kettle			48 / 42	285 / 370		DUTY = 22300 kW H2 service H2/Wet H2S serv. on channel
1	E-2204	MP Steam Generator	Kettle			48 / 42	285 / 360		DUTY = 18100 kW H2 service H2/Wet H2S serv. on channel
2	E-2204	MP Steam Generator	Kettle			48 / 42	285 / 360		DUTY = 18100 kW H2 service H2/Wet H2S serv. on channel
1	E-2205	LP Steam Generator	Kettle			12 / 42	200 / 290		DUTY = 22500 kW H2 service H2/Wet H2S serv. on channel
2	E-2205	LP Steam Generator	Kettle			12 / 42	200 / 290		DUTY = 22500 kW H2 service H2/Wet H2S serv. on channel

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning LIne - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)				Shell/tube	Shell/tube		
1	E-2206	VLP Steam Generator	Kettle			12 / 42	175 / 205		DUTY = 38430 kW H2 service H2/Wet H2S serv. on channel
2	E-2206	VLP Steam Generator	Kettle			12 / 42	175 / 205		DUTY = 38430 kW H2 service H2/Wet H2S serv. on channel
1	E-2207 A/B	Condensate Preheater	Shell & Tube			5 / 42	105 / 180		DUTY = 31930 kW H2 service H2/Wet H2S serv. on channel
2	E-2207 A/B	Condensate Preheater	Shell & Tube			5 / 42	105 / 180		DUTY = 31930 kW H2 service H2/Wet H2S serv. on channel
1	E-2208	Final Cooler	Shell & Tube			12 / 42	60 / 150		DUTY = 37350 kW H2 service H2/Wet H2S serv. on channel
2	E-2208	Final Cooler	Shell & Tube			12 / 42	60 / 150		DUTY = 37350 kW H2 service H2/Wet H2S serv. on channel
1	E-2209	Syngas Heater	Shell & Tube			12 / 42	175 / 165		DUTY = 8020 kW H2 service H2/Wet H2S serv. on channel
2	E-2209	Syngas Heater	Shell & Tube			12 / 42	175 / 165		DUTY = 8020 kW H2 service H2/Wet H2S serv. on channel

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: Netherlands
PROJ. NAME: Gasification Power Generation Study
CONTRACT N. 1- BD- 0119 A

REVISION	Rev.0	Rev.1	Rev.2	Rev.3
DATE	Oct. 02			
ISSUED BY	P.C.			
CHECKED BY	L.M.			
APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning LIne - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS							
1	D-2201	Condensate Separator	Vertical			42	180		Wet H2S service/H2 service
2	D-2201	Condensate Separator	Vertical			42	180		Wet H2S service/H2 service
1	D-2202	Condensate Separator	Vertical			42	170		Wet H2S service/H2 service
2	D-2202	Condensate Separator	Vertical			42	170		Wet H2S service/H2 service
1	D-2203	Condensate Separator	Vertical			42	70		Equipped with demister Wet H2S service/H2 service
2	D-2203	Condensate Separator	Vertical			42	70		Equipped with demister Wet H2S service/H2 service

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning LIne - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		REACTOR							
1	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
2	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
3	R-2201	Shift Catalyst Reactor - 1st Bed	vertical			42	480		H2 service Wet H2S service
1	R-2202	Shift Catalyst Reactor - 2nd Bed	vertical			42	360		H2 service Wet H2S service
2	R-2201	Shift Catalyst Reactor - 2nd Bed	vertical			42	360		H2 service Wet H2S service
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	Shift Catalyst							Catalyst volume: 580 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3100 - Gas Turbine - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			57 / 35	280 / 200		DUTY= 2633 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			57 / 35	280 / 200		DUTY= 2633 kW Tubes: H2 service
		DRUMS							
1	**D-3101**	**Syngas Final Separator**	vertical			35	200		H2 service
2	**D-3101**	**Syngas Final Separator**	vertical			35	200		H2 service
		PACKAGES							
1	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					Included in 1-Z- 3101 Included in 1-Z- 3101
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					Included in 2-Z- 3101 Included in 2-Z- 3101

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS							
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
		MISCELLANEA							
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			REVISION	Rev.0	Rev.1	Rev.2	Rev.3
	CLIENT:	IEA GREENHOUSE R&D PROGRAMME	DATE	Oct. 02			
	LOCATION:	Netherlands	ISSUED BY	P.C.			
	PROJ. NAME:	Gasification Power Generation Study	CHECKED BY	L.M.			
	CONTRACT N.	1- BD- 0119 A	APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels - Simple						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3210	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**LP Evaporator**							Included in 1-HRS-3201
1	E-3212	**LP Economizer**							Included in 1-HRS-3201
1	E-3213	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3214	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	HRSG-3201	Heat Recovery Steam Generator	Horizontal, Natural Circulated, 4 Pressure Levels , Simple						
2	D-3201	HP steam Drum							Included in 2-HRS-3201
2	D-3202	MP steam drum							Included in 2-HRS-3201
2	D-3203	LP steam drum							Included in 2-HRS-3201
2	D-3204	VLP steam drum with degassing section							Included in 2-HRS-3201
2	E-3201	HP Superheater 2nd section							Included in 2-HRS-3201
2	E-3202	MP Reheater 2nd section							Included in 2-HRS-3201
2	E-3203	HP Superheater 1st section							Included in 2-HRS-3201
2	E-3204	MP Reheater 1st section							Included in 2-HRS-3201
2	E-3205	HP Evaporator							Included in 2-HRS-3201
2	E-3206	HP Economizer 3rd section							Included in 2-HRS-3201
2	E-3207	MP Evaporator							Included in 2-HRS-3201
2	E-3209	MP Economizer 2nd section							Included in 2-HRS-3201
2	E-3210	HP Economizer 2nd section							Included in 2-HRS-3201
2	E-3211	LP Evaporator							Included in 2-HRS-3201
2	E-3212	LP Economizer							Included in 2-HRS-3201
2	E-3213	MP Economizer 1st section							Included in 2-HRS-3201
2	E-3214	HP Economizer 1st section							Included in 2-HRS-3201
2	E-3215	VLP Evaporator							Included in 2-HRS-3201

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
LOCATION: Netherlands
PROJ. NAME: Gasification Power Generation Study
CONTRACT N. 1- BD- 0119 A

REVISION	Rev.0	Rev.1	Rev.2	Rev.3
DATE	Oct. 02			
ISSUED BY	P.C.			
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	58 / 150		DUTY = 980 kW
		DRUMS							
	D-3301	**Flash Drum**	vertical			3,5	240		
	D-3302	**Continuous Blow-down Drum**	vertical			3,5	150		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	150		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**		311 MW					
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	G-3402	Steam Turbine Generator							Included in Z - 3201
	J-3301	Start-up Ejector							Included in Z - 3201
	J-3302 A/B	Holding Ejector 1st Stage							Included in Z - 3201
	J-3303 A/B	Holding Ejector 2nd Stage							Included in Z - 3201
	P-3301A/B/C	Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
	SL-3301	Start-up Ejector Silencer							Included in Z - 3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct. 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
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EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Shell Case B.3 - Low Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	G-3401	Gas Turbine Generator							Included in 1 -Z- 3101
2	G-3401	Gas Turbine Generator							Included in 2 -Z- 3101
	G-3402	Steam Turbine Generator							Included in Z- 3301

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SECTION D.6

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.6 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.6 BASIC INFORMATION FOR EACH ALTERNATIVE

6.0 Case B.4

6.1 Introduction

The main features of the Case B.4 configuration of the IGCC Complex are:

- High pressure (61 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- Double 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 Unit (ASU) and the Gas Turbines is 30%. Gas Turbine power augmentation and NO_x control are achieved with injection of compressed moisturised 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.

The arrangement of the process units is:

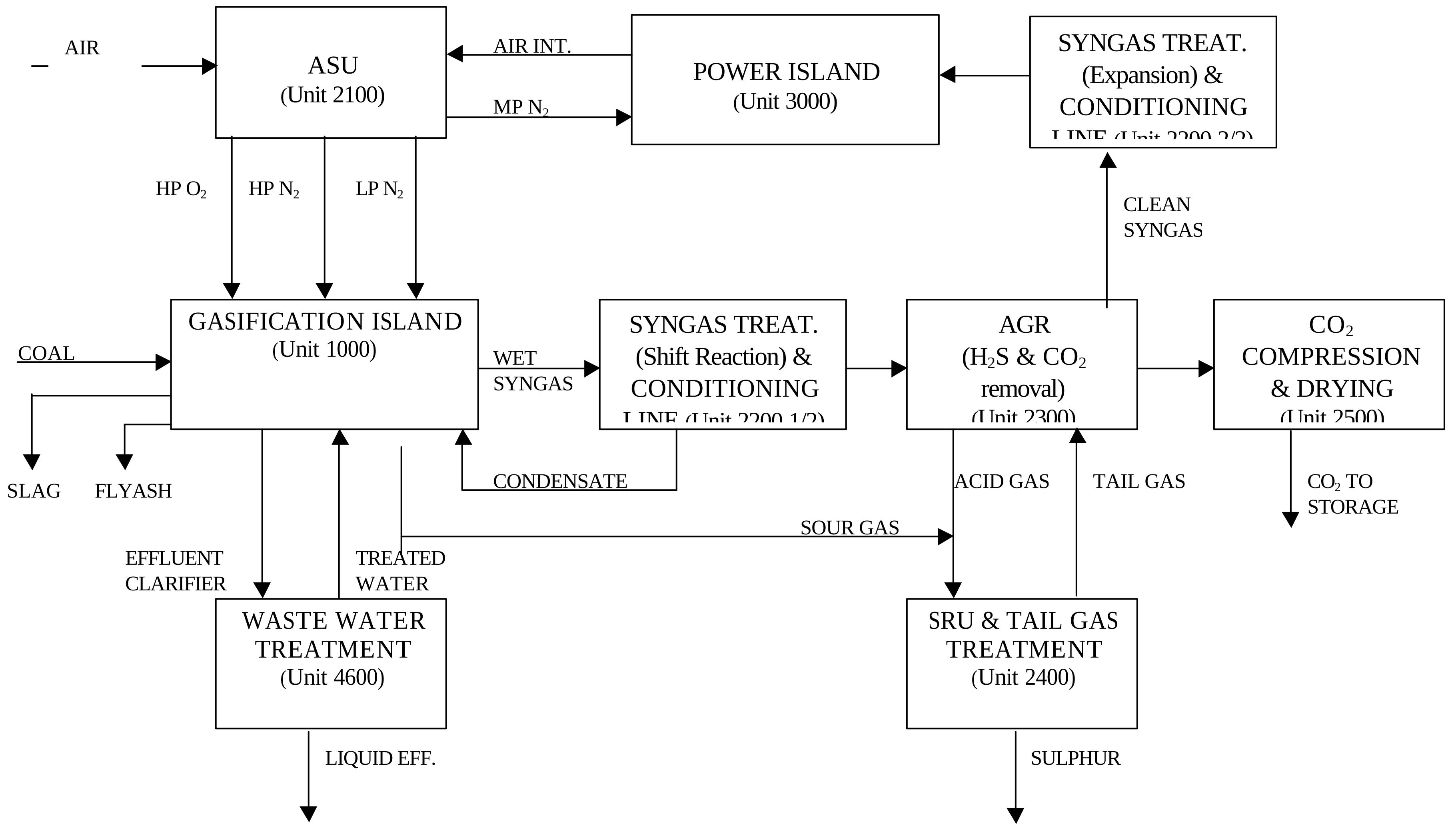
Unit		Trains
1000	Coal milling and drying	4 x 33 %
	Coal pressurisation/feeding	6 x 20 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	1 x 100 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
	Syngas Expansion	1 x 100 %
2300	AGR	1 x 100 %
2400	SRU	2 x 100%

	TGT	1 x 100%
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%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

During the 1st phase of the project, the low pressure was selected as the optimum pressure for the Shell Technology. As a consequence, Vendors were not required to provide data for this high-pressure alternative and all the process calculation have been based on in-house data, taking into account Vendors' data provided for the other alternatives of the project.

TEXACO B.4 – IGCC COMPLEX BLOCK FLOW DIAGRAM



6.2 Process Description

Unit 1000: Gasification Island

Information relevant to Shell Gasification Island are collected in para 1.1 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	80	80	70	180
Pressure (bar)		66.7	94	7.5	59
TOTAL FLOW					
Mass flow (kg/h)	271,900	215,400	244,500	69,000	603,600
Molar flow (kmol/h)			8,700	2,456	30,070
Composition (% vol)					
H_2					24.72
CO					47.07
CO_2					1.32
N_2		3.5	99.88	99.88	7.92
Ar		1.5	0.08	0.08	0.62
O_2		95	0.04	0.04	0.00
H_2S + COS					0.20
H_2O					18.13
Others					0.02

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 6.3 indicates the interconnections of ASU with the other units of the IGCC.

The degree of integration with the gas turbines is 30% and the N_2 used to augment the power of the gas turbine is moisturised by direct contact with hot water in order to increase the syngas diluent mass flow.

For this alternative General Electric was not required to provide data concerning the performance of the Gas turbine. A further investigation on the NOx emissions shall be done in order to understand if a SCR system to be installed in the Heat Recovery Steam Generator is needed.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 6.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 58 barg and 180°C, 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 451°C. Due to the low water content of the syngas, the injection of MP steam to the syngas is required before entering the shift reactor. In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. The hot shifted syngas outlet from the first stage 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

Inlet temperature to the second stage shift is controlled to 250 °C. Outlet temperature from second shift is 331°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:

E-2205 MP Steam Generator
E-2206 LP Steam Generator
E-2207 VLP Steam Generator

The final cooling step of the syngas takes place in E-2208, where syngas is cooled against cold condensate. Process condensate separated in Separator Drums D2201/2 is recycled back to the Sour Water Stripper of the Gasification Island.
The first stage of the shift reactor is split in three parallel trains. Downstream 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-2202 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 and CO_2 removal. Clean syngas is preheated in E-2209 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 preheated with VLP steam in E-2210 before flowing to Unit 3000, gas turbines.

Unit 2300: Acid Gas Removal (AGR)

In the absence of licensor data for this alternative, an open-art UOP-SLEXOL process was considered, based on data provided by UOP with reference to Case D1 (Texaco High Pressure, without nitrogen stripping).

Unit 2300 is characterised by a high syngas pressure (50 barg), and an extremely high CO_2/H_2S ratio (205/1).

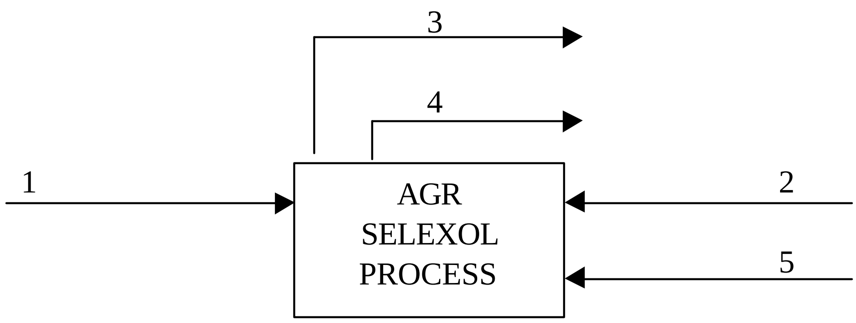
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 6.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit.

Exit Streams

3. Treated Gas to Gas Turbines
4. CO_2 to compression
5. Acid Gas to Sulphur Recovery Unit



The Selexol solvent consumption, to make-up losses, is 130 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 2 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 87%, allowing reaching 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 large power consumption.

The acid gas H_2S concentration is 23% dry basis, 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:

- 271 kmol/h of Hydrogen, corresponding to 2,0% vol and to an overall thermal power of 18,3 MWt, i.e. almost 6 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 80 ppmvd.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each having a normal sulphur production of 56.1 t/day, and normally operating at 50%

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 28 barg.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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 : 27,0 barg
- LP stream : 10,0 barg
- VLP stream : 0,5 barg

The product stream sent to final storage is mainly composed of CO_2 and CO. The main properties of the stream are as follows:

- Product stream: 550 t/h.
- Product stream: 110 bar.
- Composition :

	%wt
CO_2	99,6
$CO+H_2$	0,2
Others	0,2
TOTAL	100,0

Unit 3000: Power Island

The Process Flow Diagrams of the Unit are attached to paragraph 6.3.
For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (126 barg) : steam imported from Gasification Island and Syngas Treatment and Conditioning Line.
- MP steam (59 barg) : steam exported to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction. A small quantity of steam is also generated in the Gasification Island and in the Sulphur Recovery Unit.

- LP steam (6,5 barg) : steam exported to the Acid Gas Removal and Air Separation Unit. A considerable quantity of LP steam is generated in the Syngas Treatment and Conditioning Line.
- 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 Treatment and Conditioning Line and recycled back to the HRSG.

Flow rate of the above interfaces of the Plant are shown in table attached to para 6.4, Steam and Electrical Power Consumption.

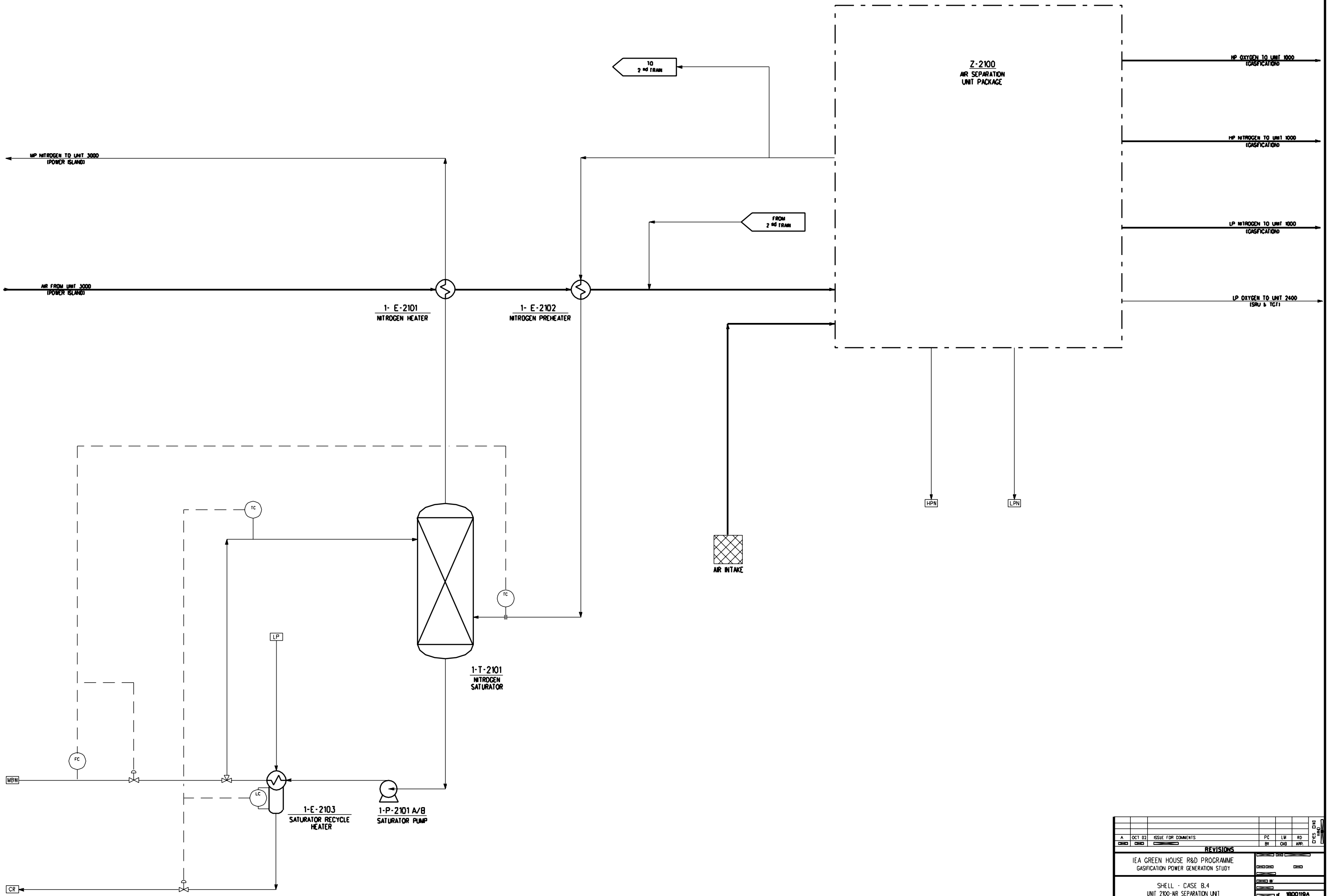
Steam imported to the Power Island are HP and VLP steam; all other streams are exported. As a consequence, the generation levels are the same of the Process Units.

6.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



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GASIFICATION POWER GENERATION STUDY

SHELL - CASE B.4
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1800119A

DWG. Nº 1800119A-3-50-2100

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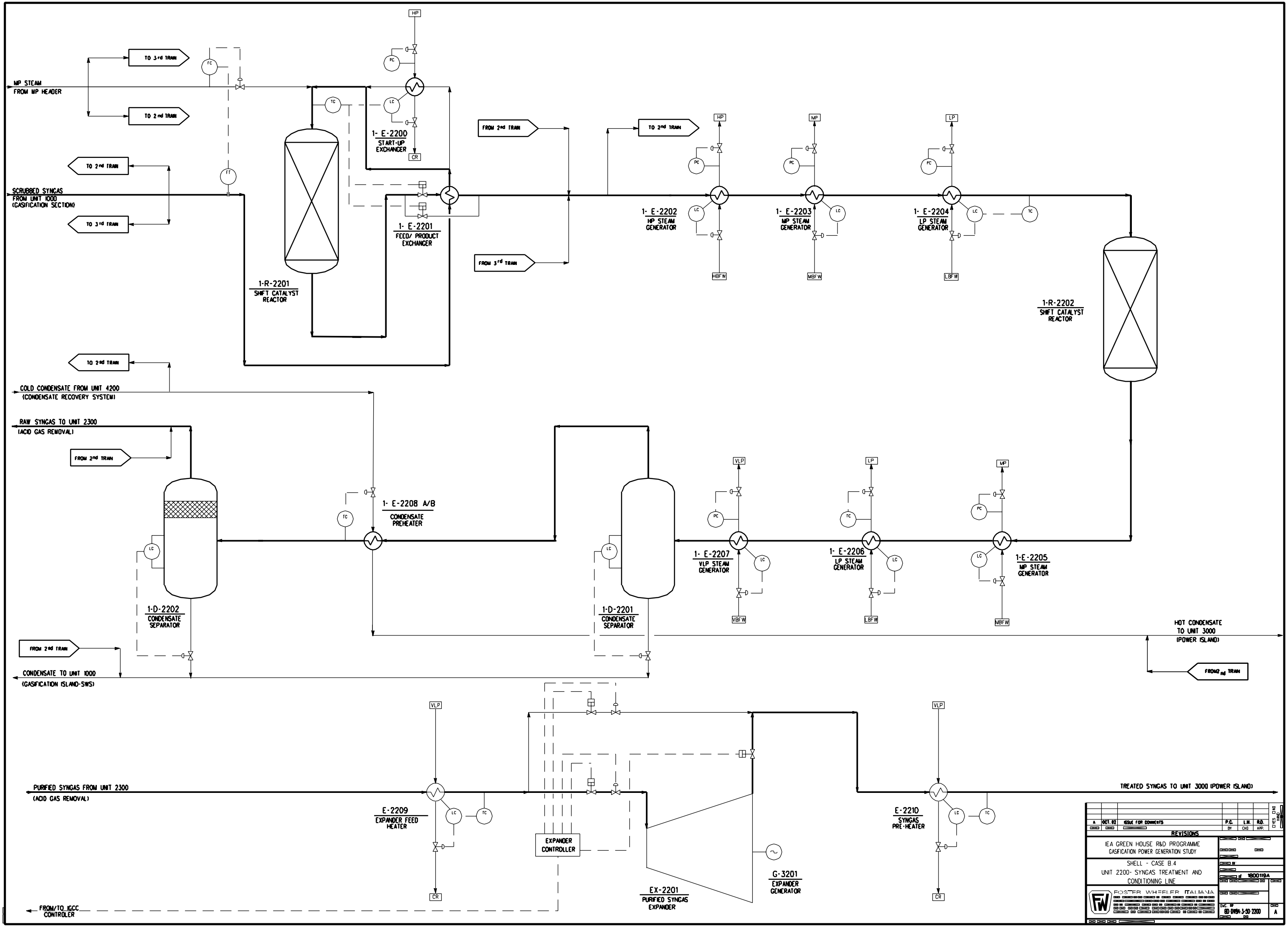

MP STEAM
FROM MP HEADER
TO 3rd TRAIN
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
1- E-2200
START-UP
EXCHANGER
1- E-2201
FEED/ PRODUCT
EXCHANGER
1-R-2201
SHIFT CATALYST
REACTOR
FROM 2nd TRAIN
FROM 3rd TRAIN
1- E-2202
HP STEAM
GENERATOR
1- E-2203
MP STEAM
GENERATOR
1- E-2204
LP STEAM
GENERATOR
1-R-2202
SHIFT CATALYST
REACTOR
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
1- E-2208 A/B
CONDENSATE
PREHEATER
1-D-2202
CONDENSATE
SEPARATOR
1-D-2201
CONDENSATE
SEPARATOR
1- E-2207
VLP STEAM
GENERATOR
1- E-2206
LP STEAM
GENERATOR
1-E-2205
MP STEAM
GENERATOR
HOT CONDENSATE
TO UNIT 3000
(POWER ISLAND)
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND-SWS)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
E-2209
EXPANDER FEED
HEATER
EXPANDER
CONTROLLER
EX-2201
PURIFIED SYNGAS
EXPANDER
G-3201
EXPANDER
GENERATOR
E-2210
SYNGAS
PRE-HEATER
TREATED SYNGAS TO UNIT 3000 (POWER ISLAND)
FROM/TO IGCC
CONTROLER
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SHELL - CASE B.4
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
FOSTER WHEELER ITALIANA
1800119A
DWG. Nº
BD-0W9A-3-50-2200
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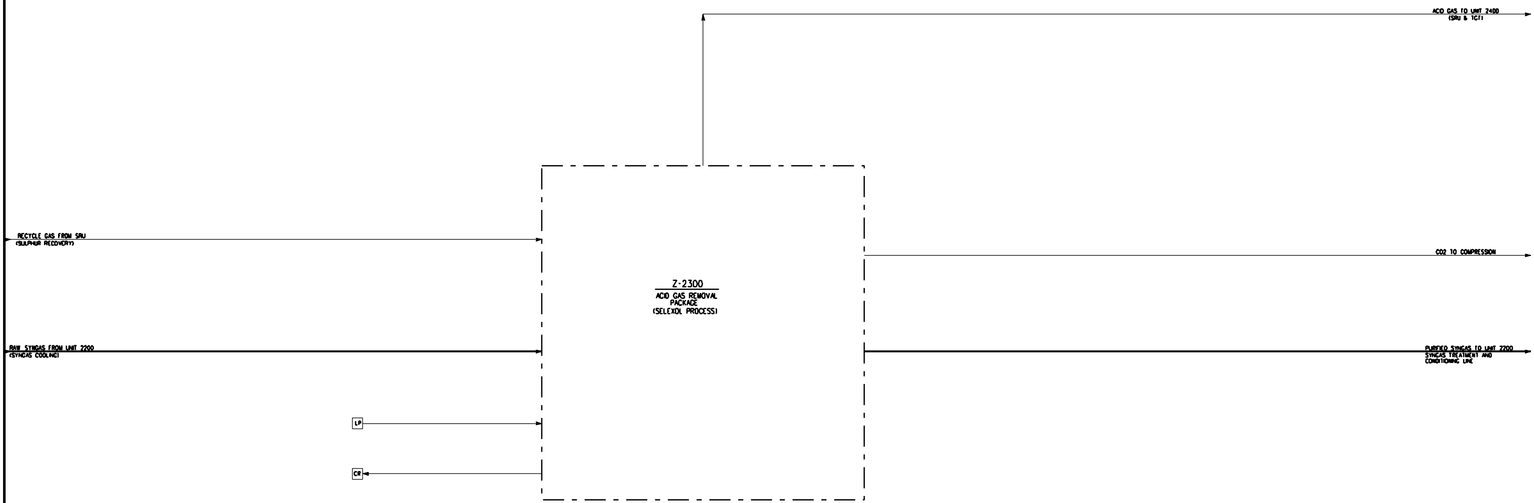

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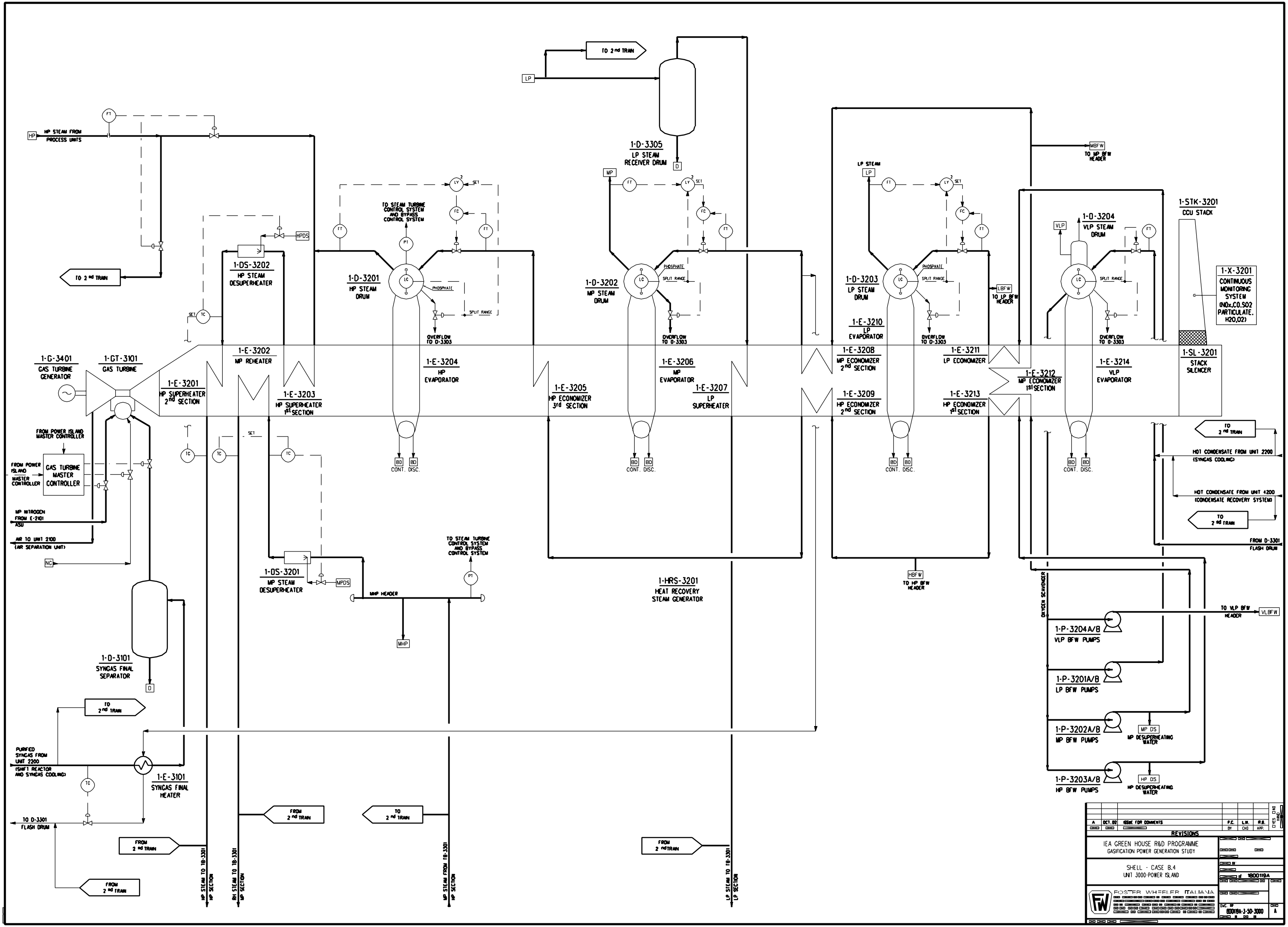
GASIFICATION POWER GENERATION STUDY

SHELL - CASE B.4
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1800119A

DWG. Nº 800119A-3-50-2300 A


HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
TO 2nd TRAIN
LP
1-D-3305
LP STEAM RECEIVER DRUM
MP
LP STEAM
TO MP BFW HEADER
1-STK-3201
CCU STACK
1-D-3204
VLP STEAM DRUM
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
HPDS
1-DS-3202
HP STEAM DESUPERHEATER
1-D-3201
HP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
TO LP BFW HEADER
1-E-3210
LP EVAPORATOR
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
HP EVAPORATOR
1-E-3205
HP ECONOMIZER 3rd SECTION
1-E-3206
MP EVAPORATOR
1-E-3207
LP SUPERHEATER
1-E-3208
MP ECONOMIZER 2nd SECTION
1-E-3209
HP ECONOMIZER 2nd SECTION
1-E-3211
LP ECONOMIZER
1-E-3212
MP ECONOMIZER 1st SECTION
1-E-3213
HP ECONOMIZER 1st SECTION
1-E-3214
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
BD BD CONT. DISC.
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
TO 2nd TRAIN
FROM D-3301 FLASH DRUM
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
MHP HEADER
MHP
HBFW
TO HP BFW HEADER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
1-D-3101
SYNGAS FINAL SEPARATOR
TO 2nd TRAIN
PURIFIED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
FROM 2nd TRAIN
FROM 2nd TRAIN
TO 2nd TRAIN
FROM 2nd TRAIN
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 HP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
A OCT.02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
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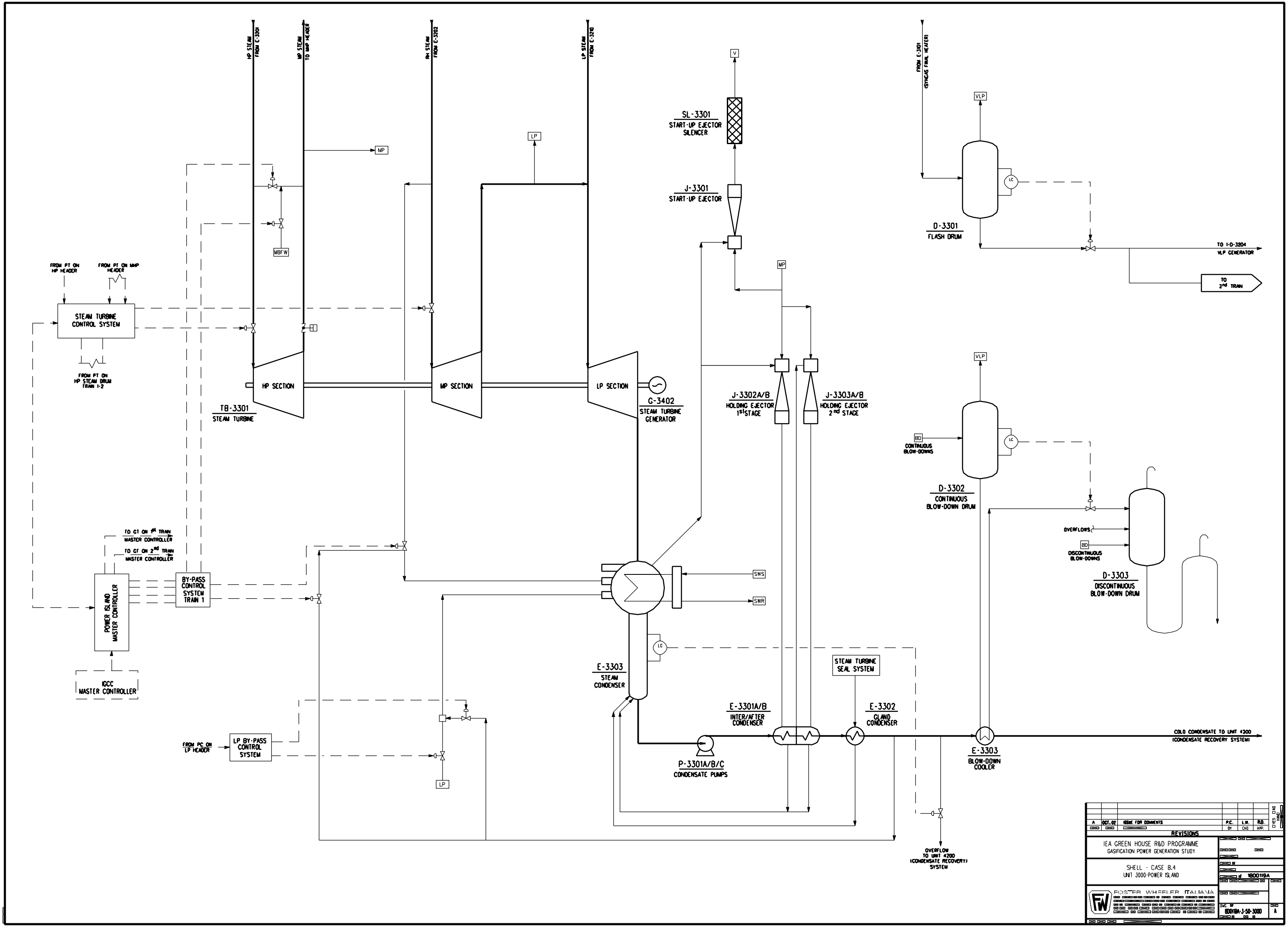
SHELL - CASE B.4
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
BD0119A-3-50-3000 A


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
MP
LP
MBFW
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
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
VLP
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
BD
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
P-3301A/B/C
CONDENSATE PUMPS
E-3301A/B
INTER/AFTER CONDENSER
E-3302
GLAND CONDENSER
E-3303
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
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UNIT 3000-POWER ISLAND
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FOSTER WHEELER ITALIANA
BD0119A-3-50-3000
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6.4 Steam and Electric Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER			REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
	CLIENT:	IEA GHG	DATE	Oct-02			
	PROJECT:	GASIFICATION POWER GENERATION STUDY	ISSUED BY	L.M.			
	LOCATION:	Netherlands	CHECKED BY	P.C.			
	FWI Nº:	1- BD 0119A	APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - SHELL - CASE B.4 - HP with CO_2 capture, separate removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 126 barg [t/h]	MP Steam 59 barg [t/h]	LP Steam 6.5 barg [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**		-339,3	-1,1			385,6	38,0			51,3	31,9
2100	**Air Separation Unit**				150,9			155,0			150,9	155,0
2200	**Syngas Treatment and Conditioning line**		-81,3	339,4	-229,5	-45,9	81,3	94,2	229,5	96,4	50,5	433,6
2300	**Acid Gas Removal**				78,6						78,6	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			-0,7	-1,0			4,3	1,0		3,6	
3000	**POWER ISLANDS UNITS**		420,6	-337,6	-8,4	45,9	-466,9	-291,5	-230,5	-96,4		
4100 to 5300	**UTILITY and OFFSITE UNITS**				9,4						9,4	
	BALANCE		0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	344,3	620,5

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Netherlands FWI Nº: 1- BD 0119A		Rev 0 oct 02 ISSUED BY: PC. CHECKED BY: LM APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - SHELL - CASE B4
HP with CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling**	**303**
1000	**Gasification Section**	**13651**
2100	**Air Separation Unit**	**131277**
2200	**Syngas treatment and conditioning line**	**0**
2300	**Acid Gas Removal**	**33288**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2746**
2500	**CO_2 Compression and Drying**	**(34700)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4670**
3200	**Heat Recovery Steam Generator**	**6890**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**1787**
3500	**Miscellanea**	**468**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**8431**
	Additional consumption including CO_2 Compression and Drying	**(400)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**792**
4600	**Waste Water Treatment**	**483**
	Other Units	**385**
	BALANCE excluding CO_2 compression	**205172**
	BALANCE including CO_2 compression	**240272**

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

6.5 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

SHELL

Case B.4 - High pressure with CO_2 capture, separated H_2S and CO_2 removal - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	271.9
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1953.9**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1622.7
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1467.2
Syngas treatment efficiency (F/E*100)	%	90.4
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	297.4
Expander Power Output	MWe	9.8
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**879.2**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	131.3
Process Units consumption	MWe	49.7
Utility Units consumption	MWe	2.2
Offsite Units consumption (including sea cooling water system)	MWe	8.2
Power Islands consumption	MWe	13.8
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**205.2**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**674.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.5**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	34.7
Offsite Units consumption (sea cooling water system)	MWe	0.4
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**240.3**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**638.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**45.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.7**

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)	14636
Slag (Carbon =~0,4% wt) *	60
Net Carbon flowing to Process Units (A)	14576
Liquid Storage	
CO	21,6
CO_2	12412,8
Total to storage (B)	12434,4
Emission	
CO_2	2135,6
CO	6,0
Total Emission	2141,6
Overall CO_2 removal efficiency, % (B/A)	85,3

* The percentage of unreacted C stated by Shell is 0.2%. However, the carbon mass balance of the whole IGCC results in a 0.4% carbon less. This value is conservatively assumed.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE C.1

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.7

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.7 BASIC INFORMATION FOR EACH ALTERNATIVE

7.0 Case C.1

7.1 Introduction

The main features of the Case C.1 configuration of the IGCC Complex are:

- High pressure (65 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- No Shift and CO_2 removal.

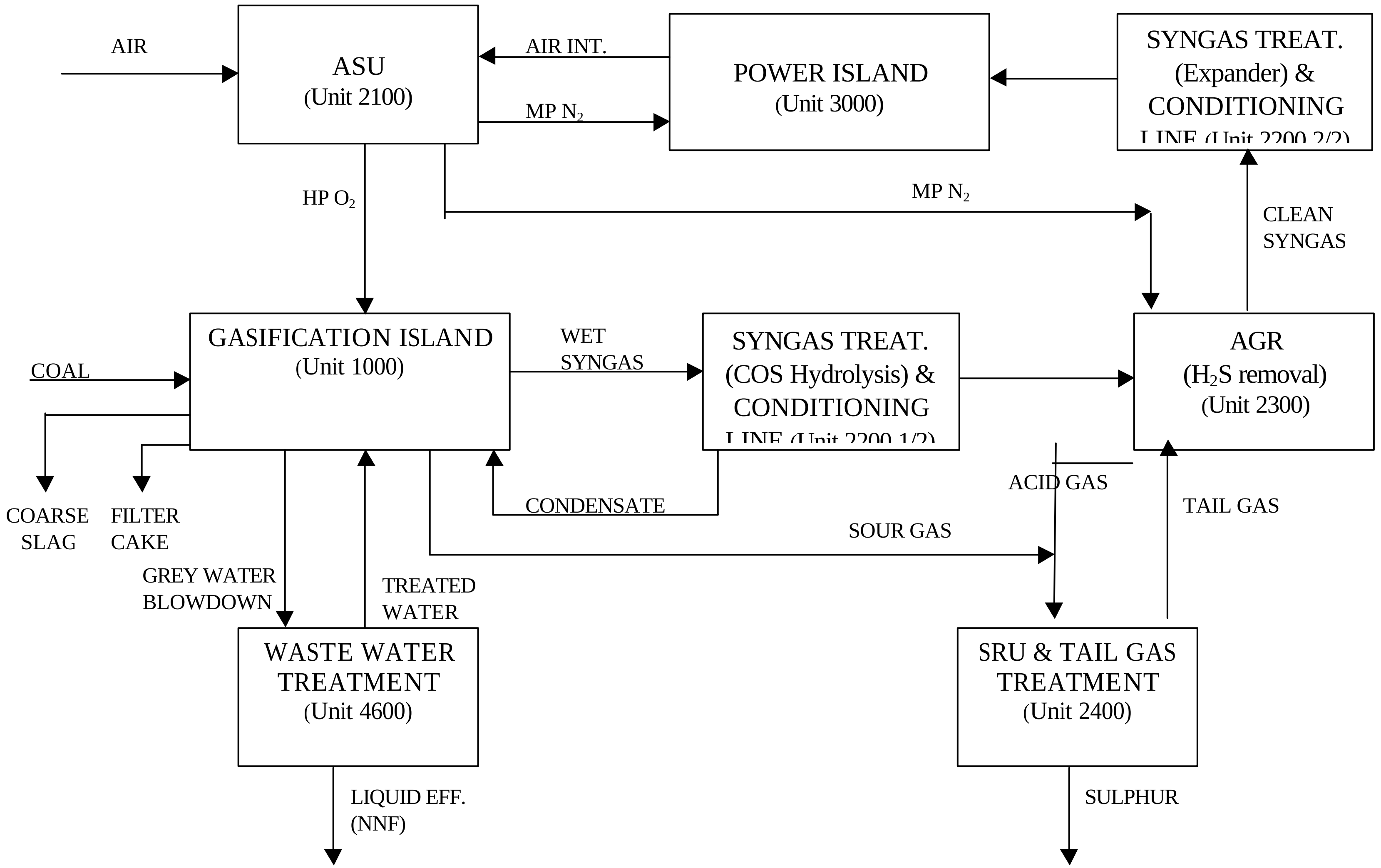
The removal of acid gas (AGR) is based on the Selexol process.
The degree of integration between the Air Separation (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and syngas dilution for NO_x control are achieved with injection of compressed N_2 from ASU to the Gas Turbines.
The Sulphur 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.

The arrangement of the process units is :

Unit		Trains
1000	Gasification	4 x 33 % 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%

Reference is made to the Block Flow Diagram of the IGCC Complex.

TEXACO C.1 – IGCC COMPLEX BLOCK FLOW DIAGRAM



7.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.3 of Section C.
The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	243
Pressure (bar)	AMB.	80	63
TOTAL FLOW			
Mass flow (kg/h)	303,000	258,000	1,301,000
Molar flow (kmol/h)		8,100	67,700
Composition (vol)			
H_2			15.1
CO			15.6
CO_2			7.3
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H2O			61
Others			0.08

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 7.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 7.4.

Unit 2200: Syngas Treatment and Conditioning line

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 7.3.
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.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a high syngas pressure (54 bar g) and a high CO_2/H_2S ratio (60/1). The following two alternatives have been considered:

- **Option 1 – Selexol**: a single train configuration that enhances the H2S concentration by using part of Nitrogen produced by the Air Separation Unit.

- **Option 2 – Ucarsol**: an Acid Gas Removal System (two twin parallel trains) followed by an Acid Gas Enrichment section (one train).

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment Costs and on the Operating Costs of the two options (reference is made to the report "AGR Technical Comparison and Optimisation" attached to Section H for all the details).
Selexol was finally selected because the higher investment cost is largely compensated by the lower Operating Costs with a simple payout time of 1.5 years.

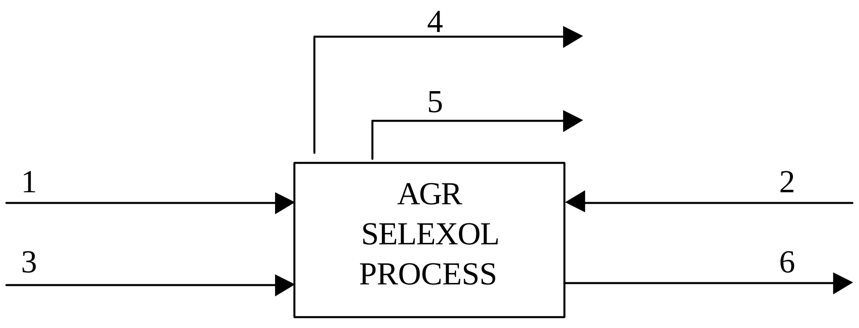
The interfaces of the Selexol process with the other Units are the following, as shown in the Process Flow Diagram attached to para 7.3:

<u>Entering Streams</u>

1. Untreated Gas from Syngas Treatment & Conditioning Unit
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit
3. Nitrogen from ASU

<u>Exit Streams</u>

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.

<u>Unit 2400: SRU and TGT</u>

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

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 hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal for the capture of H_2S by means of a compressor at a pressure of 27 barg.

Unit 3000: Power Island

The Process Flow Diagrams and the equipment list of this Unit are attached to paragraphs 7.3 and 7.8.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 7.5, Utilities Consumption.

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:

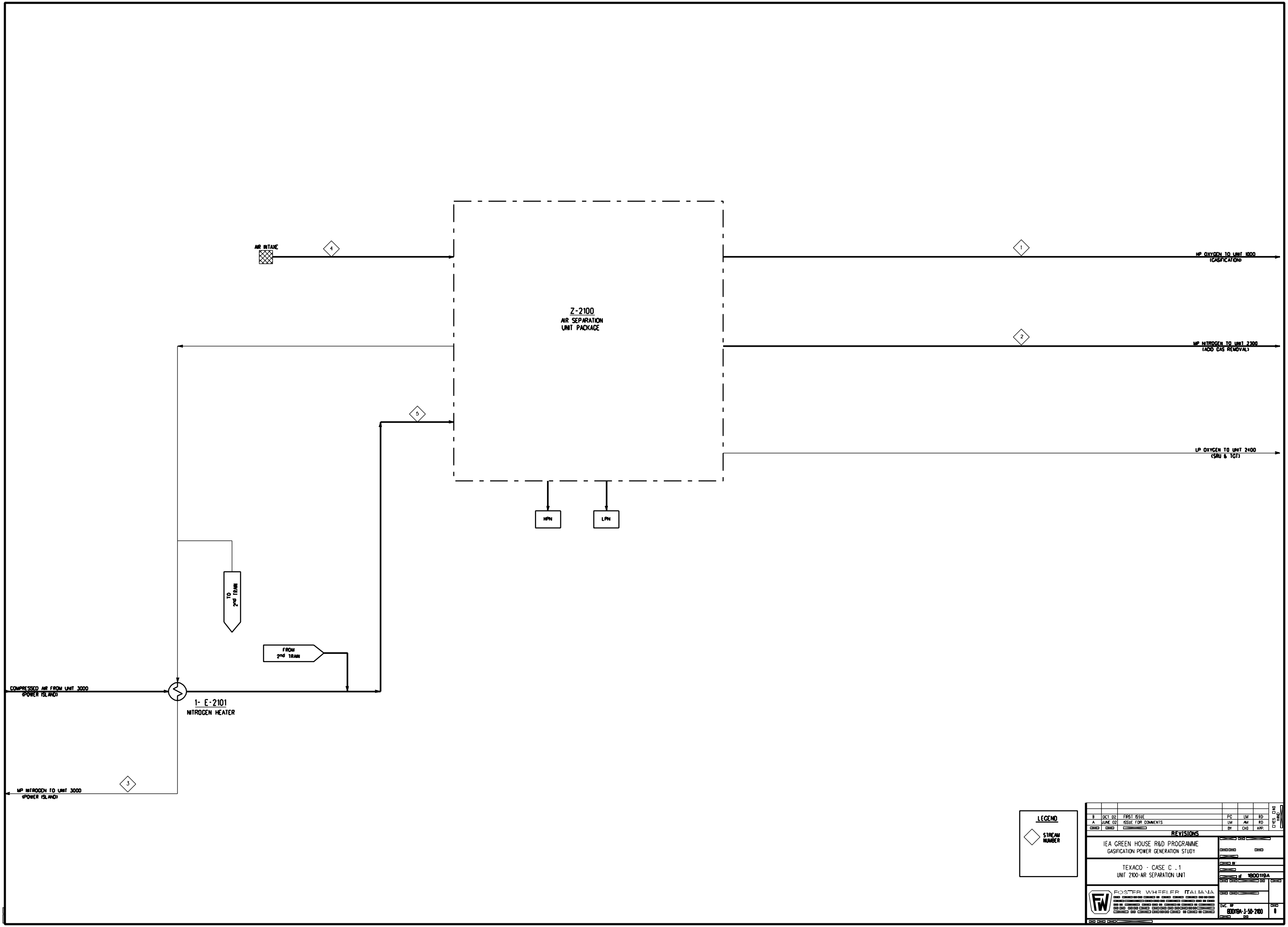
- HP steam : 160 barg
- MP steam : 40 barg
- LP steam : 6,5 barg

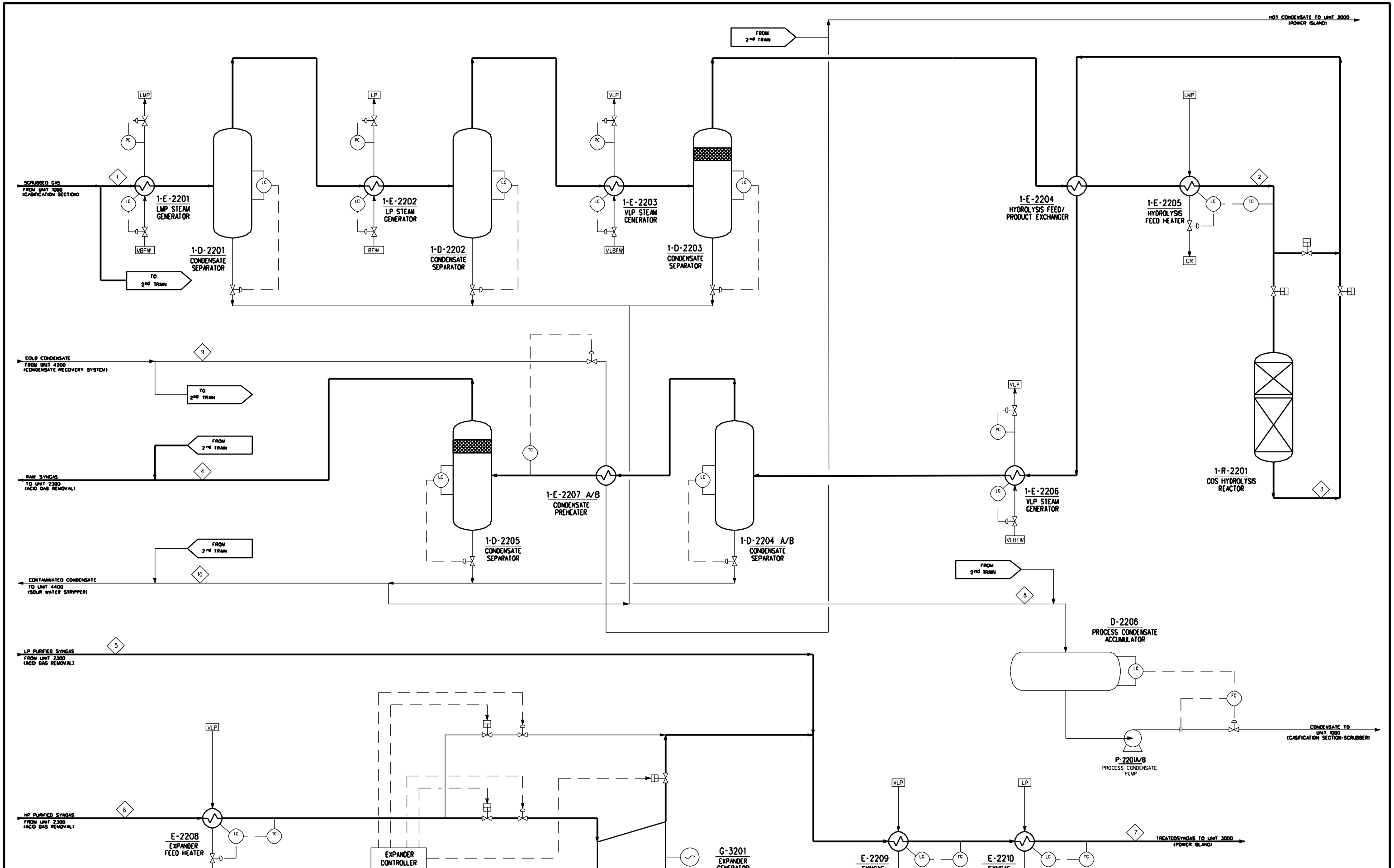
7.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0 and 9.0.


AIR INTAKE
4
Z-2100
AIR SEPARATION
UNIT PACKAGE
1
HP OXYGEN TO UNIT 1000
(GASIFICATION)
2
MP NITROGEN TO UNIT 2300
(ACID GAS REMOVAL)
LP OXYGEN TO UNIT 2400
(SRU & TGT)
5
HPN
LPN
TO
2nd TRAIN
FROM
2nd TRAIN
COMPRESSED AIR FROM UNIT 3000
(POWER ISLAND)
1- E-2101
NITROGEN HEATER
3
MP NITROGEN TO UNIT 3000
(POWER ISLAND)
LEGEND
STREAM
NUMBER
B DCT 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
YES NO
HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C .1
UNIT 2100-AIR SEPARATION UNIT
1800119A
FOSTER WHEELER ITALIANA
DWG. Nº
1800119A-3-50-2100
B



B	OCT 02	FIRST ISSUE	PC	LM	RD
A	JUNE 02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

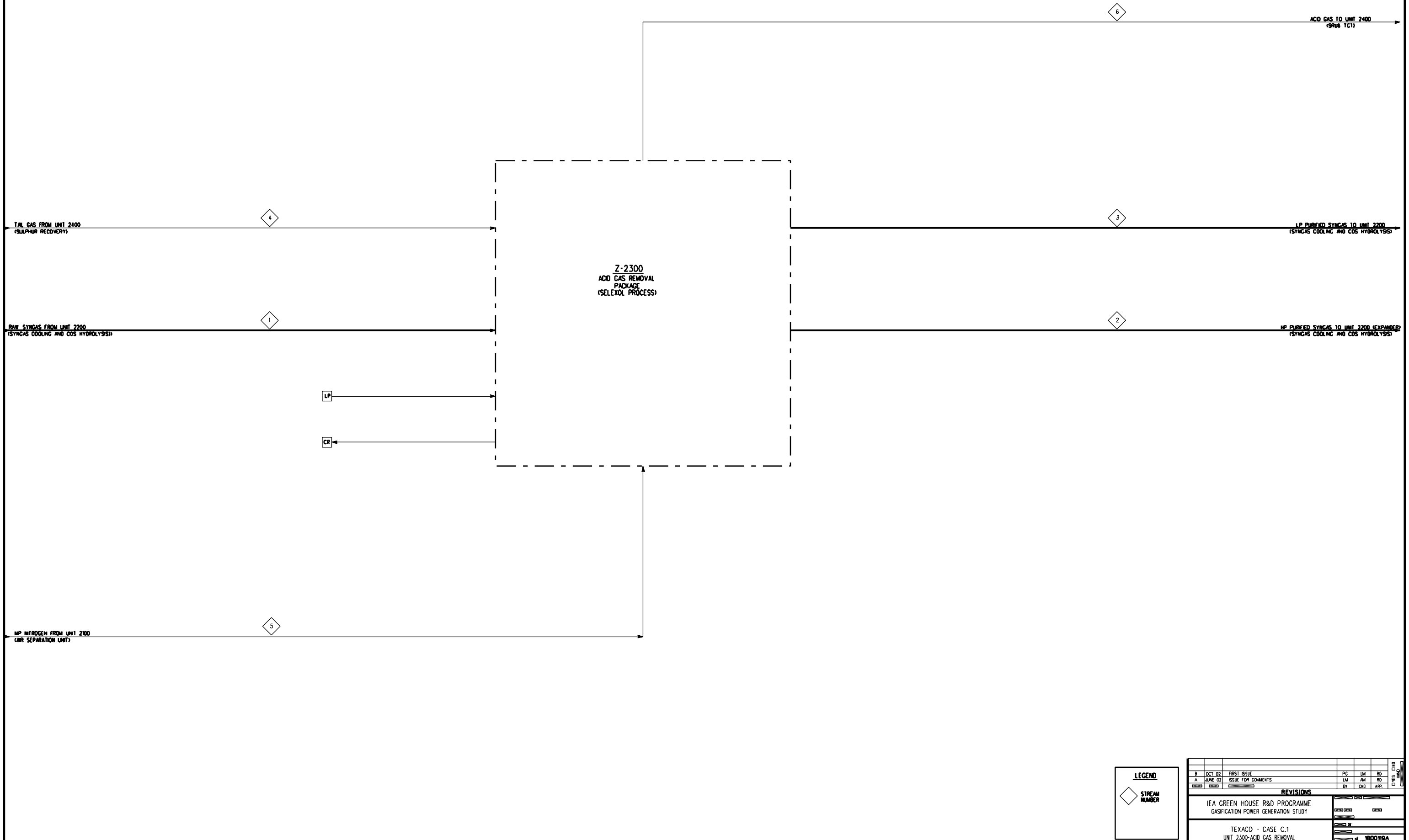
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE C.1
UNIT 2200-SYNGAS TREATMENT AND CONDITIONING LINE

1800119A

FOSTER WHEELER ITALIANA

DWG. Nº 1800119A-3-50-2200 B



B	OCT 02	FIRST ISSUE	PC	LM	RD
A	JUNE 02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

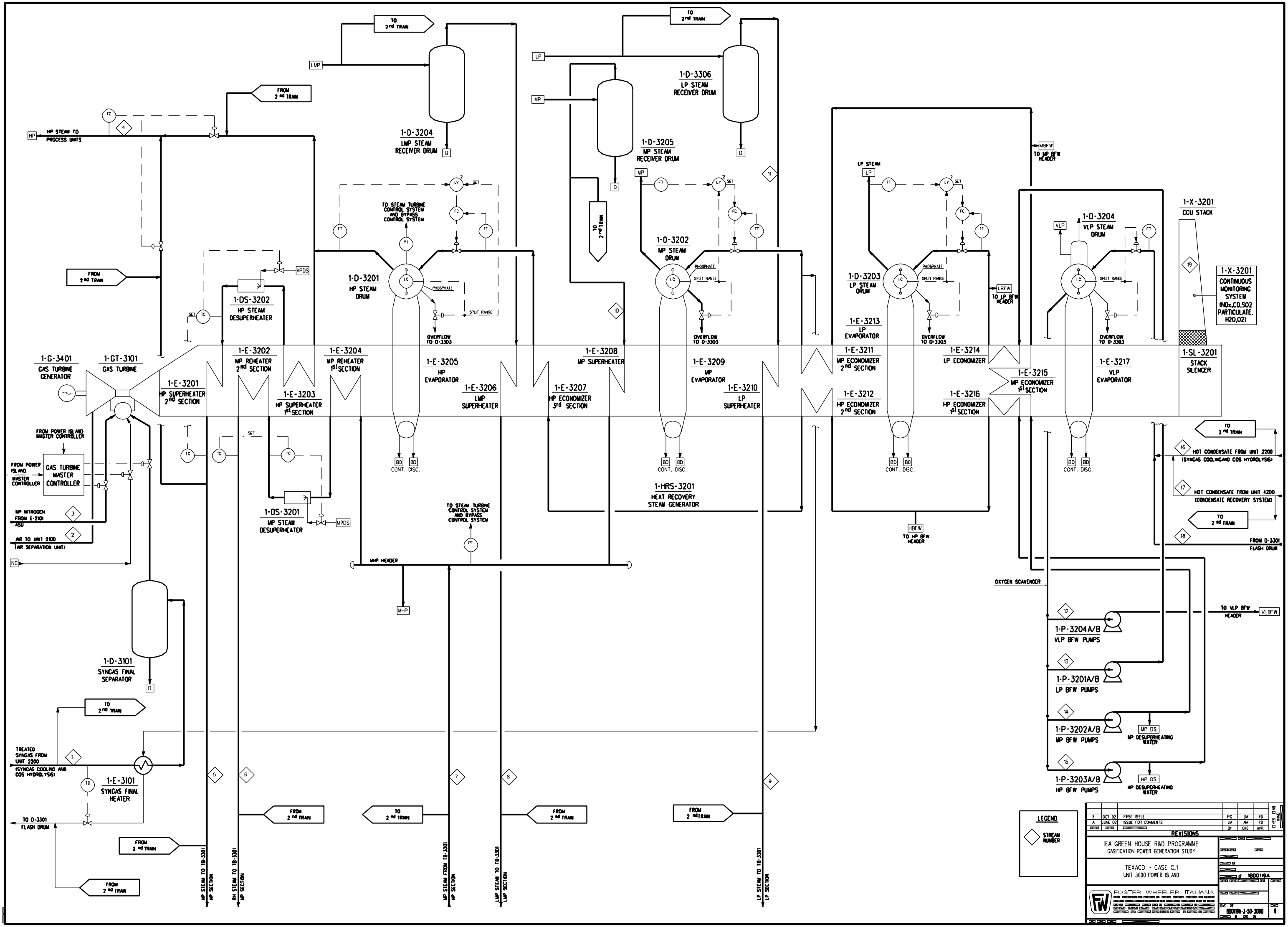
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE C.1
UNIT 2300-ACID GAS REMOVAL

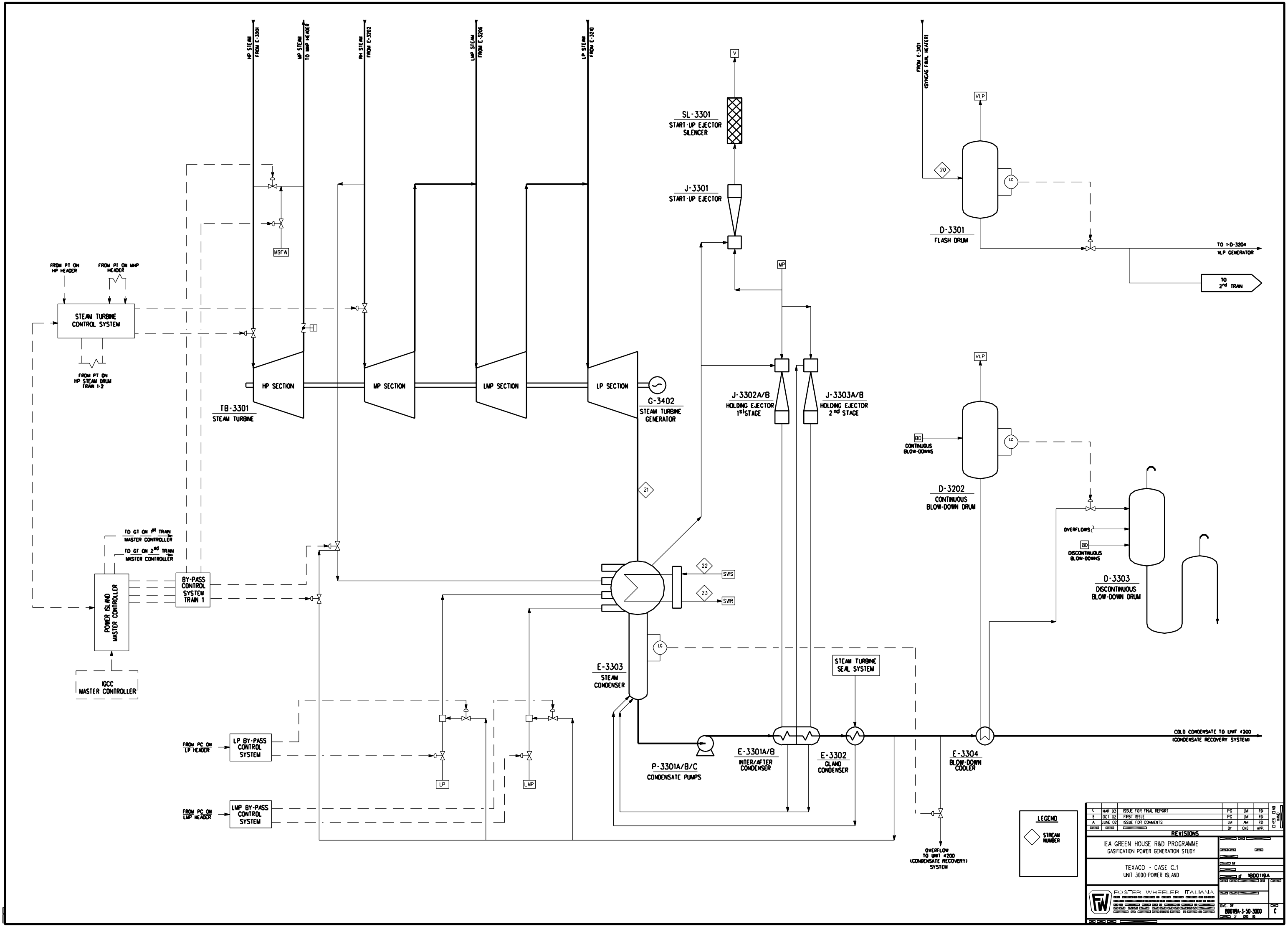
FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2300 B



1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
1-D-3101
SYNGAS FINAL SEPARATOR
TREATED SYNGAS FROM UNIT 2200 (SYNGAS COOLING AND COS HYDROLYSIS)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
TO 2nd TRAIN
FROM 2nd TRAIN
HP STEAM TO PROCESS UNITS
HP
LMP
MP
LP
HPDS
MPDS
1-DS-3202
HP STEAM DESUPERHEATER
1-DS-3201
MP STEAM DESUPERHEATER
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-D-3201
HP STEAM DRUM
1-D-3204
LMP STEAM RECEIVER DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-E-3205
HP EVAPORATOR
1-E-3206
LMP SUPERHEATER
1-E-3207
HP ECONOMIZER 3rd SECTION
1-E-3208
MP SUPERHEATER
1-D-3205
MP STEAM RECEIVER DRUM
1-D-3306
LP STEAM RECEIVER DRUM
1-D-3202
MP STEAM DRUM
1-E-3209
MP EVAPORATOR
1-E-3210
LP SUPERHEATER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
BD BD
CONT. DISC.
MHP HEADER
MHP
LP STEAM
1-D-3203
LP STEAM DRUM
1-E-3213
LP EVAPORATOR
1-E-3211
MP ECONOMIZER 2nd SECTION
1-E-3212
HP ECONOMIZER 2nd SECTION
1-E-3214
LP ECONOMIZER
1-E-3215
MP ECONOMIZER 1st SECTION
1-E-3216
HP ECONOMIZER 1st SECTION
1-D-3204
VLP STEAM DRUM
VLP
1-E-3217
VLP EVAPORATOR
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
HBFW
TO HP BFW HEADER
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-SL-3201
STACK SILENCER
HOT CONDENSATE FROM UNIT 2200 (SYNGAS COOLING AND COS HYDROLYSIS)
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LMP STEAM TO TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
LEGEND
STREAM NUMBER
B | OCT 02 | FIRST ISSUE | PC | LM | RD
A | JUNE 02 | ISSUE FOR COMMENTS | LM | AM | RD
BY | CHD | APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.1
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1BD0119A
DWG. Nº
BD0119A-3-50-3000


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LMP STEAM FROM E-3206
LP STEAM FROM E-3210
MBFW
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
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
20
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
22
23
SWS
SWR
LC
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
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
FROM PC ON LMP HEADER
LMP BY-PASS CONTROL SYSTEM
LP
LMP
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
C MAR 03 ISSUE FOR FINAL REPORT PC LM RD
B OCT 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
YES NO HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.1
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
FW
DWG.
BD0119A-3-50-3000
C
2

7.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 2400: Sulphur Recovery Unit & Tail Gas Treatment;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : TEXACO CASE C.1	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	Oct 02	Mar 03	

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					

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	of 1
	CASE : TEXACO CASE C.1						APPROVED	R.D.	R.D.	
	UNIT : 2200 SYNGAS Treatment and conditioning line						DATE	Oct 02	Mar 03	

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%

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	of 1
	CASE : TEXACO CASE C.1						APPROVED	R.D.	R.D.	
	UNIT : 2300 Acid Gas Removal						DATE	Oct 02	Mar 03	
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				

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	
	CASE : TEXACO CASE C.1						APPROVED	R.D.	R.D.	
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	Oct 02	Mar 03	
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 : TEXACO CASE C.1
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

7.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER	**CLIENT:** IEA GHG **PROJECT:** GASIFICATION POWER GENERATION STUDY **LOCATION:** Netherlands **FWI Nº:** 1- BD 0119A	REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
		DATE	Oct 02			
		ISSUED BY	P.C.			
		CHECKED BY	L.M.			
		APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE C1 - HP 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		352,3	267,6	56,6	76,1	
2300	**Acid Gas Removal**				48,9						48,9	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			-1,3	-1,1			4,1	1,1		2,8	
3000	**POWER ISLANDS UNITS**		-5,0	340,6	171,1	10,5	0,0	-356,4	-268,7	-56,6		
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	0,0

Note: Minus prior to figure means figure is generated

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	Oct 02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RM

WATER CONSUMPTION SUMMARY - TEXACO - CASE C1 - HP w/o 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				
1000	**Gasification Section**	101		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		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**	30	-30		
	Other Units		20	364	
	BALANCE	131	0	6658	121439

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	Oct 02
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE C1 - HP w/o CO_2 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**

7.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

TEXACO

Case C.1 - HIGH PRESSURE w/o CO_2 capture - Rev.2

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**

7.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristics are shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

7.7.1 Gaseous Emissions

<u>Main Emissions</u>
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.

Table 7.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 7.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	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, O2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 7.2

Table 7.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	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, O2 content 15%vol

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

7.7.2 Liquid Effluent

The effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island.

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	:	120.000	m^3/h
• Temperature	:	19	°C
• Cl_2	:	<0.05	ppm

7.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

<u>Fine Slag</u>

Flow rate	:	29,8	t/h
Water content	:	70	%wt

<u>Coarse Slag</u>

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.

7.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
1	**E-2101**	**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 %
				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		14			Nitrogen purity = 99,9 %
				Air flow rate from GTs = 603 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**LMP Steam Generator**	Kettle			24 / 68	250 / 273		DUTY = 106350 kW H2 service H2/Wet H2S serv. on channel
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
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
2	**E-2203**	**VLP Steam Generator**	Kettle			7 / 68	185 / 204		DUTY = 14305 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
2	**E-2205**	**Hydrolysis Feed Heater**	Shell & Tube			24 +FV / 68	250 / 230		DUTY = 3535 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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube		
1	**E-2207 A/B**	**Condensate Preheater**	Shell & Tube			26 / 68	100 / 185		DUTY = 33602 kW H2 service H2/Wet H2S serv. on channel
2	**E-2207 A/B**	**Condensate Preheater**	Shell & Tube			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
	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
		DRUMS		D,mm x TT,mm					
1	**D-2201**	**Condensate Separator**	Vertical			68	250		Wet H2S service/H2 service
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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS (continued)		D,mm x TT,mm					
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
	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
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					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and conditioning line - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		GENERATORS		**P, MWe**					
	G-3201	Expander Generator							
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	COS Hydrolysis Catalyst							Catalyst volume: 160 m^3

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		REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
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		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=61.9 t/d					Sulphur content = 99,9 wt min (dry basis)
				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%

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
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EQUIPMENT LIST

Unit 3100 - Gas Turbine - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			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
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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		Q,m^3/h x H,m					
1	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	**D-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
		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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMM LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct 02			
		ISSUED BY	L.M.			
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**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

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME
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PROJ. NAME: Gasification Power Generation Study
CONTRACT N. 1- BD- 0119 A

REVISION	Rev.0	Rev.1	Rev.2	Rev.3
DATE	Oct 02			
ISSUED BY	L.M.			
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	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		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	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

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		DATE	Oct 02			
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EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Texaco Case C.1 - High Pressure w/o CO_2 capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	**G-3401**	**Gas Turbine Generator**							Included in 1 -Z- 3101
2	**G-3401**	**Gas Turbine Generator**							Included in 2 -Z- 3101
	G-3402	**Steam Turbine Generator**							Included in Z- 3301

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PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE C.2

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APPROVED BY : R. DOMENICHINI

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SECTION D.8

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.8 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.8 BASIC INFORMATION FOR EACH ALTERNATIVE

8.0 Case C.2

8.1 Introduction

The main features of the Case C.2 configuration of the IGCC Complex are:

- High pressure (65 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- Single stage dirty shift;
- No CO_2 removal.

The separate removal of acid gas (AGR Unit) is based on the Selexol process.
The degree of integration between the Air Separation (ASU) and the Gas Turbines is 43.2%. Gas Turbine power augmentation and reduction of NO_x emission 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.

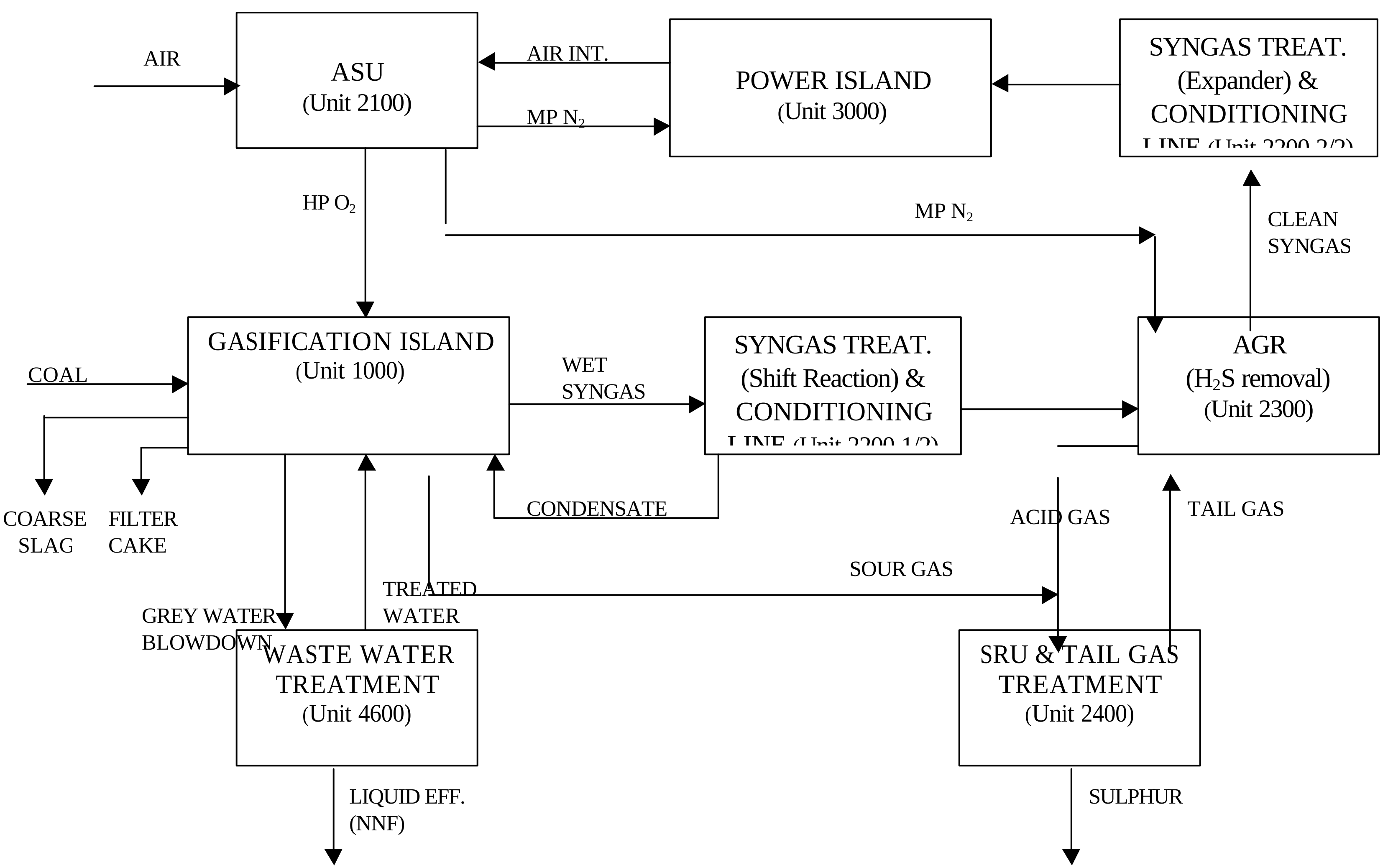
The arrangement of the process units is :

Unit		**Trains**
1000	Gasification	4 x 33 % 2 x 66 %
2100	ASU	2 x 50 %
2200	Syngas Treatmen 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 Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO C.2 – IGCC COMPLEX BLOCK FLOW DIAGRAM



8.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	243
Pressure (bar)	AMB.	80	63
TOTAL FLOW			
Mass flow (kg/h)	327,600	278,960	1,407,900
Molar flow (kmol/h)		8,660	73,250
Composition (%vol)			
H_2			15,1
CO			15,6
CO_2			7,3
N_2 + Ar		5	0,8
O_2		95	-
H_2S + COS			0,12
H_2O			61
Others			0,08

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 8.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 8.4.

Unit 2200: Syngas Treatment and Conditioning Line , shift and expansion

To follow the process description of this Unit reference should be made to the process flow diagram attached to paragraph 8.3.
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 conversion.
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 A/B, preheating cold condensate. Part of 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 limititation 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 removal.
Clean syngas is preheated in E-2207 with VLP steam and then reduced in pressure, down to 30 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-2208 and E-2209, flows to Unit 3000, Gas Turbines.

Unit 2300: Acid Gas Removal (AGR)

In the absence of licensor data for this alternative, an open-art UOP-SELEXOL process was considered, based on data provided by UOP with reference to Case C1 (Texaco High Pressure, no shift reaction).

Unit 2300 is characterised by a high syngas pressure (56 bar g) and an extremely high CO_2/H_2S ratio (183/1). The H_2S concentration of the stream fed to the Sulphur Recovery Unit is enhanced by using part of Nitrogen produced by the Air Separation Unit.

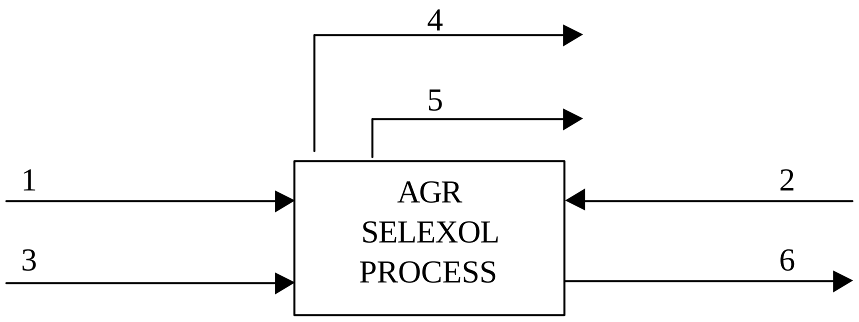
The interfaces of the process are the following, as shown in the Block Flow Diagram attached to para 8.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
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 92 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 20 ppmvd, the second one of 34 ppmvd. After the expander the two streams are mixed before entering the gas turbine and the H_2S+COS concentration of the resulting stream is 22 ppmvd.

Lean solvent is cooled down by a refrigerant package before flowing to the CO_2 absorber. CO_2 slippage with respect to expansion through the gas turbine is almost 100%. A higher CO_2 quantity flows through the expander.

The acid gas H_2S concentration is 15% dry basis, 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.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 67 t/day and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 27 barg.

Unit 3000: Power Island

The Process Flow Diagrams and the equipment list of this Unit are attached to paragraphs 8.3 and 8.8.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 8.5, Utilities Consumption.

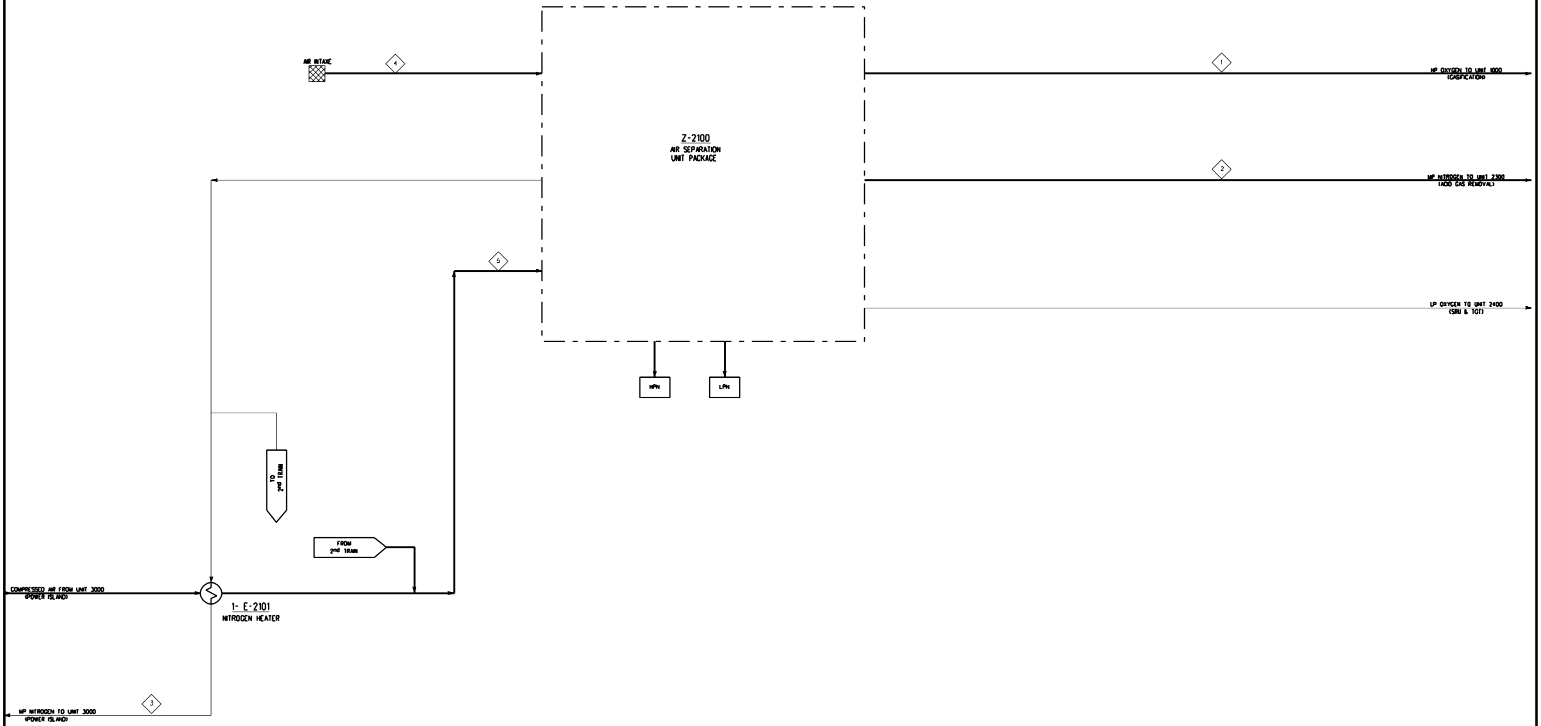
The net balance on each steam header inside the Power Island is positive, thus meaning that for all generation levels steam is imported from Process Units to the Power Island. Only steam at 85 bar g is exported to the Gasification Island. As a consequence, the generation levels of the Power Island are the same of the Process Units.

8.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0 and 9.0.



LEGEND

◇ STREAM NUMBER

A	OCT 02	FIRST ISSUE	LM	PC	RD
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

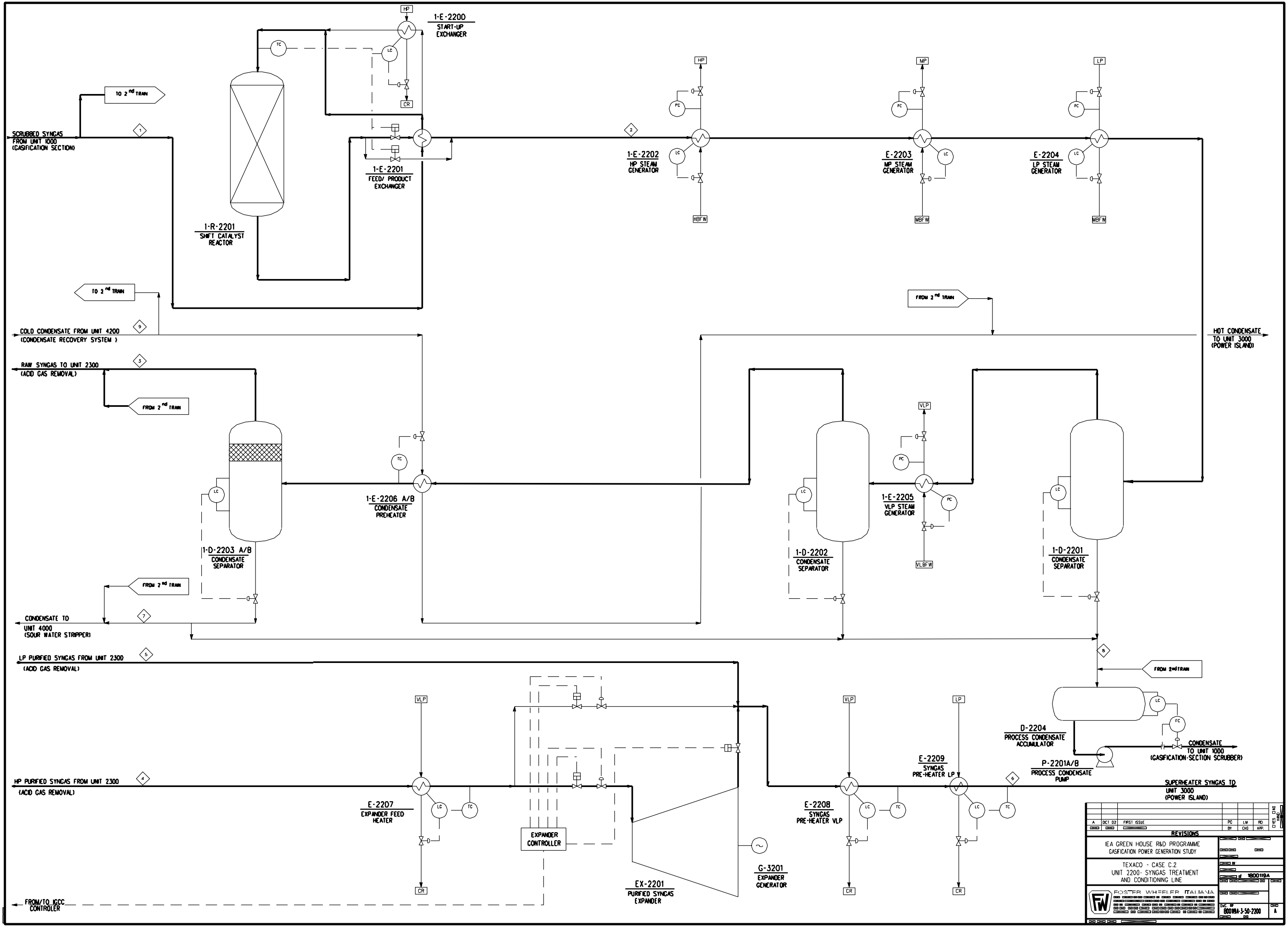
TEXACO - CASE C.2
UNIT 2100-AIR SEPARATION UNIT

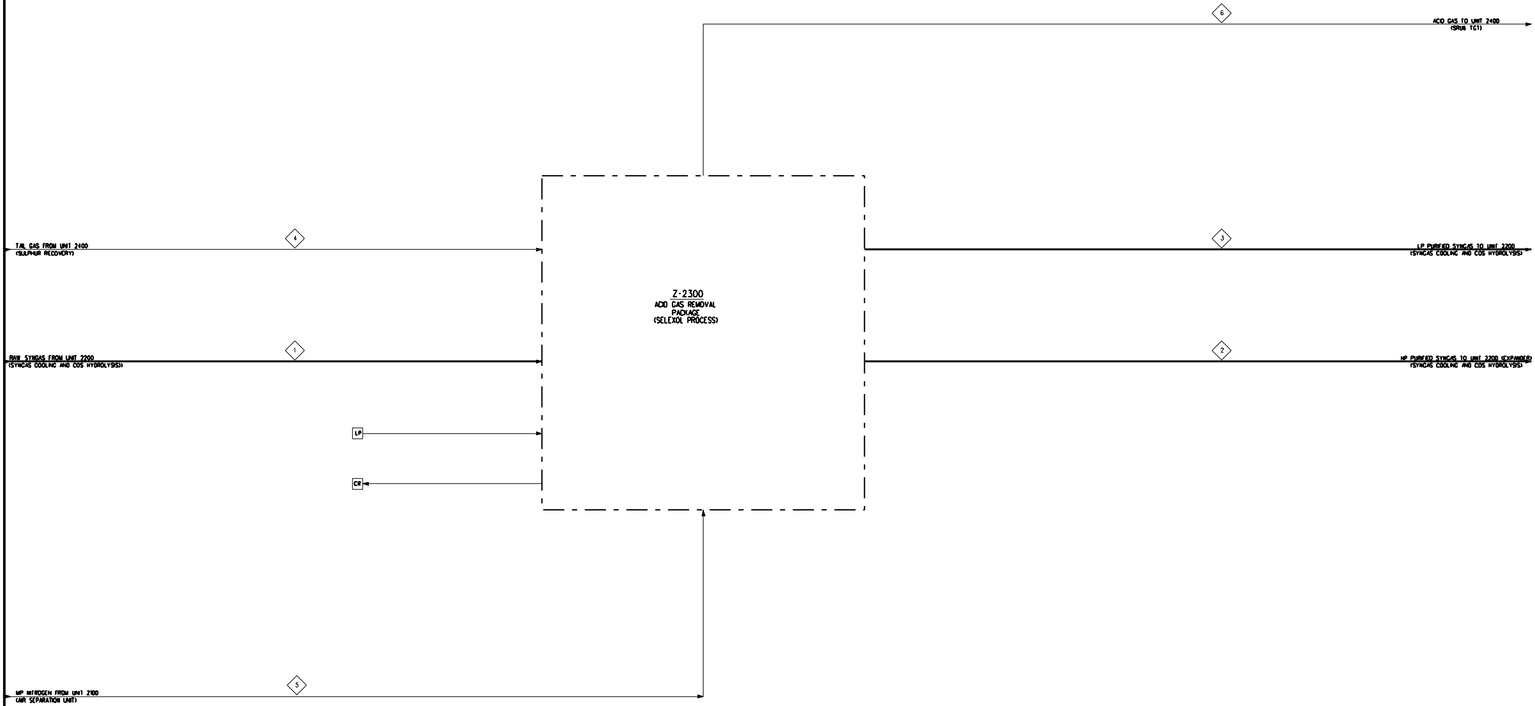
FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2100

A


1-E-2200
START-UP EXCHANGER
TO 2nd TRAIN
SCRUBBED SYNGAS FROM UNIT 1000 (GASIFICATION SECTION)
1-R-2201
SHIFT CATALYST REACTOR
1-E-2201
FEED/ PRODUCT EXCHANGER
1-E-2202
HP STEAM GENERATOR
E-2203
MP STEAM GENERATOR
E-2204
LP STEAM GENERATOR
HP
MP
LP
CR
HBFW
MBFW
LBFW
TC
LC
PC
FC
FROM 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
HOT CONDENSATE TO UNIT 3000 (POWER ISLAND)
RAW SYNGAS TO UNIT 2300 (ACID GAS REMOVAL)
1-E-2206 A/B
CONDENSATE PREHEATER
1-D-2203 A/B
CONDENSATE SEPARATOR
1-D-2202
CONDENSATE SEPARATOR
1-E-2205
VLP STEAM GENERATOR
VLP
VLBFW
1-D-2201
CONDENSATE SEPARATOR
CONDENSATE TO UNIT 4000 (SOUR WATER STRIPPER)
LP PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
D-2204
PROCESS CONDENSATE ACCUMULATOR
CONDENSATE TO UNIT 1000 (GASIFICATION SECTION SCRUBBER)
P-2201A/B
PROCESS CONDENSATE PUMP
HP PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
E-2207
EXPANDER FEED HEATER
EXPANDER CONTROLLER
EX-2201
PURIFIED SYNGAS EXPANDER
G-3201
EXPANDER GENERATOR
E-2208
SYNGAS PRE-HEATER VLP
E-2209
SYNGAS PRE-HEATER LP
SUPERHEATER SYNGAS TO UNIT 3000 (POWER ISLAND)
FROM/TO IGCC CONTROLER
A OCT 02 FIRST ISSUE PC LM RD
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.2
UNIT 2200- SYNGAS TREATMENT AND CONDITIONING LINE
FOSTER WHEELER ITALIANA
1BD0119A
BD0119A-3-50-2200
A



LEGEND

◇ STREAM NUMBER

A	OCT 02	FIRST ISSUE	PC	LM	RD
			BY	CHD	APP.

REVISIONS

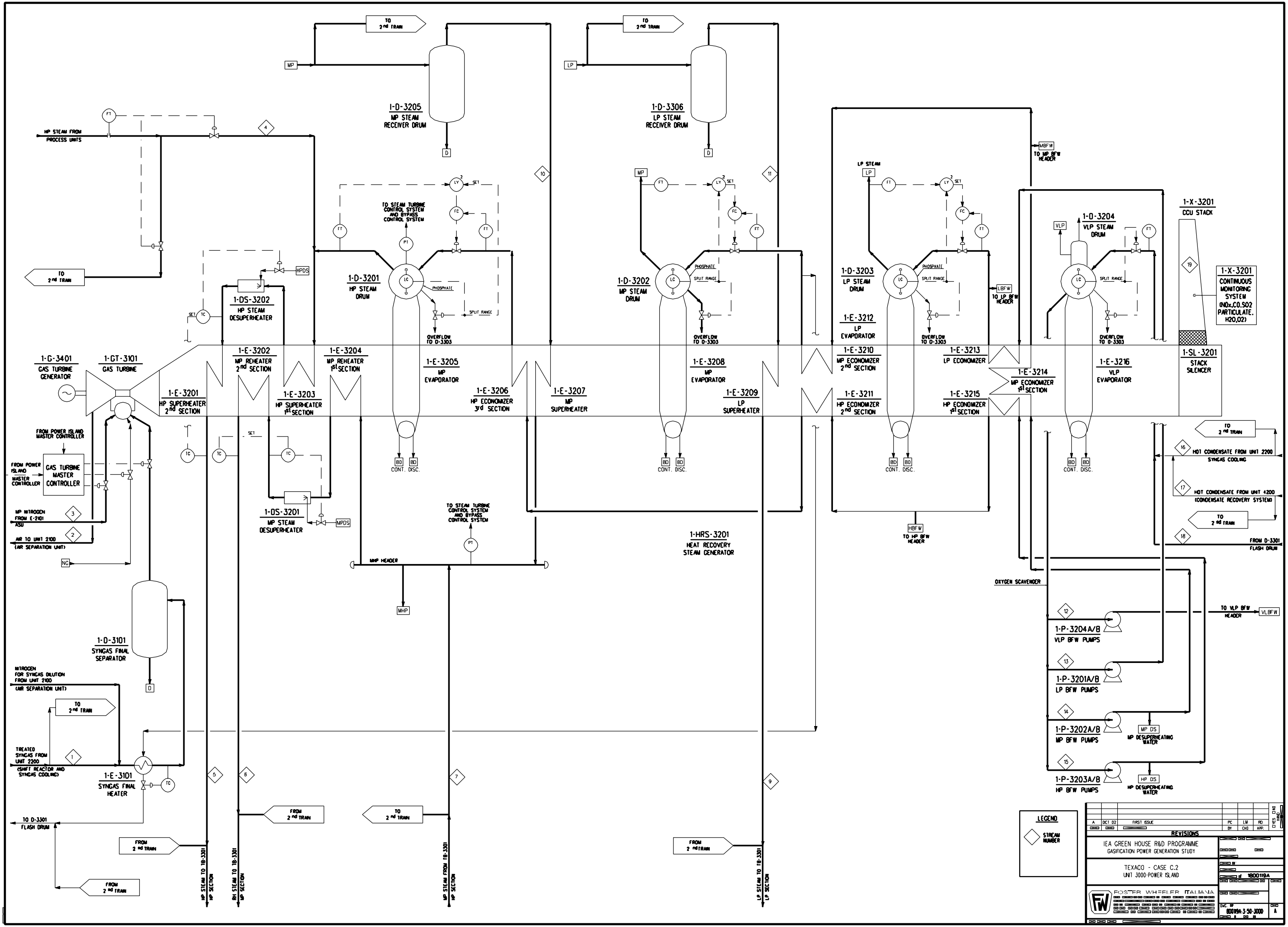
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE C.2
UNIT 2300-ACID GAS REMOVAL

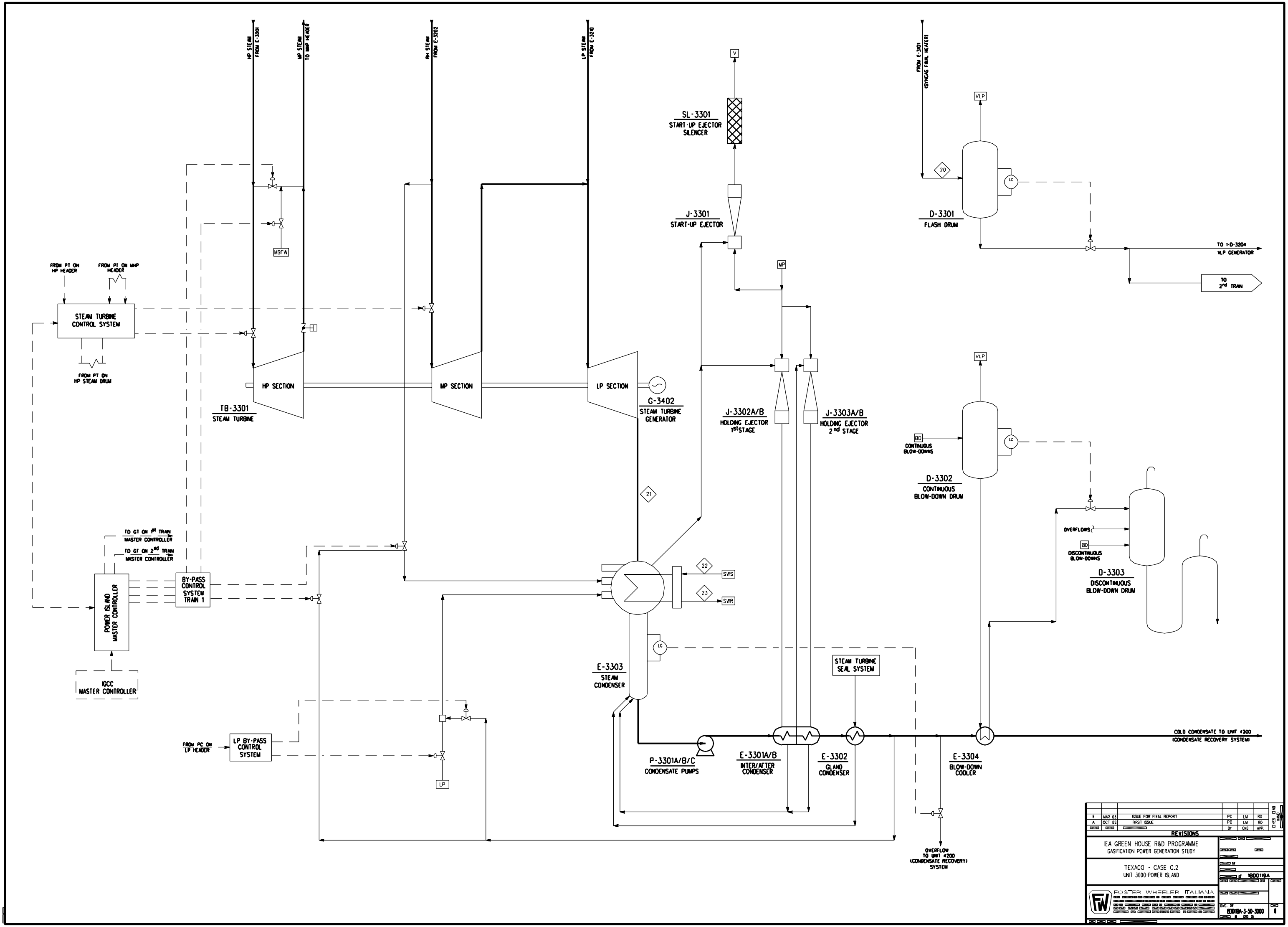
FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2300 A



TO 2nd TRAIN
MP
1-D-3205
MP STEAM RECEIVER DRUM
LP
1-D-3306
LP STEAM RECEIVER DRUM
HP STEAM FROM PROCESS UNITS
MBFW
TO MP BFW HEADER
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
LP STEAM
1-X-3201
CCU STACK
1-D-3204
VLP STEAM DRUM
VLP
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
HPDS
1-DS-3202
HP STEAM DESUPERHEATER
1-D-3201
HP STEAM DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
PHOSPHATE
SPLIT RANGE
LBFW
TO LP BFW HEADER
OVERFLOW TO D-3303
1-E-3212
LP EVAPORATOR
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3202
MP REHEATER 2nd SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3208
MP EVAPORATOR
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3209
LP SUPERHEATER
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
19
BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
HOT CONDENSATE FROM UNIT 2200
SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
FROM D-3301
FLASH DRUM
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NC
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
MHP HEADER
MHP
HBFW
TO HP BFW HEADER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
1-D-3101
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
LEGEND
STREAM NUMBER
A OCT 02 FIRST ISSUE PC LM RD
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.2
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1800119A
1800119A-3-50-3000 A


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP SECTION
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
J-3302A/B
HOLDING EJECTOR 1stSTAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
20
D-3301
FLASH DRUM
LC
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
21
22
23
SWS
SWR
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
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
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)
B MAR 03 ISSUE FOR FINAL REPORT PC LM RD
A OCT 02 FIRST ISSUE PC LM RD
BY CHD APP.
YES NO HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.2
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
DWG. Nº
800119A-3-50-3000
B

8.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 2400: Sulphur Recovery Unit & Tail Gas Treatment;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE					REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME					PREP.	L.M.	P,C.	of 1
	CASE : TEXACO CASE C.2					APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT					DATE	Oct 02	Mar 02	

STREAM	1	2	3	4	5				
	HP OXYGEN to Gasification	MP NITROGEN to AGR	MP NITROGEN to each GT	Air Intake from Atmosphere	TOTAL Air from GTs				
Temperature (°C)	149	149	212,7	AMB.	209				
Pressure (bar)	80	31	21,6	AMB.	13,9				
TOTAL FLOW									
Mass flow (kg/h)	278960	43811	200788	700700	532927				
Molar flow (kgmole/h)	8660	1565	7171	24271	18460				
LIQUID PHASE									
Mass flow (kg/h)									
GASEOUS PHASE									
Mass flow (kg/h)	278960	43811	200788	700700	532927				
Molar flow (kgmole/h)	8660	1565	7171	24271	18460				
Molecular Weight	32,21	28,0004	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				

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	L.M.	P,C.	of 1
	CASE : TEXACO CASE C.2	APPROVED	R.D.	R.D.	
	UNIT : 2200 Syngas treatment and conditioning line	DATE	Oct 02	Mar 02	

STREAM	1	2	3	4	5	6	7	8	9	
	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	LP Purified SYNGAS from Acid Gas Removal	Treated SYNGAS to Power Island	Contaminated Condensate to Stripping (2 Trains)	Return Condensate to Gasification (2 Trains)	Cold Condensate from Unit 4200 (2 Trains)	
Temperature (°C)	243	392	38	44	45	150	38	155	21	
Pressure (bar)	63	60,4	57,9	57,4	32,5	31,5	57,8	57,8	11,0	
TOTAL FLOW										
Mass flow (kg/h)	703950	704000	393450	656114	134133	825465	12000	304350	642874	
Molar flow (kgmole/h)	36635	18317,5	19455	36893	3649	40542				
LIQUID PHASE										
Mass flow (kg/h)							12000	304350	642874	
GASEOUS PHASE										
Mass flow (kg/h)	703950	704000	393450	656114	134133	825465				
Molar flow (kgmole/h)	36635	18317,5	19455	36893	3649	40542				
Molecular Weight	19,2	38,4	20,2	17,8	36,8	20,4				
Composition (vol %)										
H_2	15,10	29,25	55,04	60,97	3,93	53,07				
CO	15,60	1,51	2,84	3,13	0,28	2,74				
CO_2	7,30	21,46	40,22	34,65	61,17	38,03				
N_2	N_2+Ar 0,80	0,36	0,68	0,24	34,38	5,25				
O_2	0,00	0,00	0,00	0,00	0,00	0,00				
CH_4	-	0,01	0,02	0,02	0,00	0,02				
H_2S + COS	0,12	0,12	0,22	0,00	0,00	0,00				
Ar	-	0,42	0,79	0,88	0,09	0,76				
H2O	61,00	46,87	0,19	0,11	0,15	0,12				
Others	0,08									

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	L.M.	P,C.	of 1
	CASE : TEXACO CASE C.2						APPROVED	R.D.	R.D.	
	UNIT : 2300 Acid Gas Removal						DATE	Oct 02	Mar 02	
STREAM	1	2	3	4	5	6				
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP Purified Syngas to Syngas Cooling	Recycle Tail Gas from SRU	MP Nitrogen from ASU	Acid Gas to SRU & TGT				
Temperature (°C)	38	44	45	38	149	33				
Pressure (bar)	57,9	57,4	32,5	29,0	31,0	2,2				
TOTAL FLOW										
Mass flow (kg/h)	786900	656114	134133	14428	43811	13359				
Molar flow (kgmole/h)	38910	36893	3649	417	1565	333				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	786900	656114	134133	14428	43811	13359				
Molar flow (kgmole/h)	38910	36893	3649	417	1565	333				
Molecular Weight	20,2	17,8	36,7	34,6	28,0	40,1				
Composition (vol %)										
H_2	55,04	60,97	3,93	4,19		0,00				
CO	2,84	3,13	0,28	0,07		0,00				
CO_2	40,22	34,65	61,17	47,65		59,63				
N_2	0,68	0,24	34,38	47,09	99,99	8,28				
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				
H_2S + COS	0,22	0,00	0,00	0,59		26,24				
Ar	0,79	0,88	0,09	0,19		0,00				
H2O	0,00	0,00	0,00	0,22		5,85				

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	L.M.	P,C.	of 1
	CASE : TEXACO CASE C.2	APPROVED	R.D.	R.D.	
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)	DATE	Oct 02	Mar 02	

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)	33		88	38						
Pressure (bar)	2,2		1,7	29,0						
TOTAL FLOW										
Mass flow (kg/h)	13359	67 (t/d)	4376	14428						
Molar flow (kgmole/h)	333		206	417						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	13359		4376	14428						
Molar flow (kgmole/h)	333		206	417						
Molecular Weight	40,1		21,2	34,6						
Composition (vol %)										
H_2	0,00		21,15	4,19						
CO	0,00		28,46	0,07						
CO_2	59,63		13,49	47,65						
N_2	8,28		0,00	47,09						
O_2	0,00		0,00	0,00						
CH_4	0,00		0,00	0,00						
H_2S + COS	26,24		1,14	0,59						
Ar	0,00		0,00	0,19						
H2O	5,85		35,77	0,22						

	IGCC HEAT & MATERIAL BALANCE
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME
	CASE : TEXACO CASE C.2
	UNIT : 3000 POWER ISLAND

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	Treated SYNGAS from Syngas Cooling (*) (1)	412,7	150	31,5	326,0
2	Extraction Air to Air Separation Unit (*)	532,9	400	14,4	-
3	MP Nitrogen from ASU (*)	200,8	212,70	21,60	-
4	HP Steam from Process Units (*)	25,65	348	161,0	2582
5	HP Steam to Steam Turbine (*)	263,02	552	156,5	3447
6	Hot RH Steam to Steam Turbine (*)	399,32	527	36,7	3510
7	MP Steam from Steam Turbine (*)	263,02	344	39,7	3080
8	- - NOT USED - -				
9	LP Steam to Steam Turbine (*)	241,94	237	6,1	2930
10	MP Steam to MP -Superheater (*)	136,29	251,8	41,0	2800
11	LP Steam to LP Superheater (*)	241,94	166,8	7,2	2765
12	BFW to VLP Pumps (*)	41,70	119	1,9	499
13	BFW to LP BFW Pumps (*)	290,51	119	1,9	499
14	BFW to MP BFW Pumps (*)	181,65	119	1,9	499
15	BFW to HP BFW Pumps (*)	266,77	119	1,9	499
16	Hot Condensate returned from Unit 2200 (*)	642,87	115	2,5	454
17	Hot Condensate returned from CR (*)	90,55	94	2,5	394
18	Water from Flash Drum (*)	39,09	119	1,9	499
19	FLUE GAS AT STACK (*) (2)	2627,70	129	AMB.	117
20	Condensate from Syngas Final Heater (*)	86,95	170	1,9	722
21	LP Steam Turbine Exhaust	1285,75	21,7	0,026	2220
22	Sea Water Supply to Steam Condenser	93258	12	3,0	50,5
23	Sea Water Return from Steam Condenser	93258	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: 68.0%; H_2O: 12.1%; O_2: 10.1%; CO_2: 8.9%; Ar: 0.9%.

8.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER

CLIENT: IEA GHG	REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
PROJECT: GASIFICATION POWER GENERATION STUDY	DATE	Oct-02			
LOCATION: Netherlands	ISSUED BY	L.M.			
FWI Nº: 1- BD 0119A	CHECKED BY	P.C.			
	APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE C2 - HP, dirty shift reaction, w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Capacity	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**				**21,8**						**21,8**	
2200	**Syngas Treatment and Conditioning Line**		**-51,3**	**-118,6**	**-507,8**	**-3,8**	**51,3**	**118,6**	**515,8**	**83,4**	**87,6**	
2300	**Acid Gas Removal**				**51,2**						**51,2**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			**-1,4**	**-1,2**			**4,4**	**1,2**		**3,0**	
3000	**POWER ISLANDS UNITS**		**46,2**	**120,0**	**423,6**	**3,8**	**-51,3**	**-123,0**	**-517,0**	**-83,4**		
4000 to 5300	**UTILITY and OFFSITE UNITS**				**12,4**						**12,4**	
	BALANCE		**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**181,1**	**0,0**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	Oct-02
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - TEXACO - CASE C2 - HP, dirty shift w/o 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				
1000	**Gasification Section**	291		3179	
2100	**Air Separation Unit**				26041
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**			1320	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			338	
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**				
3200	**Heat Recovery Steam Generator**			1811	
3300/3400	**Steam Turbine and Generator auxiliaries**		4		93258
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				11459
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	28	-28		
	Other Units		24	364	
	BALANCE	319	0	7012	130758

FOSTER WHEELER	**CLIENT:** IEA GHG **PROJECT:** GASIFICATION POWER GENERATION STUDY **LOCATION:** Netherlands **FWI Nº:** 1- BD 0119A		Rev 0 Oct-02 ISSUED BY: PC. CHECKED BY: LM APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE C2 - HP, dirty shift w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**366**
1000	**Gasification Section**	**14115**
2100	**Air Separation Unit**	**102132**
2200	**Syngas treatment and conditioning line**	**271**
2300	**Acid Gas Removal**	**3245**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**2518**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4852**
3200	**Heat Recovery Steam Generator**	**6071**
3300/3400	**Steam Turbine,, Generator auxiliaries and Step-up transformer losses**	**1518**
3500	**Miscellanea**	**428**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9955**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**741**
	Other Units	**1261**
	BALANCE	**147473**

8.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	327.6
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2354.1**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1660.8
Thermal Power of Clean Syngas to GT (based on LHV) (F)	MWt	1530.2
Syngas treatment efficiency (F/E*100)	%	92.1
Gas turbines total power output	MWe	572.0
Steam turbine power output	MWe	428.0
Expander power output	MWe	12.8
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**1012.8**
ASU power consumption	MWe	100.7
Process Units consumption	MWe	26.3
Utility Units consumption	MWe	1.9
Offsite Units consumption (including sea cooling water system)	MWe	10.3
Power Islands consumption	MWe	13.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**152.2**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**860.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**36.6**

For this alternative, the pressure of the syngas at the expander outlet is higher than the other cases, being 30 barg versus 25 barg. In fact, GE is requiring a higher fuel pressure at GT B.L. because of real availability fuel control valve design. Adoption of a lower pressure drop fuel control valve may be investigated in the future. If 25 barg will be feasible also for this alternative, the expander power output increase up to be 16,2 instead of 12,8 MWe, Complex increasing the electrical efficiency to 36.9%.

8.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic is shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

8.7.1 Gaseous Emissions

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.

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	729,9
Flow, $Nm^3/h^{(1)}$	2.876.320
Temperature, °C	129
Composition	(%vol)
Ar	0,88
N_2	68,04
O_2	10,06
CO_2	8,93
H_2O	12,09
Emissions	$mg/Nm^{3\ (1)}$
NOx	30,0
SOx	9,9
CO	31,4
Particulate	4,4

(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	1459,8
Flow, $Nm^3/h^{(1)}$	5.752.640
Temperature, °C	129
Emissions	kg/h
NOx	172,6
SOx	56,9
CO	180,6
Particulate	25,3

(1) Dry gas, O_2 content 15%vol

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

8.7.2 Liquid Effluent

The effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island.

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	:	127.000	m^3/h
• Temperature	:	19	°C
• Cl_2	:	<0,05	ppm

10.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste (e.g. sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2,5 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

<u>Fine Slag (Filter Cake)</u>

Flow rate	:	32,2	t/h
Water content	:	70	%wt

<u>Coarse Slag</u>

Flow rate	:	77,3	t/h
Water content	:	50	%wt

Both slag products can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

8.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Texaco Case C.2 - High Pressure without CO_2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
1	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 15380 kW
2	**E-2101**	**Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 15380 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 = 296 t/h		85			Oxigen purity = 95 %
				MP N_2 flow rate to GTs = 422 t/h		27			Nitrogen purity = 98 %
				HMP N_2 flow rate to AGR = 52 t/h		36			Nitrogen purity = 99,99 %
				LP N_2 flow rate to Proc Unit = 2.7		14			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 557 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16900 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16900 kW H2 service H2/Wet H2S serv. on channel side
1	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 15000 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2202**	**HP Steam Generator**	Kettle			190 / 68	380 / 422		DUTY = 15000 kW H2 service H2/Wet H2S serv. on channel side
1	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37570 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2203**	**MP Steam Generator**	Kettle			48 / 68	280 / 384		DUTY = 37570 kW H2 service H2/Wet H2S serv. on channel side
1	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 157700 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2204**	**LP Steam Generator**	Kettle			12 / 68	250 / 290		DUTY = 157700 kW H2 service H2/Wet H2S serv. on channel side
1	**E-2205**	**VLP Steam Generator**	Kettle			12 / 68	250 / 205		DUTY = 25855 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2205**	**VLP Steam Generator**	Kettle			12 / 68	250 / 205		DUTY = 25855 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube		
1	**E-2206**	**Condensate Preheater**	Shell & Tube			20 / 68	125 / 182		DUTY = 50350 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2206**	**Condensate Preheater**	Shell & Tube			20 / 68	125 / 182		DUTY = 50350 kW H2 service H2/Wet H2S serv. on channel side
	E-2207	**Expander Feed Heater**	Shell & Tube			12 / 68	250 / 168		DUTY = 30850 kW H2 service H2/Wet H2S serv. on channel side
	E-2208	**Syngas pre-heater VLP**	Shell & Tube			12 / 68	250 / 168		DUTY = 19620 kW H2 service H2/Wet H2S serv. on channel side
	E-2209	**Syngas pre-heater LP**	Shell & Tube			12 / 68	250 / 180		DUTY = 4810 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION: Netherlands	DATE	Oct-02			
PROJ. NAME: Gasification Power Generation Study	ISSUED BY	L.M.			
CONTRACT N. 1- BD- 0119 A	CHECKED BY	P.C.			
	APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS		D,mm x TT,mm					
1	D-2201	Condensate Separator	Vertical			68	290		Wet H2S service/H2 service
2	D-2201	Condensate Separator	Vertical			68	290		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	182		Equipped with demister Wet H2S service/H2 service
2	D-2203	Condensate Separator	Vertical			68	182		Equipped with demister Wet H2S service/H2 service
	D-2204	Process Condensate Accumulator	Horizontal			68	290		
		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				464		H2 service Wet H2S service

FOSTER WHEELER

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION:	Netherlands	DATE	Oct-02			
PROJ. NAME:	Gasification Power Generation Study	ISSUED BY	L.M.			
CONTRACT N.	1- BD- 0119 A	CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
2	R-2201	Shift Catalyst Reactor	vertical				464		H2 service Wet H2S service
		EXPANDERS							
	EX- 2201	Purified Syngas Expander	centrifugal						
		GENERATORS		P, MWe					
	G-3201	Expander Generator							
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	Shift Catalyst							Catalyst volume: 160 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=67 t/d					Sulphur content = 99,9 wt min (dry basis)
				Acid Gas from AGR = 620 kmol/h		3,5	80		Sulphur content = 15% (wet basis)
				Sour gas from Gasif. = 205 kmol/h					Sulphur content = 1,1 % (wet basis)
				Expected Treated Tail Gas=470 kmol/h		33	70		Major components (wet basis): CO_2 = 30%, H_2=5,3%, N_2 = 63%

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
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EQUIPMENT LIST

Unit 3100 - Gas Turbine - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2800 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2800 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
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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		Q,m^3/h x H,m					
1	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	**D-3205**	**MP Steam Receiver Drum**	horizontal			48	280		
2	**D-3205**	**MP Steam Receiver Drum**	horizontal			48	280		
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	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Superheater**							Included in 1-HRS-3201
1	E-3208	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**LP Superheater**							Included in 1-HRS-3201
1	E-3210	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3212	**LP Evaporator**							Included in 1-HRS-3201
1	E-3213	**LP Economizer**							Included in 1-HRS-3201
1	E-3214	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3216	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
2	D-3201	**HP steam Drum**							Included in 2-HRS-3201
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3207	**MP Superheater**							Included in 2-HRS-3201
2	E-3208	**MP Evaporator**							Included in 2-HRS-3201
2	E-3209	**LP Superheater**							Included in 2-HRS-3201
2	E-3210	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3212	**LP Evaporator**							Included in 2-HRS-3201
2	E-3213	**LP Economizer**							Included in 2-HRS-3201
2	E-3214	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3216	**VLP Evaporator**							Included in 2-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	P.C.			
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20 / 3,5	58 / 140		DUTY = 880 kW
		DRUMS		D,mm x TT,mm					
	D-3301	**Flash Drum**	vertical			3,5	230		
	D-3302	**Continuous Blow-down Drum**	vertical			3,5	140		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	G-3402	Steam Turbine Generator							Included in Z - 3201
	J-3301	Start-up Ejector							Included in Z - 3201
	J-3302 A/B	Holding Ejector 1st Stage							Included in Z - 3201
	J-3303 A/B	Holding Ejector 2nd Stage							Included in Z - 3201
	P-3301A/B/C	Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
	SL-3301	Start-up Ejector Silencer							Included in Z - 3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
	LOCATION: Netherlands	DATE	Oct-02			
	PROJ. NAME: Gasification Power Generation Study	ISSUED BY	L.M.			
	CONTRACT N. 1- BD- 0119 A	CHECKED BY	P.C.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Texaco Case C.2 - High Pressure without CO2 capture, dirty shift reaction

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	G-3401	Gas Turbine Generator							Included in 1 -Z- 3101
2	G-3401	Gas Turbine Generator							Included in 2 -Z- 3101
	G-3402	Steam Turbine Generator							Included in Z- 3301

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE C.3

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.9

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.9 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.9 BASIC INFORMATION FOR EACH ALTERNATIVE

9.0 Case C.3

9.1 Introduction

The main features of the Case C.3 configuration of the IGCC Complex are:

- Low pressure (38 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- No shift and CO_2 removal;

The removal of acid gas (AGR-AGE) is based on DOW-UCARSOL process (activated MDEA solvent).
The degree of integration between the Air Separation (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and NO_x 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.

The arrangement of the process units is :

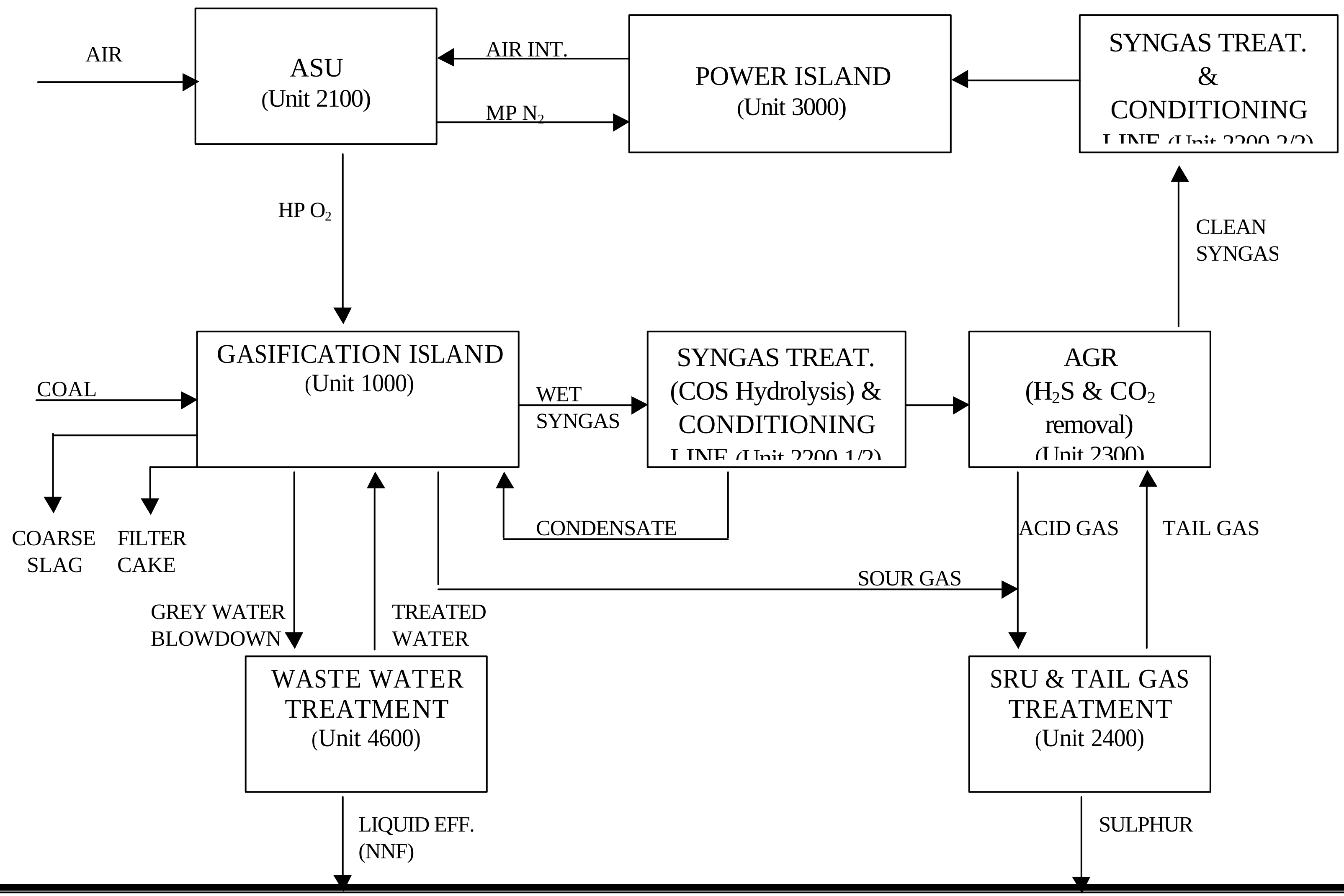
Unit		Trains
1000	Gasification	4 x 33 % 2 x 66 %
2100	ASU	2 x 50 %
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR AGE	2 x 50% 1 x 100%
2400	SRU TGT	2 x 100% 1 x 100%

3000	Gas Turbine (PG 9351-FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

During the 1st phase of the project, the high pressure was selected as the optimum pressure for the Texaco Technology. As a consequence, Vendors were not required to provide data for this low pressure alternative and all the process calculation of the 1st phase, based on in-house data, were revised in order to meet the new Gas turbine requirement (GE data).

TEXACO C.3 – IGCC COMPLEX BLOCK FLOW DIAGRAM



9.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	215
Pressure (bar)	AMB.	53	36
TOTAL FLOW			
Mass flow (kg/h)	300,900	258,500	1,321,000
Molar flow (kmol/h)		8,130	68,750
Composition (%vol)			
H_2			14.8
CO			15.5
CO_2			7.2
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H_2O			61.4
Others			0.18

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 9.3 indicates the interconnections of ASU with the other units of the IGCC.

Unit 2200: Syngas Treatment and Conditioning Line , shift and expansion

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 9.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 35 barg and 215°C, enters Unit 2200. The syngas is first cooled in the LP Steam Generator, E-2201, and in the VLP Steam Generator, E-2202. Process condensate, separated after each of these cooling steps is collected, under level control, in the process condensate accumulator D-2205, from where it is pumped back to the syngas scrubber in Unit 1000.
Raw syngas is reheated in E-2203 with the hydrolysis effluent and in E-2204 with MP steam, before entering the hydrolysis reactor R-2201, converting COS to H_2S.
The reactor effluent is further cooled in E-2203, E-2205 where cold condensate is preheated for heat recovery Process Condensate and E-2206 with sea cooling water. The condensate separated after E-2205 is routed to D-2205, while part of the process condensate separated after E-2206, being heavily contaminated, is sent to Unit 4000, Sour Water Stripper.
Cold syngas goes to Unit 2300 and returns to Unit 2200, as clean syngas, after H_2S removal. Clean syngas is preheated in E-2207/E-2208, respectively with VLP and LP steam, before flowing to Unit 3000, gas turbines.
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.

Unit 2300: Acid Gas Removal (AGR) & Acid Gas Enrichment (AGE)

In the absence of licensor data for this alternative, an open-art DOW-UCARSOL process (activated MDEA solvent) was considered, based on data provided by DOW with reference to Case C1 (Texaco High Pressure, no shift reaction).

Unit 2300 is characterised by a low syngas pressure (30 bar g) and a high CO_2/H_2S ratio (60/1). As a single-stage absorption is not suitable to accomplish all objectives, an Acid Gas Enrichment (AGE) Section was adopted. Therefore the tail gas from Sulphur Recovery Unit is mixed with the Acid Gas exiting the AGR Section before entering the AGE Section.

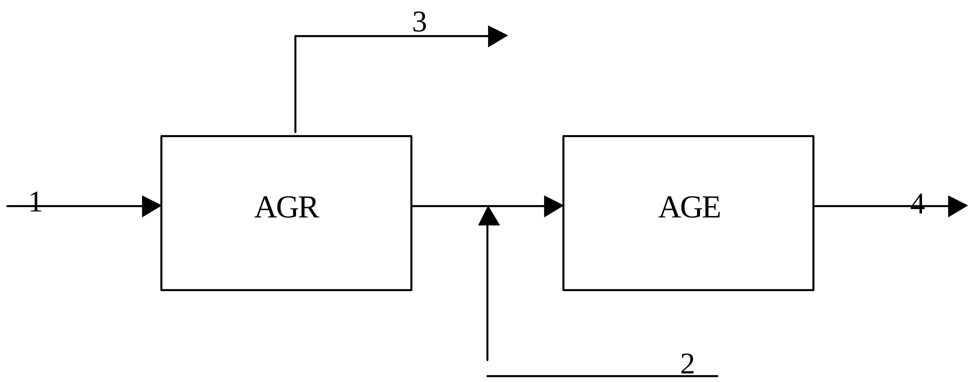
The main interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 9.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

Exit Streams

3. Treated Gas to Gas Turbines
4. Acid Gas to Sulphur Recovery Unit



The MDEA solvent consumption, to make-up losses, is 85 m^3/year.

The MDEA process matches the process specifications with reference to H_2S+COS concentration of the treated gas exiting the Unit and fed to the Combined Cycle Unit. The treated gas feeding the gas turbines has an H_2S+COS concentration of 21 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.

The acid gas H_2S concentration is 23% dry basis, suitable to feed the oxygen blown Claus process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 5.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 61.5 t/day and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 3 barg.

Unit 3000: Power Island

The process flow diagrams of this Unit are attached to paragraph 9.3.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- HP steam (85 barg) : steam exported to the Gasification Island users.
- MP steam (40 barg) : steam exported to Syngas Treatment and Conditioning Line. A small quantity is 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 : 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 9.4, Utilities Consumption.

Because of the optimisation of the heat integration, HP steam in the HRSG is generated at different pressure with respect to the Gasification Island users. The HP generation level inside the Power Island is as follows:

- HP steam : 160 barg

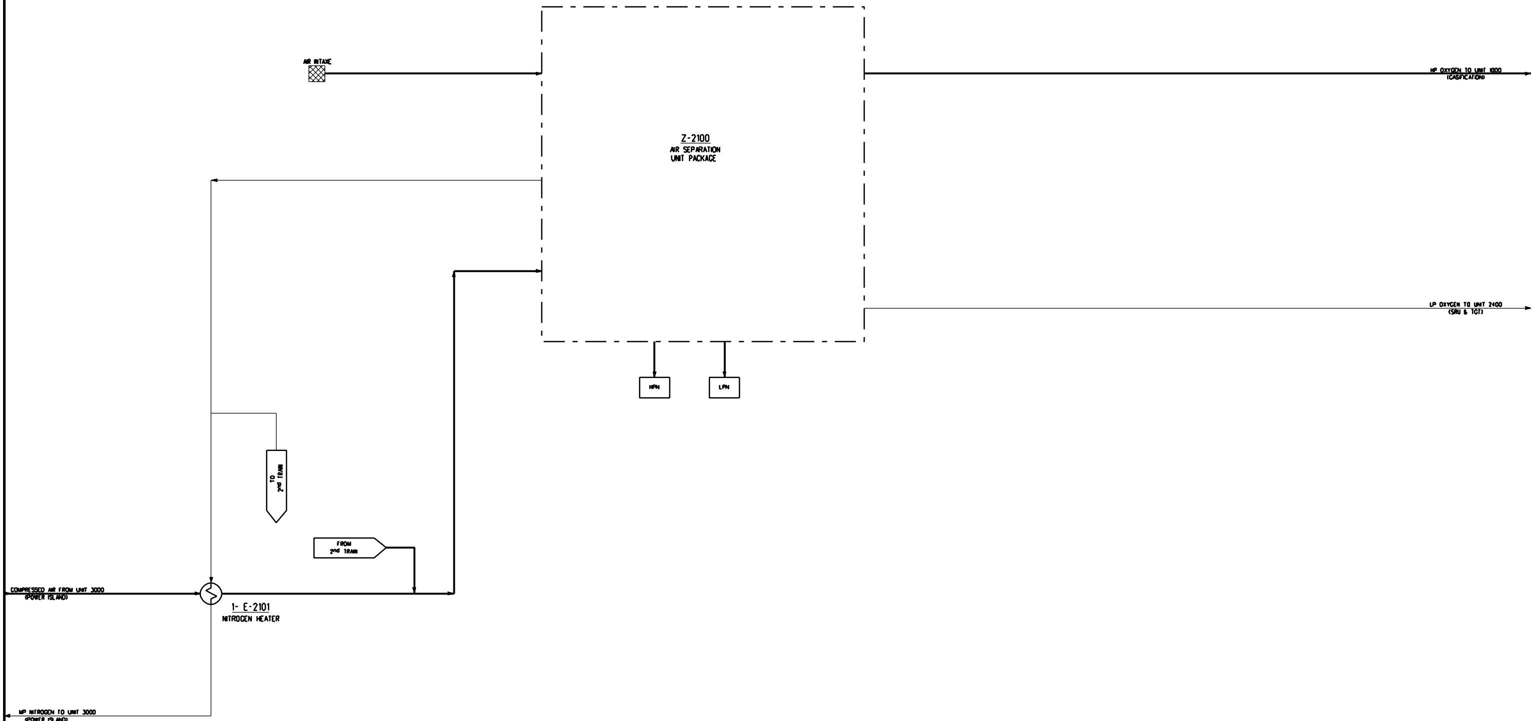
The other generation levels are the same of the Process Units.

9.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0 and 9.0.



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			BY	CHD	APP.

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IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

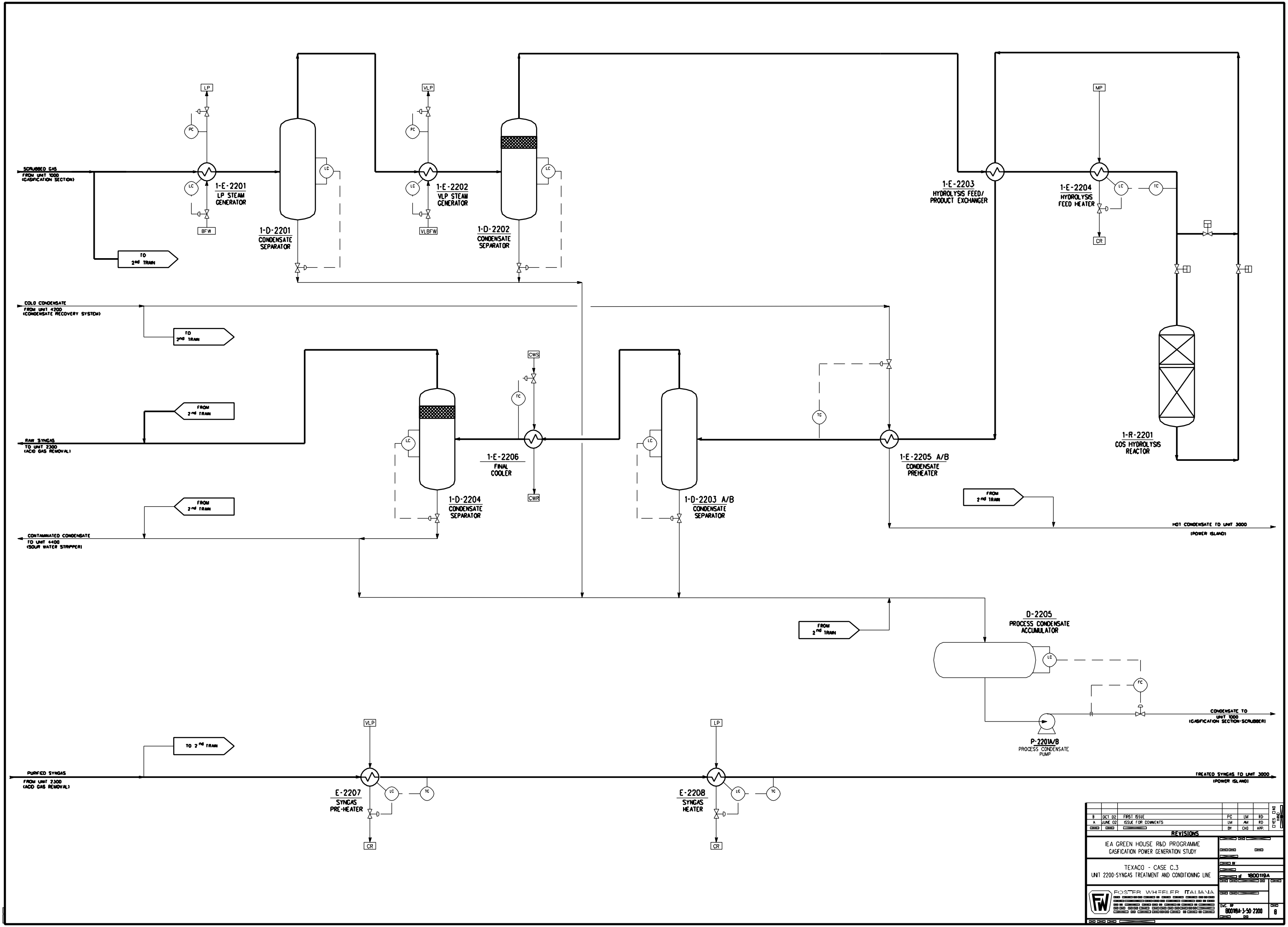
TEXACO - CASE C .3
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº
BD0119A-3-50-2100

B



SCRUBBED GAS
FROM UNIT 1000
(GASIFICATION SECTION)
LP
PC
LC
BFW
1-E-2201
LP STEAM GENERATOR
1-D-2201
CONDENSATE SEPARATOR
TO 2nd TRAIN
VLP
VLBFW
1-E-2202
VLP STEAM GENERATOR
1-D-2202
CONDENSATE SEPARATOR
1-E-2203
HYDROLYSIS FEED/ PRODUCT EXCHANGER
MP
TC
CR
1-E-2204
HYDROLYSIS FEED HEATER
1-R-2201
COS HYDROLYSIS REACTOR
COLD CONDENSATE
FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
FROM 2nd TRAIN
RAW SYNGAS
TO UNIT 2300
(ACID GAS REMOVAL)
CWS
CWR
1-E-2206
FINAL COOLER
1-D-2204
CONDENSATE SEPARATOR
1-D-2203 A/B
CONDENSATE SEPARATOR
1-E-2205 A/B
CONDENSATE PREHEATER
HOT CONDENSATE TO UNIT 3000
(POWER ISLAND)
CONTAMINATED CONDENSATE
TO UNIT 4400
(SOUR WATER STRIPPER)
D-2205
PROCESS CONDENSATE ACCUMULATOR
FC
CONDENSATE TO UNIT 1000
(GASIFICATION SECTION-SCRUBBER)
P-2201A/B
PROCESS CONDENSATE PUMP
TO 2nd TRAIN
PURIFIED SYNGAS
FROM UNIT 2300
(ACID GAS REMOVAL)
E-2207
SYNGAS PRE-HEATER
E-2208
SYNGAS HEATER
TREATED SYNGAS TO UNIT 3000
(POWER ISLAND)
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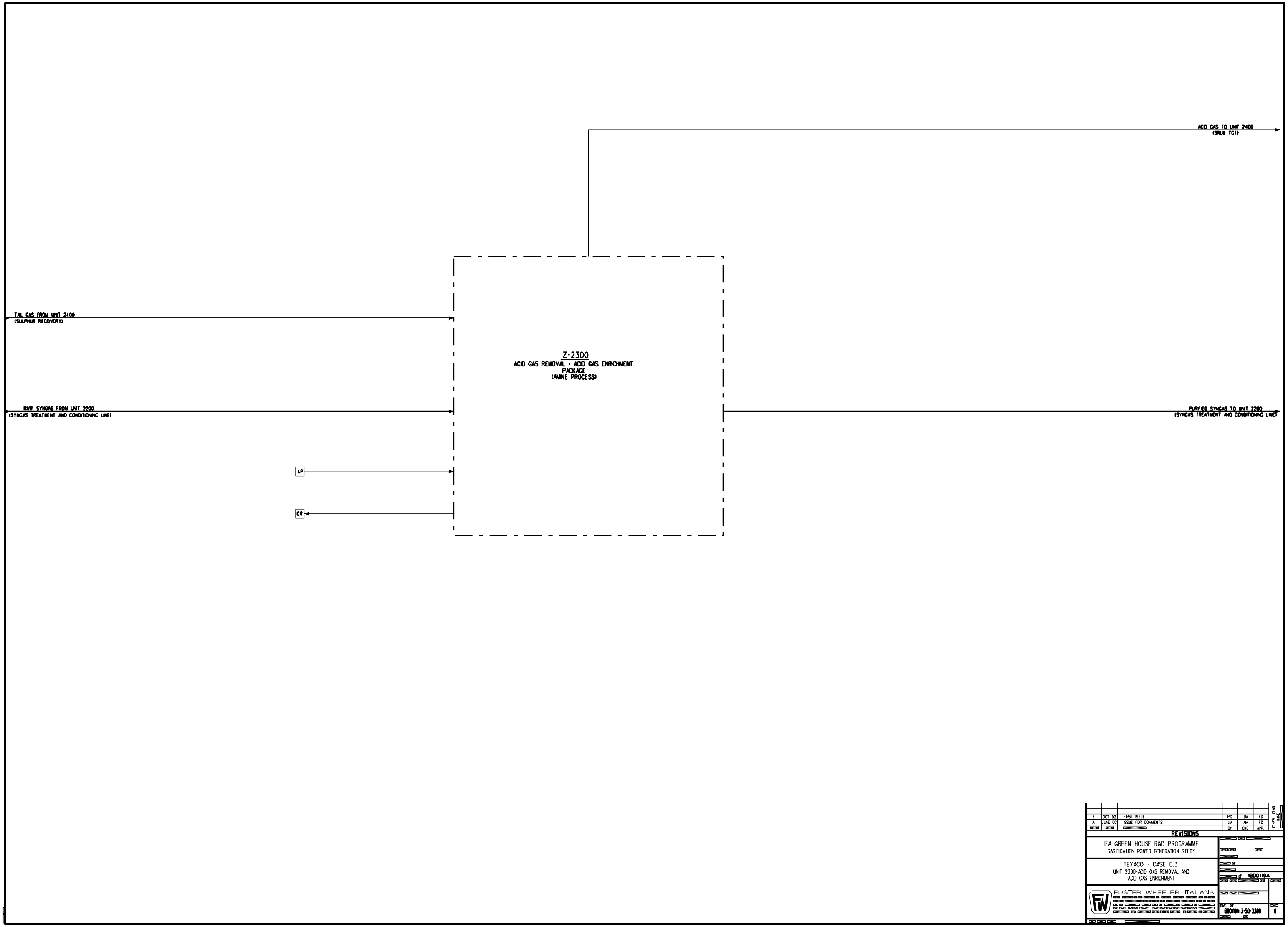
TEXACO - CASE C.3
UNIT 2200-SYNGAS TREATMENT AND CONDITIONING LINE
1BD0119A
FOSTER WHEELER ITALIANA
DWG. Nº
BD0119A-3-50-2200
B


ACID GAS TO UNIT 2400
(SRU& TGT)
TAIL GAS FROM UNIT 2400
(SULPHUR RECOVERY)
Z-2300
ACID GAS REMOVAL - ACID GAS ENRICHMENT
PACKAGE
(AMINE PROCESS)
RAW SYNGAS FROM UNIT 2200
(SYNGAS TREATMENT AND CONDITIONING LINE)
PURIFIED SYNGAS TO UNIT 2200
(SYNGAS TREATMENT AND CONDITIONING LINE)
LP
CR
B
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JUNE 02
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LM
AM
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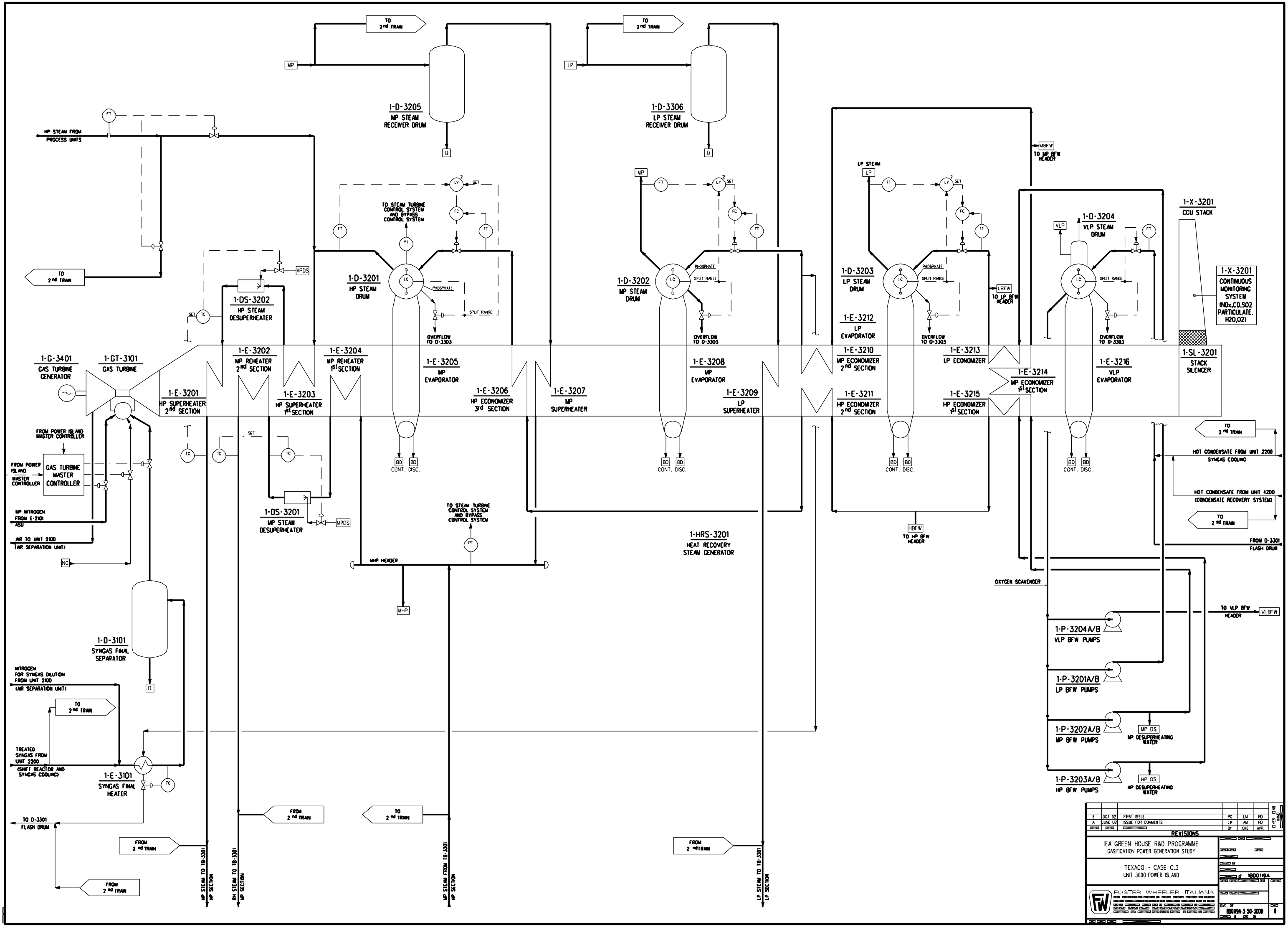
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE C.3
UNIT 2300-ACID GAS REMOVAL AND
ACID GAS ENRICHMENT
1800119A
FOSTER WHEELER ITALIANA
DWG.
1800119A-3-50-2300
B



1-D-3205
MP STEAM RECEIVER DRUM
1-D-3306
LP STEAM RECEIVER DRUM
TO 2nd TRAIN
MP
LP
HP STEAM FROM PROCESS UNITS
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
1-D-3204
VLP STEAM DRUM
1-DS-3202
HP STEAM DESUPERHEATER
1-DS-3201
MP STEAM DESUPERHEATER
HPDS
MPDS
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
HBFW
TO HP BFW HEADER
LP STEAM
VLP
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-SL-3201
STACK SILENCER
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3208
MP EVAPORATOR
1-E-3209
LP SUPERHEATER
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3212
LP EVAPORATOR
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NC
1-D-3101
SYNGAS FINAL SEPARATOR
D
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
MHP HEADER
MHP
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
HOT CONDENSATE FROM UNIT 2200 SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
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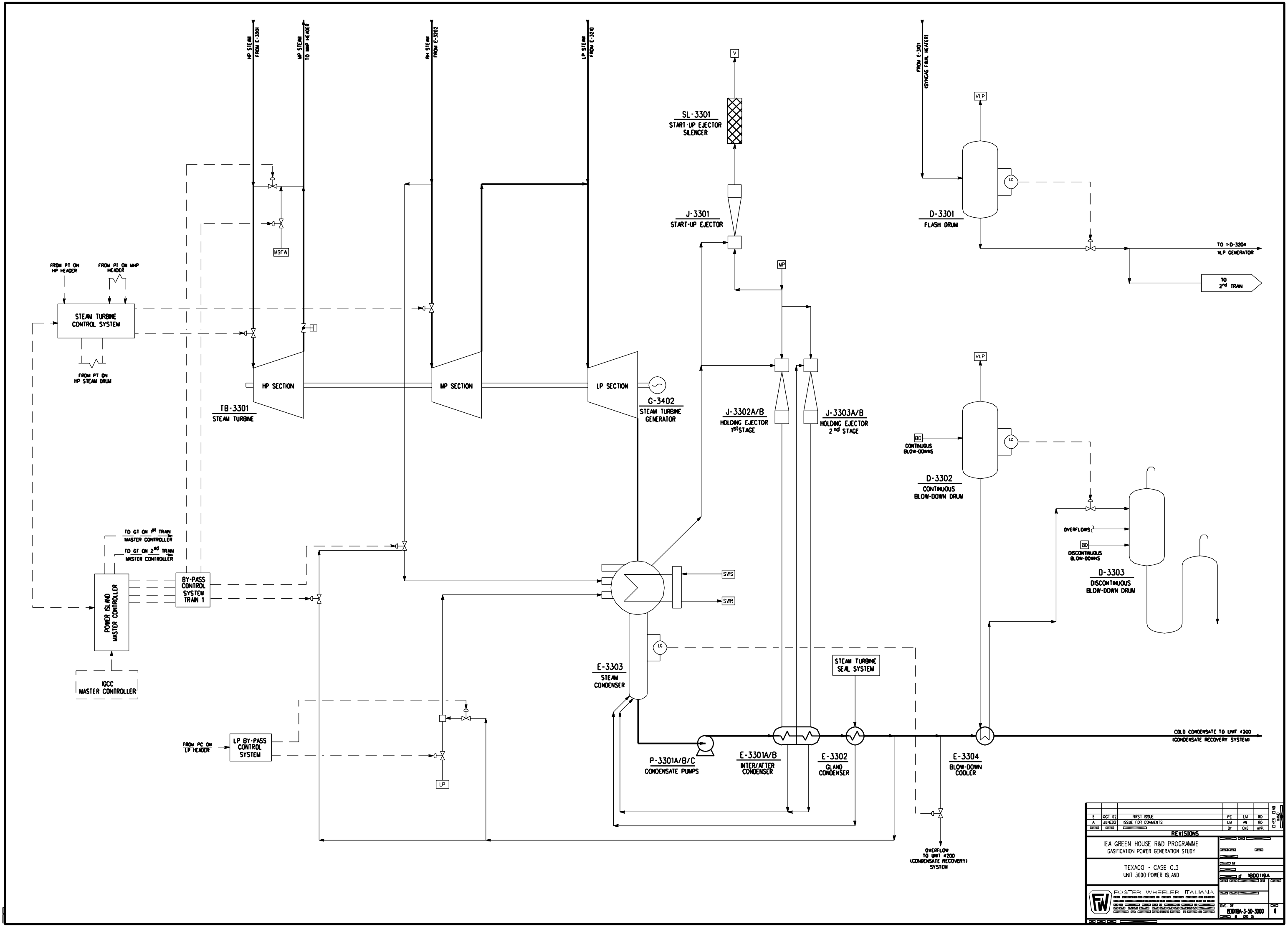
TEXACO - CASE C.3
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1800119A
800119A-3-50-3000


HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP SECTION
LP SECTION
TB-3301
STEAM TURBINE
G-3402
STEAM TURBINE GENERATOR
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
J-3302A/B
HOLDING EJECTOR 1st STAGE
J-3303A/B
HOLDING EJECTOR 2nd STAGE
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
LC
D-3301
FLASH DRUM
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
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)
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UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
DWG.
800119A-3-50-3000

9.4 Steam and Electric Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER	**CLIENT:** IEA GHG	REVISION	Rev.0	Rev.1	Rev.2
	PROJECT: GASIFICATION POWER GENERATION STUDY	DATE	Oct-02		
	LOCATION: Netherlands	ISSUED BY	P.C.		
	FWI Nº: 1- BD 0119A	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE C3 - LP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Capacity	HP Steam 85 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**		5,0								5,0	
2100	**Air Separation Unit**				20,1						20,1	
2200	**Syngas Treating and Conditioning Line**			14,0	-587,6	-48,2			592,3	84,8	55,4	
2300	**Acid Gas Removal (AGR) & Acid Gas Enrichment (AGE)**				109,2						109,2	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**			-1,3	-1,1			4,1	1,1		2,8	
3000	**POWER ISLANDS UNITS**		-5,0	-12,7	447,9	48,2		-4,1	-593,4	-84,8		
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	204,0	

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

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	nov-02
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE C3 - LP w/o CO_2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**336**
1000	**Gasification Section**	**12966**
2100	**Air Separation Unit**	**116126**
2200	**Syngas treatment and conditioning line**	**351**
2300	**Acid Gas Removal (AGR) & Acid Gas Enrichment (AGE)**	**659**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**626**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4776**
3200	**Heat Recovery Steam Generator**	**5032**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2115**
3500	**Miscellanea**	**527**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**9537**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**669**
	Other Units	**659**
	BALANCE	**154380**

Note: Minus prior to figure means figure is generated

9.5 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

TEXACO

Case C.3 - Low Pressure without CO_2 capture - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	300.9
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2162.3**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1535.2
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	382.3
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**954.3**
ASU power consumption	MWe	116.1
Process Units consumption	MWe	14.6
Utility Units consumption	MWe	1.8
Offsite Units consumption (including sea cooling water system)	MWe	9.4
Power Islands consumption	MWe	12.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**154.4**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**799.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.1**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**37.0**

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE D.1

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	**Revised Pages**	**Issued by**	**Checked by**	**Approved by**
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.10

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.10 BASIC INFORMATION FOR EACH ALTERNATIVE

10.0 Case D.1

10.1 Introduction

The main features of the Case D.1 configuration of the IGCC Complex are:

- High pressure (65 bar g) Texaco Gasification;
- 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 NO_x 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.

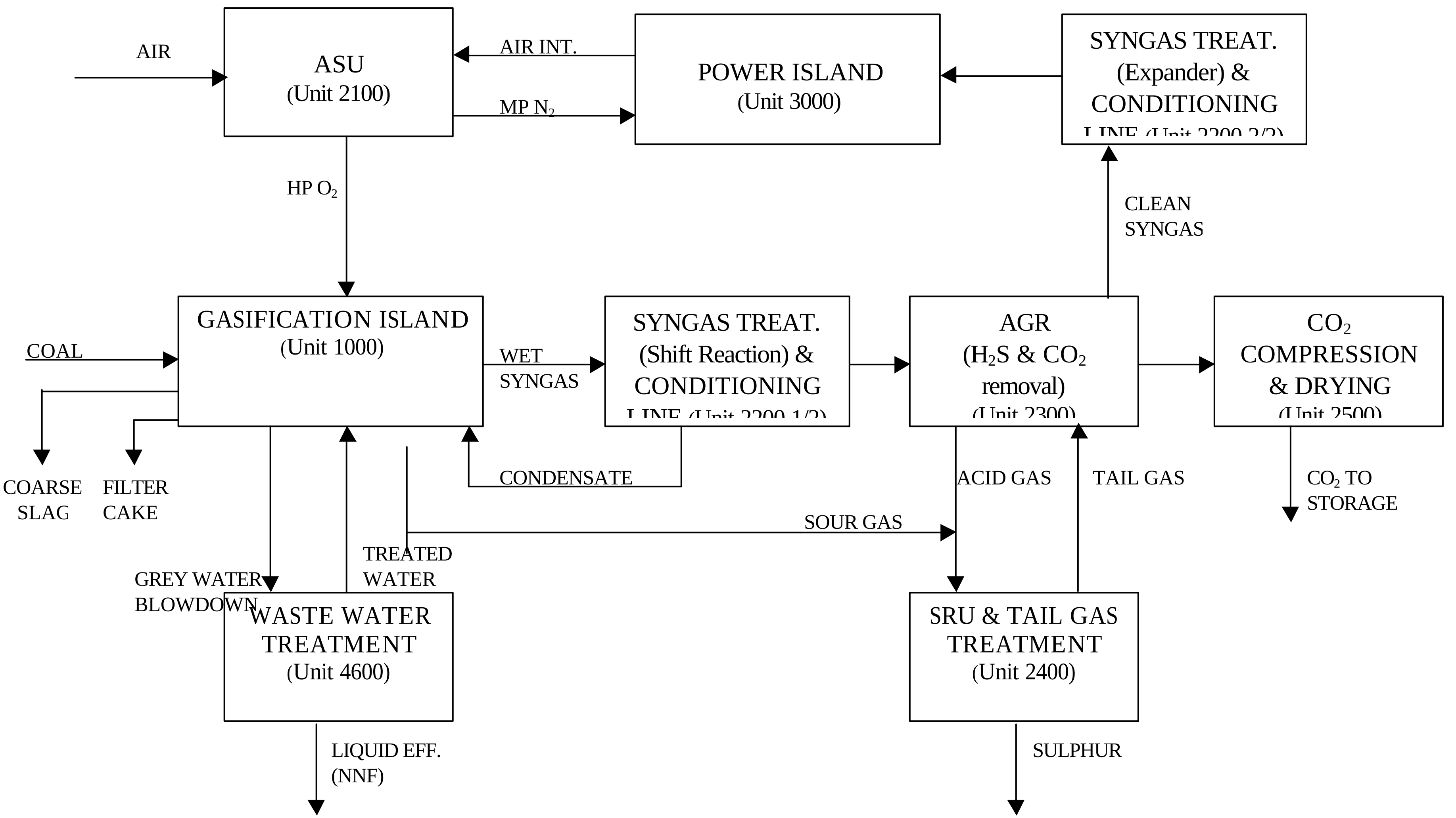
The arrangement of the process units is :

Unit		Trains
1000	Gasification	4 x 33 % 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%
2500	CO_2 Compression and Drying	2 x 50%

3000	Gas Turbine (PG 9351-FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO D.1 – IGCC COMPLEX BLOCK FLOW DIAGRAM



10.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	243
Pressure (bar)	AMB.	80	63
TOTAL FLOW			
Mass flow (kg/h)	323,100	278,700	1,388,000
Molar flow (kmol/h)		8,650	72,260
Composition (%vol)			
H_2			15.1
CO			15.6
CO_2			7.3
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H_2O			61
Others			0.08

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 10.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 10.4.

Unit 2200: Syngas Treatment and Conditioning Line

To follow the process description of this Unit reference should be made to the process flow diagram attached to paragraph 10.3.
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 limititation 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.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a high syngas pressure (55 bar g) and an extremely high CO_2/H_2S ratio (183/1). The following two alternatives, both based on a Selexol Solvent, have been considered:

- **Option 1 – with nitrogen stripping**: a single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit.

- **Option 2 – without nitrogen stripping**: a single train configuration, adopting a more complicated and electric power consuming process scheme.

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment and Operating costs of the two options (reference is made to the report "AGR Technical Comparison and Optimisation" attached to Section H for all the details).
Option 1 with nitrogen stripping is the best alternative to reduce both the investment and the operating costs. However, it was later known that a high N_2 concentration in the product CO_2 stream has a negative impact for CO_2 storage, particularly if the CO_2 is used for enhanced oil recovery. Therefore Option 2, without Nitrogen stripping, was finally selected.

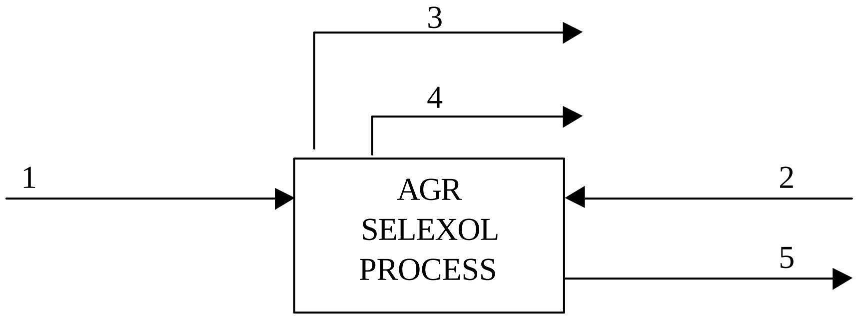
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 10.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

Exit Streams

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.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constant of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 66.8 t/day and normally operating ar 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 30 barg.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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

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

Unit 3000: Power Island

The Process Flow Diagrams and the equipment list of this Unit are attached to paragraphs 10.3 and 10.8.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 10.5, Utilities Consumption.

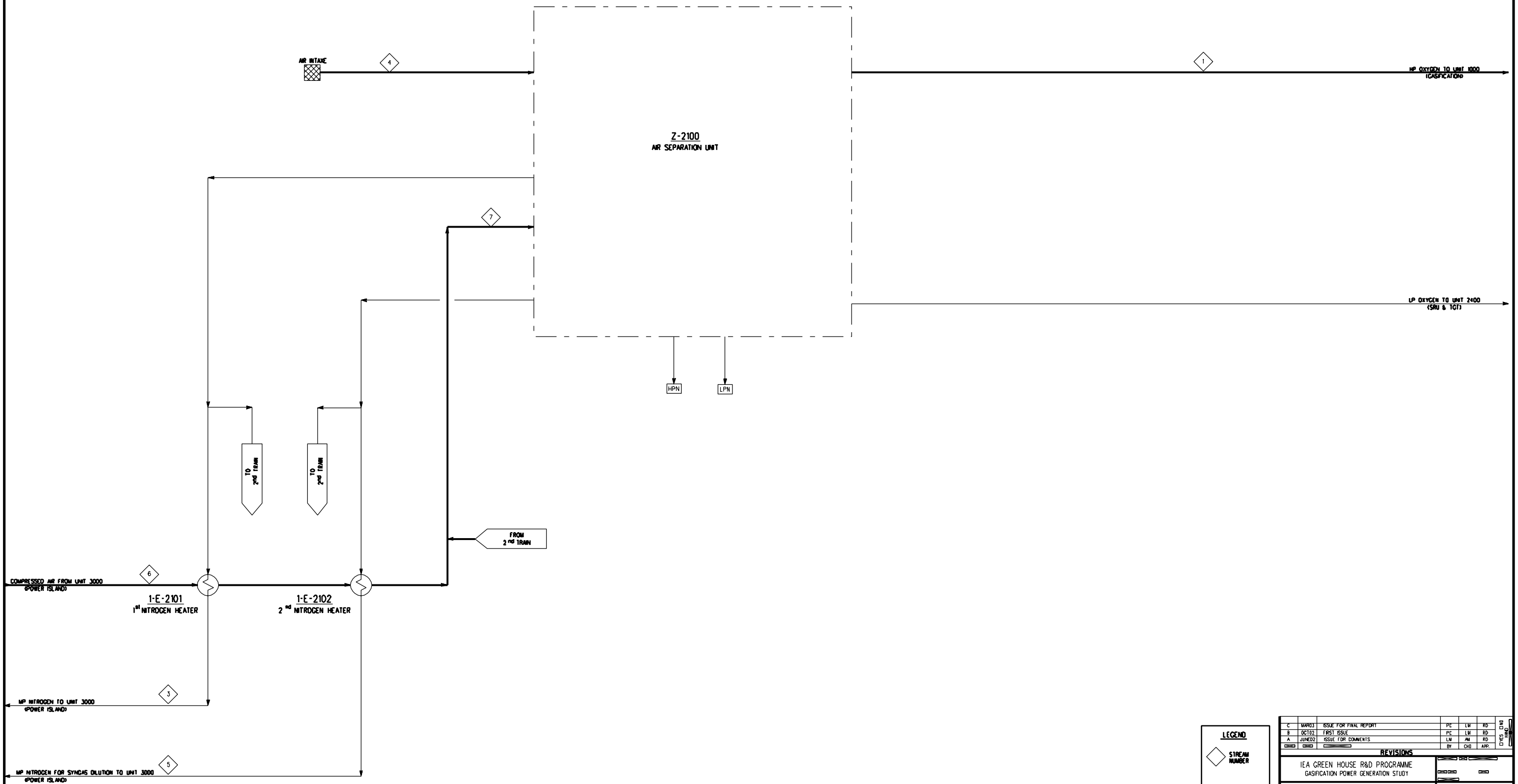
The net balance on each steam header inside the Power Island is positive, thus meaning that for all generation levels steam is imported from Process Units to the Power Island. Only steam at 85 bar g is exported to the Gasification Island. As a consequence, the generation levels of the Power Island are the same of the Process Units.

10.3 Process Flow Diagrams

The Process Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



LEGEND

◇ STREAM NUMBER

C	MAR03	ISSUE FOR FINAL REPORT	PC	LM	RD
B	OCT02	FIRST ISSUE	PC	LM	RD
A	JUNE02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

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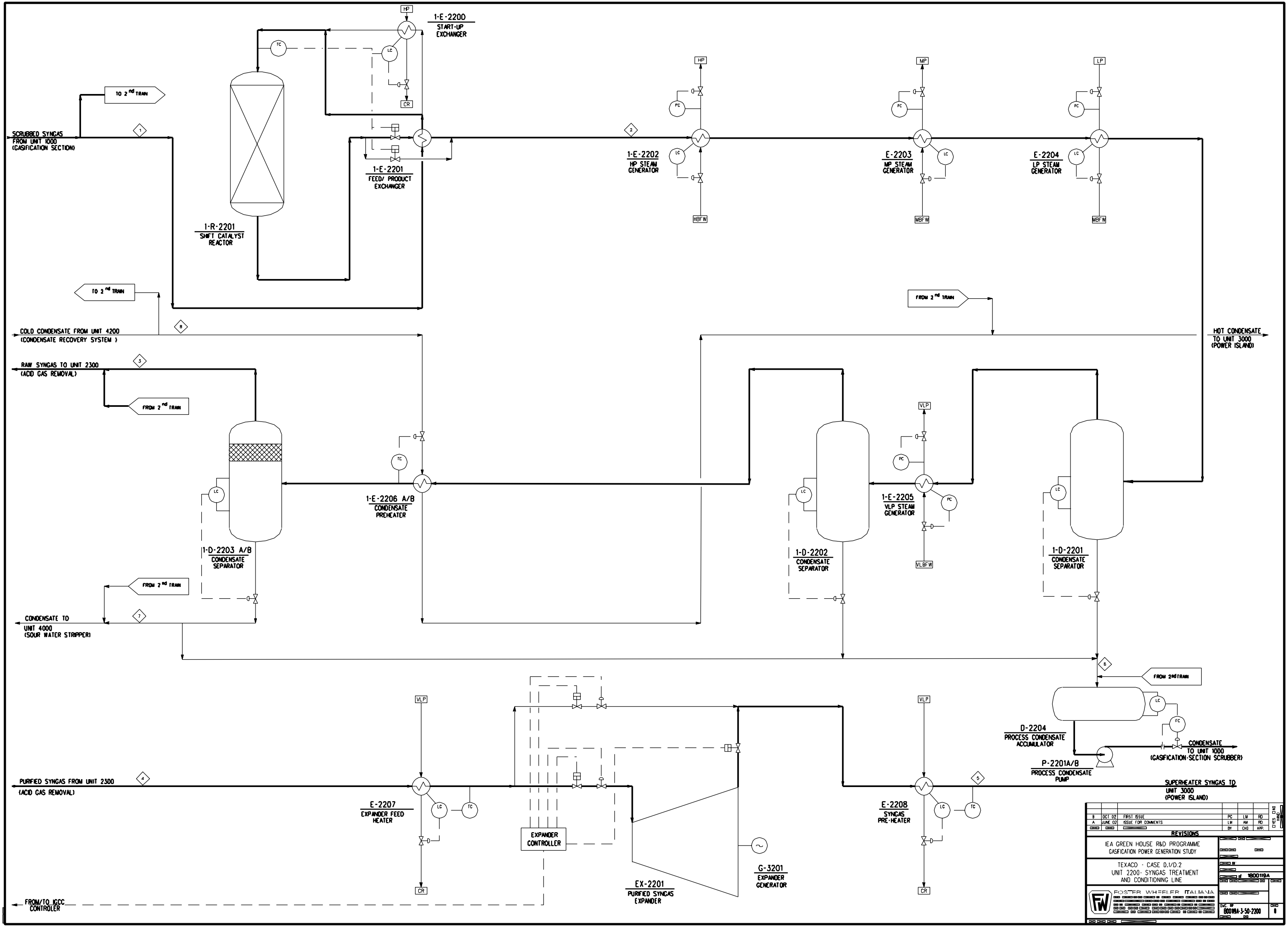
GASIFICATION POWER GENERATION STUDY

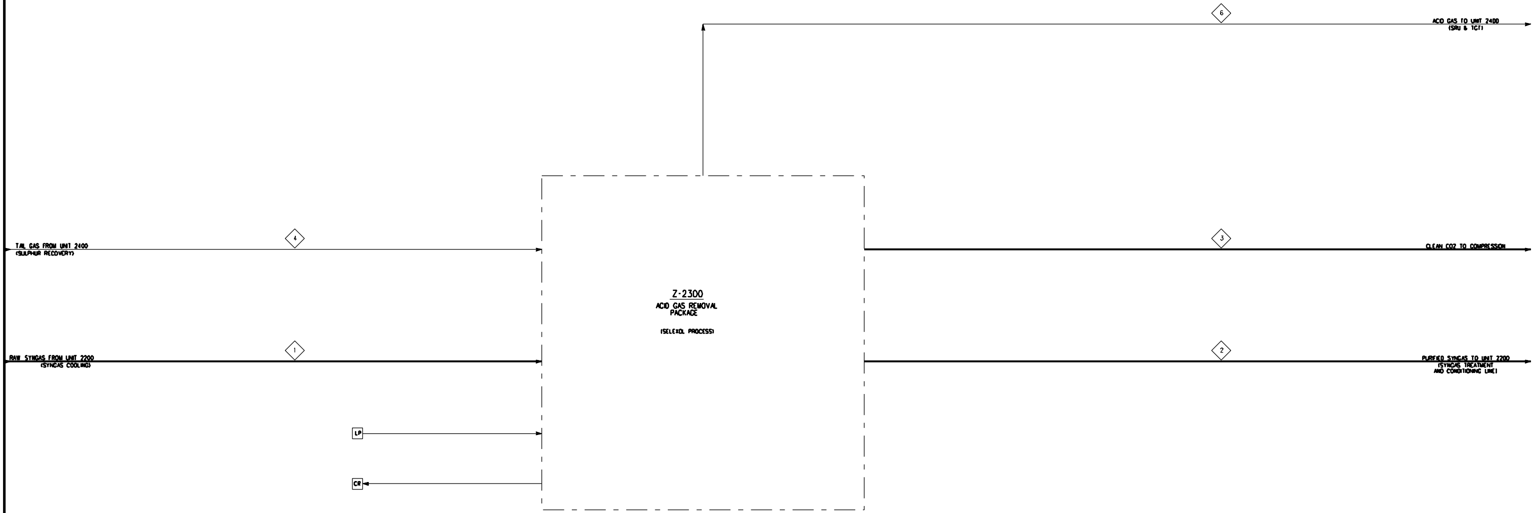
TEXACO - CASE D .1
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2100 C


1-E-2200
START-UP EXCHANGER
TO 2nd TRAIN
SCRUBBED SYNGAS FROM UNIT 1000 (GASIFICATION SECTION)
1-R-2201
SHIFT CATALYST REACTOR
1-E-2201
FEED/ PRODUCT EXCHANGER
1-E-2202
HP STEAM GENERATOR
E-2203
MP STEAM GENERATOR
E-2204
LP STEAM GENERATOR
HP
MP
LP
HBFW
MBFW
CR
TC
LC
PC
FC
COLD CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM 2nd TRAIN
HOT CONDENSATE TO UNIT 3000 (POWER ISLAND)
RAW SYNGAS TO UNIT 2300 (ACID GAS REMOVAL)
VLP
1-E-2206 A/B
CONDENSATE PREHEATER
1-E-2205
VLP STEAM GENERATOR
VLBFW
1-D-2203 A/B
CONDENSATE SEPARATOR
1-D-2202
CONDENSATE SEPARATOR
1-D-2201
CONDENSATE SEPARATOR
CONDENSATE TO UNIT 4000 (SOUR WATER STRIPPER)
D-2204
PROCESS CONDENSATE ACCUMULATOR
P-2201A/B
PROCESS CONDENSATE PUMP
CONDENSATE TO UNIT 1000 (GASIFICATION-SECTION SCRUBBER)
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
E-2207
EXPANDER FEED HEATER
EXPANDER CONTROLLER
EX-2201
PURIFIED SYNGAS EXPANDER
G-3201
EXPANDER GENERATOR
E-2208
SYNGAS PRE-HEATER
SUPERHEATER SYNGAS TO UNIT 3000 (POWER ISLAND)
FROM/TO IGCC CONTROLER
B OCT 02 FIRST ISSUE PC LM RD
A JUNE 02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
REVISIONS
YES NO
HAND
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.1/D.2
UNIT 2200- SYNGAS TREATMENT AND CONDITIONING LINE
FOSTER WHEELER ITALIANA
1BD0119A
DWG. Nº
1BD0119A-3-50-2200
B



LEGEND

STREAM NUMBER

C	MAR 03	ISSUE FOR FINAL REPORT	PC	LM	RD
B	OCT 02	FIRST ISSUE	PC	LM	RD
A	JUNE 02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

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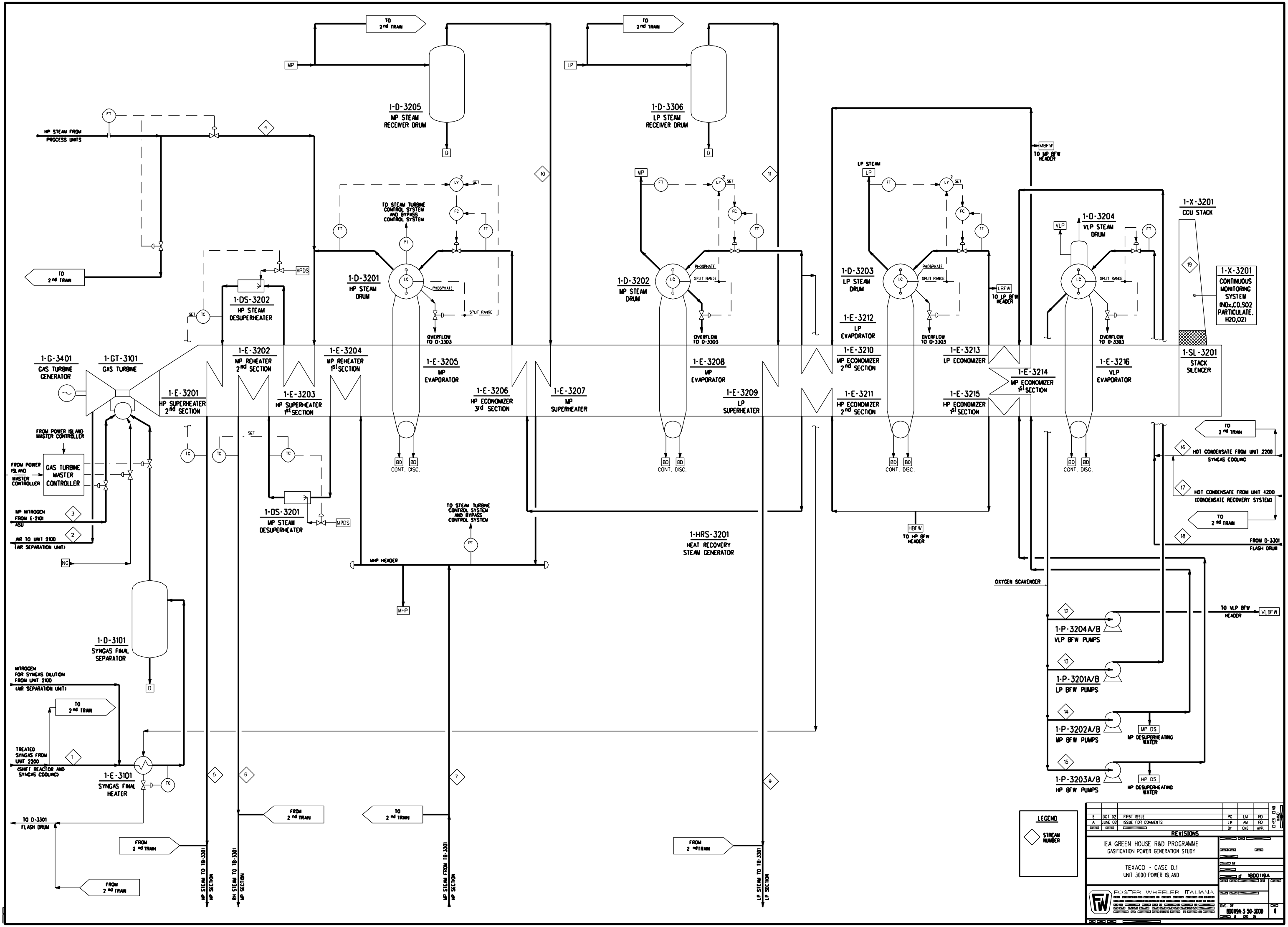
GASIFICATION POWER GENERATION STUDY

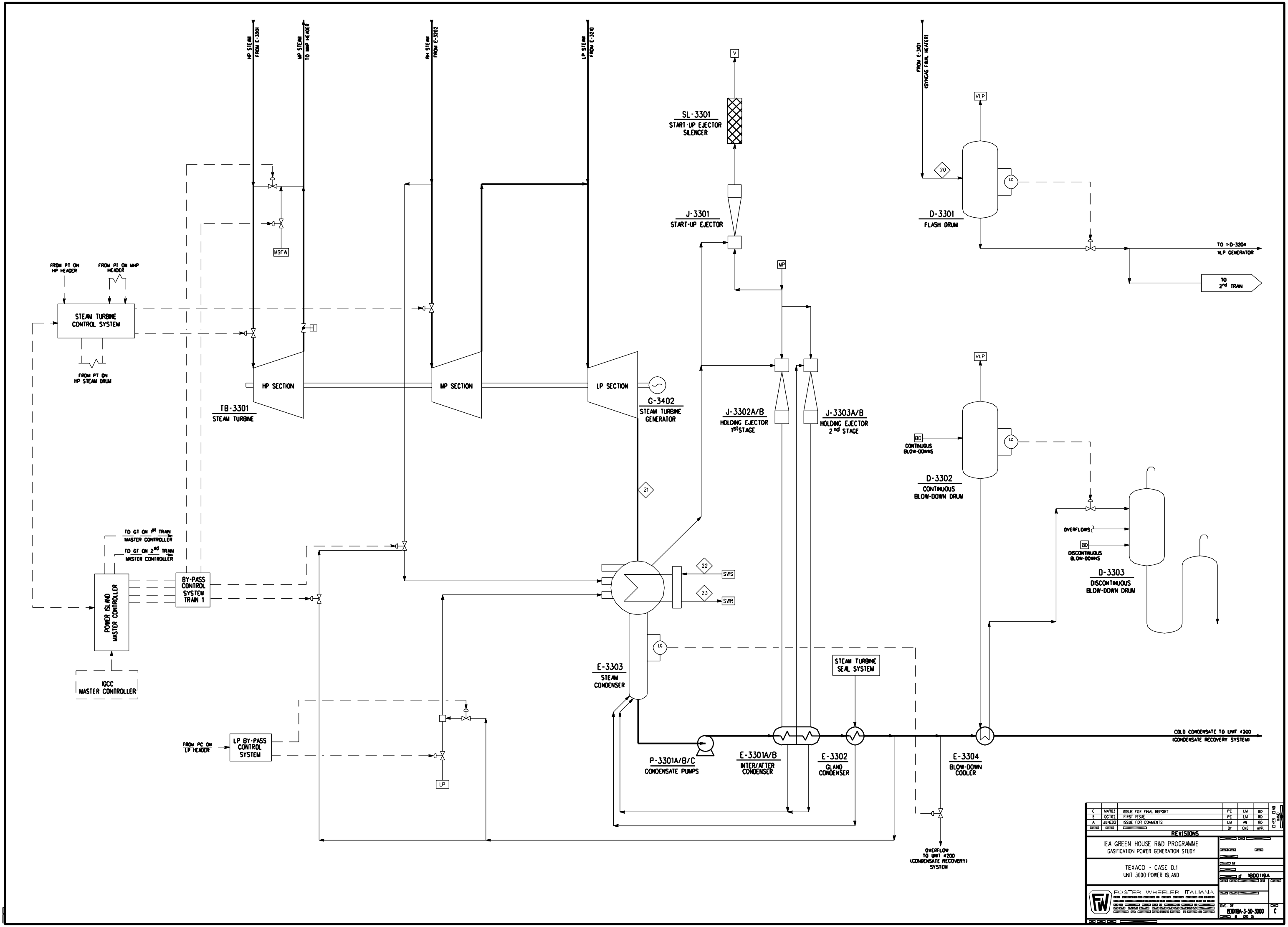
TEXACO - CASE D.1
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2300 C


1-D-3205
MP STEAM RECEIVER DRUM
1-D-3306
LP STEAM RECEIVER DRUM
TO 2nd TRAIN
HP STEAM FROM PROCESS UNITS
1-D-3201
HP STEAM DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
1-D-3204
VLP STEAM DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
OVERFLOW TO D-3303
PHOSPHATE
SPLIT RANGE
TO MP BFW HEADER
TO LP BFW HEADER
TO HP BFW HEADER
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-SL-3201
STACK SILENCER
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-DS-3202
HP STEAM DESUPERHEATER
1-DS-3201
MP STEAM DESUPERHEATER
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3208
MP EVAPORATOR
1-E-3209
LP SUPERHEATER
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3212
LP EVAPORATOR
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
MHP HEADER
1-D-3101
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
HOT CONDENSATE FROM UNIT 2200 SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DESUPERHEATING WATER
CONT. DISC.
LEGEND
STREAM NUMBER
B OCT 02 FIRST ISSUE
A JUNE 02 ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.1
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1BD0119A
BD0119A-3-50-3000



HP STEAM FROM E-3201
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
FROM E-3301 (SYNGAS FINAL HEATER)
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
VLP
D-3301
FLASH DRUM
20
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP 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
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
LC
21
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
22
23
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
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)
C MAR03 ISSUE FOR FINAL REPORT PC LM RD
B OCT02 FIRST ISSUE PC LM RD
A JUNE02 ISSUE FOR COMMENTS LM AM RD
BY CHD APP.
YES NO HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.1
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
FW
DWG.
800119A-3-50-3000
C

10.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 2400: Sulphur Recovery Unit & Tail Gas Treatment;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	
	CASE : TEXACO CASE D.1	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	Oct-02	Mar-03	

STREAM	1	2	3	4	5	6	7	8		
	HP OXYGEN to Gasification	NOT USED	MP NITROGEN to each GT	Air Intake from Atmosphere	MP NITROGEN for Syngas Dilution	Air from each GT	TOTAL Air from GTs	TOTAL Air to ASU		
Temperature (°C)	148,9		212,7	AMB.	209	400	209			
Pressure (bar)	79,8		21,6	AMB.	28,0	14,4	13,9			
TOTAL FLOW										
Mass flow (kg/h)	278700		325206	613137	246834	306569	613137	1226274		
Molar flow (kgmole/h)	8650		11581	21236	8814	10618	21236	42471		
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	278700		325206	613137	246834	306568,5	613137	1226274		
Molar flow (kgmole/h)	8650		11581	21236	8814	10618	21236	42471		
Molecular Weight	32,22		28,00	28,87	28,00	28,87	28,87	28,87		
Composition (vol %)										
H_2										
CO										
CO_2										
N_2	1,50		97,50	77,57	97,50	77,57	77,57	77,57		
O_2	95,00		2,15	20,86	2,15	20,86	20,86	20,86		
CH_4										
H_2S + COS										
Ar	3,50		0,26	0,89	0,26	0,89	0,89	0,89		
H2O			0,09	0,68	0,09	0,68	0,68	0,68		

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	of 1
	CASE : TEXACO CASE D.1						APPROVED	R.D.	R.D.	
	UNIT : 2200 Syngas treatment and conditioning line						DATE	Oct-02	Mar-03	
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	0	1	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	
	CASE : TEXACO CASE D.1						APPROVED	R.D.	R.D.	
	UNIT : 2300 Acid Gas Removal						DATE	Oct-02	Mar-03	

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	Sheet 1 of 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.	P.C.	
	CASE : TEXACO CASE D.1						APPROVED	R.D.	R.D.	
	UNIT : 2400 Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)						DATE	Oct-02	Mar-03	

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 : TEXACO CASE D.1
	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%.

10.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

	FOSTER WHEELER	CLIENT:	IEA GHG
		PROJECT:	GASIFICATION POWER GENERATION STUDY
		LOCATION:	Netherlands
		FWI Nº:	1- BD 0119A

REVISION	Rev.0	Rev.1	Rev.2
DATE	20-June-02	Sep-02	Mar-03
ISSUED BY	L.M.	P.C.	P.C
CHECKED BY	A.M.	L.M.	L.M.
APPROVED BY	R.D.	R.D.	R.D.

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE D.1 - 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**	**52,6**	**121,5**	**528,3**	**72,3**	**51,8**	
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**	
3000	**POWER ISLANDS UNITS**	**47,5**	**122,8**	**423,6**	**20,5**	**-52,6**	**-125,9**	**-529,5**	**-72,3**		
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**	**0,0**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	set-02
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

WATER CONSUMPTION SUMMARY - TEXACO - CASE D1 - 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**	289		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**		3		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**	26	-26		
	Other Units		23	364	
	BALANCE excluding CO2 compression	315	0	8611	128462
	BALANCE including CO2 compression	315	0	8611	135242

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	mar-03
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE D1 - 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

10.6 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

TEXACO

Case D.1 - High pressure with CO_2 capture, separated H_2S and CO_2 removal - Rev.2

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**

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

10.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic is shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

10.7.1 Gaseous Emissions

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.

Table 10.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 10.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	716,7
Flow, $Nm^3/h^{(1)}$	2.917.906
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 10.2

Table 10.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1433,4
Flow, $Nm^3/h^{(1)}$	5.835.812
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

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

10.7.2 Liquid Effluent

The effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island.

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	:	131.300	m^3/h
• Temperature	:	19	°C
• Cl_2	:	<0,05	ppm

10.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2,5 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

<u>Fine Slag (Filter Cake)</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.

10.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
1	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14236 kW
2	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14236 kW
1	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3550 kW
2	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3550 kW
		PACKAGES							
	Z-2100	**Air Separation Unit Package** (two parallel trains, each sized for 50% of the capacity)		HP O_2 flow rate to Gasifier = 290 t/h		85			Oxigen purity = 95 %
				MP N_2 flow rate to GTs = 685 t/h		27			Nitrogen purity = 98 %
				LP N_2 flow rate to Proc Unit = 2.7		14			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 644 t/h					Nitrogen purity = 99,99 %

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-2201**	**Feed/ Product Exchanger**	Shell & Tube			68 / 68	315 / 464		DUTY = 16670 kW H2 service H2/Wet H2S serv. on channel 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
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
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
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
2	**E-2205**	**VLP Steam Generator**	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)		S, m^2		Shell/tube	Shell/tube		
1	**E-2206 A/B**	**Condensate Preheater**	Shell & Tube			20 / 68	130 / 185		DUTY = 50670 kW H2 service H2/Wet H2S serv. on channel side
2	**E-2206 A/B**	**Condensate Preheater**	Shell & Tube			20 / 68	130 / 185		DUTY = 50670 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
	E-2208	**Syngas pre-heater**	Shell & Tube			7 / 68	165 / 175		DUTY = 11270 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS		D,mm x TT,mm					
1	**D-2201**	**Condensate Separator**	Vertical			68	205		Wet H2S service/H2 service
2	**D-2201**	**Condensate Separator**	Vertical			68	205		Wet H2S service/H2 service
1	**D-2202**	**Condensate Separator**	Vertical			68	185		Wet H2S service/H2 service
2	**D-2202**	**Condensate Separator**	Vertical			68	185		Wet H2S service/H2 service
1	**D-2203 A/B**	**Condensate Separator**	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
2	**D-2203 A/B**	**Condensate Separator**	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
	D-2204	**Process Condensate Accumulator**	Horizontal			68	190		
		PUMPS		Q,m³/h x H,m					
	P-2201 A/B	**Process condensate pump**	centrifugal						One operating, one spare
		REACTOR		D,mm x TT,mm					
1	**R-2201**	**Shift Catalyst Reactor**	vertical			68	464		H2 service Wet H2S service
2	**R-2201**	**Shift Catalyst Reactor**	vertical			68	464		H2 service Wet H2S service

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION: Netherlands	DATE	Oct-02	Mar-03		
PROJ. NAME: Gasification Power Generation Study	ISSUED BY	L.M.	P.C.		
CONTRACT N. 1- BD- 0119 A	CHECKED BY	R.D.	L.M.		
	APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas treatment and conditioning line - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		EXPANDERS							
	EX- 2201	**Purified Syngas Expander**	centrifugal	Pout/Pin = 0,51 Flow = 590 kNm^3/h Pow = 10.5 MWe					
		GENERATORS		**P, MWe**					
	G-3201	**Expander Generator**							
		PACKAGE UNITS							
	Z-2201	**Catalyst Loading System**							
	Z-2202	**Shift Catalyst**							Catalyst volume: 150 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit & Tail Gas Treatment - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Z-2400	**Sulphur Recovery Unit and Tail Gas Treatment Package** (two Sulphur Recovery Unit, each sized for 100% of the capacity and one Tail Gas Treatment Unit sized for 100% of capacity, including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.=66.8 t/d					Sulphur content = 99,9 wt min (dry basis)
				Acid Gas from AGR = 485 kmol/h		6	65		Sulphur content = 17.94 % (wet basis)
				Sour gas from Gasif. = 200 kmol/h		5	110		Sulphur content = 1,1 % (wet basis)
				Expected Treated Tail Gas=622 kmol/h		33	70		Major components (wet basis): CO_2 = 83.71%, H_2=2.88%, N_2 = 12.47%

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 3100 - Gas Turbine - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m^2		Shell/tube	Shell/tube		
1	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2050 kW Tubes: H2 service
2	**E-3101**	**Syngas Final Heater**	Shell & Tube			67 / 68	270 / 200		DUTY=2050 kW Tubes: H2 service
		DRUMS		D,mm x TT,mm					
1	**D-3101**	**Syngas Final Separator**	vertical			68	200		H2 service
2	**D-3101**	**Syngas Final Separator**	vertical			68	200		H2 service
		PACKAGES							
1	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	282 MW					Included in 1-Z- 3101 Included in 1-Z- 3101
2	**Z-3101** GT-3101 G-3401	**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9351 (FA)	282 MW					Included in 2-Z- 3101 Included in 2-Z- 3101

FOSTER WHEELER

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION:	Netherlands	DATE	Oct-02	Mar-03		
PROJ. NAME:	Gasification Power Generation Study	ISSUED BY	L.M.	P.C.		
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		APPROVED BY	R.D.	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS		Q,m^3/h x H,m					
1	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3201 A/B**	**LP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3202 A/B**	**MP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3203 A/B**	**HP BFW Pumps**	centrifugal						One operating, one spare
1	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
2	**P-3204 A/B**	**VLP BFW Pumps**	centrifugal						One operating, one spare
		DRUMS		D,mm x TT,mm					
1	**D-3205**	**MP Steam Receiver Drum**	horizontal			44	260		
2	**D-3205**	**MP Steam Receiver Drum**	horizontal			44	260		
1	**D-3206**	**LP Steam Receiver Drum**	horizontal			12	250		
2	**D-3206**	**LP Steam Receiver Drum**	horizontal			12	250		
		MISCELLANEA		D,mm x H,mm					
1	**X-3201**	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
2	**X-3201**	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
1	**STK-3201**	**CCU Stack**							
2	**STK-3201**	**CCU Stack**							
1	**SL-3201**	**Stack Silencer**							
2	**SL-3201**	**Stack Silencer**							
1	**DS-3201**	**MP Steam Desuperheater**							Included in 1-HRSG-3201
2	**DS-3201**	**MP Steam Desuperheater**							Included in 2-HRSG-3201
1	**DS-3202**	**HP Steam Desuperheater**							Included in 1-HRSG-3201
2	**DS-3202**	**HP Steam Desuperheater**							Included in 2-HRSG-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
		ISSUED BY	L.M.	P.C.		
		CHECKED BY	R.D.	L.M.		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Superheater**							Included in 1-HRS-3201
1	E-3208	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**LP Superheater**							Included in 1-HRS-3201
1	E-3210	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3212	**LP Evaporator**							Included in 1-HRS-3201
1	E-3213	**LP Economizer**							Included in 1-HRS-3201
1	E-3214	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3216	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
2	D-3201	**HP steam Drum**							Included in 2-HRS-3201
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3207	**MP Superheater**							Included in 2-HRS-3201
2	E-3208	**MP Evaporator**							Included in 2-HRS-3201
2	E-3209	**LP Superheater**							Included in 2-HRS-3201
2	E-3210	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3212	**LP Evaporator**							Included in 2-HRS-3201
2	E-3213	**LP Economizer**							Included in 2-HRS-3201
2	E-3214	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3216	**VLP Evaporator**							Included in 2-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS		S, m2		shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	58 / 140		DUTY = 853 kW
		DRUMS		D,mm x TT,mm					
	D-3301	**Flash Drum**	vertical			3,5	230		
	D-3302	**Continuous Blow-down Drum**	vertical			3,5	140		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**							
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	G-3402	Steam Turbine Generator							Included in Z - 3201
	J-3301	Start-up Ejector							Included in Z - 3201
	J-3302 A/B	Holding Ejector 1st Stage							Included in Z - 3201
	J-3303 A/B	Holding Ejector 2nd Stage							Included in Z - 3201
	P-3301A/B/C	Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
	SL-3301	Start-up Ejector Silencer							Included in Z - 3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02	Mar-03		
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EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Texaco Case D.1 - High Pressure with CO_2 capture, dirty shift reaction, separate removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	**G-3401**	**Gas Turbine Generator**							Included in 1 -Z- 3101
2	**G-3401**	**Gas Turbine Generator**							Included in 2 -Z- 3101
	G-3402	**Steam Turbine Generator**							Included in Z- 3301

Appendix 1

Alternative process flow scheme based on Radiant Cooler Gasifier (ChevronTexaco Technology).

INTRODUCTION

The process alternatives considered for the development of the Study, based on the Texaco technology, foresee to use the Quench Type Gasifier (QG) as specified by IEA GHG. However, when the study was conceptually concluded, ChevronTexaco proposed to develop a different process flow-scheme to be used for plants with CO_2 capture, based on the Radiant Cooler Gasification Technology (RCG).

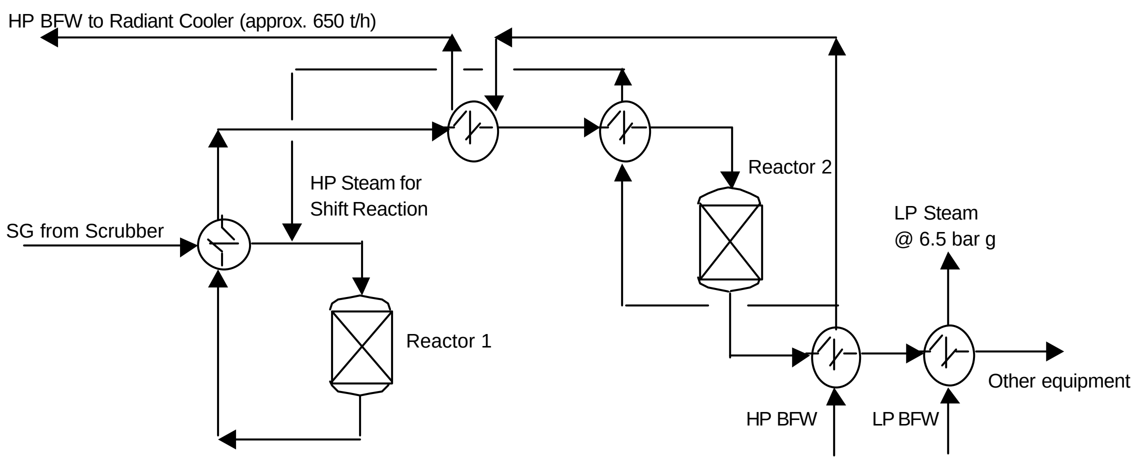
The main advantage of the RCG is the possibility to recover considerable heat from the radiant coolers, i.e. approximately 230 MWt to be used for the production of the HP steam. Main features of the Case configuration of the IGCC Complex are:

- High Pressure (55 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Radiant Cooler Gasifier Type;
- Double stage dirty shift;
- Separate removal of H_2S and CO_2.

PROCESS DESCRIPTION

Saturated raw Syngas from scrubbing in Gasification Island enters Unit 2200 at approximately 220°C and 54 bar g. For this alternative, Steam to dry Syngas ratio at scrubber outlet is 0.78 versus 1.6 for the QG technology.

The process flow scheme of the main equipment of the Syngas Cooling and Conditiong Line is shown in the following:



Syngas is first heated by the hot shift effluent and then enters the Shift Reactor, 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 450°C.
In order to meet the required degree of CO_2 removal, a double stage shift, containing sulphur tolerant shift catalyst (dirty shift), is used.

The hot shifted Syngas outlet from first stage is cooled in a series of heat exchangers:

- Shift Feed Product Exchanger;
- HP BFW Heater;
- MP Steam Generator.

Both HP BFW Heater and MP Steam Generator receive BFW from HP BFW Preheater at the outlet of the 2nd Shift Reactor. Approximately 100 t/h of MP saturated steam @ 65 bar g are generated in the MP Steam Generators; steam is further injected into Syngas to allow the development of the CO shift reaction. BFW is heated up to 315°C before flowing to the RCG in order to generate HP saturated steam @ 138 bar g.

Inlet temperature to second stage shift is controlled to 295°C. Outlet temperature from second shift is approx. 323°C. The hot shifted Syngas outlet from the second stage is cooled in a series of heat exchangers:

- HP BFW Preheater
- LP Steam Generator

Downstream the LP Steam Generator, the process flow scheme is identical to Case D1, where the final cooling of the syngas is made generating VLP Steam and preheating the cold condensate from the Power Island.

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 with VLP steam and then reduced in pressure, down to 26 bar (g) in the Expander, generating electric energy.
Expanded clean Syngas is heated with VLP steam and sent to Unit 3000 gas turbines.

The process flow scheme of Unit 2300, Acid Gas Removal, is derived from Case D1 because of the similar characteristics of the syngas entering the Unit. The Power Island process scheme is also similar to Case D1, even if the flow rates of the interfaces of the CCU with the other Process Units are quite different.

PERFORMANCES

The following Table shows the preliminary performance of the plant.

TEXACO

RCG Technology -High pressure with CO_2 capture, separated H_2S and CO_2 removal - Rev.0

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	321.4
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2309.6**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1638.2
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	428.0
Expander power output	MWe	9.0
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**1000.4**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	127.9
Process Units consumption	MWe	51.5
Utility Units consumption	MWe	1.7
Offsite Units consumption (including sea cooling water system)	MWe	11.5
Power Islands consumption	MWe	15.1
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**207.7**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**792.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.3**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	38.0
Offsite Units consumption (sea cooling water system)	MWe	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**246.2**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**754.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.7**

CONCLUSIONS

The Radiant Cooler Gasification Technology allows reaching an increase of 1.2% on the overall net electrical efficiency of the IGCC with respect to the Quench Gasification Technology (Case D1). In fact, the main advantage of the process is the possibility to recover considerable heat from the radiant coolers, i.e. approximately 230 MWt that can be used for the production of approx. 650 t/h of HP steam @ 138 bar g.

The main difference of the syngas composition, with respect to the Quench Technology, is the water content at the scrubber outlet. Even if additional water for the development of the shift reaction is needed, the less water content allows reaching higher temperature of the syngas outlet from shift reactors because the same heat of reaction is used to heat lower mass flow rate. The higher temperature of the syngas allows producing higher HP steam flow rate.

However, the above advantage is partially reduced because of the lower syngas pressure that entails the reduction of the expander power production and the increase of the AGR power requirement.

To better compare the different technologies, a detailed economical analysis should also be made. Generally, if the same process arrangement of the Gasification Island were considered, i.e. 4 parallel trains of 33% capacity, the investment cost of the RC Technology is expected to be slightly higher thanthe QG technology, thus partially reducing the effect of the higher net electrical efficiency.

In any case, the improvement of both the investment and cost of energy is to be expected with respect to the Quench Technology, but the general conclusions of the Study (reference to be made to Section F) are not affected by their results.

As previously stated, this alternative was proposed when the study was conceptually concluded; therefore, on the basis of the above considerations, it was decided not to make further development.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE D.2

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
December 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.11

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.11 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.11 BASIC INFORMATION FOR EACH ALTERNATIVE

11.0 Case D.2

11.1 Introduction

The main features of the Case D.2 configuration of the IGCC Complex are:

- High pressure (65 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- Single stage dirty shift;
- Combined removal of H_2S and CO_2.

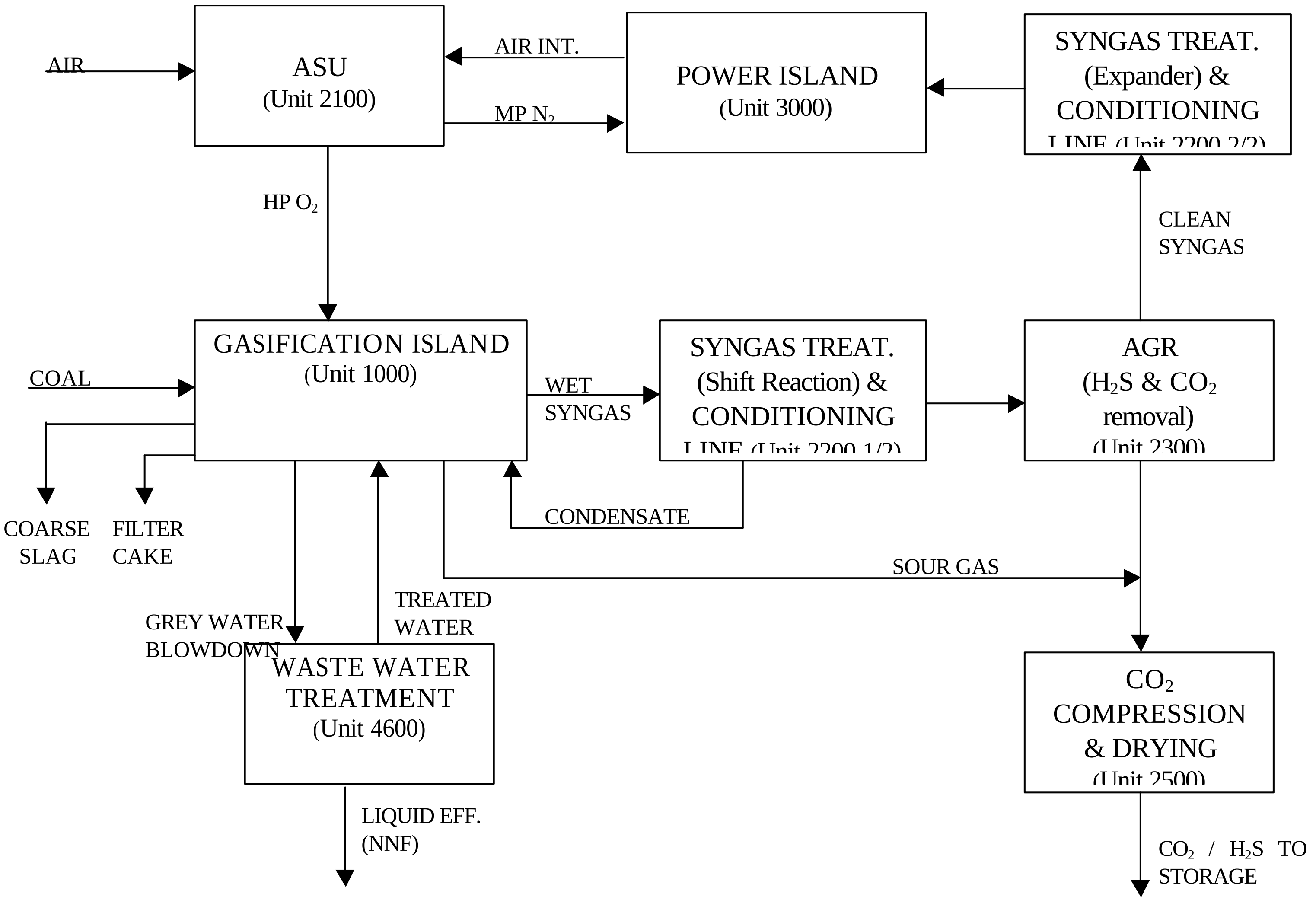
The combined removal of acid gases, H_2S and CO_2, is based on the Selexol process. The product of this process is a single stream to be compressed and delivered to plant B.L.
The degree of integration between the Air Separation (ASU) and the gas turbines is 50%. Gas Turbine power augmentation and syngas dilution for NO_x control are achieved with injection of compressed N_2 from ASU to the gas turbines.

The arrangement of the process units is:

Unit		Trains
1000	Gasification	4 x 33 % 2 x 66 %
2100	ASU	2 x 50 %
2200	Syngas Cooling and Hydrolysis	2 x 50%
	Syngas Expansion	1 x 100%
2300	AGR	1 x 100%
3000	Gas Turbine (PG 9351-FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO D.2 – IGCC COMPLEX BLOCK FLOW DIAGRAM



11.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	243
Pressure (bar)	AMB.	80	63
TOTAL FLOW			
Mass flow (kg/h)	323,200	278,800	1,389,000
Molar flow (kmol/h)		8,650	72,270
Composition (%vol)			
H_2			15.1
CO			15.6
CO_2			7.3
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H_2O			61
Others			0.08

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 3.0 for a general description of the Air Separation Unit.

The Block Flow Diagram attached to paragraph 11.3 indicates the interconnections of ASU with the other units of the IGCC. Characteristics of streams at Unit B.L. are detailed in para. 11.4.

Unit 2200: Syngas Treatment and Conditioning Line , shift and expansion

To follow the process description of this Unit reference should be made to the process flow diagram attached to paragraph 11.3.
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 H.P. 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 limititation 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 25 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.

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a high syngas pressure (56 bar g) and an extremely high CO_2/H_2S ratio (183/1). UOP believes that Selexol is the best alternative for the combined removal of CO_2 and H_2S. UOP provided information relevant to a Selexol process that achieves excellent performances on both the H_2S and CO_2 capture, with the disadvantage of a high power and steam consumption (reference is made to report "AGR Technical Comparison and Optimization" attached to Section H for all the details), thus making the alternative of combined removal of H_2S and CO_2 less efficient than the separate removal. This is against what can be conceptually expected. So a further optimization was discussed with UOP. UOP agreed with FW that a process flow scheme derived from Case D.1 may be proposed which eliminates some equipment not yet necessary as acid gas is not sent to the Sulphur Recovery Unit and tail gas is not recycled back. Performance data for this modified scheme have been evaluated by FW based on the corresponding data provided by UOP for Case D.1.
With reference to the first alternative proposed from UOP, this solution allows reducing the operating costs of the downstream CO_2/H_2S Compression Unit.
The only disadvantage of this alternative is a slightly higher steam requirement with respect to case D1.

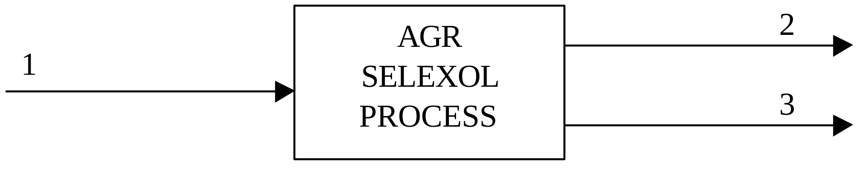
The interfaces of the Selexol process with the other Units are the following, as shown in the Block Flow Diagram attached to para 11.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line

Exit Streams

2. Treated Gas to Expander
3. CO_2 /H_2S gas to compression.



The Selexol solvent consumption, to make-up losses, is 120 m^3/year.

The proposed process matches the process specifications with reference to concentration of the treated gas exiting the Unit. In fact, the H_2S+COS concentration is 3 ppm. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large solvent circulation at low temperature, due to the adoption of a refrigerant package (Power Consumption = 32% of the overall AGR Power requirement).

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.

Together with CO_2 exiting the Unit, the following quantity of Hydrogen is sent to the final CO_2/H_2S destination, after compression:

- 250 kmol/h of Hydrogen, corresponding to 1.7% vol and to an overall thermal power of 16.8 MWt, i.e. almost 6 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constant of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 7.0 for the general information about the technology.

The main incoming stream of Unit 2500 flows from Unit 2300, Acid Gas Removal, and is the combination of two different streams delivered at the following pressure levels:

- LP stream : 10.0 barg
- VLP stream : 0.7 barg

As the Sulphur Recovery Unit is not required for this alternative, the following minor streams flowing from other Process Units are sent to compression:

- Sour Gas from Gasification Island : 0.7 barg
- Sour Gas from Sour Water Stripper: 1.3 barg

The product stream sent to final storage is mainly composed of CO_2 and H_2S. The main properties of the stream are as follows:

- Product stream : 627 t/h.
- Product stream : 110 bar.
- Composition :

	%wt
CO_2	99.3
H_2S	0.5
Others	0.2
TOTAL	100.0

Unit 3000: Power Island

The process flow diagrams and the equipment of this Unit are attached to paragraphs 11.3 and 11.8.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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.
- LP steam (6.5 barg) : steam imported from Syngas Treatment and Conditioning Line.
- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 11.5, Utilities Consumption.

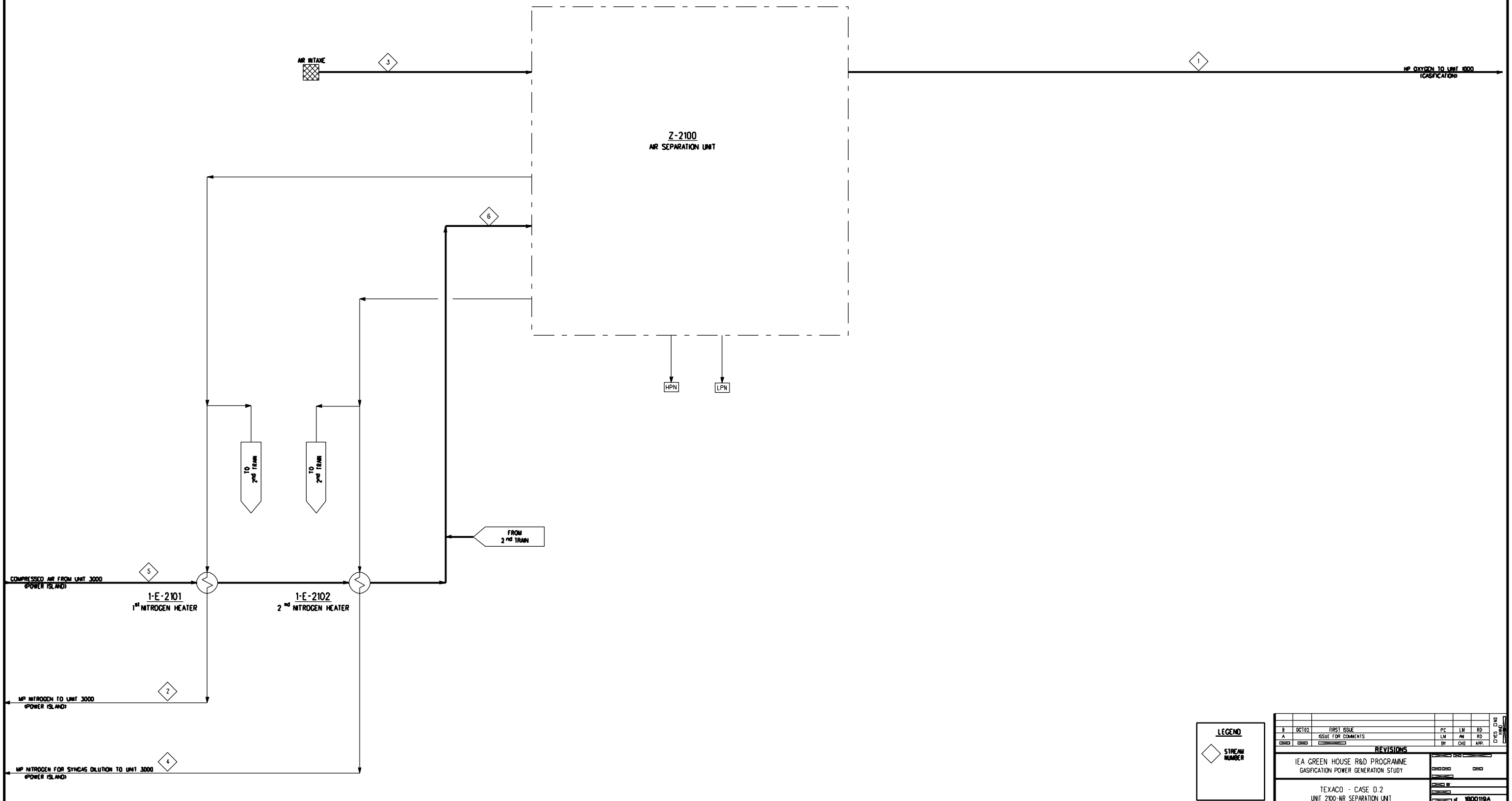
The net balance on each steam header inside the Power Island is positive, thus meaning that for all generation levels steam is imported from Process Units to the Power Island. Only steam at 85 bar g is exported to the Gasification Island. As a consequence, the generation levels of the Power Island are the same of the Process Units.

11.3 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 7.0 and 9.0.



B	OCT02	FIRST ISSUE	PC	LM	RD
A		ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

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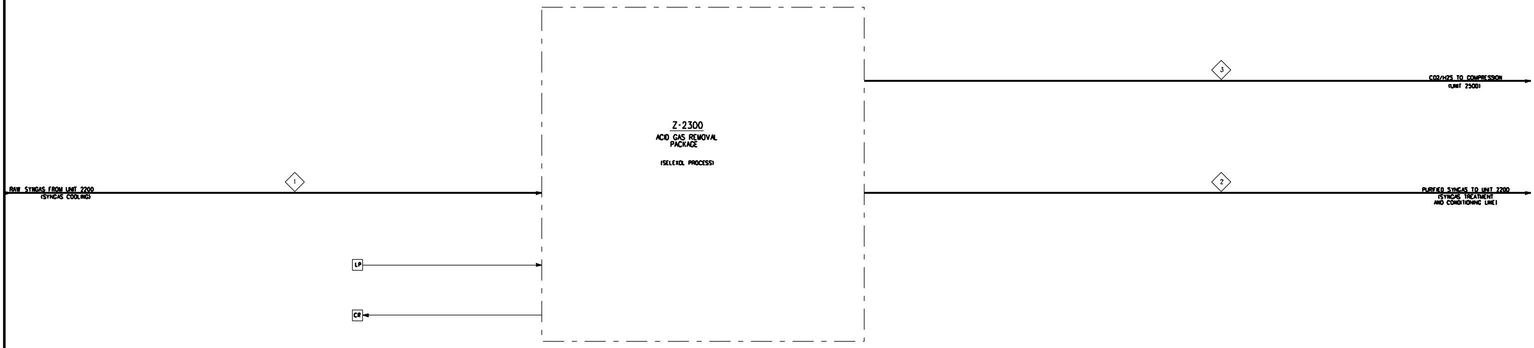
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE D.2
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2100 B



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STREAM NUMBER

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A		ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

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GASIFICATION POWER GENERATION STUDY

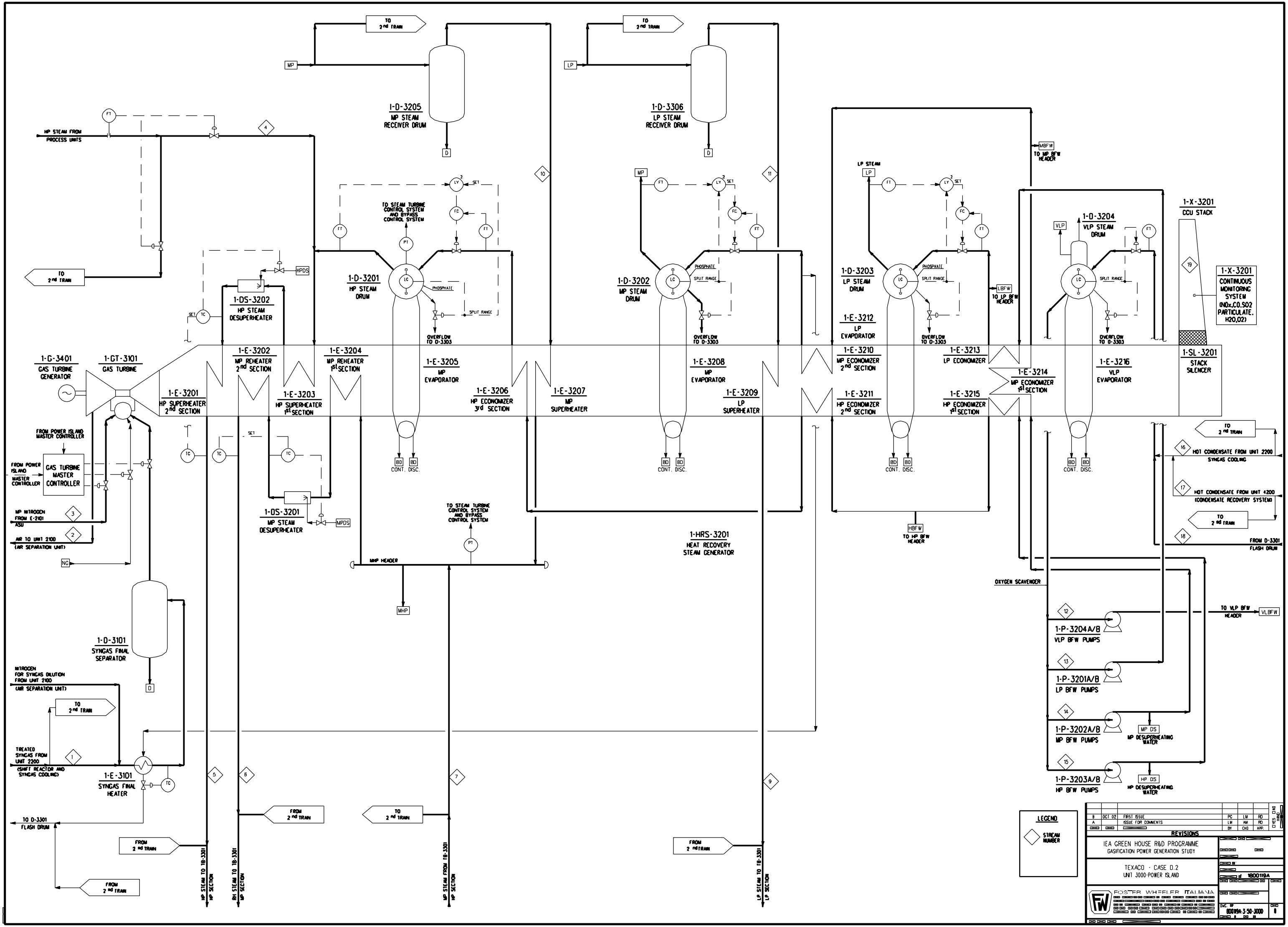
TEXACO - CASE D.2
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

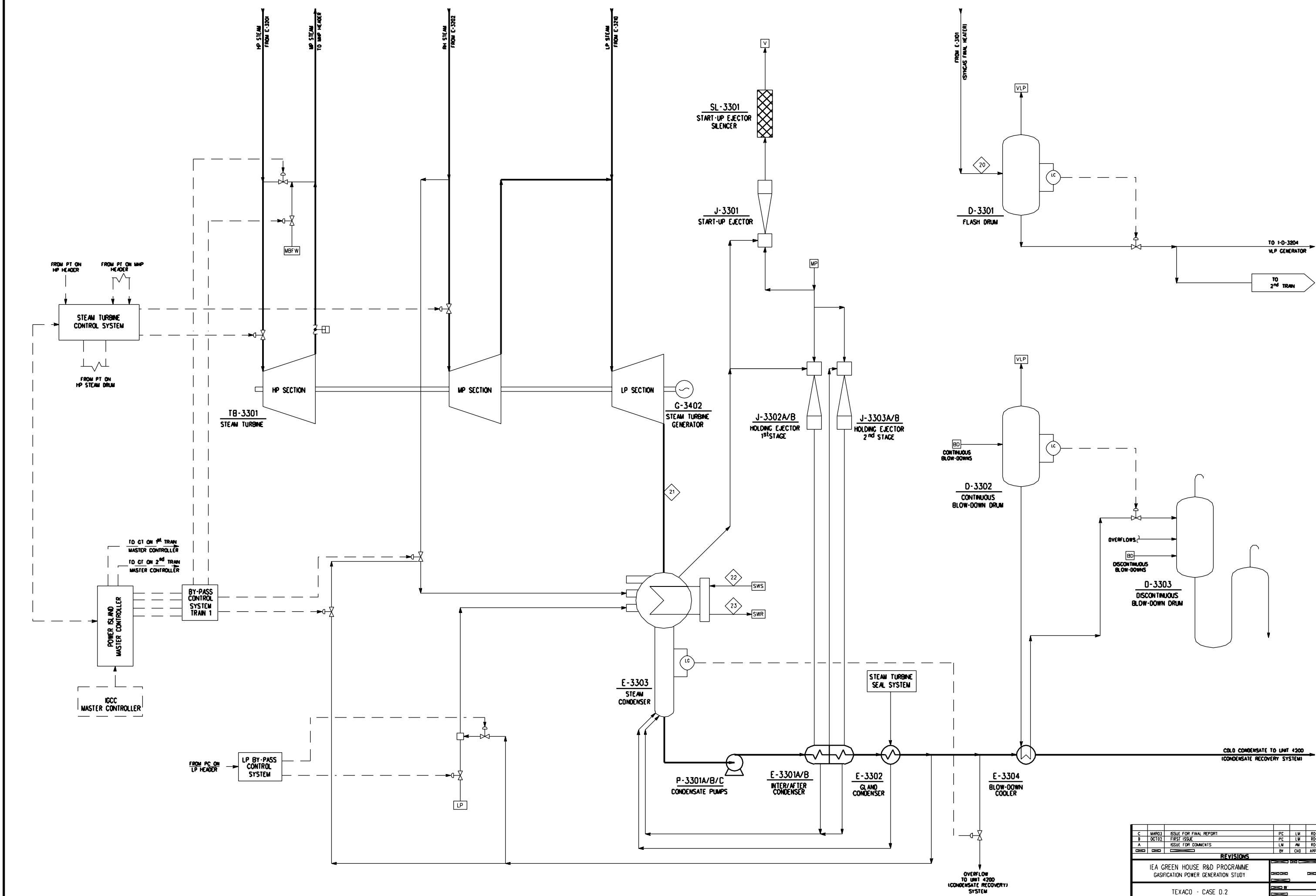
1BD0119A

DWG. Nº
BD0119A-3-50-2300

B



1-D-3205
MP STEAM RECEIVER DRUM
1-D-3306
LP STEAM RECEIVER DRUM
TO 2nd TRAIN
MP
LP
HP STEAM FROM PROCESS UNITS
1-D-3201
HP STEAM DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
1-D-3204
VLP STEAM DRUM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-DS-3202
HP STEAM DESUPERHEATER
1-DS-3201
MP STEAM DESUPERHEATER
HPDS
MPDS
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3208
MP EVAPORATOR
1-E-3209
LP SUPERHEATER
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3212
LP EVAPORATOR
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-SL-3201
STACK SILENCER
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
HBFW
TO HP BFW HEADER
VLP
BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NC
1-D-3101
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
MHP HEADER
MHP
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
HOT CONDENSATE FROM UNIT 2200 SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
1-P-3203A/B
HP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
HP DS
HP DESUPERHEATING WATER
LEGEND
STREAM NUMBER
B OCT 02 FIRST ISSUE
A ISSUE FOR COMMENTS
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.2
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1BD0119A



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A		ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

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IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE D.2
UNIT 3000-POWER ISLAND

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-3000 C

11.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2100: Air Separation Unit;
- UNIT 2200: Syngas Treatment and Conditioning Line;
- UNIT 2300: Acid Gas Removal;
- UNIT 3000: Power Island.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE	REVISION	0	1	Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	P.C.	P.C.	of 1
	CASE : TEXACO CASE D.2	APPROVED	R.D.	R.D.	
	UNIT : 2100 AIR SEPARATION UNIT	DATE	Nov 02	Mar 03	

STREAM	1	2	3	4	5	6				
	HP OXYGEN to Gasification	MP NITROGEN to each GT	Air Intake from Atmosphere	MP NITROGEN for Syngas Dilution	Air from each turbine	TOTAL Air from GTs				
Temperature (°C)	149	212,8	AMB.	208	400	210				
Pressure (bar)	79,8	21,6	AMB.	28,0	14,4	13,9				
TOTAL FLOW										
Mass flow (kg/h)	275209	348818	611160	123317	305580	611160				
Molar flow (kgmole/h)	8542	12458	21169	4404	10585	21169				
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	275209	348818	611160	123317	305580	611160				
Molar flow (kgmole/h)	8542	12458	21169	4404	10585	21169				
Molecular Weight	32,22	28,00	28,87	28,00	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				
O_2	95,00	2,15	20,86	2,15	20,86	20,86				
CH_4										
H_2S + COS										
Ar	3,50	0,26	0,89	0,26	0,89	0,89				
H2O		0,09	0,68	0,09	0,68	0,68				

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0		Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.		of 1
	CASE : TEXACO CASE D.2						APPROVED	R.D.		
	UNIT : 2200 Syngas treatment and conditioning line						DATE	Nov 02		

STREAM	1	2	3	4	5	6	7	8	9	10
	SYNGAS at Scrubber Outlet to Shift Reactor (2 Trains)	SYNGAS at Shift Reactor Outlet (2 Trains)	RAW SYNGAS to Acid Gas Removal (Total)	Purified SYNGAS from Acid Gas Removal (Total)	Treated SYNGAS to Power Island (Total)	Return Condensate to Gasification (Scrubber) (2 Trains)	Contaminated Condensate to Stripping (2 Trains)	Cold Condensate from Unit 4200 (2 Trains)		
Temperature (°C)	243,4	392	38	30	155	162	38	21		
Pressure (bar)	63,3	60,4	57,2	56,2	26,5	57,9	57,2	11,0		
TOTAL FLOW										
Mass flow (kg/h)	693705	693705	775710	152902	152902	603860	4250	604250		
Molar flow (kgmole/h)	36135	36135	38376	23913	23913					
LIQUID PHASE										
Mass flow (kg/h)						603860	4250	604250		
GASEOUS PHASE										
Mass flow (kg/h)	693705	693705	775710	152902	152902					
Molar flow (kgmole/h)	36135	36135	38376	23913	23913					
Molecular Weight	19,2	19,2	20,2	6,4	6,4					
Composition (vol %)										
H_2	15,13	29,25	55,04	87,28	87,28					
CO	15,64	1,51	2,84	4,45	4,45					
CO_2	7,33	21,46	40,22	5,89	5,89					
N_2	0,36	0,36	0,68	1,08	1,08					
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	0,42	0,42	0,79	1,25	1,25					
H2O	60,99	46,87	0,19	0,02	0,02					

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE						REVISION	0		Sheet 1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	P.C.		of 1
	CASE : TEXACO CASE D.2						APPROVED	R.D.		
	UNIT : 2300 Acid Gas Removal						DATE	Nov 02		
STREAM	1	2	3							
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	Combined acid gas and CO2 to Compression							
Temperature (°C)	38	30	12							
Pressure (bar)	57,2	56,2	4,5							
TOTAL FLOW										
Mass flow (kg/h)	775710	152902	627575							
Molar flow (kgmole/h)	38376	23913	14556							
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	775710	152902	627575							
Molar flow (kgmole/h)	38376	23913	14556							
Molecular Weight	20,2	6,4	43,1							
Composition (vol %)										
H_2	55,04	87,28	1,72							
CO	2,84	4,45	0,17							
CO_2	40,22	5,89	97,17							
N_2	0,68	1,08	0,02							
O_2	0,00	0,00	0,00							
CH_4	0,02	0,03	0,00							
H_2S + COS	0,22	0,00	0,58							
Ar	0,79	1,25	0,04							
H2O	0,19	0,02	0,30							

	IGCC HEAT & MATERIAL BALANCE				
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME				
	CASE : TEXACO CASE D.2				
	UNIT : 3000 POWER ISLAND				
Stream	**Description**	**Flowrate t/h**	**Temperature °C**	**Pressure bar a**	**Entalphy kJ/kg**
1	Treated SYNGAS from Syngas Cooling (*) (1)	76,45	155	26,5	319
2	Extraction Air to Air Separation Unit (*)	305,58	400	14,4	-
3	MP Nitrogen from ASU (*)	348,8	213	21,6	-
4	HP Steam from Process Units (*)	26,28	348	161,0	2582
5	HP Steam to Steam Turbine (*)	231,58	552	156,5	3447
6	Hot RH Steam to MP Steam Turbine (*)	368,85	527	36,7	3510
7	MP Steam from HP Steam Turbine (*)	231,58	346	39,7	3084
8	- - NOT USED - -				
9	LP Steam to Steam Turbine (*)	234,09	237	6,1	2930
10	MP Steam to MP -Superheater (*)	137,27	252	41,0	2800
11	LP Steam to LP Superheater (*)	234,09	167	7,2	2765
12	BFW to VLP Pumps (*)	36,20	119	1,9	499
13	BFW to LP BFW Pumps (*)	299,19	119	1,9	499
14	BFW to MP BFW Pumps (*)	160,93	119	1,9	499
15	BFW to HP BFW Pumps (*)	235,17	119	1,9	499
16	Hot Condensate returned from Unit 2200 (*)	604,25	95	13,0	454
17	Hot Condensate returned from CR (*)	84,60	94	1,9	394
18	Water from Flash Drum (*)	20,93	119	1,9	499
19	FLUE GAS AT STACK (*) (2)	2556,00	129	AMB.	123
20	Condensate from Syngas Final Heater (*)	46,56	170	54,2	722
21	LP Steam Turbine Exhaust	1208,50	21,7	0,026	2220
22	Sea Water Supply to Steam Condenser	87694	12	3,0	51
23	Sea Water Return from Steam Condenser	87694	19	2,1	80

(*) flowrate for one train

(1) Syngas composition as per stream 5 of Material Balance for Unit 2200 .

(2) Flues gas molar composition: N_2: 75.5%; H_2O: 11.6%; O_2: 10.6%; CO_2: 1.4%; Ar: 0.9%.

11.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

	FOSTER WHEELER	CLIENT:	IEA GHG	REVISION	Rev.0	Rev.1	Rev.2
		PROJECT:	GASIFICATION POWER GENERATION STUDY	DATE	Sep 02		
		LOCATION:	Netherlands	ISSUED BY	L.M.		
		FWI Nº:	1- BD 0119A	CHECKED BY	P.C.		
				APPROVED BY	R.D.		

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE D.2 - HP with CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Capacity	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 Cooling and COS Hydrolysis**		**-52,6**	**-121,5**	**-528,5**	**-20,4**	**52,6**	**121,5**	**528,5**	**72,4**	**52,0**	
2300	**Acid Gas Removal**				**78,6**						**78,6**	
3000	**POWER ISLANDS UNITS**		**47,5**	**121,5**	**416,4**	**20,4**	**-52,6**	**-121,5**	**-528,5**	**-72,4**		
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**	**169,2**	**0,0**

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
		PROJECT:	GASIFICATION POWER GENERATION STUDY	sept-02
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RM

WATER CONSUMPTION SUMMARY - TEXACO - CASE D2 - HP with combined CO_2 and H_2S 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**	289		3123	
2100	**Air Separation Unit**				25691
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**			3496	
2500	**CO_2 Compression and drying**				(6312)
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			1752	
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		3		87693
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4100	**Cooling Water (Sea Water / Machinery Water)**				14970
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	26	-26		
	Other Units		23	352	
	BALANCE excluding CO_2 compression	315	0	8723	128354
	BALANCE including CO_2 compression	315	0	8723	134666

Note: Minus prior to figure means figure is generated

FOSTER WHEELER	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	sept-02
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE D2 - HP with combined CO_2 and H_2S removal

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13928**
2100	**Air Separation Unit**	**131336**
2200	**Syngas treatment and conditioning line**	**250**
2300	**Acid Gas Removal**	**28018**
2500	**CO_2 Compression and drying**	**(39800)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4658**
3200	**Heat Recovery Steam Generator**	**4716**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2067**
3500	**Miscellanea**	**521**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10446**
	Additional consumption including CO_2 compression and drying	**(500)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**348**
	Other Units	**667**
	BALANCE excluding CO_2 compression	**197315**
	BALANCE including CO_2 compression	**237615**

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

11.6 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

TEXACO

Case D.2 - HIGH PRESSURE with CO_2 capture, combined H_2S and CO_2 removal - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	323.2
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2322.5**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1638.3
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	572.0
Steam turbine power output	MWe	397.4
Expander power output	MWe	10.5
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**979.9**
IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	131.3
Process Units consumption	MWe	42.2
Utility Units consumption	MWe	1.7
Offsite Units consumption (including sea cooling water system)	MWe	10.1
Power Islands consumption	MWe	12.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**197.3**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**782.60**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**42.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.7**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	39.8
Offsite Units consumption (sea cooling water system)	MWe	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**237.6**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**742.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**42.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.0**

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)	17398
Slag (Carbon =~4% wt)	708
Net Carbon flowing to Process Units (A)	16690
Liquid Storage	
CO	24.7
CO_2	14143.6
CH_4	0.3
Total to storage (B)	14168.6
Emission	
CO_2	2515.2
CO	6.2
Total Emission	2521.4
Overall CO_2 removal efficiency, % (B/A)	84.9

11.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic is shown at Section B - para 2.0, and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the IGCC Complex are summarised in this section.

11.7.1 Gaseous Emissions

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.

Table 11.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 11.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	710.5
Flow, $Nm^3/h^{(1)}$	2,759,750
Temperature, °C	129
Composition	(%vol)
Ar	0.97
N_2	75.47
O_2	10.60
CO_2	1.36
H_2O	11.60
Emissions	$mg/Nm^{3\ (1)}$
NOx	50
SOx	0.7
CO	31
Particulate	4.5

(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 11.2

Table 11.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1420.0
Flow, $Nm^3/h^{(1)}$	5,519,500
Temperature, °C	129
Emissions	kg/h
NOx	276.0
SOx	3.9
CO	171.1
Particulate	24.8

(1) Dry gas, O_2 content 15%vol

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.

A small continuous emission is generated in the Waste Water Treatment plant; in fact a small burner is installed to destroy the biogas stream coming from the anaerobic section of the plant.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation prevent them.

11.7.2 Liquid Effluent

The effluent from the Waste Water Treatment (Unit 4600) is recovered and recycled back to the gasification island.

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	:	132,200	m^3/h
• Temperature	:	19	°C
• Cl_2	:	<0.05	ppm

11.7.3 Solid Effluent

The process does not produce any solid waste, except for typical industrial plant waste e.g. (sludge from Waste Water Treatment etc.). In any case, the waste water sludge (expected flow rate: 2.5 m^3/h) can be recovered, recycled back to the Gasification Island and burned into the Gasifier.

In addition, the Gasification Island is expected to produce the following solid by-products:

<u>Fine Slag (Filter Cake)</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.

11.8 Equipment List

The duty specifications of the equipment and process packages are included in this paragraph.

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
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		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
1	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14000 kW
2	**E-2101**	**1st Nitrogen heater**	Shell & Tube			19 / 27	430 / 243		DUTY = 14000 kW
1	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3560 kW
2	**E-2101**	**2nd Nitrogen heater**	Shell & Tube			19 / 31	278 / 239		DUTY = 3560 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 %
				MP N_2 flow rate to GTs = 685 t/h		27			Nitrogen purity = 98 %
				HMP N_2 flow rate to AGR = 46 t/h		36			Nitrogen purity = 99,99 %
				LP N_2 flow rate to Proc Unit = 2.7		14			Nitrogen purity = 99,99 %
				Air flow rate from GTs = 639 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A		

REVISION	Rev.0	Rev.1	Rev.2	Rev.3
DATE	Oct-02			
ISSUED BY	L.M.			
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APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				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
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
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
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
2	E-2205	VLP Steam Generator	Kettle			7 / 68	175 / 205		DUTY = 22710 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)				Shell/tube	Shell/tube		
1	E-2206 A/B	Condensate Preheater	Shell & Tube			20 / 68	130 / 185		DUTY = 50685 kW H2 service H2/Wet H2S serv. on channel side
2	E-2206 A/B	Condensate Preheater	Shell & Tube			20 / 68	130 / 185		DUTY = 50685 kW H2 service H2/Wet H2S serv. on channel side
	E-2207	Expander Feed Heater	Shell & Tube			7 / 68	165 / 175		DUTY = 20610 kW H2 service H2/Wet H2S serv. on channel side
	E-2208	Syngas pre-heater	Shell & Tube			7 / 68	165 / 175		DUTY = 10440 kW H2 service H2/Wet H2S serv. on channel side

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS							
1	D-2201	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service
2	D-2201	Condensate Separator	Vertical			68	205		Wet H2S service/H2 service
1	D-2202	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service
2	D-2202	Condensate Separator	Vertical			68	185		Wet H2S service/H2 service
1	D-2203 A/B	Condensate Separator	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
2	D-2203 A/B	Condensate Separator	Vertical			68	105		Equipped with demister Wet H2S service/H2 service
	D-2204	Process Condensate Accumulator	Horizontal			68	190		
		PUMPS							
	P-2201 A/B	Process condensate pump	centrifugal		250				One operating, one spare
		REACTOR							
1	R-2201	Shift Catalyst Reactor	vertical			68	464		H2 service Wet H2S service
2	R-2201	Shift Catalyst Reactor	vertical			68	464		H2 service Wet H2S service

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		EXPANDERS							
	EX- 2201	Purified Syngas Expander	centrifugal	Pout/Pin = 0,51 Flow = 590 kNm^3/h Pow = 10.5 MWe					
		GENERATORS		P, MWe					
	G-3201	Expander Generator		10,5					
		PACKAGE UNITS							
	Z-2201	Catalyst Loading System							
	Z-2202	Shift Catalyst							Catalyst volume: 150 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3100 -Gas Turbine - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				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							
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
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

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS							
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							
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							
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	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		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

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		DATE	Oct-02			
		ISSUED BY	L.M.			
		CHECKED BY	R.D.			
		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
1	D-3201	**HP steam Drum**							Included in 1-HRS-3201
1	D-3202	**MP steam drum**							Included in 1-HRS-3201
1	D-3203	**LP steam drum**							Included in 1-HRS-3201
1	D-3204	**VLP steam drum with degassing section**							Included in 1-HRS-3201
1	E-3201	**HP Superheater 2nd section**							Included in 1-HRS-3201
1	E-3202	**MP Reheater 2nd section**							Included in 1-HRS-3201
1	E-3203	**HP Superheater 1st section**							Included in 1-HRS-3201
1	E-3204	**MP Reheater 1st section**							Included in 1-HRS-3201
1	E-3205	**HP Evaporator**							Included in 1-HRS-3201
1	E-3206	**HP Economizer 3rd section**							Included in 1-HRS-3201
1	E-3207	**MP Superheater**							Included in 1-HRS-3201
1	E-3208	**MP Evaporator**							Included in 1-HRS-3201
1	E-3209	**LP Superheater**							Included in 1-HRS-3201
1	E-3210	**MP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3211	**HP Economizer 2nd section**							Included in 1-HRS-3201
1	E-3212	**LP Evaporator**							Included in 1-HRS-3201
1	E-3213	**LP Economizer**							Included in 1-HRS-3201
1	E-3214	**MP Economizer 1st section**							Included in 1-HRS-3201
1	E-3215	**HP Economizer 1st section**							Included in 1-HRS-3201
1	E-3216	**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Netherlands PROJ. NAME: Gasification Power Generation Study CONTRACT N. 1- BD- 0119 A	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
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		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2	**HRSG-3201**	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple						
2	D-3201	**HP steam Drum**							Included in 2-HRS-3201
2	D-3202	**MP steam drum**							Included in 2-HRS-3201
2	D-3203	**LP steam drum**							Included in 2-HRS-3201
2	D-3204	**VLP steam drum with degassing section**							Included in 2-HRS-3201
2	E-3201	**HP Superheater 2nd section**							Included in 2-HRS-3201
2	E-3202	**MP Reheater 2nd section**							Included in 2-HRS-3201
2	E-3203	**HP Superheater 1st section**							Included in 2-HRS-3201
2	E-3204	**MP Reheater 1st section**							Included in 2-HRS-3201
2	E-3205	**HP Evaporator**							Included in 2-HRS-3201
2	E-3206	**HP Economizer 3rd section**							Included in 2-HRS-3201
2	E-3207	**MP Superheater**							Included in 2-HRS-3201
2	E-3208	**MP Evaporator**							Included in 2-HRS-3201
2	E-3209	**LP Superheater**							Included in 2-HRS-3201
2	E-3210	**MP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3211	**HP Economizer 2nd section**							Included in 2-HRS-3201
2	E-3212	**LP Evaporator**							Included in 2-HRS-3201
2	E-3213	**LP Economizer**							Included in 2-HRS-3201
2	E-3214	**MP Economizer 1st section**							Included in 2-HRS-3201
2	E-3215	**HP Economizer 1st section**							Included in 2-HRS-3201
2	E-3216	**VLP Evaporator**							Included in 2-HRS-3201

FOSTER WHEELER

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
LOCATION: Netherlands	DATE	Oct-02			
PROJ. NAME: Gasification Power Generation Study	ISSUED BY	L.M.			
CONTRACT N. 1- BD- 0119 A	CHECKED BY	R.D.			
	APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
	E-3304	**Blow-Down Cooler**	Shell & Tube			20,2 / 4	58 / 140		DUTY = 850 kW
		DRUMS							
	D-3301	**Flash Drum**	vertical			3,5	230		
	D-3302	**Continuous Blow-down Drum**	vertical			3,5	140		
	D-3303	**Discontinuous Blow-down Drum**	vertical			3,5	140		
		PACKAGES							
	Z-3301	**Steam Turbine & Condenser Package**		397 MW					
	TB-3301	Steam Turbine							Included in Z - 3201
	E-3301A/B	Inter/After condenser							
	E-3302	Gland Condenser							Included in Z - 3201
	E-3303	Steam Condenser							Included in Z - 3201
	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

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		APPROVED BY	R.D.			

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Texaco Case D.2 - High Pressure with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	G-3401	Gas Turbine Generator							Included in 1 -Z- 3101
2	G-3401	Gas Turbine Generator							Included in 2 -Z- 3101
	G-3402	Steam Turbine Generator							Included in Z- 3301

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE D.3

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

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SECTION D.12

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.12 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.12 BASIC INFORMATION FOR EACH ALTERNATIVE

12.0 Case D.3

12.1 Introduction

The main features of the Case D.3 configuration of the IGCC Complex are:

- High pressure (65 bar g) Texaco Gasification;
- Coal Water Slurry Feed;
- Gasifier Quench Type;
- Double 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 Unit (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and syngas dilution for NO_x 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.

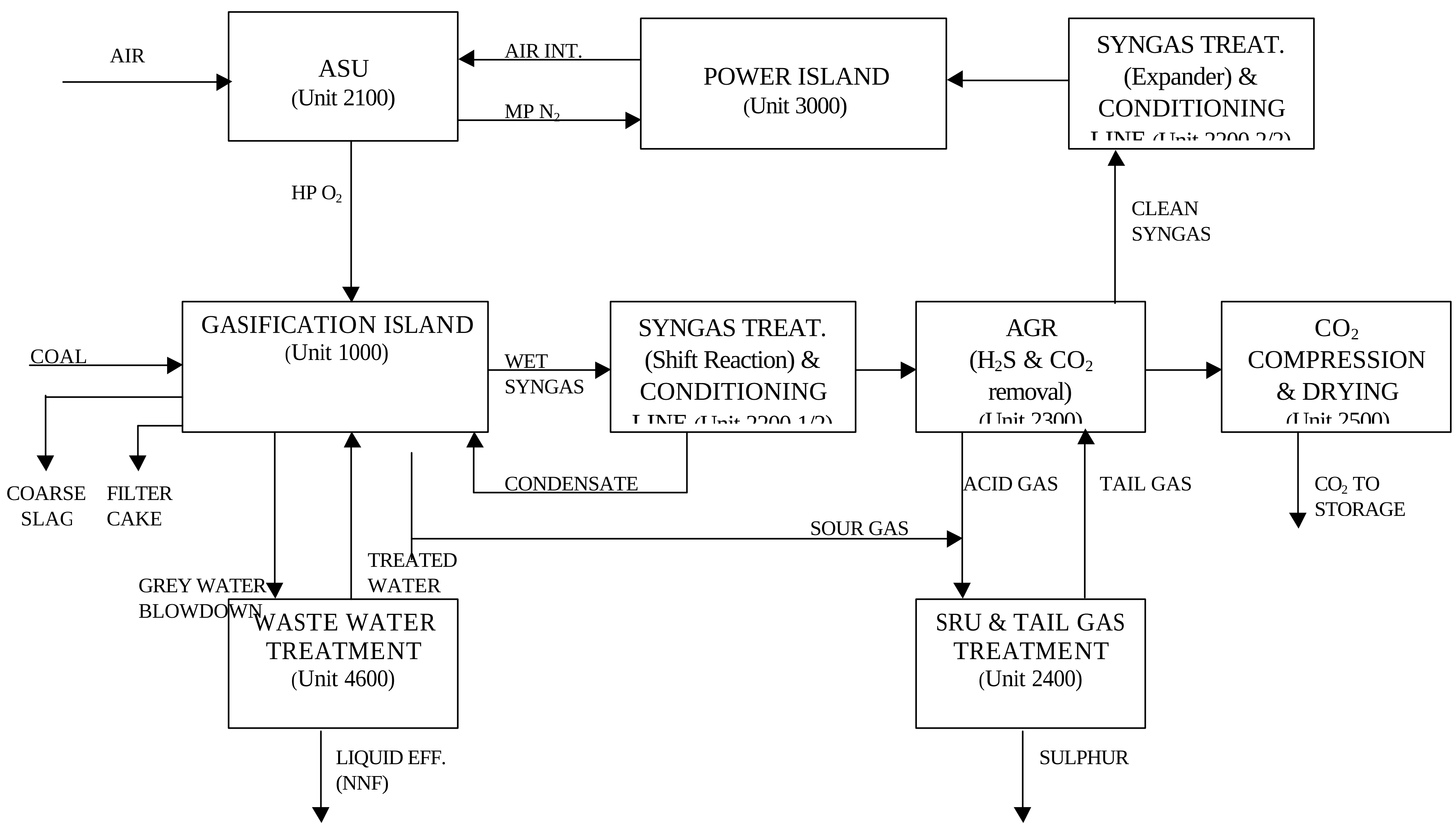
The arrangement of the process units is :

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)	2 x 50%
	HRSG	2 x 50%
	Steam Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

TEXACO D.3 – IGCC COMPLEX BLOCK FLOW DIAGRAM



12.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	243
Pressure (bar)	AMB.	80	63
TOTAL FLOW			
Mass flow (kg/h)	323,100	278,700	1,388,000
Molar flow (kmol/h)		8,650	72,260
Composition (%vol)			
H_2			15.1
CO			15.6
CO_2			7.3
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H_2O			61
Others			0.08

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 12.3 indicates the interconnections of ASU with the other units of the IGCC.

Unit 2200: Syngas Treatment and Conditioning Line , Shift and Expansion

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 12.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 62 barg and 240°C, 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 408°C. In order to meet the required degree of CO conversion a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. The hot shifted syngas outlet from the first stage is cooled in a series of heat exchangers:

E-2201 Shift feed product exchanger
E-2202 HP Steam Generator
E-2203 MP Steam Generator

Inlet temperature to the second stage shift is controlled to 275 °C. Outlet temperature from second shift is 313°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:

E-2204 MP Steam Generator
E-2205 LP Steam Generator
E-2206 VLP Steam Generator
E-2207 A/B Condensate Preheater

Process condensate collected Separator Drums D2201/3 during the cooling process of the syngas is accumulated in D-2205 and from there pumped back to the syngas scrubber of Unit 1000.
The final cooling step of the syngas takes place in E-2208, where syngas is cooled against cooling water. The process condensate separated after this step is heavily contaminated, so it is not recycled to gasification but is routed to Unit 4000, Sour Water Stripper.
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 limititation of the exchangers involved. Downstream D-2204 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-2209 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-2210 with VLP steam and sent to Gas Turbines (Unit 3000).

Unit 2300: Acid Gas Removal (AGR)

This Unit utilises Selexol as acid gas solvent.

Unit 2300 is characterised by a high syngas pressure (55 bar g) and an extremely high CO_2/H_2S ratio (188/1).

Both alternatives provided by UOP, based on a Selexol Solvent, enhance the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit. It was later known that a high N_2 concentration in the product CO_2 stream has a negative impact for CO_2 storage, particularly if the CO_2 is used for enhanced oil recovery.

Therefore, it was decided to use a flow scheme derived from case D1, without Nitrogen stripping.

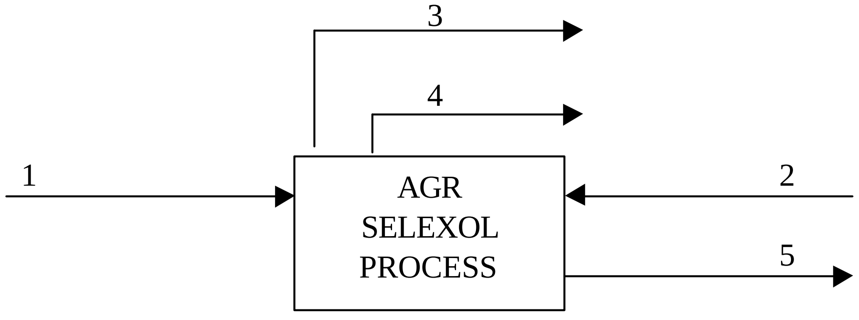
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 12.3:

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line
2. Recycle Gas (Tail Gas) from Sulphur Recovery Unit

Exit Streams

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 115 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 before (Power Consumption = 32% of the overall AGR Power requirement) flowing to the CO_2 absorber.
The CO_2 removal rate is more than 82% as required, allowing to reach an overall CO_2 capture of 80% 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 18% 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:

- 170 kmol/h of Hydrogen, corresponding to 1,25% vol and to an overall thermal power of 11,5 MWt, i.e. more than 3,7 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 30 ppmvd.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constant of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

Unit 2400: SRU and TGT

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 66.8 t/day and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 30 barg.

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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

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 : 589,0 t/h.
- Product stream : 110 bar.
- Composition :

	%wt
CO_2	99,5
N_2	0,4
H_2+Others	0,1
TOTAL	100,0

Unit 3000: Power Island

The Process Flow Diagrams of this Unit are attached to paragraphs 12.3.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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 Treatment and Conditioning Line and recycled back to the HRSG.

Flow rate of the above interfaces of the Plant are shown in table attached to para 12.4, Utilities Consumption.

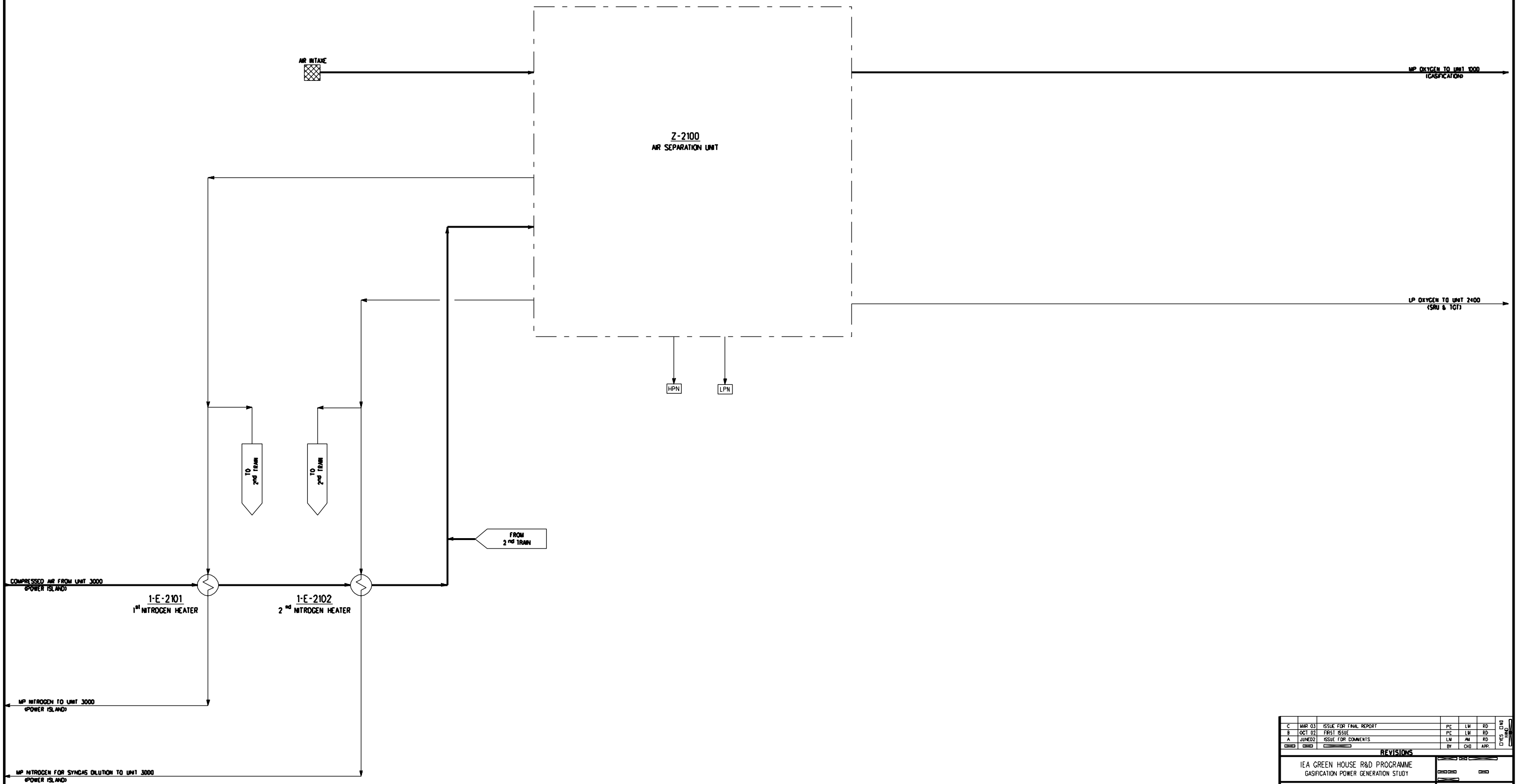
The net balance on each steam header inside the Power Island is positive, thus meaning that for all generation levels steam is imported from Process Units to the Power Island. Only steam at 85 barg is exported to the Gasification Island. As a consequence, the generation levels of the Power Island are the same of the Process Units.

12.3 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



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B	OCT 02	FIRST ISSUE	PC	LM	RD
A	JUNE02	ISSUE FOR COMMENTS	LM	AM	RD
			BY	CHD	APP.

REVISIONS

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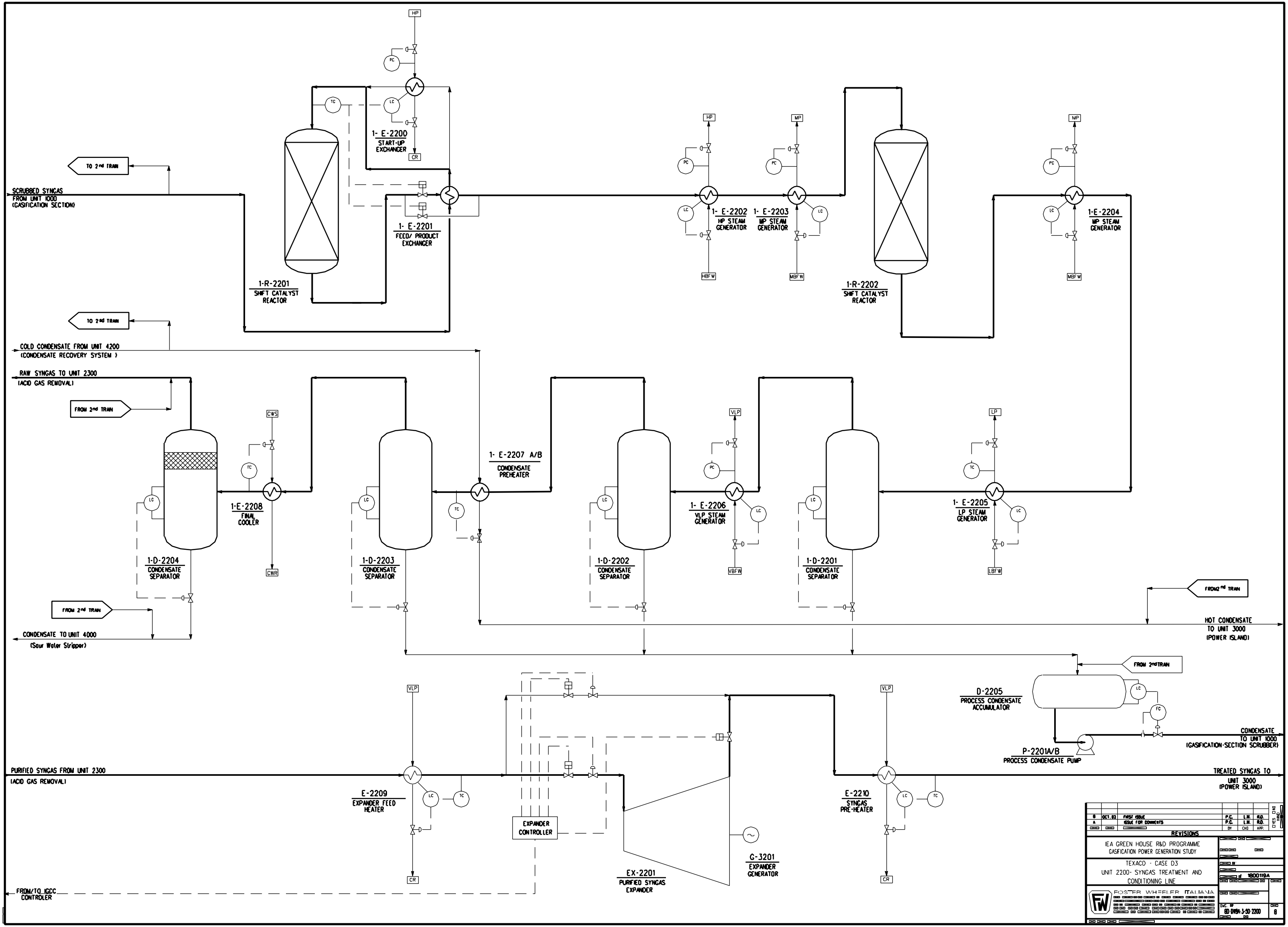
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE D.3
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº 1BD0119A-3-50-2100 C


SCRUBBED SYNGAS FROM UNIT 1000 (GASIFICATION SECTION)
TO 2nd TRAIN
1-R-2201 SHIFT CATALYST REACTOR
1- E-2200 START-UP EXCHANGER
1- E-2201 FEED/ PRODUCT EXCHANGER
1- E-2202 HP STEAM GENERATOR
1- E-2203 MP STEAM GENERATOR
1-R-2202 SHIFT CATALYST REACTOR
1-E-2204 MP STEAM GENERATOR
HP
MP
CR
HBFW
MBFW
COLD CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300 (ACID GAS REMOVAL)
FROM 2nd TRAIN
1-D-2204 CONDENSATE SEPARATOR
1-E-2208 FINAL COOLER
CWS
CWR
1-D-2203 CONDENSATE SEPARATOR
1- E-2207 A/B CONDENSATE PREHEATER
1-D-2202 CONDENSATE SEPARATOR
1- E-2206 VLP STEAM GENERATOR
VLP
VBFW
1-D-2201 CONDENSATE SEPARATOR
1- E-2205 LP STEAM GENERATOR
LP
LBFW
CONDENSATE TO UNIT 4000 (Sour Water Stripper)
HOT CONDENSATE TO UNIT 3000 (POWER ISLAND)
D-2205 PROCESS CONDENSATE ACCUMULATOR
P-2201A/B PROCESS CONDENSATE PUMP
CONDENSATE TO UNIT 1000 (GASIFICATION-SECTION SCRUBBER)
PURIFIED SYNGAS FROM UNIT 2300 (ACID GAS REMOVAL)
E-2209 EXPANDER FEED HEATER
EXPANDER CONTROLLER
EX-2201 PURIFIED SYNGAS EXPANDER
G-3201 EXPANDER GENERATOR
E-2210 SYNGAS PRE-HEATER
TREATED SYNGAS TO UNIT 3000 (POWER ISLAND)
FROM/TO IGCC CONTROLER
PC
LC
TC
FC
B OCT.92 FIRST ISSUE P.C. L.M. R.O.
A ISSUE FOR COMMENTS P.C. L.M. R.O.
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D3
UNIT 2200- SYNGAS TREATMENT AND CONDITIONING LINE
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FOSTER WHEELER ITALIANA
BD-9454-3-50-2200
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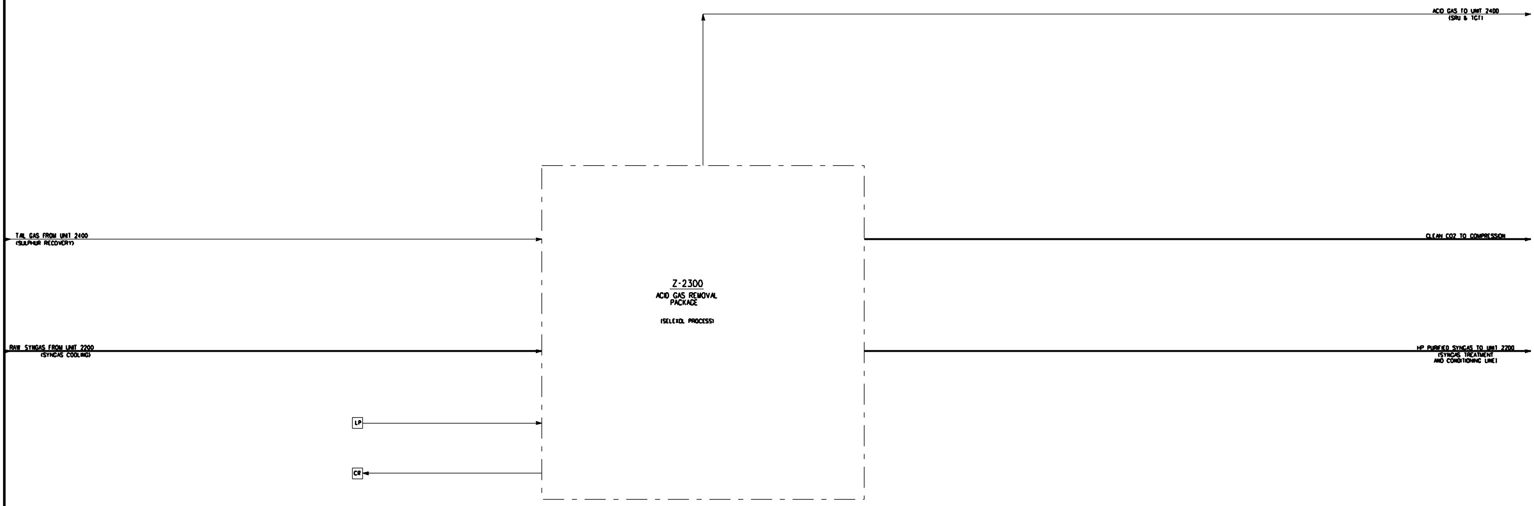

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B	OCT 02	FIRST ISSUE	PC	LM	RD
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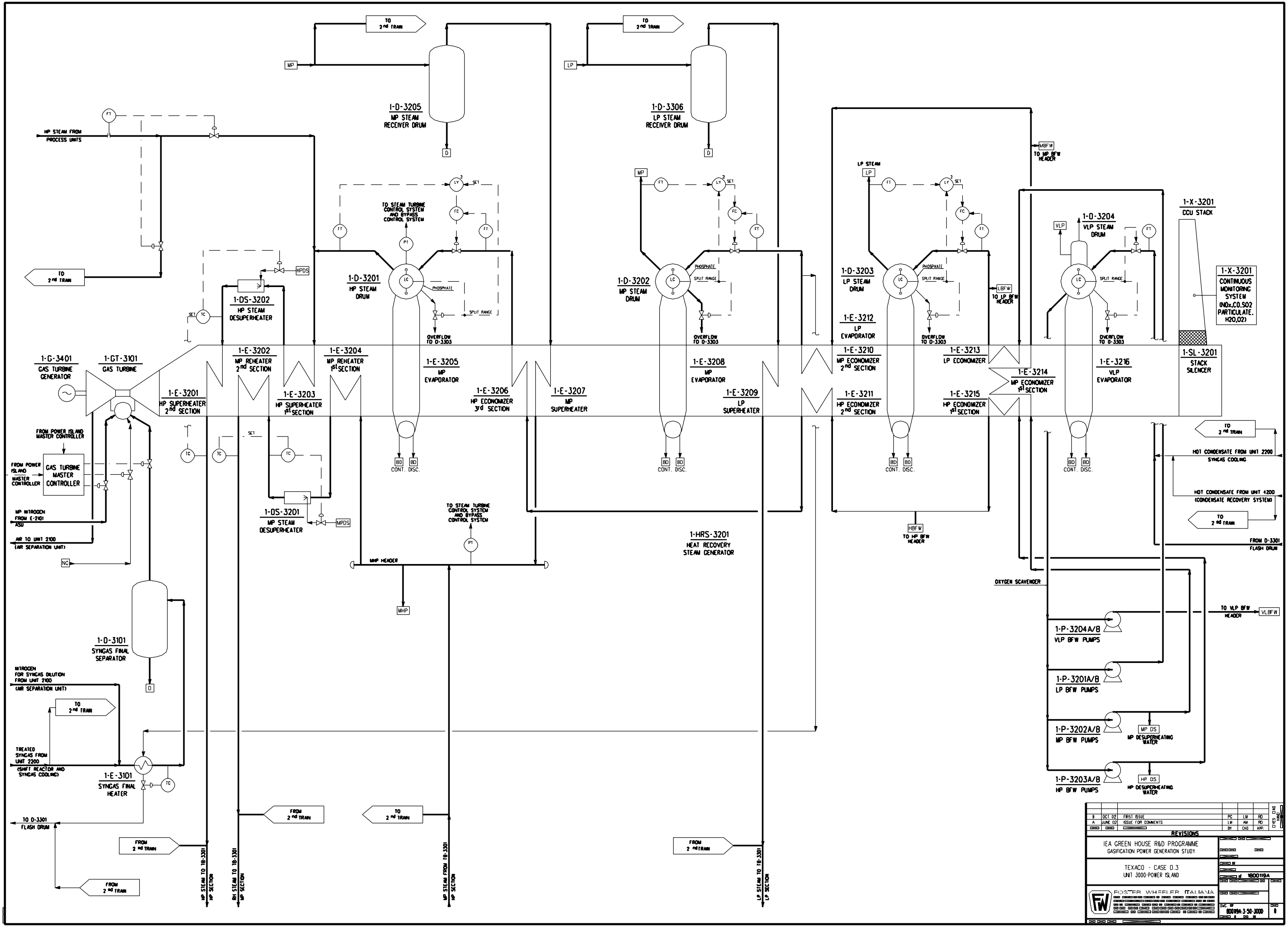
GASIFICATION POWER GENERATION STUDY

TEXACO - CASE D.3
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº BD0119A-3-50-2300 C


1-D-3205
MP STEAM RECEIVER DRUM
1-D-3306
LP STEAM RECEIVER DRUM
TO 2nd TRAIN
MP
LP
D
HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
1-D-3202
MP STEAM DRUM
1-D-3203
LP STEAM DRUM
1-D-3204
VLP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
HPDS
MPDS
1-DS-3202
HP STEAM DESUPERHEATER
1-DS-3201
MP STEAM DESUPERHEATER
LP STEAM
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
HBFW
TO HP BFW HEADER
VLP
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-SL-3201
STACK SILENCER
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3208
MP EVAPORATOR
1-E-3209
LP SUPERHEATER
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3212
LP EVAPORATOR
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
BD BD
CONT. DISC.
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NC
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
MHP HEADER
MHP
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
1-D-3101
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TO 2nd TRAIN
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
FROM 2nd TRAIN
FROM 2nd TRAIN
TO 2nd TRAIN
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 MP SECTION
LP STEAM TO TB-3301 LP SECTION
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
TO 2nd TRAIN
FROM D-3301 FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
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IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.3
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
800119A-3-50-3000
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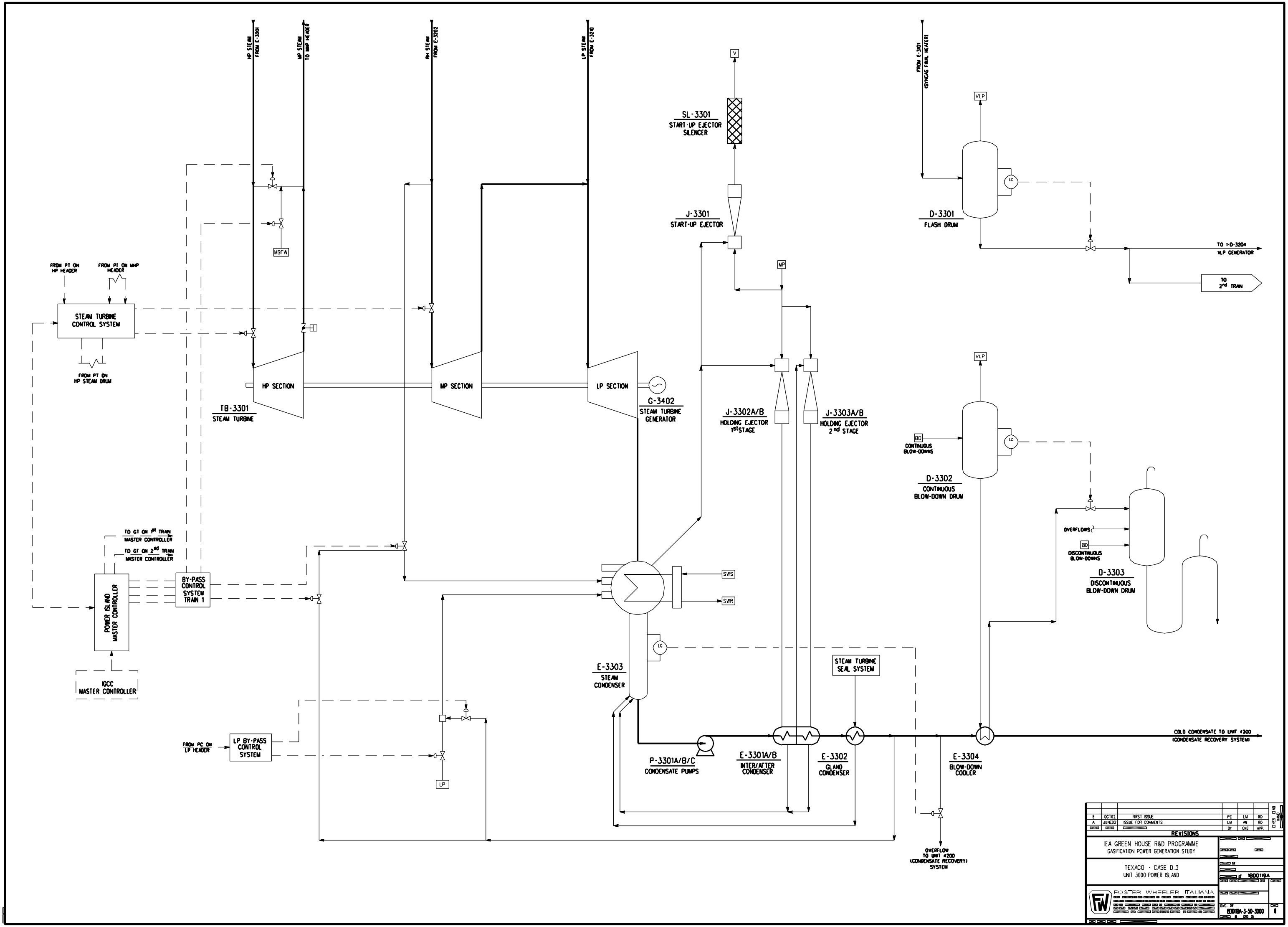

HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
MP
FROM E-3301 (SYNGAS FINAL HEATER)
VLP
LC
D-3301
FLASH DRUM
TO I-D-3204 VLP GENERATOR
TO 2nd TRAIN
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP 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
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
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
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
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)
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GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.3
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA

12.4 Steam and Electric Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Netherlands FWI Nº: 1- BD 0119A				
		REVISION	Rev.1	Rev.1	Rev.2
		DATE	Mar-03		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE D.3 - HP with low 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**	**-14,3**	**-171,1**	**-512,6**	**-27,0**	**14,3**	**171,1**	**512,6**	**80,8**	**53,8**	
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**	
3000	**POWER ISLANDS UNITS**	**9,3**	**172,4**	**407,9**	**27,0**	**-14,3**	**-175,4**	**-513,8**	**-80,8**		
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**	**167,8**	

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

	FOSTER WHEELER	CLIENT:	IEA GHG	Rev 1
		PROJECT:	GASIFICATION POWER GENERATION STUDY	Mar-03
		LOCATION:	Netherlands	ISSUED BY: PC.
		FWI Nº:	1- BD 0119A	CHECKED BY: LM
				APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE D3 - HP with low CO2 capture, separate removal of H2S and CO2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**361**
1000	**Gasification Section**	**13323**
2100	**Air Separation Unit**	**127289**
2200	**Syngas treatment and conditioning line**	**241**
2300	**Acid Gas Removal**	**30131**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3473**
2500	**CO_2 Compression and drying**	**(35500)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4708**
3200	**Heat Recovery Steam Generator**	**4661**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2127**
3500	**Miscellanea**	**520**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**10635**
	Additional consumption including CO_2 compression and drying	**(500)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**348**
	Other Units	**617**
	BALANCE excluding CO_2 compression	**198434**
	BALANCE including CO_2 compression	**234434**

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

12.5 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

TEXACO

Case D.3 - High pressure with low CO_2 capture, separated H_2S and CO_2 removal - Rev.2

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	1637.5
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	567.4
Steam turbine power output	MWe	399.5
Expander power output	MWe	11.8
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**978.7**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	127.3
Process Units consumption	MWe	47.2
Utility Units consumption	MWe	1.7
Offsite Units consumption (including sea cooling water system)	MWe	10.2
Power Islands consumption	MWe	12.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**198.4**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**780.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**42.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.6**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	35.5
Offsite Units consumption (sea cooling water system)	MWe	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**234.4**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**744.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**42.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.1**

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	6,6
CO_2	13312,8
CH_4	0,3
Total to storage (B)	13319,7
Emission	
CO_2	3358,6
CO	6,4
Total Emission	3365,0
Overall CO_2 removal efficiency, % (B/A)	79,8

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : CASE D.4

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini

SECTION D.13

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D.13 BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D.13 BASIC INFORMATION FOR EACH ALTERNATIVE

13.0 Case D.4

13.1 Introduction

The main features of the Case D.4 configuration of the IGCC Complex are:

- Low pressure (38 bar g) Texaco Gasification;
- 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 Unit (ASU) and the Gas Turbines is 50%. Gas Turbine power augmentation and syngas dilution for NO_x 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.

The arrangement of the process units is :

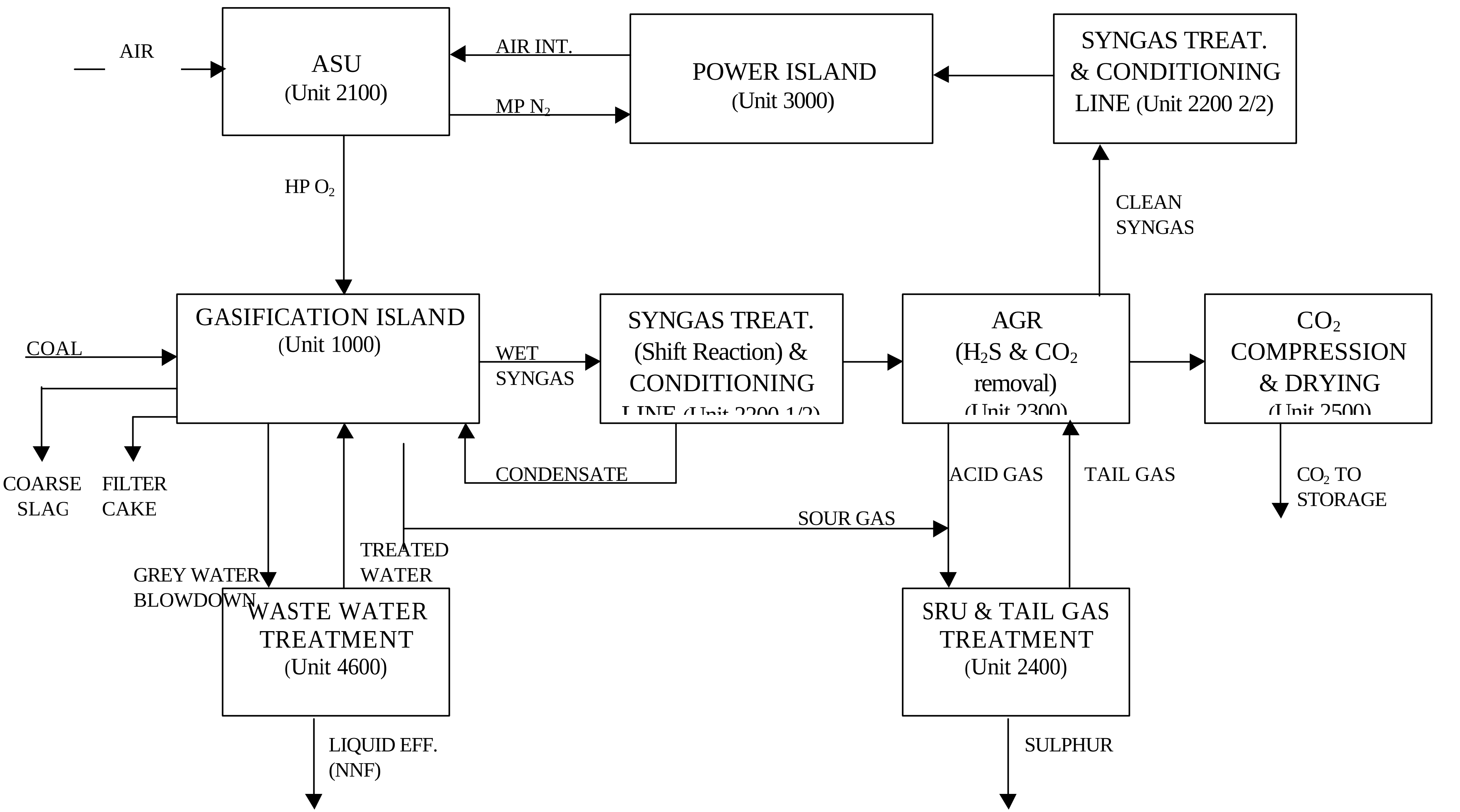
Unit		Trains
1000	Gasification	4 x 33 % 2 x 66 %
2100	ASU	2 x 50 %
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	1 x 100%
2400	SRU TGT	2 x 100% 1 x 100%
2500	CO_2 Compression and Drying	2 x 50%

3000	Gas Turbine (PG 9351-FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbines	1 x 100%

Reference is made to the attached Block Flow Diagram of the IGCC Complex.

During the 1st phase of the project, the high pressure was selected as the optimum pressure for the Texaco Technology. As a consequence, Vendors were not required to provide data for this low-pressure alternative and all the process calculations have been based on in-house data, taking into account Vendors' data provided for the other alternatives of the project.

TEXACO D.4 – IGCC COMPLEX BLOCK FLOW DIAGRAM



13.2 Process Description

Unit 1000: Gasification Island

Information relevant to Texaco Gasification Island are collected in para 1.2 of Section C.

The main process data of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	149	215
Pressure (bar)	AMB.	53	36
TOTAL FLOW			
Mass flow (kg/h)	320,400	272,200	1407000
Molar flow (kmol/h)		8,970	73210
Composition (%vol)			
H_2			14.8
CO			15.5
CO_2			7.2
N_2 + Ar		5	0.8
O_2		95	-
H_2S + COS			0.12
H_2O			61.4
Others			0.18

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors. Reference is made to Section C, para. 2.0 for a general description of the Air Separation Unit.

The Process Flow Diagram attached to paragraph 13.3 indicates the interconnections of ASU with the other units of the IGCC.

Unit 2200: Syngas Treatment and Conditioning Line , shift and expansion

To follow the process description of this Unit reference should be made to the Process Flow Diagram attached to paragraph 13.3.
Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 35 barg and 215°C, 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
E-2206 Condensate Preheater

Process condensate collected in the cooling process of the syngas is accumulated in D-2205 and from there pumped back to the syngas scrubber of Unit 1000.
The final cooling step of the syngas takes place in E-2207 with cooling water. The process condensate separated after this step is heavily contaminated, so it is not totally recycled to gasification but is partially routed to Unit 4000, Sour Water Stripper.
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-2208 with VLP steam before flowing to Unit 3000, gas turbines.
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.

Unit 2300: Acid Gas Removal (AGR)

In the absence of licensor data for this alternative, an open-art UOP-SLEXOL process was considered, based on data provided by UOP with reference to Case D1 (Texaco High Pressure, shift reaction) and Case B1 (Shell, Low Pressure, shift reaction).

Unit 2300 is characterised by a low syngas pressure (29 bar g) and an extremely high CO_2/H_2S ratio (178/1). The H_2S concentration of the stream fed to the Sulphur Recovery Unit is enhanced by using part of Nitrogen produced by the Air Separation Unit.

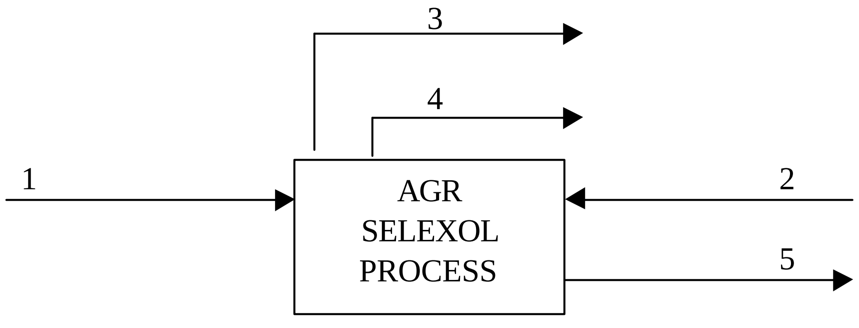
The interfaces of the process are the following, as shown in the Process Flow Diagram attached to para 13.3:

<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 Gas Turbines
4. CO_2 to compression
5. Acid Gas to Sulphur Recovery Unit



The Selexol solvent consumption, to make-up losses, is 116 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 3 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 90%, 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 20% 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:

- 222 kmol/h of Hydrogen, corresponding to 1,6% vol and to an overall thermal power of 14,9 MWt, i.e. more than 4,7 MWe.
- A very low quantity of H_2S, corresponding to a concentration of about 110 ppmvd.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constant of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

<u>Unit 2400: SRU and TGT</u>

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

The Sulphur Recovery Section consists of two trains each sized for a production of 66.3 t/day and normally operating at 50%.

The hydrogenated tail gas is recycled to Unit 2300, Acid Gas Removal, for the capture of H_2S by means of a compressor at a pressure of 30 barg.

<u>Unit 2500: CO_2 Compression and Drying</u>

This Unit is a Package Unit supplied by specialised Vendor.
Reference is made to Section C, para. 6.0 for the general information about the technology.

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 : 3,5 barg
- VLP stream : 0,5 barg

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 : 625,9 t/h.
- Product stream : 110 bar.
- Composition :

	%wt
CO_2	99,7
H_2	0,1
N_2+Others	0,2
TOTAL	100,0

Unit 3000: Power Island

The Process Flow Diagrams of this Unit are attached to paragraphs 13.3.

For this configuration, the integration between the Process Units and the Power Island consists of the following interfaces:

- 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.

Flow rate of the above interfaces of the Plant are shown in table attached to para 13.4, Utilities Consumption.

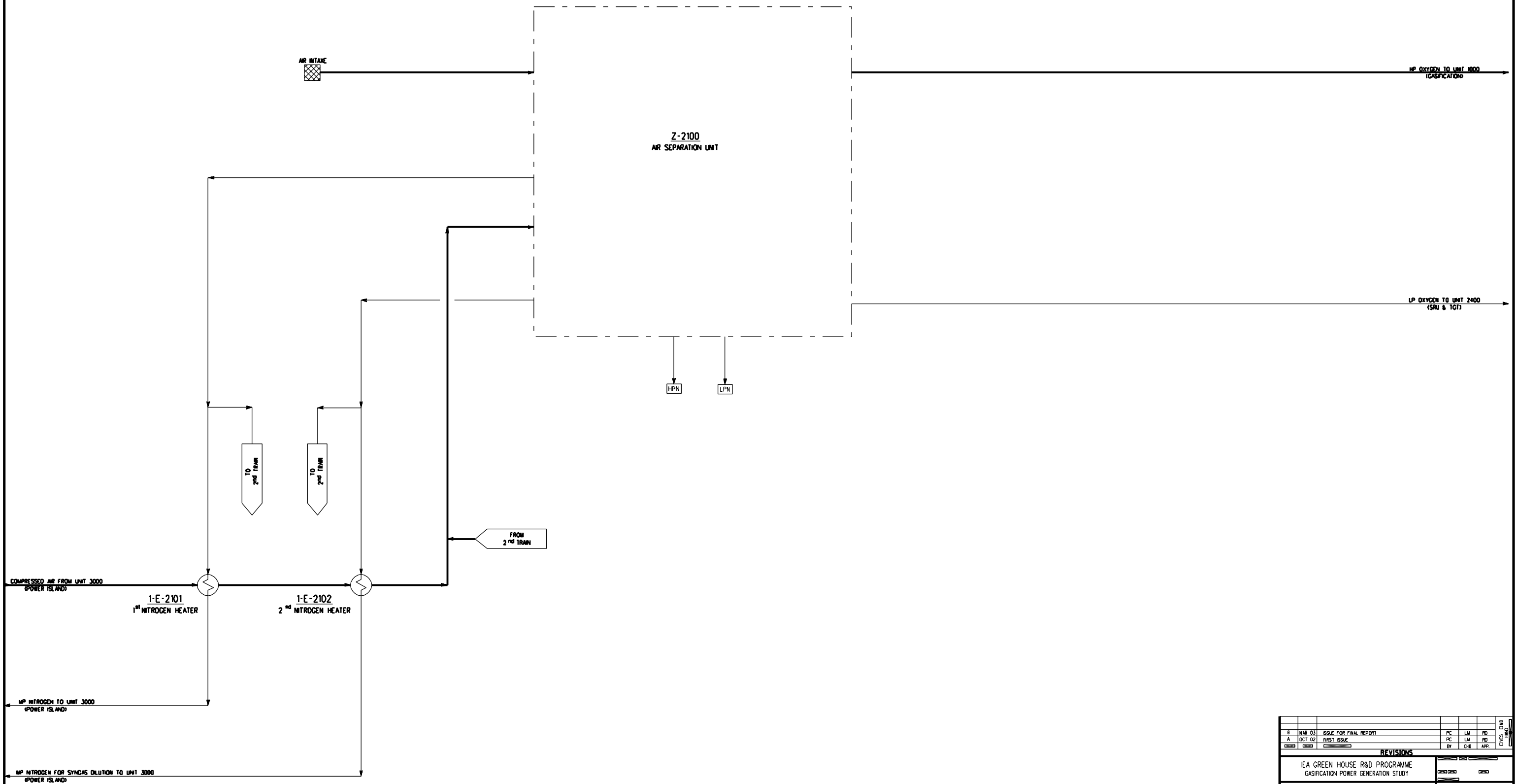
The net balance on each steam header inside the Power Island is positive, thus meaning that for all generation levels steam is imported from Process Units to the Power Island. Only steam at 85 bar g is exported to the Gasification Island. As a consequence, the generation levels of the Power Island are the same of the Process Units.

13.3 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 2100: Air Separation Unit (PFD n° BD0119A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0119A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0119A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0119A-3-50-3000; sheet 1 and 2).

For the other process and utility units reference is made to Section C, para. 6.0, 7.0 and 9.0.



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GASIFICATION POWER GENERATION STUDY

TEXACO - CASE D .4
UNIT 2100-AIR SEPARATION UNIT

FOSTER WHEELER ITALIANA

1BD0119A

DWG. No BD0119A-3-50-2100

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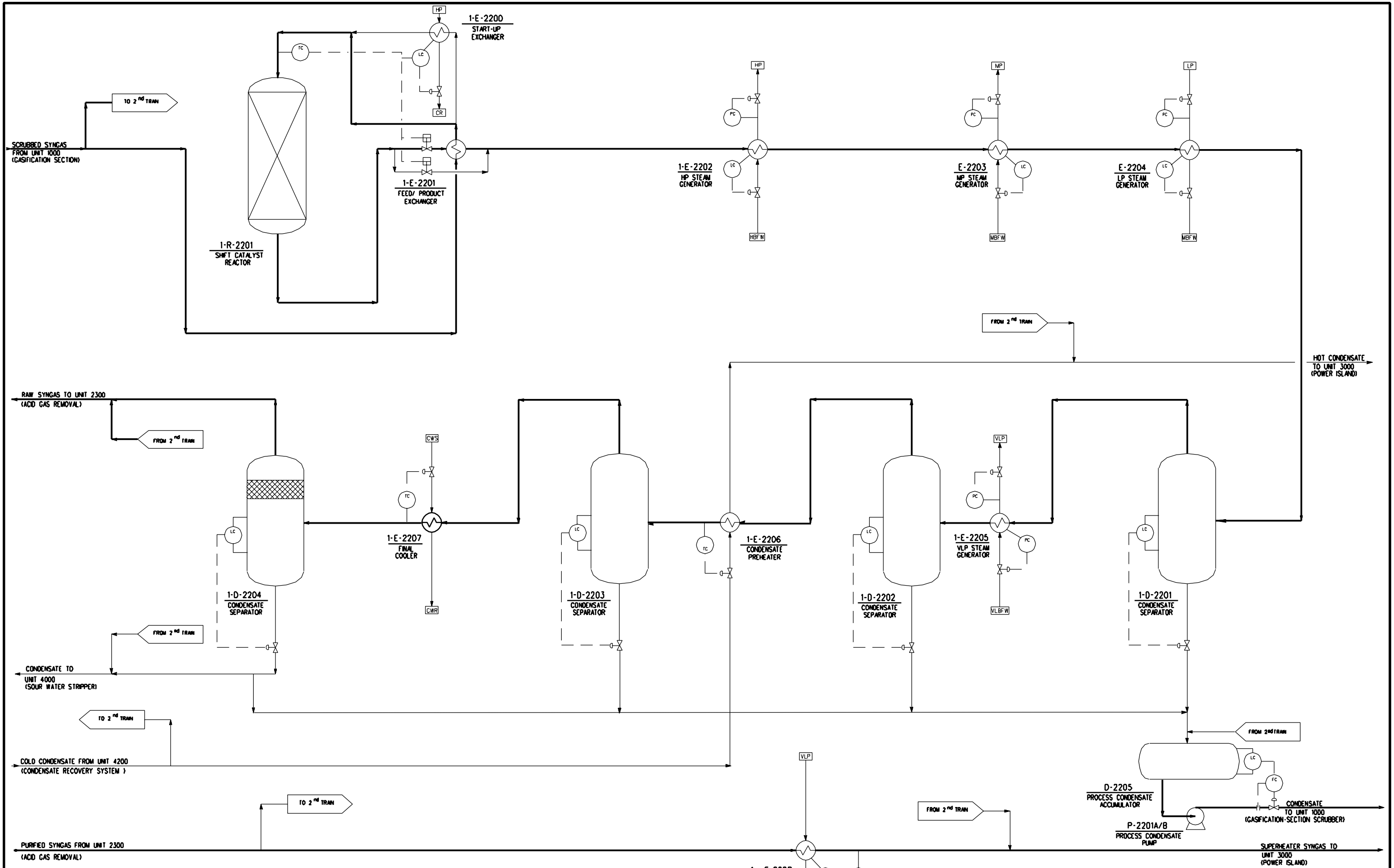

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TEXACO - CASE D.4
UNIT 2200- SYNGAS TREATMENT AND CONDITIONING LINE

FOSTER WHEELER ITALIANA

1BD0119A

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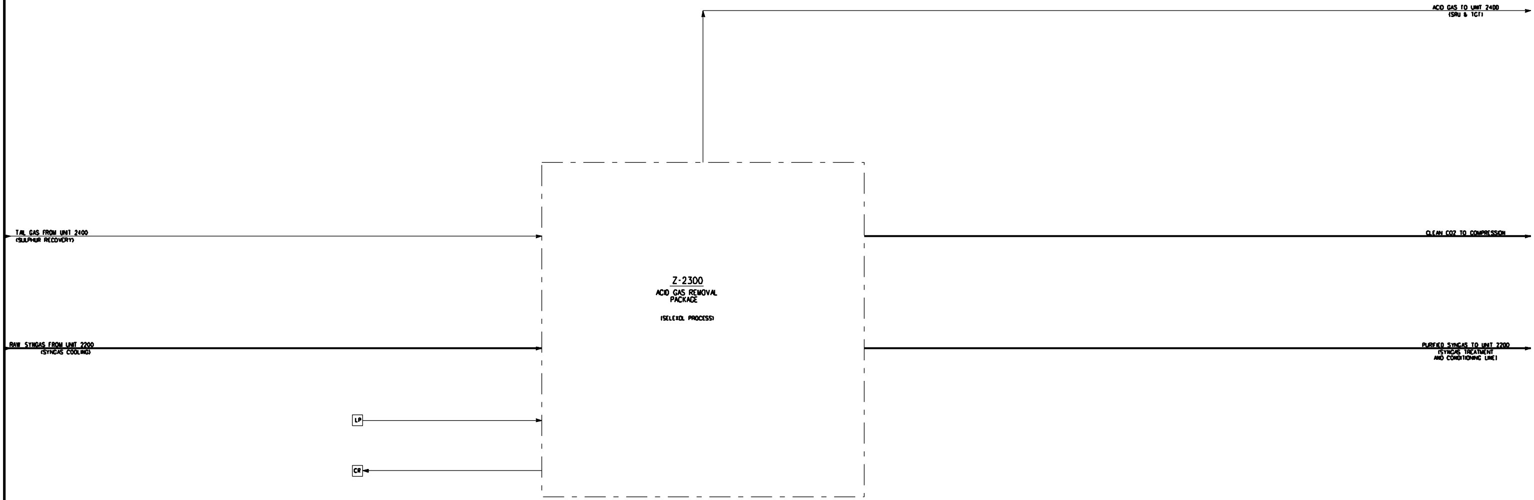

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			BY	CHD	APP.

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HAND

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TEXACO - CASE D.4
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

1BD0119A

DWG. Nº
BD0119A-3-50-2300

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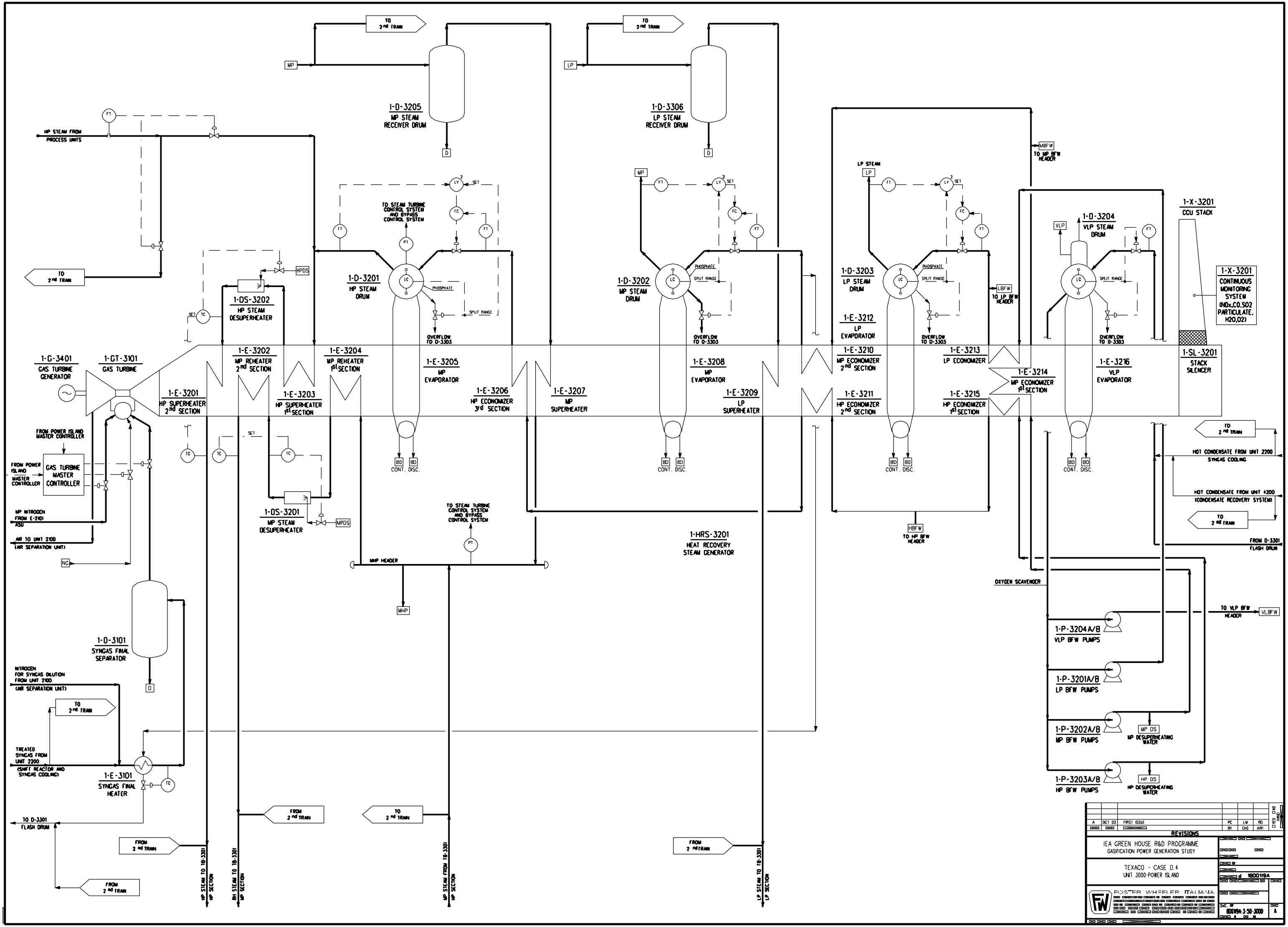
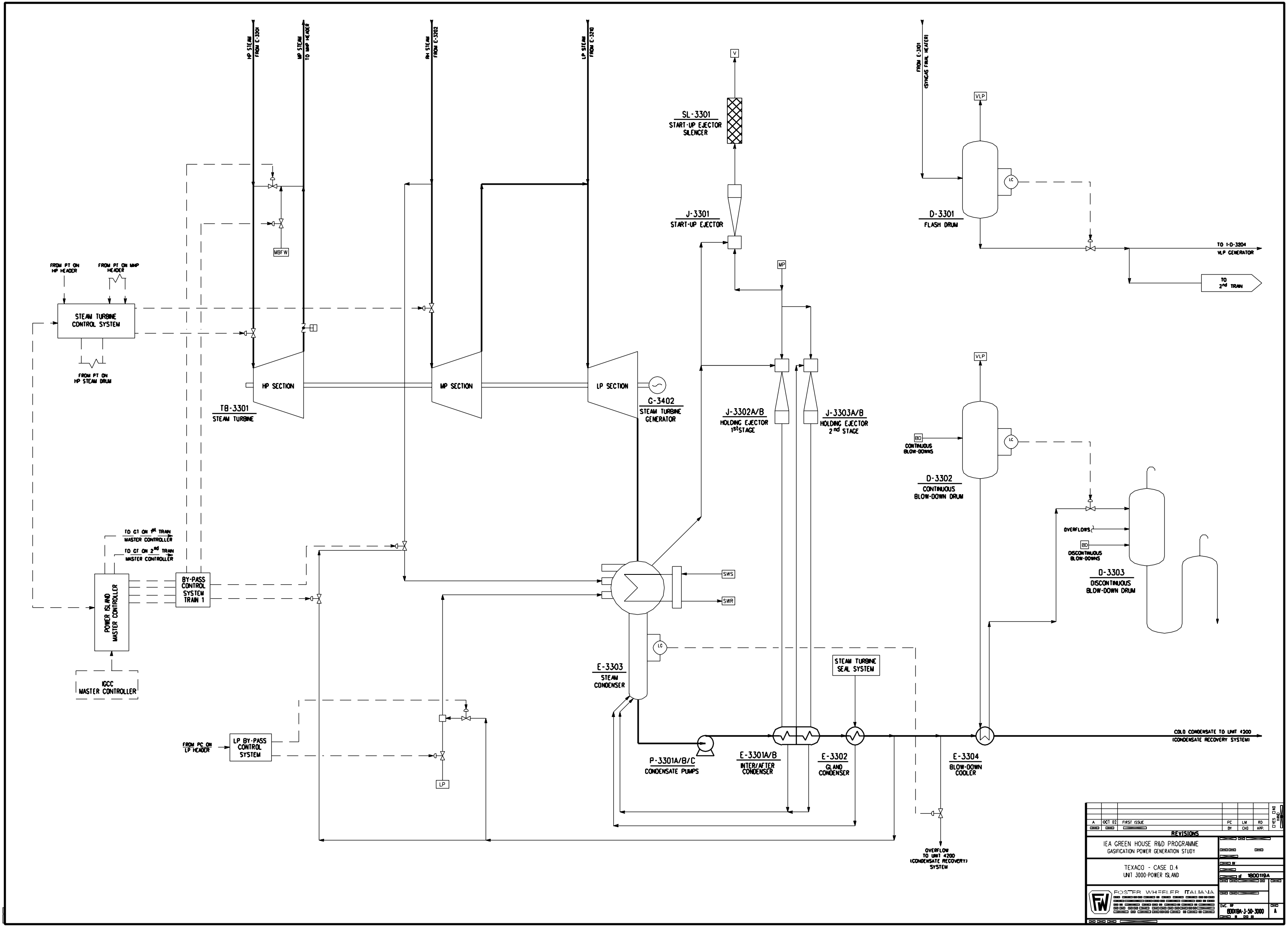


TO 2nd TRAIN
MP
1-D-3205
MP STEAM RECEIVER DRUM
LP
1-D-3306
LP STEAM RECEIVER DRUM
HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
HPDS
1-DS-3202
HP STEAM DESUPERHEATER
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
1-D-3201
HP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW TO D-3303
1-D-3202
MP STEAM DRUM
LP STEAM
1-D-3203
LP STEAM DRUM
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
1-D-3204
VLP STEAM DRUM
VLP
1-X-3201
CCU STACK
1-X-3201
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
1-G-3401
GAS TURBINE GENERATOR
1-GT-3101
GAS TURBINE
1-E-3201
HP SUPERHEATER 2nd SECTION
1-E-3202
MP REHEATER 2nd SECTION
1-E-3203
HP SUPERHEATER 1st SECTION
1-E-3204
MP REHEATER 1st SECTION
1-E-3205
MP EVAPORATOR
1-E-3206
HP ECONOMIZER 3rd SECTION
1-E-3207
MP SUPERHEATER
1-E-3208
MP EVAPORATOR
1-E-3209
LP SUPERHEATER
1-E-3212
LP EVAPORATOR
1-E-3210
MP ECONOMIZER 2nd SECTION
1-E-3211
HP ECONOMIZER 2nd SECTION
1-E-3213
LP ECONOMIZER
1-E-3214
MP ECONOMIZER 1st SECTION
1-E-3215
HP ECONOMIZER 1st SECTION
1-E-3216
VLP EVAPORATOR
1-SL-3201
STACK SILENCER
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 2200 SYNGAS COOLING
HOT CONDENSATE FROM UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
TO 2nd TRAIN
FROM D-3301 FLASH DRUM
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
BD BD CONT. DISC.
1-DS-3201
MP STEAM DESUPERHEATER
MPDS
HBFW
TO HP BFW HEADER
1-HRS-3201
HEAT RECOVERY STEAM GENERATOR
MP NITROGEN FROM E-2101 ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NC
MHP HEADER
MHP
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
1-P-3204A/B
VLP BFW PUMPS
1-P-3201A/B
LP BFW PUMPS
1-P-3202A/B
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
1-P-3203A/B
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
1-D-3101
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TO 2nd TRAIN
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
1-E-3101
SYNGAS FINAL HEATER
TO D-3301 FLASH DRUM
FROM 2nd TRAIN
TO 2nd TRAIN
FROM 2nd TRAIN
FROM 2nd TRAIN
FROM 2nd TRAIN
HP STEAM TO TB-3301 HP SECTION
RH STEAM TO TB-3301 MP SECTION
MP STEAM FROM TB-3301 HP SECTION
LP STEAM TO TB-3301 LP SECTION
A OCT 02 FIRST ISSUE
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.4
UNIT 3000-POWER ISLAND
1BD0119A
FOSTER WHEELER ITALIANA
BD0119A-3-50-3000
A



HP STEAM FROM E-3301
MP STEAM TO MHP HEADER
RH STEAM FROM E-3202
LP STEAM FROM E-3210
FROM E-3101 (SYNGAS FINAL HEATER)
V
SL-3301
START-UP EJECTOR SILENCER
J-3301
START-UP EJECTOR
VLP
D-3301
FLASH DRUM
LC
TO 1-D-3204 VLP GENERATOR
TO 2nd TRAIN
MP
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP 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
BD
CONTINUOUS BLOW-DOWNS
D-3302
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
D-3303
DISCONTINUOUS BLOW-DOWN DRUM
TO GT ON 1st TRAIN MASTER CONTROLLER
TO GT ON 2nd TRAIN MASTER CONTROLLER
BY-PASS CONTROL SYSTEM TRAIN 1
POWER ISLAND MASTER CONTROLLER
IGCC MASTER CONTROLLER
SWS
SWR
E-3303
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
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)
A
OCT 02
FIRST ISSUE
PC
LM
RD
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
GASIFICATION POWER GENERATION STUDY
TEXACO - CASE D.4
UNIT 3000-POWER ISLAND
1800119A
FOSTER WHEELER ITALIANA
1800119A-J-50-3000

13.4 Steam and Electric Power Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Table.

	FOSTER WHEELER	CLIENT:	IEA GHG	REVISION	Rev.0	Rev. 1	Rev.2
		PROJECT:	GASIFICATION POWER GENERATION STUDY	DATE	Oct 02	Mar 03	
		LOCATION:	Netherlands	ISSUED BY	P.C.	P.C.	
		FWI Nº:	1- BD 0119A	CHECKED BY	L.M.	L.M.	
				APPROVED BY	R.D.	R.D.	

UTILITIES CONSUMPTION SUMMARY - TEXACO - CASE D.4 - LP 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**	**5,0** (2)								**5,0**	
2100	**Air Separation Unit**			**21,4**						**21,4**	
2200	**Syngas Treating and Conditioning Line**	**-16,1**	**-119,0**	**-423,9**	**-46,8**	**16,1**	**119,0**	**423,9**	**77,6**	**30,9**	
2300	**Acid Gas Removal**			**75,1**						**75,1**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-1,3**	**-1,2**			**4,3**	**1,2**		**3,0**	
3000	**POWER ISLANDS UNITS**	**11,1**	**120,3**	**316,7**	**46,8**	**-16,1**	**-123,3**	**-425,1**	**-77,6**		
4000 to 5300	**UTILITY and OFFSITE UNITS**			**12,0**						**12,0**	
	BALANCE	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**147,3**	

Note: (1) Minus prior to figure means figure is generated
(2) Steam exported @ 85 barg

FOSTER WHEELER	**CLIENT:**	IEA GHG	Rev 1
	PROJECT:	GASIFICATION POWER GENERATION STUDY	mar-03
	LOCATION:	Netherlands	ISSUED BY: PC.
	FWI Nº:	1- BD 0119A	CHECKED BY: LM
			APPR. BY: RM

ELECTRICAL CONSUMPTION SUMMARY - TEXACO - CASE D4 - LP with Separated H_2S and CO_2 capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**358**
1000	**Gasification Section**	**13807**
2100	**Air Separation Unit**	**121031**
2200	**Syngas treatment and conditioning line**	**257**
2300	**Acid Gas Removal (AGR)**	**34300**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**3008**
2500	**CO_2 Compression and Drying**	**(39200)**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**4700**
3200	**Heat Recovery Steam Generator**	**4648**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**2029**
3500	**Miscellanea**	**507**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**11769**
	Additional Consumption including CO2 compression and drying	**(500)**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**342**
	Other Units	**677**
	BALANCE excluding CO_2 compression	**197431**
	BALANCE including CO_2 compression	**237131**

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

13.5 IGCC Overall Performance

The following Table shows the performance of the plant, highlighting the heavy impact of the Unit 2500, CO_2 compression and drying, on the overall efficiency of the IGCC Complex.

TEXACO

Case D.4 - Low pressure with CO_2 capture, separated H_2S and CO_2 removal - Rev.1

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (fresh, air dried basis)	t/h	320.4
Coal LHV (air dried basis)	kJ/kg	25869.5
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2302.4**
Thermal Power of Raw Syngas exit Scrubber (based on LHV) (E)	MWt	1634.8
Thermal Power of Clean Syngas to Gas Turbines (based on LHV) (F)	MWt	1488.4
Syngas treatment efficiency (F/E*100)	%	91.0
Gas turbines total power output	MWe	563.4
Steam turbine power output	MWe	378.7
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**942.1**

IGCC PERFORMANCES EXCLUDING CO_2 COMPRESSION		
ASU power consumption	MWe	121.0
Process Units consumption	MWe	51.4
Utility Units consumption	MWe	2.3
Offsite Units consumption (including sea cooling water system)	MWe	10.8
Power Islands consumption	MWe	11.9
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**197.4**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**744.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**40.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.3**

IGCC PERFORMANCES INCLUDING CO_2 COMPRESSION		
Additional consumption		
Unit 2500: CO_2 Compression and Drying	MWe	39.2
Offsite Units consumption (sea cooling water system)	MWe	0.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**237.1**
NET ELECTRIC POWER OUTPUT OF IGCC (C)	**MWe**	**705.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**40.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**30.6**

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)	17237
Slag (Carbon =~4% wt)	694
Net Carbon flowing to Process Units (A)	16543
Liquid Storage	
CO	33,0
CO_2	14022,0
Total to storage (B)	14055,0
Emission	
CO_2	2481,5
CO	6,4
Total Emission	2488,0
Overall CO_2 removal efficiency, % (B/A)	85,0

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : ECONOMICS

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002	First Issue	P. Cotone	L. Mancuso	R. Domenichini
December 2002	1,16,17, 18,19,21	P. Cotone	L. Mancuso	R. Domenichini
March 2003	General Revision	P. Cotone	L. Mancuso	R. Domenichini
May 2003	Page 1, Tables E.3.6; E.3.7	P. Cotone	L. Mancuso	R. Domenichini

SECTION E

ECONOMICS

INDEX

SECTION E ECONOMICS

SECTION E

1.0 Introduction

This section summarizes the economic data evaluated for the study, including:

a. the investment cost estimate for all the alternatives; for some alternatives the investment cost estimate together with the process performances developed in the first phase of study, were the basis for the selection of key parameters, like the gasification pressure and the shift catalyst type (sour vs clean). Reference is made to Section B for results of comparison:

   - low gasification pressure is selected for Shell alternative, thus excluding the economic analyses of cases A.2 and B.4;
   - high gasification pressure is selected for Texaco alternative, thus excluding the economic analysis of cases C.3 and D.4.
   - sour shift is selected for Shell alternative with CO_2 capture, thus eliminating the economic analysis of case B.2.

b. the evaluation of the Operation & Maintenance costs for the alternatives selected after the first screen described at point a., i.e. A.1, B.1, B.3, C.1, C.2, D.1, D.2, D.3;

c. for the same alternatives, the evaluation of the electric power production cost and the carbon dioxide removal cost.

2.0 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 Sections C and D of this Study.
In particular the investment cost of the following Units or blocks of Units is detailed:

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
Unit 3000	:	Power Island
Units 4000 to 5200	:	Utilities and Offsites

The overall investment cost of each Unit or block of Units is split into the following items:

- Direct Materials, including equipment and bulk materials;
- Construction, including mechanical erection, instrument and electrical installation, civil works and, where applicable, buildings and site preparation;
- Other Costs, including temporary facilities, solvents, catalysts, chemicals, training, commissioning and start-up costs, spare parts etc.;
- EPC Services including Contractor's home office services and construction supervision.

2.2 Estimate Methodology and Cost Basis

2.2.1 Direct Materials

The direct materials cost estimate of the Units or Blocks of Units listed at para. 2.1 is developed according to the following general criteria:

Unit 900 (Coal Handling and Storage)

The cost of equipment delivered and erected is based on a budget quotation received from a qualified Vendor, detailing direct materials and construction costs.
The Unit capacity and consequently the investment cost, as detailed in Section C, is identical for some alternatives, i.e.:

- A1, A2;
- B1, B2, B3, B4;
- C1, C3;
- C2, D1, D2, D3, D4;

Unit 1000 (Gasification)

Shell provided investment cost data of the main equipment for four reference cases: low and high gasification pressure, with/without CO_2 capture.
These figures have been adjusted based on the actual coal flowrate resulting from finalization of the IGCC performances of alternatives A1 to B.4.
After this adjustment the investment cost of main equipment has been increased by a factor derived from in-house data to take into account minor equipment and bulk materials.
The resulting figure is the direct materials cost.

Texaco provided the cost of all the equipment, bulk materials and labour for four reference cases: high and low gasification pressure with/without CO_2 capture.

As per Shell cases, these figures have been adjusted based on the actual coal flowrate resulting from finalization of the IGCC performances of alternatives C1 to D4.
The resulting figure includes the direct materials plus the mechanical erection and instrument/electrical installation on a US Gulf basis. The direct materials cost was taken out in order to adjust the construction cost for civil works inclusion.

Process Packages: Unit 2100 (Air Separation Unit) and Unit 2400 (Sulphur Recovery and Tail Gas Treatment)

Unit 2100 (Air Separation Unit) and Unit 2400 (Sulphur Recovery and Tail Gas Treatment) are Process Packages. The investment cost is derived from competitive bids received and technically evaluated by FW in the past for similar projects.
For each alternative the figure taken as a reference has been adjusted based on suitable parameters like feedstocks flowrate and characteristics, products flowrate, purity and conditions.

Unit 2200 (Syngas Cooling and Conditioning Line) and 2300 (Acid Gas Removal)

The basic estimate has been developed using a FW proprietary software like ICARUS.
The computerized system allows to estimate complete units starting from preliminary technical information.

The program on the basis of the equipment type and its design characteristics evaluates costs of the equipment, and the associated bulk material and erection.

Equipment are specified through the following inputs:

- Dimensions (diameter/length or height);
- Design conditions (pressure and temperature);
- Materials of construction;
- Heat transfer surface for the heat exchangers;
- Flowrates and differential heat for the pumps;
- Etc.

The program output is the cost of direct materials and construction for each equipment and for the entire Unit.

All the costs generated by the program are relevant to a specific location selected as general input before starting up the estimate.

Unit 2500 (CO_2 Compression and Drying)

Direct materials cost of CO_2 compressors and drivers is based on a budget quotation received from qualified Vendors. Costs of other equipment are derived from in house data.

Unit 3000 (Power Island)

The direct materials cost is based on competitive bids received in the past for similar equipment (gas turbine, HRSG, steam turbine) and on proprietary software output for other equipment and bulk materials.

Unit 4000 to 5200 (Utilities and Offsite)

Cost of each Unit is evaluated based on in house data for similar Units.
Unit 5100 (Interconnecting) includes DCS, ESD, EMS, Electrical Systems and HV substation.
The overall investment cost evaluated for a reference case selected among Shell alternatives and Texaco alternatives is then adjusted case by case, on the basis of the actual coal flowrate.

2.2.2 Construction, Other Costs and EPC Services

Per each Unit (if necessary, for each Technology), or block of Units, the other costs (i.e. Construction, Other Costs and EPC Services) are calculated multiplying the cost of direct materials by factors, built up by FW from statistics based on cost estimates of similar plants.
Overnight construction is taken into account. Despite of dutch location, an average labour cost is assumed for construction.

2.2.3 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.

Different percentages of contingency are applied to the IGCC sections on the basis of historical data:

Air Separation Unit	:	5%
Process Units	:	7%
Power Island	:	7%
Utility and Offsite Units	:	5%

The overall figure of Total Investment Cost including contigency for each alternative represents the "installed plant cost" (overnight construction).

2.2.4 Estimate Currencies

The estimate was developed in Euro.
The following exchange Euro to US $ rate has been used:

1 US $ equivalent to 1 Euro.

2.2.5 Inflation

No escalation is applied to the estimated installed cost.

2.2.6 Other Costs

Land purchase, surveys and general site preparation are taken into account at a cost equal to 5% of the installed plant cost.
Additional costs for process/patent fees, fees for agents and consultants, legal and planning activities, are taken into account at a cost equal to 2% of the installed plant cost.
The sum of the installed plant cost plus the other cost is the Total Investment Cost.

2.3 Estimate Accuracy

The estimate accuracy is within the range +/- 25%.

3.0 Investment Cost of the Alternatives

3.1 Shell Alternative

The following Tables E.3.1/6 show the investment break down and the total figures for each alternative investigated.
Table E.3.7 summarizes the results and shows the specific investment cost for all the alternatives.

FOSTER
WHEELER
ITALIANA

Table E.3.1 - ESTIMATE SUMMARY

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAI
Plant : GASIFICATION POWER GENERATION S
Location : NETHERLANDS
Date : March 2003 REV. 1

SHELL CASE A1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		4.670.000	202.404.000	63.600.000	7.113.000	6.232.000	8.365.000	223.771.000	54.667.000	570.822.000
2	CONSTRUCTION		934.000	101.202.000	19.080.000	3.528.000	3.960.000	3.764.000	55.943.000	30.067.000	218.478.000
3	OTHER COSTS		467.000	12.144.000	2.544.000	2.854.000	5.536.000	1.171.000	22.377.000	5.467.000	52.560.000
4	EPC SERVICES		701.000	50.601.000	9.540.000	2.188.000	1.911.000	1.255.000	17.902.000	10.933.000	95.031.000
A	**Installed costs** (contingency excluded)		**6.772.000**	**366.351.000**	**94.764.000**	**15.683.000**	**17.639.000**	**14.555.000**	**319.993.000**	**101.134.000**	**936.891.000**
B	Contingency	%	7	7	5	7	7	7	7	5	6,6
		Euro	474.040	25.644.570	4.738.200	1.097.810	1.234.730	1.018.850	22.399.510	5.056.700	61.664.410
C	Fees (2% of A)		135.440	7.327.020	1.895.280	313.660	352.780	291.100	6.399.860	2.022.680	18.737.820
D	Land Purchases; surveys (5% of A)		338.600	18.317.550	4.738.200	784.150	881.950	727.750	15.999.650	5.056.700	46.844.550
TOTAL INVESTMENT COST			**7.720.080**	**417.640.140**	**106.135.680**	**17.878.620**	**20.108.460**	**16.592.700**	**364.792.020**	**113.270.080**	**1.064.137.780**

REMARKS

1) ESTIMATE ACCURACY +/- 25%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling & Storage**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2400	**SRU & TGT**
2500	**CO2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities&Offsites**

FOSTER
WHEELER
ITALIANA

Table E.3.2 - ESTIMATE SUMMARY

SHELL CASE A2

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		4.670.000	246.538.000	68.600.000	7.824.000	6.544.000	7.788.000	221.412.000	54.667.000	618.043.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		934.000	123.269.000	19.080.000	3.881.000	4.158.000	3.505.000	55.353.000	30.067.000	240.247.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		467.000	12.144.000	2.544.000	2.854.000	4.047.000	1.090.000	22.141.000	5.467.000	50.754.000	
4	EPC SERVICES		701.000	53.131.000	9.540.000	2.188.000	1.911.000	1.168.000	17.713.000	10.933.000	97.285.000	**900 Coal Handling & Storage**
												1000 Gasification Section
												2100 Air Separation Unit
												2200 Syngas Treat.&Condt. Line
A	**Installed costs** (contingency excluded)		**6.772.000**	**435.082.000**	**99.764.000**	**16.747.000**	**16.660.000**	**13.551.000**	**316.619.000**	**101.134.000**	**1.006.329.000**	**2300 Acid Gas Removal**
												2400 SRU & TGT
B	Contingency	%	7	7	5	7	7	7	7	5	6,6	**2500 CO2 Compression&Drying**
		Euro	474.040	30.455.740	4.988.200	1.172.290	1.166.200	948.570	22.163.330	5.056.700	66.425.070	**3000 Power Island**
												4000+ Utilities&Offsites
C	Fees (2% of A)		135.440	8.701.640	1.995.280	334.940	333.200	271.020	6.332.380	2.022.680	20.126.580	
D	Land Purchases; surveys (5% of A)		338.600	21.754.100	4.988.200	837.350	833.000	677.550	15.830.950	5.056.700	50.316.450	
TOTAL INVESTMENT COST			**7.720.080**	**495.993.480**	**111.735.680**	**19.091.580**	**18.992.400**	**15.448.140**	**360.945.660**	**113.270.080**	**1.143.197.100**	

FOSTER
WHEELER
ITALIANA

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

Table E.3.3 - ESTIMATE SUMMARY

SHELL CASE B1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		5.050.000	217.404.000	67.200.000	18.210.000	34.213.000	15.096.000	15.184.000	222.369.000	59.714.000	654.440.000
2	CONSTRUCTION		1.010.000	108.702.000	20.160.000	8.792.000	21.080.000	6.793.000	3.796.000	55.592.000	32.843.000	258.768.000
3	OTHER COSTS		505.000	13.044.000	2.688.000	12.734.000	20.056.000	2.113.000	759.000	22.237.000	5.971.000	80.107.000
4	EPC SERVICES		758.000	54.351.000	10.080.000	5.451.000	10.177.000	2.264.000	1.063.000	17.790.000	11.943.000	113.877.000
A	**Installed costs** (contingency excluded)		**7.323.000**	**393.501.000**	**100.128.000**	**45.187.000**	**85.526.000**	**26.266.000**	**20.802.000**	**317.988.000**	**110.471.000**	**1.107.192.000**
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,5
		Euro	512.610	27.545.070	5.006.400	3.163.090	5.986.820	1.838.620	1.040.100	22.259.160	5.523.550	72.362.810
C	Fees (2% of A)		146.460	7.870.020	2.002.560	903.740	1.710.520	525.320	416.040	6.359.760	2.209.420	22.143.840
D	Land Purchases; surveys (5% of A)		366.150	19.675.050	5.006.400	2.259.350	4.276.300	1.313.300	1.040.100	15.899.400	5.523.550	55.359.600
	TOTAL INVESTMENT COST		**8.348.220**	**448.591.140**	**112.143.360**	**51.513.180**	**97.499.640**	**29.943.240**	**23.298.240**	**362.506.320**	**123.727.520**	**1.257.058.250**

REMARKS

1) ESTIMATE ACCURACY +/- 25%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling & Storage**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2400	**SRU & TGT**
2500	**CO2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities&Offsites**

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Table E.3.4 - ESTIMATE SUMMARY

SHELL CASE B2

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		5.050.000	218.173.000	67.500.000	25.323.000	34.336.000	13.173.000	16.115.000	220.126.000	59.714.000	659.510.000
2	CONSTRUCTION		1.010.000	109.087.000	20.250.000	12.320.000	21.156.000	5.928.000	4.029.000	55.032.000	32.843.000	261.655.000
3	OTHER COSTS		505.000	13.090.000	2.700.000	6.616.000	20.128.000	1.844.000	806.000	22.013.000	5.971.000	73.673.000
4	EPC SERVICES		758.000	54.543.000	10.125.000	7.639.000	10.214.000	1.976.000	1.128.000	17.610.000	11.943.000	115.936.000
A	**Installed costs** (contingency excluded)		**7.323.000**	**394.893.000**	**100.575.000**	**51.898.000**	**85.834.000**	**22.921.000**	**22.078.000**	**314.781.000**	**110.471.000**	**1.110.774.000**
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,5
		Euro	512.610	27.642.510	5.028.750	3.632.860	6.008.380	1.604.470	1.103.900	22.034.670	5.523.550	72.579.090
C	Fees (2% of A)		146.460	7.897.860	2.011.500	1.037.960	1.716.680	458.420	441.560	6.295.620	2.209.420	22.215.480
D	Land Purchases; surveys (5% of A)		366.150	19.744.650	5.028.750	2.594.900	4.291.700	1.146.050	1.103.900	15.739.050	5.523.550	55.538.700
	TOTAL INVESTMENT COST		**8.348.220**	**450.178.020**	**112.644.000**	**59.163.720**	**97.850.760**	**26.129.940**	**24.727.360**	**358.850.340**	**123.727.520**	**1.261.107.270**

REMARKS

1) ESTIMATE ACCURACY +/- 25%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling & Storage**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2400	**SRU & TGT**
2500	**CO2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities&Offsites**

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Table E.3.5 - ESTIMATE SUMMARY

SHELL CASE B3

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2500 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		5.050.000	216.523.000	66.928.000	18.136.000	18.073.000	16.683.000	221.209.000	58.159.000	620.761.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.010.000	108.262.000	20.078.000	8.756.000	11.484.000	4.171.000	55.302.000	31.987.000	241.050.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		505.000	12.991.000	2.677.000	12.682.000	14.947.000	834.000	22.121.000	5.816.000	72.573.000	
4	EPC SERVICES		758.000	54.131.000	10.039.000	5.429.000	3.440.000	1.168.000	17.697.000	11.632.000	104.294.000	**900 Coal Handling & Storage**
												1000 Gasification Section
												2100 Air Separation Unit
												2200 Syngas Treat.&Condt. Line
A	**Installed costs** (contingency excluded)		**7.323.000**	**391.907.000**	**99.722.000**	**45.003.000**	**47.944.000**	**22.856.000**	**316.329.000**	**107.594.000**	**1.038.678.000**	**2300 Acid Gas Removal**
												2500 CO2 Compression&Drying
B	Contingency	%	7	7	5	7	7	5	7	5	6,5	**3000 Power Island**
		Euro	512.610	27.433.490	4.986.100	3.150.210	3.356.080	1.142.800	22.143.030	5.379.700	67.591.410	**4000+ Utilities&Offsites**
C	Fees (2% of A)		146.460	7.838.140	1.994.440	900.060	958.880	457.120	6.326.580	2.151.880	20.773.560	
D	Land Purchases; surveys (5% of A)		366.150	19.595.350	4.986.100	2.250.150	2.397.200	1.142.800	15.816.450	5.379.700	51.933.900	
TOTAL INVESTMENT COST			**8.348.220**	**446.773.980**	**111.688.640**	**51.303.420**	**54.656.160**	**25.598.720**	**360.615.060**	**120.505.280**	**1.178.976.870**	

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Table E.3.6 - ESTIMATE SUMMARY

SHELL CASE B4

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : May 2003 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		5.050.000	263.173.000	72.100.000	20.031.000	14.581.018	15.865.000	15.956.000	219.480.000	59.048.000	685.284.018	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.010.000	131.587.000	20.160.000	9.671.000	22.134.000	7.139.000	3.989.000	54.870.000	32.476.000	283.036.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		505.000	13.044.000	2.688.000	12.734.000	14.880.000	2.221.000	798.000	21.948.000	5.905.000	74.723.000	
4	EPC SERVICES		758.000	57.068.550	10.080.000	5.451.000	10.177.000	2.380.000	1.117.000	17.558.000	11.810.000	116.399.550	
A	**Installed costs** (contingency excluded)		**7.323.000**	**464.872.550**	**105.028.000**	**47.887.000**	**61.772.018**	**27.605.000**	**21.860.000**	**313.856.000**	**109.239.000**	**1.159.442.568**	
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,6	
		Euro	512.610	32.541.079	5.251.400	3.352.090	4.324.041	1.932.350	1.093.000	21.969.920	5.461.950	75.925.830	
C	Fees (2% of A)		146.460	9.297.451	2.100.560	957.740	1.235.440	552.100	437.200	6.277.120	2.184.780	23.188.851	
D	Land Purchases; surveys (5% of A)		366.150	23.243.628	5.251.400	2.394.350	3.088.601	1.380.250	1.093.000	15.692.800	5.461.950	57.972.128	
TOTAL INVESTMENT COST			**8.348.220**	**529.954.707**	**117.631.360**	**54.591.180**	**70.420.100**	**31.469.700**	**24.483.200**	**357.795.840**	**122.347.680**	**1.316.529.377**	

900 **Coal Handling & Storage**
1000 **Gasification Section**
2100 **Air Separation Unit**
2200 **Syngas Treat.&Condt. Line**
2300 **Acid Gas Removal**
2400 **SRU & TGT**
2500 **CO2 Compression&Drying**
3000 **Power Island**
4000+ **Utilities&Offsites**

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Table E.3.7 - ESTIMATE SUMMARY

Refer : 1-BD-0119A
Client : IEA GREENHOUSE R & D PROJ.
Plant : GASIFICATION POWER GENERAL STUDY
Location : NETHERLANDS
Date : May 2003 REV. 2

SHELL CASES

FIGURE IN MM EURO

POS	DESCRIPTION	A1		A2		B1		B2		B3		B4	
		€	%	€	%	€	%	€	%	€	%	€	%
1	Air Separation Unit	106,1	10,0	111,7	9,8	112,1	8,9	112,6	8,9	111,7	9,5	117,6	8,9
2	Process Units	479,9	45,1	557,2	48,7	635,9	50,6	641,7	50,9	561,1	47,6	694,8	52,7
3	CO_2 Compression and Drying	0	0,0	0	0,0	23,3	1,9	24,7	2,0	25,6	2,2	24,5	1,9
4	Power Island	364,8	34,3	360,9	31,6	362,5	28,8	358,9	28,4	360,6	30,6	357,8	27,2
5	Utilities and Offsite Units	113,3	10,6	113,3	9,9	123,7	9,8	123,7	9,8	120,5	10,2	122,3	9,3
	TOTAL INVESTMENT COST	**1.064,1**	**100,0**	**1.143,2**	**100,0**	**1.257,6**	**100,0**	**1.261,6**	**100,0**	**1.179,5**	**100,0**	**1.317,0**	**100,0**

	A1	A2	B1	B2	B3	B4
NET POWER OUTPUT, MWe	775,9	748,3	676,2	651,3	683,3	638,9
SPECIFIC INVESTMENT COST, Euro/kW	1371,5	1527,7	1859,8	1937,1	1726,2	2061,4

3.2 Texaco Alternatives

The following Tables E.3.8/14 show the investment break down and the total figures for each alternative investigated.
Table E.3.15 summarizes the results and shows the specific investment cost for all the alternatives.

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Table E.3.8 - ESTIMATE SUMMARY

TEXACO CASE C1

Refer : 1-BD-0119A
Client : IEA GREENHOUSE R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		5.607.000	108.500.000	76.800.000	19.979.000	13.650.000	13.558.000	222.661.000	62.952.000	523.707.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.121.000	48.825.000	23.040.000	9.910.000	8.677.000	6.101.000	55.665.000	34.624.000	187.963.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		561.000	16.275.000	3.072.000	4.074.000	5.693.000	1.898.000	22.266.000	6.295.000	60.134.000	
4	EPC SERVICES		841.000	37.975.000	11.520.000	6.146.000	4.189.000	2.034.000	17.813.000	12.590.000	93.108.000	
A	**Installed Costs** (Contingency excluded)		**8.130.000**	**211.575.000**	**114.432.000**	**40.109.000**	**32.209.000**	**23.591.000**	**318.405.000**	**116.461.000**	**864.912.000**	
B	Contingency	%	7	7	5	7	7	7	7	5	6,5	
		Euro	569.100	14.810.250	5.721.600	2.807.630	2.254.630	1.651.370	22.288.350	5.823.050	55.925.980	
C	Fees (2% of A)		162.600	4.231.500	2.288.640	802.180	644.180	471.820	6.368.100	2.329.220	17.298.240	
D	Land Purchases; surveys (5% of A)		406.500	10.578.750	5.721.600	2.005.450	1.610.450	1.179.550	15.920.250	5.823.050	43.245.600	
TOTAL INVESTMENT COST			**9.268.200**	**241.195.500**	**128.163.840**	**45.724.260**	**36.718.260**	**26.893.740**	**362.981.700**	**130.436.320**	**981.381.820**	

900 Coal Handling & Storage
1000 Gasification Section
2100 Air Separation Unit
2200 Syngas Treat.&Condt. Line
2300 Acid Gas Removal
2400 SRU & TGT
2500 CO2 Compression&Drying
3000 Power Island
4000+ Utilities&Offsites

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Table E.3.9 - ESTIMATE SUMMARY

TEXACO CASE C2

Refer : 1-BD-0119A
Client : IEA GREENHOUSE R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		6.075.000	114.100.000	78.400.000	27.837.000	16.002.000	13.694.000	224.485.000	65.238.000	545.831.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.215.000	51.345.000	23.520.000	13.809.000	10.172.000	6.162.000	56.121.000	35.881.000	198.225.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		608.000	17.115.000	3.136.000	7.629.000	6.674.000	1.917.000	22.449.000	6.524.000	66.052.000	
4	EPC SERVICES		911.000	39.935.000	11.760.000	8.564.000	4.911.000	2.054.000	17.959.000	13.048.000	99.142.000	
A	**Installed Costs** (Contingency excluded)		**8.809.000**	**222.495.000**	**116.816.000**	**57.839.000**	**37.759.000**	**23.827.000**	**321.014.000**	**120.691.000**	**909.250.000**	
B	Contingency	%	7	7	5	7	7	7	7	5	6,5	
		Euro	616.630	15.574.650	5.840.800	4.048.730	2.643.130	1.667.890	22.470.980	6.034.550	58.897.360	
C	Fees (2% of A)		176.180	4.449.900	2.336.320	1.156.780	755.180	476.540	6.420.280	2.413.820	18.185.000	
D	Land Purchases; surveys (5% of A)		440.450	11.124.750	5.840.800	2.891.950	1.887.950	1.191.350	16.050.700	6.034.550	45.462.500	
	TOTAL INVESTMENT COST		**10.042.260**	**253.644.300**	**130.833.920**	**65.936.460**	**43.045.260**	**27.162.780**	**365.955.960**	**135.173.920**	**1.031.794.860**	

900 **Coal Handling & Storage**
1000 **Gasification Section**
2100 **Air Separation Unit**
2200 **Syngas Treat.&Condt. Line**
2300 **Acid Gas Removal**
2400 **SRU & TGT**
2500 **CO2 Compression&Drying**
3000 **Power Island**
4000+ **Utilities&Offsites**

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Table E.3.10 - ESTIMATE SUMMARY

TEXACO CASE C3

Refer	: 1-BD-0119A
Client	: IEA GREENHOUSE GAS R & D PROGRAMME
Plant	: GASIFICATION POWER GENERATION STUDY
Location	: NETHERLANDS
Date	: March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		5.607.000	103.400.000	73.900.000	17.981.000	7.763.000	13.750.000	220.655.000	67.714.000	510.770.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.121.000	46.530.000	23.040.000	8.919.000	4.658.000	6.188.000	55.164.000	37.243.000	182.863.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		561.000	16.275.000	3.072.000	4.074.000	7.599.000	1.925.000	22.066.000	6.771.000	62.343.000	
4	EPC SERVICES		841.000	36.076.250	11.520.000	6.146.000	2.329.000	2.063.000	17.652.000	13.543.000	90.170.250	**900** **Coal Handling & Storage**
												1000 **Gasification Section**
												2100 **Air Separation Unit**
												2200 **Syngas Treat.&Condt. Line**
A	**Installed Costs** (Contingency excluded)		**8.130.000**	**202.281.250**	**111.532.000**	**37.120.000**	**22.349.000**	**23.926.000**	**315.537.000**	**125.271.000**	**846.146.250**	**2300** **Acid Gas Removal**
												2400 **SRU & TGT**
B	Contingency	%	7	7	5	7	7	7	7	5	6,4	**2500** **CO2 Compression&Drying**
		Euro	569.100	14.159.688	5.576.600	2.598.400	1.564.430	1.674.820	22.087.590	6.263.550	54.494.178	**3000** **Power Island**
												4000+ **Utilities&Offsites**
C	Fees (2% of A)		162.600	4.045.625	2.230.640	742.400	446.980	478.520	6.310.740	2.505.420	16.922.925	
D	Land Purchases; surveys (5% of A)		406.500	10.114.063	5.576.600	1.856.000	1.117.450	1.196.300	15.776.850	6.263.550	42.307.313	
TOTAL INVESTMENT COST			**9.268.200**	**230.600.625**	**124.915.840**	**42.316.800**	**25.477.860**	**27.275.640**	**359.712.180**	**140.303.520**	**959.870.665**	

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Table E.3.11 - ESTIMATE SUMMARY

TEXACO CASE D1

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		6.075.000	112.700.000	78.600.000	27.561.000	25.381.000	18.000.000	17.330.000	221.998.000	71.143.000	578.788.000
2	CONSTRUCTION		1.215.000	50.715.000	23.580.000	13.672.000	11.859.000	8.100.000	4.333.000	55.500.000	39.129.000	208.103.000
3	OTHER COSTS		608.000	16.905.000	3.144.000	7.553.000	11.918.000	2.520.000	867.000	22.200.000	7.114.000	72.829.000
4	EPC SERVICES		911.000	39.445.000	11.790.000	8.479.000	5.997.000	2.700.000	1.213.000	17.760.000	14.229.000	102.524.000
A	**Installed Costs** (Contingency excluded)		**8.809.000**	**219.765.000**	**117.114.000**	**57.265.000**	**55.155.000**	**31.320.000**	**23.743.000**	**317.458.000**	**131.615.000**	**962.244.000**
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,4
		Euro	616.630	15.383.550	5.855.700	4.008.550	3.860.850	2.192.400	1.187.150	22.222.060	6.580.750	61.291.010
C	Fees (2% of A)		176.180	4.395.300	2.342.280	1.145.300	1.103.100	626.400	474.860	6.349.160	2.632.300	19.244.880
D	Land Purchases; surveys (5% of A)		440.450	10.988.250	5.855.700	2.863.250	2.757.750	1.566.000	1.187.150	15.872.900	6.580.750	48.112.200
TOTAL INVESTMENT COST			**10.042.260**	**250.532.100**	**131.167.680**	**65.282.100**	**62.876.700**	**35.704.800**	**26.592.160**	**361.902.120**	**147.408.800**	**1.090.892.090**

REMARKS

1) ESTIMATE ACCURACY +/- 25%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling & Storage**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2400	**SRU & TGT**
2500	**CO2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities&Offsites**

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Table E.3.12 - ESTIMATE SUMMARY

TEXACO CASE D2

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GASR & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2500 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		6.075.000	112.700.000	78.600.000	27.061.000	22.786.000	17.800.000	221.931.000	71.143.000	558.096.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.215.000	50.715.000	23.580.000	13.424.000	11.151.000	4.450.000	55.483.000	39.129.000	199.147.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		608.000	16.905.000	3.144.000	7.553.000	10.699.000	890.000	22.193.000	7.114.000	69.106.000	
4	EPC SERVICES		911.000	39.445.000	11.790.000	8.325.000	5.384.000	1.246.000	17.754.000	14.229.000	99.084.000	
A	**Installed Costs** (Contingency excluded)		**8.809.000**	**219.765.000**	**117.114.000**	**56.363.000**	**50.020.000**	**24.386.000**	**317.361.000**	**131.615.000**	**925.433.000**	
B	Contingency	%	7	7	5	7	7	5	7	5	6,3	
		Euro	616.630	15.383.550	5.855.700	3.945.410	3.501.400	1.219.300	22.215.270	6.580.750	58.701.380	
C	Fees (2% of A)		176.180	4.395.300	2.342.280	1.127.260	1.000.400	487.720	6.347.220	2.632.300	18.508.660	
D	Land Purchases; surveys (5% of A)		440.450	10.988.250	5.855.700	2.818.150	2.501.000	1.219.300	15.868.050	6.580.750	46.271.650	
	TOTAL INVESTMENT COST		**10.042.260**	**250.532.100**	**131.167.680**	**64.253.820**	**57.022.800**	**27.312.320**	**361.791.540**	**147.408.800**	**1.048.914.690**	

900 Coal Handling & Storage
1000 Gasification Section
2100 Air Separation Unit
2200 Syngas Treat.&Condt. Line
2300 Acid Gas Removal
2500 CO2 Compression&Drying
3000 Power Island
4000+ Utilities&Offsites

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Table E.3.13 - ESTIMATE SUMMARY

TEXACO CASE D3

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GASR & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		6.075.000	112.700.000	78.600.000	28.654.000	23.897.000	18.100.000	16.437.000	222.023.000	71.238.000	577.724.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.215.000	50.715.000	23.580.000	14.214.000	11.469.000	8.145.000	4.109.000	55.506.000	39.181.000	208.134.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		608.000	16.905.000	3.144.000	12.787.000	10.996.000	2.534.000	822.000	22.202.000	7.124.000	77.122.000	
4	EPC SERVICES		911.000	39.445.000	11.790.000	8.815.000	5.538.000	2.715.000	1.151.000	17.762.000	14.248.000	102.375.000	**900 Coal Handling & Storage**
													1000 Gasification Section
													2100 Air Separation Unit
													2200 Syngas Treat.&Condt. Line
A	**Installed Costs** (Contingency excluded)		**8.809.000**	**219.765.000**	**117.114.000**	**64.470.000**	**51.900.000**	**31.494.000**	**22.519.000**	**317.493.000**	**131.791.000**	**965.355.000**	**2300 Acid Gas Removal**
													2400 SRU & TGT
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,4	**2500 CO2 Compression&Drying**
		Euro	616.630	15.383.550	5.855.700	4.512.900	3.633.000	2.204.580	1.125.950	22.224.510	6.589.550	61.529.740	**3000 Power Island**
													4000+ Utilities&Offsites
C	Fees (2% of A)		176.180	4.395.300	2.342.280	1.289.400	1.038.000	629.880	450.380	6.349.860	2.635.820	19.307.100	
D	Land Purchases; surveys (5% of A)		440.450	10.988.250	5.855.700	3.223.500	2.595.000	1.574.700	1.125.950	15.874.650	6.589.550	48.267.750	
	TOTAL INVESTMENT COST		**10.042.260**	**250.532.100**	**131.167.680**	**73.495.800**	**59.166.000**	**35.903.160**	**25.221.280**	**361.942.020**	**147.605.920**	**1.094.459.590**	

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Table E.3.14 - ESTIMATE SUMMARY

TEXACO CASE D4

Refer : 1-BD-0119A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : GASIFICATION POWER GENERATION STUDY
Location : NETHERLANDS
Date : March 2003 REV. 1

FIGURE IN EURO

POS	DESCRIPTION		UNIT 900 €	1000 €	2100 €	2200 €	2300 €	2400 €	2500 €	3000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		6.075.000	107.500.000	76.100.000	24.805.000	42.176.000	17.400.000	17.598.000	220.350.000	70.762.000	582.766.000	1) ESTIMATE ACCURACY +/- 25%
2	CONSTRUCTION		1.215.000	48.375.000	24.030.000	12.305.000	22.404.000	7.830.000	4.400.000	55.088.000	38.919.000	214.566.000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		608.000	16.905.000	3.204.000	7.553.000	21.315.000	2.436.000	880.000	22.035.000	7.076.000	82.012.000	
4	EPC SERVICES		911.000	37.472.750	12.015.000	8.479.000	10.816.000	2.610.000	1.232.000	17.628.000	14.152.000	105.315.750	
A	**Installed Costs** (Contingency excluded)		**8.809.000**	**210.252.750**	**115.349.000**	**53.142.000**	**96.711.000**	**30.276.000**	**24.110.000**	**315.101.000**	**130.909.000**	**984.659.750**	
B	Contingency	%	7	7	5	7	7	7	5	7	5	6,4	
		Euro	616.630	14.717.693	5.767.450	3.719.940	6.769.770	2.119.320	1.205.500	22.057.070	6.545.450	62.902.193	
C	Fees (2% of A)		176.180	4.205.055	2.306.980	1.062.840	1.934.220	605.520	482.200	6.302.020	2.618.180	19.693.195	
D	Land Purchases; surveys (5% of A)		440.450	10.512.638	5.767.450	2.657.100	4.835.550	1.513.800	1.205.500	15.755.050	6.545.450	49.232.988	
	TOTAL INVESTMENT COST		**10.042.260**	**239.688.135**	**129.190.880**	**60.581.880**	**110.250.540**	**34.514.640**	**27.003.200**	**359.215.140**	**146.618.080**	**1.116.488.125**	

900 **Coal Handling & Storage**
1000 **Gasification Section**
2100 **Air Separation Unit**
2200 **Syngas Treat.&Condt. Line**
2300 **Acid Gas Removal**
2400 **SRU & TGT**
2500 **CO2 Compression&Drying**
3000 **Power Island**
4000+ **Utilities&Offsites**

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Table E.3.15 - ESTIMATE SUMMARY

Refer : 1-BD-0119A
Client : IEA GREENHOUSE R & D PROJ.
Plant : GASIFICATION POWER GENERAL STUDY
Location : NETHERLANDS
Date : March 2003 REV. 2

TEXACO CASES

FIGURE IN MM EURO

POS	DESCRIPTION	C1		C2		C3		D1		D2		D3		D4	
		€	%	€	%	€	%	€	%	€	%	€	%	€	%
1	Air Separation Unit	128,2	13,1	130,8	12,7	124,9	13,0	131,2	12,0	131,2	12,5	131,2	12,0	129,2	11,6
2	Process Units	359,8	36,7	399,8	38,8	334,9	34,9	424,4	38,9	381,9	36,4	429,1	39,2	455,1	40,7
3	CO_2 Compression and Drying	0	0,0	0	0,0	0,0	0,0	26,6	2,4	27,3	2,6	25,2	2,3	27,0	2,4
4	Power Island	363,0	37,0	366,0	35,5	359,7	37,5	361,9	33,2	361,8	34,5	361,9	33,1	359,2	32,2
5	Utilities and Offsite Units	130,4	13,3	135,2	13,1	140,3	14,6	147,4	13,5	147,4	14,0	147,6	13,5	146,6	13,1
	TOTAL	**981,4**	**100,0**	**1.031,8**	**100,0**	**959,9**	**100,0**	**1.091,5**	**100,0**	**1.049,5**	**100,0**	**1.095,1**	**100,0**	**1.117,1**	**100,0**

	C1	C2	C3	D1	D2	D3	D4
NET POWER OUTPUT, MWe	826,5	860,6	799,9	730,3	742,3	744,3	705,0
SPECIFIC INVESTMENT COST, Euro/kW	1187,4	1198,9	1200,0	1494,6	1413,9	1471,3	1584,5

4.0 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 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 variable costs of the IGCC Complex are summarized in the attached Tables E.4.1/2.

The consumption of the various items and the corresponding costs are yearly, based on the expected equivalent availability of 7446 equivalent hours of operation in one year with syngas. Other 554 equivalent hours of operation in one year with natural gas as back-up fuel are expected, but this operation has not been conservatively considered in the economical analysis.

4.1.1 Shell Alternatives

The attached Table E.4.1 shows the Variable Costs for alternatives A.1, B.1 and B.3.

FOSTER WHEELER ITALIANA	Table E.4.1 - Shell Alternatives - Yearly Variable Costs	Refer: 1-BD-0119A Client: IEA GREENHOUSE R & D PROJ. Date: March 2003 REV. 2

Yearly Operating hours =	7446	Shell - Case A.1			Shell - Case B.1			Shell - Case B.3		
Consumables	**Unit Cost** Euro/t	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**
Feedstock										
Coal	38,8	250600	1865967,6	72399543	273100	2033502,6	78899901	271400	2020844,4	78408763
Flux	15,0	7767	57831,1	867466	8340	62097,4	931461	8288	61710,8	925663
Auxiliary feedstock										
Natural Gas (Flare)	80,0	75	558,5	44676	75	558,5	44676	75	558,5	44676
Make-up water	0,100	224000	1667904,0	166790	406000	3023076,0	302308	403000	3000738,0	300074
Solvents										
MDEA	4500	8,36	62,3	280179	0,00	0,0	0	8,36	62,3	280179
Selexol	6500	0,00	0,0	0	16,76	124,8	561600	0,00	0,0	0
Catalyst										
Claus Catalyst (5 years life)	7770	0,295	2,20	17084	0,322	2,40	18634	0,000	0,00	0
Hydrogenation Catalyst (5 years life)	13200	0,093	0,69	9105	0,191	1,42	18775	0,000	0,00	0
S. Degassing Catalyst	12250	0,001	0,01	82	0,001	0,01	89	0,000	0,00	0
COS Hydrolysis Catalyst (5 years life)	11760	0,552	4,11	48363	0,000	0,00	0	0,000	0,00	0
Sour Shift Catalyst (3-5 years life) (1)	20000	0,000	0,00	0	18,802	140,00	1646400	18,685	139,13	1636151
Chemicals										
NaOH (50%)	155,0	265,6	1977,7	306549	289,5	2155,3	334072	287,7	2141,9	331993
HCL (20%)	150,0	758,2	5645,3	846789	826,2	6152,1	922818	821,1	6113,8	917074
Coordinate phosphate	1,9	1,4	10,5	20	1,3	9,8	19	1,3	9,9	19
Nalco Eliminox or equivalent	4132,0	0,9	7,0	28728	0,9	6,5	26756	0,9	6,5	27018
Nalco Tri-Act 1801 or equivalent	3615,0	1,0	7,6	27393	1,1	8,3	29852	1,1	8,2	29666
Filter Polyelectrolyte	2580,0	0,3	1,9	4888	0,3	2,1	5326	0,3	2,1	5293
IAF Polyelectrolyte	2580,0	0,3	1,9	4888	0,3	2,1	5326	0,3	2,1	5293
Phosporic acid (20%)	400,0	0,3	1,9	758	0,3	2,1	826	0,3	2,1	821
Waste Disposal										
Slag disposal (wet)	7,0	37200,0	276991,2	1938938	40500,0	301563,0	2110941	40200,0	299329,2	2095304
TOTAL YEARLY OPERATING COSTS, Euro/year				**76.992.239**			**85.859.781**			**85.007.986**

NOTES: (1) Two catalyst beds are required. 1st bed years life: 3; 2nd bed years life: 5.

4.1.2 Texaco Alternatives

The attached Table E.4.2 shows the Variable Costs for alternatives C.1, C.2, D.1, D.2 and D.3.

FOSTER WHEELER ITALIANA

Table E.4.2 - Texaco Alternatives - Yearly Variable Costs

Refer : 1-BD-0119A
Client : IEA GREENHOUSE R & D PROJ.
Date : March 2003 REV. 2

Yearly Operating hours =	7446	Texaco - Case C.1			Texaco - Case C.2			Texaco - Case D.1			Texaco - Case D.2			Texaco - Case D.3		
Consumables	**Unit Cost**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**
		Hourly	Yearly	**(yearly basis)**	Hourly	Yearly	**(yearly basis)**	Hourly	Yearly	**(yearly basis)**	Hourly	Yearly	**(yearly basis)**	Hourly	Yearly	**(yearly basis)**
	Euro/t	kg/h	t/y		kg/h	t/y		kg/h	t/y		kg/h	t/y		kg/h	t/y	
Feedstock																
Coal	38,8	303000	2256138,0	87538154	327600	2439309,6	94645212	323100	2405802,6	93345141	323200	2406547,2	93374031	323100	2405802,6	93345141
Auxiliary feedstock																
Natural Gas (Flare)	80,0	80	595,7	47654	80	595,7	47654	80	595,7	47654	80	595,7	47654	80	595,7	47654
Make-up water	0,100	131000	975426,0	97543	319000	2375274,0	237527	315000	2345490,0	234549	315000	2345490,0	234549	315000	2345490,0	234549
Solvents																
MDEA	4500	0,00	0,0	0	0,00	0,0	0	0,00	0,0	0	0,00	0,0	0	0,00	0,0	0
Selexol	6500	11,87	88,4	397800	12,85	95,7	430560	16,76	124,8	561600	16,76	124,8	561600	15,08	112,3	505440
Catalyst																
Claus Catalyst (5 years life)	7770	0,357	2,66	20667	0,386	2,88	22354	0,381	2,84	22038	0,000	0,00	0	0,381	2,84	22038
Hydrogenation Catalyst (5 years life)	13200	0,182	1,35	17871	0,240	1,79	23582	0,358	2,66	35176	0,000	0,00	0	0,370	2,75	36363
S. Degassing Catalyst	12250	0,001	0,01	99	0,001	0,01	107	0,001	0,01	105	0,000	0,00	0	0,001	0,01	105
COS Hydrolysis Catalyst (5 years life)	11760	0,252	1,88	22079	0,000	0,00	0	0,000	0,00	0	0,000	0,00	0	0,000	0,00	0
Sour Shift Catalyst (5 years life) (1)	20000	0,000	0,00	0	10,894	81,11	953903	10,744	80,00	940800	10,744	80,00	940800	15,758	117,33	1379840
Chemicals																
NaOH (20%)	150,0	615,2	4581,0	710054	665,2	4952,9	767701	656,0	4884,9	757156	656,2	4886,4	757390	656,0	4884,9	757156
NaOH (50%)	155,0	75,1	558,9	86627	81,2	604,3	93660	80,0	596,0	92373	80,1	596,1	92402	80,0	596,0	92373
HCL (20%)	150,0	916,7	6825,7	1023851	991,1	7379,8	1106976	977,5	7278,5	1091770	977,8	7280,7	1092108	977,5	7278,5	1091770
$FeSO_4$ (20%)	120,0	0,1	1,0	145	0,1	1,0	157	0,1	1,0	155	0,1	1,0	155	0,1	1,0	155
Polimer1	2580,0	31,4	233,6	35038	33,9	252,5	37882	33,5	249,1	37362	33,5	249,2	37374	33,5	249,1	37362
Coordinate phosphate	1,9	1,5	11,4	22	1,5	11,4	22	1,4	10,5	20	1,4	10,4	20	1,4	10,6	20
Nalco Eliminox or equivalent	4132,0	1,0	7,6	31219	1,0	7,5	31175	0,9	6,9	28637	0,9	6,9	28584	0,9	7,0	29057
Nalco Tri-Act 1801 or equivalent	3615,0	1,2	9,2	33121	1,3	9,9	35810	1,3	9,8	35318	1,3	9,8	35329	1,3	9,8	35318
Filter Polyelectrolyte	2580,0	0,3	2,3	5909	0,3	2,5	6389	0,3	2,4	6301	0,3	2,4	6303	0,3	2,4	6301
IAF Polyelectrolyte	2580,0	0,3	2,3	5909	0,3	2,5	6389	0,3	2,4	6301	0,3	2,4	6303	0,3	2,4	6301
Phosporic acid (20%)	400,0	0,3	2,3	916	0,3	2,5	991	0,3	2,4	977	0,3	2,4	977	0,3	2,4	977
Waste Disposal																
Slag disposal (wet)	7,0	101400,0	755024,4	5285171	109500,0	815337,0	5707359	108067,6	804671,1	5632698	108100,0	804912,6	5634388	108067,6	804671,1	5632698
TOTAL YEARLY OPERATING COSTS, Euro/year				**95.359.848**			**104.155.412**			**102.876.132**			**102.849.968**			**103.260.620**

NOTES: (1) Two catalyst beds are required for case D.3. 1st bed years life: 3; 2nd bed years life: 5.

4.2 Fixed Costs

The fixed costs of the IGCC Complex operation include the following items:

- direct labour;
- administrative and general overhead;
- maintenance.

For maintenance, variable element of cost, such as gas turbine inspections, have been treated as part of fixed costs, on the assumption that Complex operates at the design capacity and with the expected design service factor.

4.2.1 Direct Labour

The Owner's personnel engaged in the Operation and Maintenance of the IGCC Complex is shown in Table E.4.3. The Complex has been divided in 3 areas of operation: Air Separation Unit, Gasification, including syngas processing and sulfur plant, and Power Island with common Utilities. The same division will be reflected in the design of the centralized Control Room, which will have, correspondingly, 3 main DCS control groups, each one equipped with a number of control stations, from where the operation of the plants of each of the three areas will be controlled.

Each area of operation will be supervised by the Area Responsible and his Assistant; both are daily position.
The Shift Superintendent and the Electrical Assistant are common for the 3 areas; both are shift position. The rest of the Operation staff is structured around the standard positions: shift supervisors, control room operators and field operators.

The maintenance personnel are based on large use of external subcontractor for all medium-major type of maintenance work. Maintenance costs described at para. 4.2.3 take into account the service outsourcing. Plant Maintenance personnel like the instrument specialists perform routine maintenance and resolve emergency problems.

Personnel shown in Table E.4.3 are directly engaged in the Complex. Management, Administration, Technical Services and supporting clerical staff are not included since their composition and strength are very much dependent on Owner's policy.

Table E.4.3 – IGCC personnel.

OPERATION	ASU	GASIFICATION	CCU & UTILITIES	TOTAL	NOTES
Area Responsible	1	1	1	3	daily position
Assistant Area Responsible	1	1	1	3	daily position
Shift Superintendent		5		5	1 shift position
Electrical Assistant		5		5	1 shift position
Shift Supervisor	5	5	5	15	3 shift position
Control Room Operator	5	10	10	25	5 shift position
Field Operator	5	25	20	50	10 shift position
Subtotal				**106**	
MAINTENANCE					
Mechanical group		4		4	daily position
Instrument group		7		7	daily position
Electrical group		5		5	daily position
Subtotal				**16**	
LABORATORY					
Superintendent + Analysts		6		**6**	daily position
TOTAL				**128**	

The yearly cost of the direct labour is calculated assuming for each individual an average cost equal to 50,000 Euro/year, equivalent to a total cost equal to 6,400,000 Euro/year.

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, equivalent to 1,920,000 Euro/year, was considered.

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 Vendors, 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 has been estimated, as suggested by EPRI Technical Evaluation Guide, as a percentage of the installed capital cost of the facilities.

In accordance with EPRI recommendations the Complex has been divided in four major sections, applying to each section different percentage of the capital cost of the section to determine the relative cost of maintenance, as shown in the attached tables.

Percentage applied to Power Island has been adjusted to take into account the gas turbine maintenance cost based on the assumption of a Long Term Service Agreement (LTSA) with the gas turbine manufacturer.

The total yearly maintenance cost of the Complex is assumed to be subcontracted to external firms under the supervision of the maintenance staff of the Owner, included in the fixed cost as direct labour.

The overall cost of maintenance can be statistically split as follows:

- maintenance materials : 60% of total maintenance cost;
- maintenance labour : 40% of total maintenance cost.

Attached Tables E.4.4 and 5 summarize overall maintenance costs for both the Shell and the Texaco alternatives.

FOSTER WHEELER ITALIANA

Table E.4.4 - Shell Alternatives - Maintenance Costs

Refer : 1-BD-0119A
Client : IEA
Date : March 2003

Complex section	Maintenance %	Shell - Case A.1 Capital Cost Euro x 10^3 (1)	Shell - Case A.1 Maintenance 10^3 Euro/Year	Shell - Case B.1 Capital Cost Euro x 10^3 (1)	Shell - Case B.1 Maintenance 10^3 Euro/Year	Shell - Case B.3 Capital Cost Euro x 10^3 (1)	Shell - Case B.3 Maintenance 10^3 Euro/Year
ASU, AGR, SRU & TGT, CO_2 Comp., Coal St. (Units: 900, 2100,2300,2400,2500)	2,5	133730	3343	240045	6001	177845	4446
Gasification, Syngas Treat., (Units: 1000,2200)	4,0	382034	15281	438688	17548	436910	17476
Power Island (Unit: 3000)	5,0 (1)	319993	16000	317988	15899	316329	15816
Common facilities (Utilities, Offsite, etc.)	1,7	101134	1719	110471	1878	107594	1829
TOTAL		936891	36343	1107192	41326	1038678	39568
		Maint. % =	3,9	Maint. % =	3,7	Maint. % =	3,8

NOTES: (1) Including the Gas Turbine Long Term Service Agreement.

FOSTER WHEELER ITALIANA	Table E.4.5 - Texaco Alternatives - Maintenance Costs										Refer : 1-BD-0119A Client : IEA Date : March 2003
		Texaco - Case C.1		Texaco - Case C.2		Texaco - Case D.1		Texaco - Case D.2		Texaco - Case D.3	
Complex section	**Maintenance** %	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year
ASU, AGR, SRU & TGT, CO_2 Comp., Coal St. (Units: 900, 2100,2300,2400,2500)	2,5	178362	4459	187211	4680	236141	5904	200329	5008	231836	5796
Gasification, Syngas Treat., (Units:1000,2200)	4,0	251684	10067	280334	11213	277030	11081	276128	11045	284235	11369
Power Island (Unit: 3000)	5,0 (1)	318405	15920	321014	16051	317458	15873	317361	15868	317493	15875
Common facilities (Utilities, Offsite, etc.)	1,7	116461	1980	120691	2052	131615	2237	131615	2237	131791	2240
TOTAL		864912	32426	909250	33996	962244	35094	925433	34158	965355	35279
		Maint. % =	3,7	Maint. % =	3,7	Maint. % =	3,6	Maint. % =	3,7	Maint. % =	3,7

NOTES: (1) Including the Gas Turbine Long Term Service Agreement.

4.3 Summary

The following tables summarize the total Operating and Maintenance Costs on yearly basis for all the alternatives (Shell and Texaco technologies).

Table E.4.6 – Shell Alternatives – Total O&M Costs

FIXED COSTS	Shell Case A.1 Euro/year	Shell Case B.1 Euro/year	Shell Case B.3 Euro/year
Direct Labour Administration/General Overheads Maintenance	6,400,000 1,920,000 36,343,000	6,400,000 1,920,000 41,326,000	6,400,000 1,920,000 39,568,000
Subtotal	44,663,000	49,646,000	47,888,000
Variable Costs	76,992,000	85,860,000	85,008,000
Total O&M Costs	**121,655,000**	**135,506,000**	**132,896,000**

Table E.4.7 – Texaco Alternatives – Total O&M Costs

FIXED COSTS	Tex. Case C.1 Euro/year	Tex. Case C.2 Euro/year	Tex. Case D.1 Euro/year	Tex. Case D.2 Euro/year	Tex. Case D.3 Euro/year
Direct Labour Administration/ General Overheads Maintenance	6,400,000 1,920,000 32,426,000	6,400,000 1,920,000 33,996,000	6,400,000 1,920,000 35,094,000	6,400,000 1,920,000 34,158,000	6,400,000 1,920,000 35,279,000
Subtotal	40,746,000	42,316,000	43,414,000	42,478,000	43,599,000
Variable Costs	95,360,000	104,155,000	102,876,000	102,850,000	103,261,000
Total O&M Costs	**136,106,000**	**146,471,000**	**146,290,000**	**145,328,000**	**146,860,000**

5.0 Evaluation of the Electric Power Cost and CO_2 removal cost of the Alternatives

5.1 Electric Power Cost

The following Tables summarize the economic analyses performed on each alternative in order to evaluate the electric power production cost, based on the following assumptions:

- 7446 equivalent operating hours of IGCC fed by syngas at 100% capacity;
- total investment cost as evaluated in para.3.0 of this Section;
- O&M costs as evaluated in para 4.0;
- 10% discount rate on the investment cost over 25 operating years;
- No selling price is attribute to CO_2;
- other financial parameters as per Project Design Basis, Section B, para. 2.7

A sensitivity analysis with 5% discount rate is also provided.

5.1.1 Shell Alternatives

The attached Tables E.5.1/3 show the economic analysis for alternatives A.1, B.1 and B.3.

The sensitivity analysis with 5% discount rate on the investment cost is shown in Tables E.5.4/6.

Table E.5.7 summarizes the electric power cost for the Shell alternatives with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.7 – Electric Power Cost

ALTERNATIVE		**A1**	**B1**	**B3**	**A1**	**B1**	**B3**
Discount rate	**%**	**10**	**10**	**10**	**5**	**5**	**5**
Coal Flowrate	t/h	250.6	273.1	271.4	250.6	273.1	271.4
Net Power Out.	MW	775.9	676.2	683.3	775.9	676.2	683.3
Total Inv. Cost	MM Euro	1064.1	1257.6	1179.5	1064.1	1257.6	1179.5
Revenues/year	**MM Euro/y**	**276.7**	**318.6**	**304.7**	**223.3**	**255.6**	**245.5**
Electricity Prod. Cost	**Euro/kWh**	**0.048**	**0.063**	**0.060**	**0.038**	**0.050**	**0.048**

TABLE E.5.1 - SHELL CASE A.1 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	250,6	t/h
Net Power Output	775,9	MW
Sold Sulphur	2,15	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures	**MM Euro**	
Installed Costs		936,9
Land purchase; surveys	5%	46,8
Fees	2%	18,7
Average Contingencies	6,6%	61,7
Total Investment Cost		1064,1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	72,4
Maintenance	36,3
Waste Disposal (7€/t)	1,9
Chemicals + Consumable	2,7
Insurance and local taxes	18,7

Working Capital	**MM Euro**
30 days Chemical Storage	0,3
30 days Coal Storage	7,0
Total Working capital	7,3

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Cost	0,048	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	276,7	MM Euro/year

NPV	**0,00**
IRR	**10,00%**

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				145,6	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	275,0	
Sulphur				0,9	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	
Operating Costs																													
Fuel Cost				-38,3	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	
Maintenance				-24,2	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-1,4	-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	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	
Waste Disposal				-1,0	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	
Insurance				-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	
Working Capital Cost				-7,3																									7,3
Fixed Capital Expenditures	-212,8	-478,9	-372,4																										
Total Cash flow (yearly)	-212,8	-478,9	-372,4	47,2	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	136,3	7,3
Total Cash flow (cumulated)	-212,8	-691,7	-1064,1	-1017,0	-880,7	-744,4	-608,1	-471,8	-335,5	-199,2	-62,9	73,4	209,7	346,0	482,2	618,5	754,8	891,1	1027,4	1163,7	1300,0	1436,3	1572,6	1708,9	1845,2	1981,5	2117,7	2254,0	2261,3
Discounted Cash Flow (Yearly)	-193,5	-395,8	-279,8	32,2	84,6	76,9	69,9	63,6	57,8	52,5	47,8	43,4	39,5	35,9	32,6	29,7	27,0	24,5	22,3	20,3	18,4	16,7	15,2	13,8	12,6	11,4	10,4	9,5	0,5
Discounted Cash Flow (Cumul.)	-193,5	-589,2	-869,1	-836,8	-752,2	-675,3	-605,3	-541,8	-484,0	-431,4	-383,6	-340,2	-300,7	-264,8	-232,2	-202,6	-175,6	-151,1	-128,8	-108,5	-90,1	-73,4	-58,2	-44,3	-31,7	-20,3	-9,9	-0,5	0,0

TABLE E.5.2 - SHELL CASE B.1 - Cost Evaluation - Discount Rate = 10%

Production
Coal Florate 273,1 t/h
Net Power Output 676,2 MW
Sold Sulphur 2,35 t/h
Fuel Price 38,8 USD/t (*)
Insurance and local taxes 2% Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures **MM Euro**
Installed Costs 1107,2
Land purchase; surveys 5% 55,4
Fees 2% 22,1
Average Contingencies 6,6% 72,9
Total Investment Cost 1257,6

Operating Costs [MM Euro/year]
at 85% load factor
Fuel Cost 78,9
Maintenance 41,3
Waste Disposal (7€/t) 2,1
Chemicals + Consumab 4,8
Insurance and local taxe 22,1

Working Capita **MM Euro**
30 days Chemical Stora 0,5
30 days Coal Storage 7,6
Total Working capital 8,1

Labour Cost **MM Euro/year**
operators 128
Salary 0,05
Direct Labour Cost 6,4
Administration 30% L.C 1,9
Total Labour Cost 8,3

Electricity Production Cos 0,063 Euro/kWh
Sulphur Price 103,3 Euro/t
Inflation 0,00 %
Taxes 0,00 %
Discount rate 10,00 %
Revenues / year 318,6 MM Euro/year

NPV **0,00**
IRR **10,00%**

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CASH FLOW ANALYSYS Millions Euro	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
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				167,7	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	316,8	
Sulphur				1,0	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	
Operating Costs																													
Fuel Cost				-41,8	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	
Maintenance				-27,6	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,6	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	
Waste Disposal				-1,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	
Insurance				-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	
Working Capital Cost				-8,1																									8,1
Fixed Capital Expenditures	-251,5	-565,9	-440,1																										
Total Cash flow (yearly)	-251,5	-565,9	-440,1	57,1	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	160,9	8,1
Total Cash flow (cumulated)	-251,5	-817,4	-1257,6	-1200,5	-1039,5	-878,6	-717,7	-556,8	-395,9	-234,9	-74,0	86,9	247,8	408,7	569,7	730,6	891,5	1052,4	1213,3	1374,3	1535,2	1696,1	1857,0	2017,9	2178,9	2339,8	2500,7	2661,6	2669,7
Discounted Cash Flow (Yearly)	-228,6	-467,7	-330,7	39,0	99,9	90,8	82,6	75,1	68,2	62,0	56,4	51,3	46,6	42,4	38,5	35,0	31,8	28,9	26,3	23,9	21,7	19,8	18,0	16,3	14,9	13,5	12,3	11,2	0,5
Discounted Cash Flow (Cumul.)	-228,6	-696,3	-1027,0	-988,0	-888,1	-797,3	-714,7	-639,6	-571,4	-509,3	-452,9	-401,7	-355,1	-312,7	-274,2	-239,1	-207,3	-178,4	-152,0	-128,1	-106,4	-86,6	-68,6	-52,3	-37,4	-23,9	-11,7	-0,5	0,0

Production		
Coal Florate	271,4	t/h
Net Power Output	683,3	MW
Sold Sulphur	0,00	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures	**MM Euro**	
Installed Costs		1038,7
Land purchase; surveys	5%	51,9
Fees	2%	20,8
Average Contingencies	6,6%	68,1
Total Investment Cost		1179,5

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	78,4
Maintenance	39,6
Waste Disposal (7€/t)	2,1
Chemicals + Consumab	4,5
Insurance and local taxe	20,8

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	7,6
Total Working capital	8,0

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Co	0,060	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	304,7	MM Euro/year

NPV **0,00**
IRR **10,00%**

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				161,3	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	304,7	
Sulphur				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	
Operating Costs																													
Fuel Cost				-41,5	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	
Maintenance				-26,4	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,4	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	
Waste Disposal				-1,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	
Insurance				-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	
Working Capital Cost				-8,0																									8,0
Fixed Capital Expenditures	-235,9	-530,8	-412,8																										
Total Cash flow (yearly)	-235,9	-530,8	-412,8	52,8	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	151,0	8,0
Total Cash flow (cumulated)	-235,9	-766,7	-1179,5	-1126,7	-975,7	-824,7	-673,6	-522,6	-371,6	-220,6	-69,6	81,4	232,4	383,4	534,4	685,4	836,4	987,4	1138,4	1289,4	1440,4	1591,4	1742,4	1893,4	2044,4	2195,5	2346,5	2497,5	2505,5
Discounted Cash Flow (Yearly)	-214,4	-438,6	-310,2	36,1	93,8	85,2	77,5	70,4	64,0	58,2	52,9	48,1	43,7	39,8	36,1	32,9	29,9	27,2	24,7	22,4	20,4	18,6	16,9	15,3	13,9	12,7	11,5	10,5	0,5
Discounted Cash Flow (Cumul.)	-214,4	-653,1	-963,2	-927,2	-833,4	-748,2	-670,7	-600,2	-536,2	-478,0	-425,1	-376,9	-333,2	-293,4	-257,3	-224,4	-194,5	-167,4	-142,7	-120,3	-99,8	-81,3	-64,4	-49,1	-35,2	-22,5	-11,0	-0,5	0,0

TABLE E.5.4 - SHELL CASE A.1 - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	250,6	t/h
Net Power Output	775,9	MW
Sold Sulphur	2,15	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		936,9
Land purchase; surveys	5%	46,8
Fees	2%	18,7
Average Contingencies	6,6%	61,7
Total Investment Cost		1064,1

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	72,4
Maintenance	36,3
Waste Disposal (7€/t)	1,9
Chemicals + Consumab	2,7
Insurance and local taxe	18,7

Working Capita	**MM Euro**
30 days Chemical Stora	0,3
30 days Coal Storage	7,0
Total Working capital	7,3

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Cc	0,038	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	223,3	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				117,4	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	221,7	
Sulphur				0,9	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	1,7	
Operating Costs																													
Fuel Cost				-38,3	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	-72,4	
Maintenance				-24,2	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	-36,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-1,4	-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	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	-2,7	
Waste Disposal				-1,0	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	
Insurance				-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	-18,7	
Working Capital Cost				-7,3																									7,3
Fixed Capital Expenditures	-212,8	-478,9	-372,4																										
Total Cash flow (yearly)	-212,8	-478,9	-372,4	18,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	82,9	7,3
Total Cash flow (cumulated)	-212,8	-691,7	-1064,1	-1045,2	-962,3	-879,4	-796,4	-713,5	-630,6	-547,6	-464,7	-381,8	-298,8	-215,9	-133,0	-50,1	32,9	115,8	198,7	281,7	364,6	447,5	530,5	613,4	696,3	779,2	862,2	945,1	952,4
Discounted Cash Flow (Yearly)	-202,7	-434,3	-321,7	15,6	65,0	61,9	58,9	56,1	53,5	50,9	48,5	46,2	44,0	41,9	39,9	38,0	36,2	34,5	32,8	31,3	29,8	28,3	27,0	25,7	24,5	23,3	22,2	21,2	1,8
Discounted Cash Flow (Cumul.)	-202,7	-637,0	-958,8	-943,2	-878,2	-816,3	-757,4	-701,3	-647,8	-596,9	-548,4	-502,2	-458,3	-416,4	-376,5	-338,5	-302,3	-267,8	-235,0	-203,8	-174,0	-145,7	-118,7	-92,9	-68,5	-45,1	-22,9	-1,8	0,0

Production		
Coal Florate	273,1	t/h
Net Power Output	676,2	MW
Sold Sulphur	2,35	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		1107,2
Land purchase; surveys	5%	55,4
Fees	2%	22,1
Average Contingencies	6,6%	72,9
Total Investment Cost		1257,6

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	78,9
Maintenance	41,3
Waste Disposal (7€/t)	2,1
Chemicals + Consumab	4,8
Insurance and local tax	22,1

Working Capita	**MM Euro**
30 days Chemical Stora	0,5
30 days Coal Storage	7,6
Total Working capital	8,1

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,050	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	255,6	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Millions Euro	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
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				134,3	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	253,8	
Sulphur				1,0	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	
Operating Costs																													
Fuel Cost				-41,8	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	-78,9	
Maintenance				-27,6	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	-41,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,6	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	-4,8	
Waste Disposal				-1,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	
Insurance				-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	-22,1	
Working Capital Cost				-8,1																									8,1
Fixed Capital Expenditures	-251,5	-565,9	-440,1																										
Total Cash flow (yearly)	-251,5	-565,9	-440,1	23,7	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	97,9	8,1
Total Cash flow (cumulated)	-251,5	-817,4	-1257,6	-1233,8	-1135,9	-1038,0	-940,1	-842,2	-744,3	-646,3	-548,4	-450,5	-352,6	-254,7	-156,8	-58,8	39,1	137,0	234,9	332,8	430,7	528,6	626,6	724,5	822,4	920,3	1018,2	1116,1	1124,2
Discounted Cash Flow (Yearly)	-239,5	-513,3	-380,2	19,5	76,7	73,1	69,6	66,3	63,1	60,1	57,2	54,5	51,9	49,5	47,1	44,9	42,7	40,7	38,7	36,9	35,1	33,5	31,9	30,4	28,9	27,5	26,2	25,0	2,0
Discounted Cash Flow (Cumul.)	-239,5	-752,8	-1133,0	-1113,5	-1036,8	-963,7	-894,1	-827,9	-764,8	-704,6	-647,4	-592,9	-540,9	-491,5	-444,4	-399,5	-356,8	-316,1	-277,4	-240,5	-205,3	-171,9	-140,0	-109,6	-80,7	-53,2	-26,9	-2,0	0,0

TABLE E.5.6 - SHELL CASE B.3 - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	271,4	t/h
Net Power Output	683,3	MW
Sold Sulphur	0,00	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		1038,7
Land purchase; surveys	5%	51,9
Fees	2%	20,8
Average Contingencies	6,6%	68,1
Total Investment Cost		1179,5

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	78,4
Maintenance	39,6
Waste Disposal (7€/t)	2,1
Chemicals + Consumab	4,5
Insurance and local tax	20,8

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	7,6
Total Working capital	8,0

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,048	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	245,5	MM Euro/year

NVP	**0,00**
IRR	**5,00%**

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				130,0	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5
Sulphur				0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Operating Costs														
Fuel Cost				-41,5	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4
Maintenance				-26,4	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3
Chemicals & Consumables				-2,4	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5
Waste Disposal				-1,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1
Insurance				-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8
Working Capital Cost				-8,0										
Fixed Capital Expenditures	-235,9	-530,8	-412,8											
Total Cash flow (yearly)	-235,9	-530,8	-412,8	21,5	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9
Total Cash flow (cumulated)	-235,9	-766,7	-1179,5	-1158,0	-1066,1	-974,2	-882,3	-790,4	-698,6	-606,7	-514,8	-422,9	-331,0	-239,2
Discounted Cash Flow (Yearly)	-224,7	-481,4	-356,6	17,7	72,0	68,6	65,3	62,2	59,2	56,4	53,7	51,2	48,7	46,4
Discounted Cash Flow (Cumul.)	-224,7	-706,1	-1062,7	-1045,0	-973,0	-904,4	-839,1	-776,9	-717,7	-661,3	-607,6	-556,4	-507,7	-461,3

CASH FLOW ANALYSYS Millions Euro	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	245,5	
Sulphur	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	
Operating Costs															
Fuel Cost	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	-78,4	
Maintenance	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	-39,6	
Labour	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	-4,5	
Waste Disposal	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	-2,1	
Insurance	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	-20,8	
Working Capital Cost															8,0
Fixed Capital Expenditures															
Total Cash flow (yearly)	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	91,9	8,0
Total Cash flow (cumulated)	-147,3	-55,4	36,5	128,4	220,2	312,1	404,0	495,9	587,8	679,6	771,5	863,4	955,3	1047,2	1055,2
Discounted Cash Flow (Yearly)	44,2	42,1	40,1	38,2	36,4	34,6	33,0	31,4	29,9	28,5	27,1	25,8	24,6	23,4	1,9
Discounted Cash Flow (Cumul.)	-417,1	-375,0	-334,9	-296,7	-260,4	-225,8	-192,8	-161,4	-131,5	-103,0	-75,8	-50,0	-25,4	-1,9	0,0

5.1.2 Texaco Alternatives

The attached Tables E.5.8/12 show the economic analysis for alternatives C.1, C.2 D.1, D.2 and D.3.

The sensitivity analysis with 5% discount rate on the investment cost is shown in Tables E.5.13/17.

Table E.5.18 summarizes the electric power cost for the Texaco alternatives with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.18 – Electric Power Cost

ALTERNATIVE		**C1**	**C2**	**D1**	**D2**	**D3**
Discount rate	**%**	**10**	**10**	**10**	**10**	**10**
Coal Flowrate	t/h	303.0	327.6	323.1	323.2	323.1
Net Power Out.	MW	826.5	860.6	730.3	742.3	744.3
Total Inv. Cost	MM Euro	981.4	1031.8	1091.5	1049.5	1095.1
Revenues/year	**MM Euro/y**	**279.3**	**297.0**	**305.5**	**298.4**	**295.3**
Electricity Prod. Cost	**Euro/kWh**	**0.045**	**0.046**	**0.056**	**0.054**	**0.053**
Discount rate	**%**	**5**	**5**	**5**	**5**	**5**
Coal Flowrate	t/h	303.0	327.6	323.1	323.2	323.1
Net Power Out.	MW	826.5	860.6	730.3	742.3	744.3
Total Inv. Cost	MM Euro	981.4	1031.8	1091.5	1049.5	1095.1
Revenues/year	**MM Euro/y**	**230.0**	**245.2**	**250.7**	**245.7**	**240.3**
Electricity Prod. Cost	**Euro/kWh**	**0.037**	**0.038**	**0.046**	**0.044**	**0.043**

TABLE E.5.8 - TEXACO CASE C.1 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	303,0	t/h
Net Power Output	826,5	MW
Sold Sulphur	2,58	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		864,9
Land purchase; surveys	5%	43,2
Fees	2%	17,3
Average Contingencies	6,5%	55,9
Total Investment Cost		981,4

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	87,5
Maintenance	32,4
Waste Disposal (7€/t)	5,3
Chemicals + Consumabl	2,5
Insurance and local taxe	17,3

Working Capita	**MM Euro**
30 days Chemical Stora	0,2
30 days Coal Storage	8,5
Total Working capital	8,7

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Co	0,045	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	279,3	MM Euro/year
NPV	**0,00**	
IRR	**10,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				146,8	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3
Sulphur				1,1	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0
Operating Costs														
Fuel Cost				-46,3	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5
Maintenance				-21,6	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3
Chemicals & Consumables				-1,3	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5
Waste Disposal				-2,8	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3
Insurance				-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3
Working Capital Cost				-8,7										
Fixed Capital Expenditures	-196,3	-441,6	-343,5											
Total Cash flow (yearly)	-196,3	-441,6	-343,5	41,4	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9
Total Cash flow (cumulated)	-196,3	-637,9	-981,4	-939,9	-814,0	-688,1	-562,2	-436,3	-310,4	-184,5	-58,6	67,3	193,2	319,1
Discounted Cash Flow (Yearly)	-178,4	-365,0	-258,1	28,3	78,2	71,1	64,6	58,7	53,4	48,5	44,1	40,1	36,5	33,2
Discounted Cash Flow (Cumul.)	-178,4	-543,4	-801,5	-773,2	-695,0	-623,9	-559,3	-500,6	-447,2	-398,7	-354,5	-314,4	-277,9	-244,8

CASH FLOW ANALYSYS Millions Euro	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	277,3	
Sulphur	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	
Operating Costs															
Fuel Cost	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	
Maintenance	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	
Labour	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	
Waste Disposal	-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	-5,3	
Insurance	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	
Working Capital Cost															8,7
Fixed Capital Expenditures															
Total Cash flow (yearly)	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	125,9	8,7
Total Cash flow (cumulated)	445,0	570,9	696,8	822,7	948,6	1074,5	1200,4	1326,3	1452,2	1578,1	1704,0	1829,9	1955,8	2081,7	2090,4
Discounted Cash Flow (Yearly)	30,1	27,4	24,9	22,6	20,6	18,7	17,0	15,5	14,1	12,8	11,6	10,6	9,6	8,7	0,5
Discounted Cash Flow (Cumul.)	-214,6	-187,2	-162,3	-139,7	-119,1	-100,4	-83,4	-67,9	-53,8	-41,1	-29,4	-18,9	-9,3	-0,5	0,0

TABLE E.5.9 - TEXACO CASE C.2 - Cost Evaluation - Discount Rate = 10%

Production

Coal Florate	327,6	t/h
Net Power Output	860,6	MW
Sold Sulphur	2,79	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		909,3
Land purchase; surveys	5%	45,5
Fees	2%	18,2
Average Contingencies	6,5%	58,9
Total Investment Cost		1031,8

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	94,6
Maintenance	34,0
Waste Disposal (7€/t)	5,7
Chemicals + Consumab	3,8
Insurance and local tax	18,2

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	9,2
Total Working capital	9,5

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production C	0,046	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	297,0	MM Euro/year
NPV	**0,00**	
IRR	**10,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				156,1	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	294,9	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-50,1	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	
Maintenance				-22,7	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,0	-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	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	
Waste Disposal				-3,0	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	
Insurance				-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	
Working Capital Cost				-9,5																									9,5
Fixed Capital Expenditures	-206,4	-464,3	-361,1																										
Total Cash flow (yearly)	-206,4	-464,3	-361,1	43,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	132,4	9,5
Total Cash flow (cumulated)	-206,4	-670,7	-1031,8	-988,4	-856,0	-723,6	-591,2	-458,8	-326,5	-194,1	-61,7	70,7	203,1	335,4	467,8	600,2	732,6	865,0	997,3	1129,7	1262,1	1394,5	1526,9	1659,3	1791,6	1924,0	2056,4	2188,8	2198,3
Discounted Cash Flow (Yearly)	-187,6	-383,7	-271,3	29,7	82,2	74,7	67,9	61,8	56,1	51,0	46,4	42,2	38,3	34,9	31,7	28,8	26,2	23,8	21,6	19,7	17,9	16,3	14,8	13,4	12,2	11,1	10,1	9,2	0,6
Discounted Cash Flow (Cumul.)	-187,6	-571,3	-842,6	-813,0	-730,8	-656,1	-588,1	-526,4	-470,2	-419,2	-372,8	-330,6	-292,3	-257,4	-225,7	-196,9	-170,7	-146,9	-125,3	-105,6	-87,7	-71,4	-56,6	-43,2	-31,0	-19,9	-9,8	-0,6	0,0

FOSTER WHEELER ITALIANA

TABLE E.5.10 - TEXACO CASE D.1 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	323,1	t/h
Net Power Output	730,3	MW
Sold Sulphur	2,78	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		962,2
Land purchase; surveys	5%	48,1
Fees	2%	19,2
Average Contingencies	6,4%	61,8
Total Investment Cost		1091,5

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	93,3
Maintenance	35,1
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	3,9
Insurance and local tax	19,2

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	9,0
Total Working capital	9,4

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,056	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	305,5	MM Euro/year
NPV	**0,00**	
IRR	**10,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				160,6	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	303,3	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-49,4	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	
Maintenance				-23,4	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,1	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	
Waste Disposal				-3,0	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	
Insurance				-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-218,3	-491,2	-382,0																										
Total Cash flow (yearly)	-218,3	-491,2	-382,0	46,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	139,9	9,4
Total Cash flow (cumulated)	-218,3	-709,4	-1091,5	-1044,6	-904,6	-764,7	-624,8	-484,8	-344,9	-204,9	-65,0	74,9	214,9	354,8	494,7	634,7	774,6	914,5	1054,5	1194,4	1334,3	1474,3	1614,2	1754,2	1894,1	2034,0	2174,0	2313,9	2323,3
Discounted Cash Flow (Yearly)	-198,4	-405,9	-287,0	32,0	86,9	79,0	71,8	65,3	59,3	54,0	49,0	44,6	40,5	36,8	33,5	30,5	27,7	25,2	22,9	20,8	18,9	17,2	15,6	14,2	12,9	11,7	10,7	9,7	0,6
Discounted Cash Flow (Cumul.)	-198,4	-604,4	-891,4	-859,3	-772,4	-693,5	-621,6	-556,4	-497,0	-443,1	-394,0	-349,4	-308,9	-272,1	-238,6	-208,1	-180,4	-155,2	-132,4	-111,6	-92,7	-75,5	-59,8	-45,6	-32,7	-21,0	-10,3	-0,6	0,0

TABLE E.5.11 - TEXACO CASE D.2 - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	323,2	t/h
Net Power Output	742,3	MW
Sold Sulphur	0,00	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		925,4
Land purchase; surveys	5%	46,3
Fees	2%	18,5
Average Contingencies	6,4%	59,2
Total Investment Cost		1049,5

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	93,4
Maintenance	34,2
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	3,8
Insurance and local tax	18,5

Working Capita		**MM Euro**
30 days Chemical Stora		0,4
30 days Coal Storage		9,0
Total Working capital		9,4

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production C	0,054	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	298,4	MM Euro/year
NPV	**0,00**	
IRR	**10,00%**	

CASH FLOW ANALYSYS Millions Euro	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	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
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				158,0	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	298,4	
Sulphur				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	
Operating Costs																													
Fuel Cost				-49,4	-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	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	
Maintenance				-22,8	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,0	-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	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	
Waste Disposal				-3,0	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	
Insurance				-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-209,9	-472,3	-367,3																										
Total Cash flow (yearly)	-209,9	-472,3	-367,3	44,5	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	134,6	9,4
Total Cash flow (cumulated)	-209,9	-682,1	-1049,5	-1004,9	-870,3	-735,7	-601,1	-466,5	-331,9	-197,3	-62,7	72,0	206,6	341,2	475,8	610,4	745,0	879,6	1014,2	1148,8	1283,4	1418,0	1552,6	1687,2	1821,9	1956,5	2091,1	2225,7	2235,1
Discounted Cash Flow (Yearly)	-190,8	-390,3	-276,0	30,4	83,6	76,0	69,1	62,8	57,1	51,9	47,2	42,9	39,0	35,4	32,2	29,3	26,6	24,2	22,0	20,0	18,2	16,5	15,0	13,7	12,4	11,3	10,3	9,3	0,6
Discounted Cash Flow (Cumul.)	-190,8	-581,1	-857,1	-826,6	-743,1	-667,1	-598,0	-535,2	-478,1	-426,2	-379,0	-336,2	-297,2	-261,7	-229,5	-200,2	-173,6	-149,4	-127,3	-107,3	-89,1	-72,6	-57,6	-43,9	-31,5	-20,2	-9,9	-0,6	0,0

Production		
Coal Florate	323,1	t/h
Net Power Output	744,3	MW
Sold Sulphur	2,78	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		MM Euro
Installed Costs		965,4
Land purchase; surveys	5%	48,3
Fees	2%	19,3
Average Contingencies	6,4%	62,2
Total Investment Cost		1095,1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	93,3
Maintenance	35,3
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	4,3
Insurance and local taxe	19,3

Working Capita	MM Euro
30 days Chemical Stora	0,4
30 days Coal Storage	9,0
Total Working capital	9,4

Labour Cost	MM Euro/year
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Co	0,053	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	295,3	MM Euro/year
NPV	**0,00**	
IRR	**10,00%**	

CASH FLOW ANALYSYS Millions Euro	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	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
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				155,7	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	294,2	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-49,4	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	
Maintenance				-23,5	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	
Waste Disposal				3,0	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	
Insurance				-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-219,0	-492,8	-383,3																										
Total Cash flow (yearly)	-219,0	-492,8	-383,3	47,6	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	141,4	9,4
Total Cash flow (cumulated)	-219,0	-711,8	-1095,1	-1047,5	-906,1	-764,6	-623,2	-481,8	-340,3	-198,9	-57,5	83,9	225,4	366,8	508,2	649,7	791,1	932,5	1074,0	1215,4	1356,8	1498,2	1639,7	1781,1	1922,5	2064,0	2205,4	2346,8	2356,3
Discounted Cash Flow (Yearly)	-199,1	-407,3	-288,0	32,5	87,8	79,8	72,6	66,0	60,0	54,5	49,6	45,1	41,0	37,2	33,9	30,8	28,0	25,4	23,1	21,0	19,1	17,4	15,8	14,4	13,1	11,9	10,8	9,8	0,6
Discounted Cash Flow (Cumul.)	-199,1	-606,4	-894,3	-861,8	-774,0	-694,2	-621,6	-555,6	-495,6	-441,1	-391,5	-346,5	-305,5	-268,3	-234,4	-203,6	-175,7	-150,2	-127,1	-106,1	-87,0	-69,6	-53,8	-39,4	-26,4	-14,5	-3,7	6,1	6,7

FOSTER WHEELER ITALIANA

TABLE E.5.13 - TEXACO CASE C.1 - Cost Evaluation - Discount Rate = 5%

Rev. : 1
Date : March 2003

Production		
Coal Florate	303,0	t/h
Net Power Output	826,5	MW
Sold Sulphur	2,58	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		864,9
Land purchase; surveys	5%	43,2
Fees	2%	17,3
Average Contingencies	6,5%	55,9
Total Investment Cost		981,4

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	87,5
Maintenance	32,4
Waste Disposal (7€/t)	5,3
Chemicals + Consumab	2,5
Insurance and local taxe	17,3

Working Capita		**MM Euro**
30 days Chemical Stora		0,2
30 days Coal Storage		8,5
Total Working capital		8,7

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,037	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	230,0	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS Millions Euro	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				120,7	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	228,0	
Sulphur				1,1	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	
Operating Costs																													
Fuel Cost				-46,3	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	-87,5	
Maintenance				-21,6	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	-32,4	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-1,3	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	-2,5	
Waste Disposal				-2,8	-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	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	
Insurance				-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	-17,3	
Working Capital Cost				-8,7																									8,7
Fixed Capital Expenditures	-196,3	-441,6	-343,5																										
Total Cash flow (yearly)	-196,3	-441,6	-343,5	15,3	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	76,6	8,7
Total Cash flow (cumulated)	-196,3	-637,9	-981,4	-966,0	-889,5	-812,9	-736,3	-659,7	-583,1	-506,5	-429,9	-353,3	-276,7	-200,1	-123,5	-47,0	29,6	106,2	182,8	259,4	336,0	412,6	489,2	565,8	642,4	719,0	795,6	872,1	880,9
Discounted Cash Flow (Yearly)	-186,9	-400,6	-296,7	12,6	60,0	57,2	54,4	51,8	49,4	47,0	44,8	42,6	40,6	38,7	36,8	35,1	33,4	31,8	30,3	28,9	27,5	26,2	24,9	23,7	22,6	21,5	20,5	19,5	2,1
Discounted Cash Flow (Cumul.)	-186,9	-587,5	-884,2	-871,6	-811,6	-754,4	-700,0	-648,2	-598,8	-551,8	-507,0	-464,3	-423,7	-385,0	-348,2	-313,1	-279,7	-247,9	-217,6	-188,7	-161,2	-135,0	-110,1	-86,3	-63,7	-42,2	-21,7	-2,1	0,0

Production		
Coal Florate	327,6	t/h
Net Power Output	860,6	MW
Sold Sulphur	2,79	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures	**MM Euro**	
Installed Costs		909,3
Land purchase; surveys	5%	45,5
Fees	2%	18,2
Average Contingencies	6,5%	58,9
Total Investment Cost		1031,8

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	94,6
Maintenance	34,0
Waste Disposal (7€/t)	5,7
Chemicals + Consumab	3,8
Insurance and local tax	18,2

Working Capita		**MM Euro**
30 days Chemical Stora		0,4
30 days Coal Storage		9,2
Total Working capital		9,5

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,038	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	245,2	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				128,7	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	243,0	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-50,1	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	-94,6	
Maintenance				-22,7	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	-34,0	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,0	-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	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	
Waste Disposal				-3,0	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	-5,7	
Insurance				-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	-18,2	
Working Capital Cost				-9,5																									9,5
Fixed Capital Expenditures	-206,4	-464,3	-361,1																										
Total Cash flow (yearly)	-206,4	-464,3	-361,1	16,0	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	80,5	9,5
Total Cash flow (cumulated)	-206,4	-670,7	-1031,8	-1015,8	-935,3	-854,8	-774,2	-693,7	-613,2	-532,6	-452,1	-371,6	-291,1	-210,5	-130,0	-49,5	31,1	111,6	192,1	272,6	353,2	433,7	514,2	594,8	675,3	755,8	836,3	916,9	926,4
Discounted Cash Flow (Yearly)	-196,5	-421,1	-312,0	13,1	63,1	60,1	57,2	54,5	51,9	49,4	47,1	44,8	42,7	40,7	38,7	36,9	35,1	33,5	31,9	30,4	28,9	27,5	26,2	25,0	23,8	22,6	21,6	20,5	2,3
Discounted Cash Flow (Cumul.)	-196,5	-617,7	-929,6	-916,5	-853,4	-793,3	-736,1	-681,6	-629,7	-580,2	-533,1	-488,3	-445,6	-404,9	-366,2	-329,3	-294,2	-260,7	-228,8	-198,5	-169,6	-142,0	-115,8	-90,9	-67,1	-44,4	-22,9	-2,3	0,0

TABLE E.5.15 - TEXACO CASE D.1 - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	323,1	t/h
Net Power Output	730,3	MW
Sold Sulphur	2,78	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		962,2
Land purchase; surveys	5%	48,1
Fees	2%	19,2
Average Contingencies	6,4%	61,8
Total Investment Cost		1091,5

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	93,3
Maintenance	35,1
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	3,9
Insurance and local tax	19,2

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	9,0
Total Working capital	9,4

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production C	0,046	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	250,7	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Millions Euro	**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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				131,6	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	248,5	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-49,4	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	
Maintenance				-23,4	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	-35,1	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,1	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	-3,9	
Waste Disposal				-3,0	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	
Insurance				-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	-19,2	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-218,3	-491,2	-382,0																										
Total Cash flow (yearly)	-218,3	-491,2	-382,0	17,9	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	85,1	9,4
Total Cash flow (cumulated)	-218,3	-709,4	-1091,5	-1073,6	-988,4	-903,3	-818,2	-733,1	-647,9	-562,8	-477,7	-392,6	-307,4	-222,3	-137,2	-52,0	33,1	118,2	203,3	288,5	373,6	458,7	543,9	629,0	714,1	799,2	884,4	969,5	978,9
Discounted Cash Flow (Yearly)	-207,9	-445,5	-330,0	14,7	66,7	63,5	60,5	57,6	54,9	52,3	49,8	47,4	45,1	43,0	40,9	39,0	37,1	35,4	33,7	32,1	30,6	29,1	27,7	26,4	25,1	23,9	22,8	21,7	2,3
Discounted Cash Flow (Cumul.)	-207,9	-653,4	-983,4	-968,7	-902,0	-838,4	-777,9	-720,3	-665,5	-613,2	-563,4	-516,0	-470,9	-427,9	-386,9	-347,9	-310,8	-275,4	-241,7	-209,6	-179,1	-150,0	-122,3	-95,9	-70,7	-46,8	-24,0	-2,3	0,0

FOSTER WHEELER ITALIANA

TABLE E.5.16 - TEXACO CASE D.2 - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	323,2	t/h
Net Power Output	742,3	MW
Sold Sulphur	0,00	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures	**MM Euro**	
Installed Costs		925,4
Land purchase; surveys	5%	46,3
Fees	2%	18,5
Average Contingencies	6,4%	59,2
Total Investment Cost		1049,5

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	93,4
Maintenance	34,2
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	3,8
Insurance and local taxe	18,5

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	9,0
Total Working capital	9,4

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Co	0,044	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	245,7	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CASH FLOW ANALYSYS Millions Euro	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
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				130,1	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	245,7	
Sulphur				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	
Operating Costs																													
Fuel Cost				-49,4	-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	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	-93,4	
Maintenance				-22,8	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,0	-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	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	-3,8	
Waste Disposal				-3,0	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	-5,6	
Insurance				-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	-18,5	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-209,9	-472,3	-367,3																										
Total Cash flow (yearly)	-209,9	-472,3	-367,3	16,6	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	81,9	9,4
Total Cash flow (cumulated)	-209,9	-682,1	-1049,5	-1032,8	-950,9	-869,0	-787,2	-705,3	-623,4	-541,5	-459,6	-377,7	-295,9	-214,0	-132,1	-50,2	31,7	113,6	195,5	277,3	359,2	441,1	523,0	604,9	686,8	768,6	850,5	932,4	941,8
Discounted Cash Flow (Yearly)	-199,9	-428,3	-317,3	13,7	64,2	61,1	58,2	55,4	52,8	50,3	47,9	45,6	43,4	41,4	39,4	37,5	35,7	34,0	32,4	30,9	29,4	28,0	26,7	25,4	24,2	23,0	21,9	20,9	2,3
Discounted Cash Flow (Cumul.)	-199,9	-628,2	-945,5	-931,9	-867,7	-806,6	-748,4	-693,0	-640,2	-589,9	-542,0	-496,4	-453,0	-411,7	-372,3	-334,8	-299,0	-265,0	-232,6	-201,7	-172,4	-144,4	-117,7	-92,3	-68,1	-45,1	-23,2	-2,3	0,0

TABLE E.5.17 - TEXACO CASE D.3 - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	323,1	t/h
Net Power Output	744,3	MW
Sold Sulphur	2,78	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		965,4
Land purchase; surveys	5%	48,3
Fees	2%	19,3
Average Contingencies	6,4%	62,2
Total Investment Cost		1095,1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	93,3
Maintenance	35,3
Waste Disposal (7€/t)	5,6
Chemicals + Consumab	4,3
Insurance and local taxe	19,3

Working Capita	**MM Euro**
30 days Chemical Stora	0,4
30 days Coal Storage	9,0
Total Working capital	9,4

Labour Cost	**MM Euro/year**
# operators	128
Salary	0,05
Direct Labour Cost	6,4
Administration 30% L.C	1,9
Total Labour Cost	8,3

Electricity Production Co	0,043	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	5,00	%
Revenues / year	240,3	MM Euro/year
NPV	**0,00**	
IRR	**5,00%**	

CASH FLOW ANALYSYS Millions Euro	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	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**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	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				126,1	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	238,2	
Sulphur				1,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	
Operating Costs																													
Fuel Cost				-49,4	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	-93,3	
Maintenance				-23,5	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	-35,3	
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables				-2,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	-4,3	
Waste Disposal				3,0	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	5,6	
Insurance				-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	-19,3	
Working Capital Cost				-9,4																									9,4
Fixed Capital Expenditures	-219,0	-492,8	-383,3																										
Total Cash flow (yearly)	-219,0	-492,8	-383,3	17,9	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	85,4	9,4
Total Cash flow (cumulated)	-219,0	-711,8	-1095,1	-1077,2	-991,7	-906,3	-820,9	-735,5	-650,1	-564,7	-479,3	-393,9	-308,4	-223,0	-137,6	-52,2	33,2	118,6	204,0	289,4	374,8	460,3	545,7	631,1	716,5	801,9	887,3	972,7	982,2
Discounted Cash Flow (Yearly)	-208,6	-447,0	-331,1	14,8	66,9	63,7	60,7	57,8	55,1	52,4	49,9	47,6	45,3	43,1	41,1	39,1	37,3	35,5	33,8	32,2	30,7	29,2	27,8	26,5	25,2	24,0	22,9	21,8	2,3
Discounted Cash Flow (Cumul.)	-208,6	-655,6	-986,7	-971,9	-905,0	-841,2	-780,5	-722,7	-667,7	-615,2	-565,3	-517,7	-472,4	-429,3	-388,2	-349,1	-311,8	-276,3	-242,5	-210,3	-179,7	-150,5	-122,7	-96,2	-71,0	-47,0	-24,1	-2,3	0,0

5.2 CO_2 removal cost

The CO2 removal cost can be expressed as follows:

$$\frac{\Delta \text{ Electric Power Cost}}{\Delta \text{ Specific } CO_2 \text{ emission}} [=] \frac{\text{Euro}}{\text{t of } CO_2 \text{ captured}}$$

where:

- Δ Electric Power Cost = Electric Power Cost of the alternative with CO_2 capture – Electric Power Cost of corresponding alternative w/o CO_2 capture. The Unit of measurement is Euro/kWh.
- Δ Specific CO_2 emission = Ratio of (CO_2 emission/Power production) of alternative with CO_2 capture – ratio of (CO_2 emission/Power production) of the corresponding alternative with CO_2 capture. The unit of measurement is t CO_2/kWh.

For Shell and Texaco alternatives, the reference cases for the evaluation of the CO_2 removal cost are respectively case A.1 and C.1.

5.2.1 Shell Alternatives

The following Table E.5.19 summarizes the CO_2 removal cost with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.19 – CO_2 removal cost

ALTERNATIVE		A1	B1	B3	A1	B1	B3
Discount rate	**%**	**10**	**10**	**10**	**5**	**5**	**5**
Coal Flowrate	t/h	250.6	273.1	271.4	250.6	273.1	271.4
Net Power Out.	MW	775.9	676.2	683.3	775.9	676.2	683.3
Total Investment Cost	MM Euro	1064.1	1257.6	1179.5	1064.1	1257.6	1179.5
Revenues/year	MM Euro/y	276.7	318.6	304.7	223.3	255.6	245.5
Electricity Prod. Cost	**Euro/kWh**	**0.048**	**0.063**	**0.060**	**0.038**	**0.050**	**0.048**
CO_2 emission	t/h	591.8	95.8	90.5	591.8	95.8	90.5
CO_2 Specific Emission	10^{-3} kg/kWh	762.7	141.7	132.5	762.7	141.7	132.5
CO_2 Removal Cost	**Euro/t**		**24.2**	**19.0**		**19.3**	**15.9**

5.2.2 Texaco Alternatives

The following Table E.5.20 summarizes the CO_2 removal cost with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.20 – CO_2 removal cost

ALTERNATIVE		C1	D1	D2	D3	C1	D1	D2	D3
Discount rate	**%**	**10**	**10**	**10**	**10**	**5**	**5**	**5**	**5**
Coal Flowrate	t/h	303.0	323.1	323.2	323.1	303.0	323.1	323.2	323.1
Net Power Out.	MW	826.5	730.3	742.3	744.3	826.5	730.3	742.3	744.3
Total Inv. Cost	MM Euro	981.4	1091.5	1049.5	1095.1	981.4	1091.5	1049.5	1095.1
Revenues/year	MM Euro/y	279.3	305.5	298.4	296.3	230.0	250.7	245.7	240.3
Electricity Prod. Cost	**Euro/kWh**	**0.045**	**0.056**	**0.054**	**0.053**	**0.037**	**0.046**	**0.044**	**0.043**
CO_2 emission	t/h	675.6	111.0	110.7	147.8	675.6	111.0	110.7	147.8
CO_2 Specific Emission	10^{-3} kg/kWh	817.4	152.1	149.1	198.6	817.4	152.1	149.1	198.6
CO_2 Removal Cost	**Euro/t**		**16.5**	**13.5**	**15.2**		**13.5**	**10.5**	**11.4**

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SECTION F

COMPARISON OF ALTERNATIVES

I N D E X

SECTION F

SECTION F

1.0 Introduction

Purpose of this Section F is to present the performance and cost data developed for the 13 cases, studied in the previous sections, in order to bring to evidence the major features and merits of the several IGCC schemes studied.
Due to the complexity of the study and the number of cases analysed it is necessary to split the comparison in separate groups to compare IGCC schemes of similar structure and purpose. For this reason we have first compared Cases based on the same gasification technology, Shell or Texaco, without and with recovery of CO_2. Then the comparison is extended to similar cases using Shell or Texaco gasification, in order to see mainly the difference between these two gasification technologies.
Section F ends with a conclusion paragraph attempting to establish a ranking of the alternative IGCC schemes studied.

2.0 Shell Gasification Cases without CO_2 Recovery

The two Cases confronted in this paragraph are Case A.1 and Case A.2.
Case A.1 and Case A.2 have the following common features:

- Shell Gasification with heat recovery;
- No shift and CO_2 recovery;
- AGR: MDEA;

but differ for the following design parameter:

Case A.1: low gasification pressure (36 bar)
Case A.2: high gasification pressure (61 bar)

This comparison is therefore aimed mainly to evaluate the effect of pressure on the Shell gasification alternative.
In the following Table F.2.1, the most important performance and cost data are compared.

It is evident from the above Table that both performance and investment cost of the Shell based IGCC are penalised by an increase of pressure.
The maximum limit of 40 bar is set by the type of coal feed system chosen by Shell, which is based on lock hoppers. Actually, high pressure (61 bar) Shell gasification is not commercial, but the Licensor is confidant to be able to develop it, if required.

Table F.2.1

PERFORMANCE AND COST DATA

PERFORMANCE DATA		**A.1 (Low P)**	**A.2 (High P)**
Coal Feed rate	t/h	250.6	252.1
Cold Gas Efficiency	%	83.5	83.0
Gross Power Output	MWe	909.8	895.0
Auxiliary Power Consumptions	MWe	133.9	146.7
Net Power Output	MWe	775.9	748.3
Net Electrical Efficiency	%	43.1	41.3
INVESTMENT COST DATA			
Total Investment	10^6 Euro	1064.1	1143.2
Specific Investment	Euro/kW	1371.5	1527.7
PRODUCTION COST DATA			
C.O.E. (DCF=10%)	Euro/kW	0.048	-
CO_2 Removal (DCF=10%)	Euro/t	-	-

The environmental impacts of Cases A.1 and A.2 are identical as shown below:

Table F.2.2

EMISSIONS/EFFLUENTS

EMISSIONS/EFFLUENTS		**A.1 (Low P)**	**A.2 (High P)**
Gaseous Emissions:			
NOx	mg/Nm^3 (dry – 15% O_2)	80	80
SOx	mg/Nm^3 (dry – 15% O_2)	5	5
CO	mg/Nm^3 (dry – 15% O_2)	31	31
Particulate	mg/Nm^3 (dry – 15% O_2)	5	5
Liquid Effluent:			
Gross P.O.	m^3/h	-	-
Solid Effluent:			
Slag	t/h	37.2	37.5
Fly ash	t/h	1.2	1.2

3.0 Shell Gasification Cases with CO_2 Recovery

The Cases confronted in this paragraph are Cases B.1, B.2, B.3 and B.4.
The common features of these cases are:

- Shell Gasification with heat recovery
- CO_2 capture

The differences are shown in the following Table:

Table F.3.1

	Low P 39 bar	High P 61 bar	Shift Type	Shift Stages	AGR	Acid Gas Recovery
B.1	yes	-	Sour	2	Selexol	CO_2 (85%)
B.2	yes	-	Clean	3	Selexol	CO_2 (85%)
B.3	yes	-	Sour	2	MDEA	CO_2 (85%) + H_2S
B.4	-	yes	Sour	2	Selexol	CO_2 (85%)

This comparison permits to compare the following options:

- Sour vs. clean shift (B.1 vs. B.2)
- Combined capture of H_2S + CO_2 vs. the capture of CO_2 alone (B.3 vs.B.1)
- Low pressure vs. high pressure scheme (B.1 vs. B.4)

In the following Table F.3.2 the most important performance and cost data are given.

The following conclusions can be derived from Table F.3.2 data:

- Sour shift gives a better performance, equal investment but a lower investment per kW with respect to the clean shift option (B.1 vs. B.2). Therefore sour shift is the preferred choice.

- The combined capture of CO_2 + H_2S is preferable to the separate capture of CO_2 (B.3 vs. B.1); both performance and investment cost are better. Obviously this option can be considered only if CO_2 and H_2S sequestered together may have a final destination.
  The cost of electricity (C.O.E.) and CO_2 removal cost confirm this conclusion.

- The best option to capture 85% of the CO_2 with an IGCC based on Shell Gasification is the combination low pressure, sour shift, two stages and Selexol (B.1 vs. B.2 and B.4).

Table F.3.2 configures also for the IGCC option with CO_2 capture that low pressure is preferable to high pressure of gasification (see B.1 vs. B.4).

Table F.3.2

PERFORMANCE AND COST DATA

PERFORMANCE DATA		**B.1**	**B.2**	**B.3**	**B.4**
Coal Feed rate	t/h	273.1	274.6	271.4	271.9
Cold Gas Efficiency	%	83.5	83.5	83.5	83.0
Gross Power Output	MWe	896.2	875.0	883.3	879.2
Auxiliary Power Consumptions	MWe	220.0	223.7	200.0	240.3
Net Power Output	MWe	676.2	651.3	683.3	638.9
Net Electrical Efficiency	%	34.5	33.0	35.0	32.7
INVESTMENT COST DATA					
Total Investment	10^6 Euro	1257.6	1261.6	1179.5	1317.0
Specific Investment	Euro/kW	1859.8	1937.1	1726.2	2061.4
PRODUCTION COST DATA					
C.O.E. (DCF=10%)	Euro/kW	0.063	-	0.060	-
CO2 Removal (DCF=10%)	Euro/t	24.2	-	19.0	-

2

The environmental impacts of Cases B.1, B.2, B.3 and B.4 are identical as shown below:

Table F.3.3

EMISSIONS/EFFLUENTS		B.1	B.2	B.3	B.4
Gaseous Emissions:					
NOx	mg/Nm^3 (dry – 15% O_2)	74	74	74	74
SOx	mg/Nm^3 (dry – 15% O_2)	1	1	1	1
CO	mg/Nm^3 (dry – 15% O_2)	31	31	31	31
Particulate	mg/Nm^3 (dry – 15% O_2)	5	5	5	5
Liquid Effluent:		46	46	46	46
Solid Effluent:					
Slag	t/h	40.5	40.5	40.2	40.2
Fly ash	t/h	1.3	1.3	1.3	1.3

4.0 Texaco Gasification Cases without CO_2 Recovery

The Cases confronted in this paragraph are Cases C.1, C.2, C.3.

The common feature of these cases is Texaco quench gasification only.

The differences are:

	Low P 38 bar	High P 65 bar	Shift Type	Shift Stages	AGR
C.1	-	yes	no	-	Selexol
C.2	-	yes	Sour	1	Selexol
C.3	yes	-	no	-	MDEA

The comparison permits to compare the following two options:

- High pressure vs. low pressure (C.1 vs. C.3)
- No CO shift scheme vs. a CO shift scheme; both for power production without capture of CO_2 (C.1 vs. C.2)

In the following Table F.4.1 the most important performance and cost data are given:

Table F.4.1

PERFORMANCE AND COST DATA

PERFORMANCE DATA		**C.1**	**C.2**	**C.3**
Coal Feed rate	t/h	303.0	327.6	300.9
Cold Gas Efficiency	%	70.5	70.5	71.0
Gross Power Output	MWe	988.7	1012.8	954.3
Auxiliary Power Consumptions	MWe	162.2	152.2	154.4
Net Power Output	MWe	826.5	860.6	799.9
Net Electrical Efficiency	%	38.0	36.6	37.0
INVESTMENT COST DATA				
Total Investment	10^6 Euro	981.4	1031.8	959.9
Specific Investment	Euro/kW	1187.4	1198.9	1200.0
PRODUCTION COST DATA				
C.O.E. (DCF=10%)	Euro/kW	0.045	-	-
CO_2 Removal (DCF=10%)	Euro/t	-	-	-

The following conclusions can be derived from Table F.4.1 data:

- Contrary to Shell gasification, Texaco Gasification shows a better performance with high pressure (C.1 vs. C.3). In fact power output and efficiency are superior with high pressure; total investment of C.1 is slightly higher but investment per kW is lower. The simple pay out time is four years which justifies the HP pressure selection.

- The use of shift when power is produced without CO_2 capture, does not give any advantage over the case with no shift (C.1 vs. C.2). Net electrical efficiency, investment cost per kW and cost of electricity (C.O.E.) are better for the IGCC scheme without shift.

The environmental impacts of Cases C.1, C.2 and C.3 are very similar, as shown below:

Table F.4.2

EMISSIONS/EFFLUENTS		C.1	C.2	C.3
Gaseous Emissions:				
NOx	mg/Nm^3 (dry – 10% O_2)	51	30	51
SOx	mg/Nm^3 (dry – 10% O_2)	10	9.9	10
CO	mg/Nm^3 (dry – 10% O_2)	31	31.4	31
Particulate	mg/Nm^3 (dry – 10% O_2)	4	4.4	4
Liquid Effluent:		-	-	-
Solid Effluent:				
Slag	t/h	8.9	9.6	8.9
Fly ash	t/h	35.8	38.6	35.8

5.0 Texaco Gasification Cases with CO_2 Recovery

The Cases confronted in this paragraph are Cases D.1, D.2, D.3 and D.4.
The common features of these Cases are:

- Texaco quench gasification
- Sour Shift
- AGR Selexol.

The differences are:

	Low P 38 bar	High P 65 bar	Shift Stages	Acid Gas Recovery
D.1	-	yes	1	CO_2 (85%)
D.2	-	yes	1	CO_2 (85%) + H_2S
D.3	-	yes	2	CO_2 (80%)
D.4	yes	-	1	CO_2 (85%)

This comparison permits to compare the following options:

- High pressure vs. low pressure scheme (D.1 vs. D.4)
- Combined capture of CO_2 + H_2S vs. the capture of CO_2 alone (D.2 vs. D.1)
- Slight reduction of the CO_2 capture (80%) vs. standard CO_2 capture (85%) (D.3 vs. D.1)

In the following Table F.5.1 the most important performance and cost data are given:

Table F.5.1

PERFORMANCE AND COST DATA

PERFORMANCE DATA		D.1	D.2	D.3	D.4
Coal Feed rate	t/h	323.1	323.2	323.1	320.4
Cold Gas Efficiency	%	70.5	70.5	70.5	71.0
Gross Power Output	MWe	972.8	979.9	978.7	942.1
Auxiliary Power Consumptions	MWe	242.5	237.6	234.4	237.1
Net Power Output	MWe	730.3	742.3	744.3	705.0
Net Electrical Efficiency	%	31.5	32.0	32.1	30.6
INVESTMENT COST DATA					
Total Investment	10^6 Euro	1091.5	1049.5	1095.1	1117.1
Specific Investment	Euro/kW	1494.6	1413.9	1471.3	1584.5
PRODUCTION COST DATA					
C.O.E. (DCF=10%)	Euro/kW	0.056	0.054	0.053	-
CO_2 Removal (DCF=10%)	Euro/t	16.5	13.5	15.2	-

The following conclusions can be derived from Table F.5.1 data:

- Texaco based IGCC shows a better performance with high pressure (D.1 vs. D.4). Compared to the low pressure case (D.4), the high pressure case (D.1) shows a superior Net P.O., a better efficiency and a lower investment (total and specific). This preference for high pressure of Texaco gasification is applicable to the two configurations, without CO_2 capture (see paragraph 4.0) and with CO_2 capture (paragraph 5.0).

- The combined capture of CO_2 + H_2S is preferable to the capture of CO_2 alone (D.2 vs. D.1). Net P.O., efficiency and specific investments, C.O.E. and cost of CO_2 capture are all slightly better.

- Case D.3 attempts to determine if there is an advantage in slightly reducing the CO_2 recovery from 85% to 80% (D.3 vs. D.1). This is obtained using a reduced circulation Selexol but 2 stages of shift. Power performances, specific investment cost, C.O.E. and cost of CO_2 removal are only marginally better.

The environmental impacts of Cases D.1, D.2, D.3 and D.4 are identical, as shown below:

Table F.5.2

EMISSIONS/EFFLUENTS		D.1	D.2	D.3	D.4
Gaseous Emissions:					
NOx	mg/Nm^3 (dry – 10% O_2)	50	50	50	50
SOx	mg/Nm^3 (dry – 10% O_2)	0.7	0.7	0.7	0.7
CO	mg/Nm^3 (dry – 10% O_2)	31	31	31	31
Particulate	mg/Nm^3 (dry – 10% O_2)	4.3	4.5	4.5	4.5
Liquid Effluent:	m^3/h	-	-	-	-
Solid Effluent:					
Slag	t/h	9.5	9.5	9.5	9.5
Fly ash	t/h	38.1	38.1	38.1	38.1

6.0 Shell Gasification vs. Texaco Gasification

To compare the performances of the two gasification technologies, Shell and Texaco, in an IGCC without and with capture of CO_2, the following cases have been selected:

- **No CO_2 Capture**

			Pressure	AGR	Shift
Shell	:	A.1	36 bar	MDEA	No
Texaco	:	C.1	65 bar	Selexol	No

- **With CO_2 Capture**

			Pressure	AGR	Shift	CO_2 rec.
Shell	:	B.1	39 bar	Selexol	Sour (2 st)	85%
Texaco	:	D.1	65 bar	Selexol	Sour (1 st)	85%

Table F.6.1 compares performance and cost data of the IGCC without CO_2 capture
Table F.6.2 compares performance and cost data of the IGCC with CO_2 capture.

Table F.6.1 shows that in an IGCC without capture of CO_2 the Shell gasification has a superior performance, as shown by the cold gas efficiency and net electric efficiency. However the specific investment, Euro/kW, of Shell is substantially higher to the point that the efficiency advantage is more than compensated by the lower specific investment of Texaco: the C.O.E. of Texaco is slightly better, even at a low DCF rate equal to 10%.

Table F.6.2 data lead to the same conclusion: C.O.E. and cost of CO_2 removal of Texaco IGCC are lower than those of Shell IGCC.

Table F.6.1
NO CAPTURE OF CO_2

PERFORMANCE DATA		**Shell LP A.1**	**Tex. HP C.1**
Coal Feed rate	t/h	250.6	303
Cold Gas Efficiency	%	83.5	70.5
Gross Power Output	MWe	909.8	988.7
Auxiliary Power Consumptions	MWe	133.9	162.2
Net Power Output	MWe	775.9	826.5
Net Electrical Efficiency	%	43.1	38.0
INVESTMENT COST DATA			
Total Investment	10^6 Euro	1064.1	981.4
Specific Investment	Euro/kW	1371.5	1187.4
PRODUCTION COST DATA			
C.O.E. (DCF=10%)	Euro/kW	0.048	0.045
CO_2 Removal (DCF=10%)	Euro/t	-	-

Table F.6.2
WITH CAPTURE OF CO_2 (85%)

PERFORMANCE DATA		**Shell LP B.1**	**Tex. HP D.1**
Coal Feed rate	t/h	273.1	323.1
Cold Gas Efficiency	%	83.5	70.5
Gross Power Output	MWe	896.2	972.8
Auxiliary Power Consumptions	MWe	220.0	242.5
Net P ower Output	MWe	676.2	730.3
Net Electrical Efficiency	%	34.5	31.5
INVESTMENT COST DATA			
Total Investment	10^6 Euro	1257.6	1091.5
Specific Investment	Euro/kW	1859.8	1494.6
PRODUCTION COST DATA			
C.O.E. (DCF=10%)	Euro/kW	0.063	0.056
CO_2 Removal (DCF=10%)	Euro/t	24.2	16.5

7.0 Conclusions

Based on the performance and cost data contained in the previous paragraphs of Section F, we have come to the following conclusions:

A. Texaco IGCC, compared to Shell IGCC, shows an inferior performance but a lower investment and a slightly lower C.O.E., for both alternatives, without and with CO_2 capture.

B. Shell IGCC is more competitive at low pressure for both alternatives, without and with CO_2 capture.

C. Texaco IGCC is more competitive at high pressure for both alternatives, without and with CO_2 capture.

D. Sour shift, compared to the clean shift, is the preferred option for both Shell and Texaco IGCC.

E. The combined capture of CO_2 and H_2S is advantageous with respect to the capture of CO_2 alone, for both Shell and Texaco IGCC.

F. CO shift in a Texaco IGCC, producing power without CO_2 capture, is not justified.

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SECTION G

YEAR 2020 IMPROVEMENTS

I N D E X

SECTION G

SECTION G

IGCC IMPROVEMENTS

IGCC, being a technology that has only recently moved to the commercial market place, has a considerable potential for improvements for all the key components of the technology. The areas of improvements are reviewed in the following paragraphs.

1.0 Gas turbine

Gas Turbines utilized in IGCC plants, currently in operation or construction, are the large, heavy duty frames of second generation, E class, and third generation, F/FA class.
All these turbines have been originally developed to fire natural gas or liquid fuels. Afterwards they have been adapted to process syngas, a fuel with very different combustion characteristics: a lower calorific value, different Wobbe number, higher flame propagation speed and high flame stability. This adaptation has involved several modifications regarding the burner design, the air compressor flowrate, the surge protection, a higher expander inlet pressure and new controls and instrumentation.

The E class Turbines have been in use since many years. The firing temperature is below or slightly higher than 1200°C and the efficiency (natural gas – ISO conditions) is around 34%.
The F/FA class Turbines are more recent but already widely spread in the market. They accept higher firing temperature, 1260-1320°C, and consequently display a better efficiency, 36-38%.

The gas turbine technology is, today, further progressing. A key role in this process has been played by the USA Department of Energy (DOE), through the Advanced Turbine System (ATS) program, providing financial support to four manufacturers:

- Solar and Allison for the 5-15 MW range;
- GE and Siemens-Westinghouse for the 300 MW frames

The target of the ATS Program is to achieve:

- higher efficiencies;
- single digit NOx and CO less than 20 ppm (without postcombustion clean-up);
- fuel flexibility;
- RAM performance better than current state-of-the-art systems.

General Electric commercialized outside the ATS program the G class technology, with a firing temperature of 1430°C and ISO efficiency equal to 39.5%. With a G class turbine it is possible to achieve in a combined cycle an efficiency of conversion of natural gas to electricity close to 60%.
Within the ATS Program General Electric and Siemens-Westinghouse have developed the H class technology. GE H machines are available for 50 and 60 cycles, respectively MS9001 H and MS7001 H. The firing temperature is 1430°C; the efficiency is close to 40% and in a combined cycle exceed 60%. The air compressor develops with 18 steps a compression ratio equal to 23:1.
The Siemens-Westinghouse 501 ATS advanced turbine has similar firing temperature and efficiency. The 19 stages air compressor develops a 27:1 compression ratio.
Both, GE and Siemens-Westinghouse systems, use a closed-loop steam cooling of the first raw of blades, utilizing the superior heat transfer characteristics of steam and permitting a better integration between the gas turbine and the steam cycle, for a better overall efficiency.

ABB (now Alstom) has also recently introduced two advanced gas turbines, GT 24 (60 Hz) and GT 26 (50 Hz), featuring a two stage sequential combustion and a compression ratio of 30:1. Injecting fuel in two stages permits to increase output and cycle efficiency without increasing the firing temperature to extreme levels, thereby reducing concerns over hot parts material life and cost.
This fourth generation of gas turbines are commercially available for natural gas combined cycle of 60% efficiency and will be also available to enhance performance of IGCC.

EPRI (Report TR-106905) has attempted to evaluate the impact on IGCC performance of H class technology compared to the performance of IGCC with an FA class gas turbine.
This comparison was made on the base of 60 Hz machines; the results of this comparison are:

	Coal IGCC	**Coal IGCC**
Gasification	Shell	Shell
Gas Turbine	one GE7FA	one GE7H
Coal Rate MBTU/h (HHV)	2335	3372
Net power output MW	284	444
Efficiency % (HHV)	41.5	44.9
Capital Cost $/kW	1486	1215

The capital cost difference is largely due to the scale economy. The difference in performance is probably overestimated; even EPRI admitted to have only a limited knowledge of the effect of integration between H technology and steam cycle.

Another study was performed, on the same subject, by a team including Texaco, General Electric and Praxair. This study compares investment cost and performance of several IGCC configurations based on following options:

Feed: heavy oil and coal

Gasification: Texaco quench and heat recovery

Gas Turbine: 9FA and 9H (both 50 Hz)

The results of this comparison for the oil feed case are:

	Quench 9FA	**Quench 9H**	**Heat R. 9H**
Coal rate BTU/h x 10^6 (HHV)	3478	3857	3783
IGCC Net MW	435.8	505.7	510.3
Efficiency % (HHV)	42.8	44.7	46.0
Capital cost $/kW	800	792	824

For the coal feed case:

	Quench 9FA	**Quench 9H**	**Heat R. 9H**
Coal rate BTU/h x 10^6 (HHV)	3665	4125	4125
IGCC Net MW	449.2	520.9	527.6
Efficiency % (HHV)	41.8	43.1	43.7
Capital cost $/kW	860	852	935

Efficiency and Capital cost absolute values seem also in this case too optimistic, but the percentage improvement of efficiency is reasonable.

In the next decade additional improvements are expected beyond the H technology. The most likely developments will be:

a. Air compressor staging and intercooling

This feature reduces the air compressor power demand, making available more power for the electric generator. Since the power absorbed by the air compressor is two thirds of the power developed by the expander, even a small saving in air compressor power can provide an important improvement of the turbine efficiency.

b. Fuel firing in two or more stages

This feature increases power output and cycle efficiency.

c. Improved thermal barrier coatings and oxidation coatings; use of ceramic and ceramic-composite for hot parts

All these improvements are aimed to achieve higher firing temperatures and better efficiencies.

d. Low NO_x

Advanced low NO_x burners are expected to achieve single digit NO_x (9ppmdv) with natural gas and less than 25 ppmdv with syngas.
To further reduce NO_x, specially with high temperature combustors, postcombustion catalytic deNO_x must be used.

The combination of these improvements with the H technology may result in a new generation of gas turbines able to achieve in a natural gas combined cycle an efficiency close to 70% and in a coal IGCC an efficiency approaching 50%.

2.0 Steam cycle

Heat Recovery Steam Generators (HRSG), used in IGCC, can be either flue gas vertical flow or flue gas horizontal flow. The water tubes in the former are horizontal while in the latter are vertical; consequently the vertical gas flow is a forced circulation design, while the horizontal gas flow can be natural circulation design.
These two rather different designs coexist. The vertical design requires a much lower plot area but needs very large circulation pumps; the horizontal design saves the power of the circulating pumps but requires a much larger plot area. From the operational point of view both systems are satisfactory; response to load changes are comparable.

The exhaust gas temperature of large heavy-duty gas turbines of F class is about 600°C. At this temperature the steam cycle becomes quite effective.
Steam can be generated at multiple pressures. The HP steam can be at 120 bar or more, with 565°C superheating and subsequent reheating at 565°C, without supplemental firing. Furthermore the HRSG can superheat the high pressure steam generated in the syngas cooler in a more effective way, because of the syngas cooler premium metallurgical requirements for the superheating service in a syngas cooler.

An interesting development of the HRSG design is the once-through circulation, subcritical or supercritical. Advanced gas turbines, such as G-24 and G-26 have exhaust gas temperature of 610-620°C. Even higher exhaust temperatures can be expected with the progressive increase of future turbines firing temperature. At this temperatures the supercritical operation of the HRSG may become attractive.

The once-through design, subcritical or supercritical, offers several advantages. No need of steam drum, level control and several control valves; no need of circulation pumps and piping. All this reduces the capital cost of HRSG. Furthermore a once-through HRSG can handle much quicker transients thanks to the elemination of the limiting factor, related to the maximum temperature gradient of the HP steam drum, which may induce unacceptable stress. The separator used in subcritical once-through is a smaller vessel, with less thick walls and lower risk of overstressing.

Up to now once-through HRSGs have been commercialized by IST (Innovative Steam Technology) on small power plants (downstream of less than 60 MWe gas turbine).

In addition implementation of supercritical once-through HRSG may enhance CCU steam cycle efficiency similarly to what achieved by conventional PC boiler based steam cycle.

3.0 Advanced power generation systems

Advance power generation systems, based on fuel cells or advanced combustion turbines, all need a clean fuel; therefore integration with IGCC is the only way to use coal with such high efficiency generation concepts.

a. Humid Air Turbine Cycle (HAT)

The HAT cycle is an innovative design which eliminates, in an IGCC, the steam turbine, condenser and the steam generation in the syngas cooler and HRSG.

The basic idea behind the HAT cycle is the substitution of the large excess combustion air of a gas turbine with water vapour. This reduces the air compressor power demand making available more power, coming from the expander, for electricity generation. In the HAT cycle the gasifier is operated in quench mode; the low temperature heat from quench is utilized to saturate the combustion air. Further heat, coming from the low temperature side of the HRSG and from the turbine intercooling, is used to further saturate the combustion air, while the hot side of the HRSG is used to superheat the wet air to 550°C before entering the gas turbine (see fig. 1).

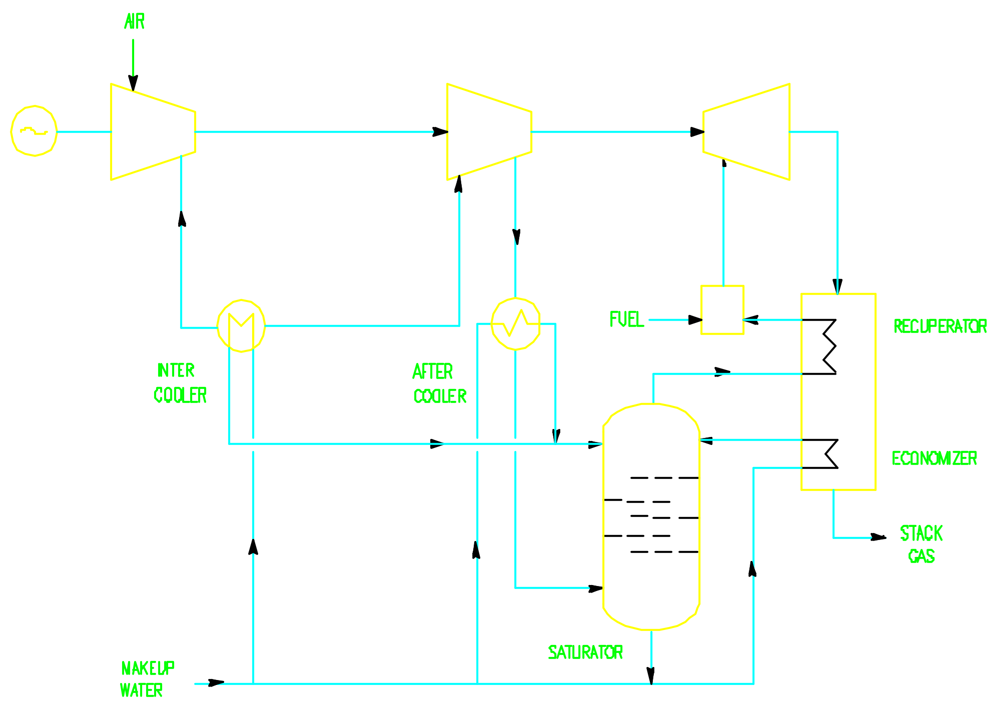


FIG 1: HUMID AIR TURBINE (HAT)

The advantages of the HAT cycle are:

- significant reduction of the IGCC capital cost;
- very low NOx as a result of the large quantity of water vapour;
- effective use of the low level heat from the quench gasifier and other parts of the IGCC.

According to EPRI (TR-102034), the HAT concept is very promising, resulting in 15% lower cost of electricity from a coal IGCC. However various problems must still be overcome. First the gas turbine to accommodate the HAT cycle does not yet exist and its development requires a significant effort. Second the large make-up water, to compensate the water discharged with the flue gas, may not be suitable in regions with water shortage.

b. Cascade Humidified Advanced Turbine (CHAT)

The CHAT cycle, like the HAT cycle, eliminates the steam generation, steam turbine and condenser thus achieving significant reduction in investment cost with efficiency equivalent to a combined cycle.

Fig. 2 provides the simplified flow scheme of the CHAT cycle. Combustion air is compressed in the LP compressor on the power generation shaft and further compressed in the IP and HP compressors on the high pressure shaft. After each stage of compression air is cooled, preheating water, which, after additional heating in the economizer, is used to humidify combustion air in the saturator. Wet air is heated in the economizer up to 550°C and then fed to the combustor of the HP expander. The exhaust gas from the HP expander is used as combustion air of the LP expander.

A large fraction of the LP expander power is available for electricity generation not only because the air mass flow is reduced thanks to the water addition in the saturator, but also because of the low compression ratio of the LP expander.

When combined with an IGCC quench gasifier, the CHAT cycle can increase the degree of air humidification due to the large quantity of low level heat from the quench gasifier. The syngas flame stability can accept combustion air with moisture content up to 50% or more.

CHAT cycle is based on components commercially available. The power generation shaft is based on Westinghouse W501F; the HP shaft is based on compressors and standard turboexpander from Dresser Rand.

The use of CHAT in a coal IGCC is expected to reduce investment cost by 150 $/kW, compared to the use of a combined cycle.

Expected Performance:
Gross Power = 292 MW (at gen. Terminals)
Net Power = 288.3 MW
Gross Heat Range (LHV) = 6565 Btu/kWh
Net Heat Rate (LHV) = 6649 Btu/kWh
Gross Efficiency = 52.0%
Net Efficiency = 51.3%
Methane LHV = 21.517 Btu/lb

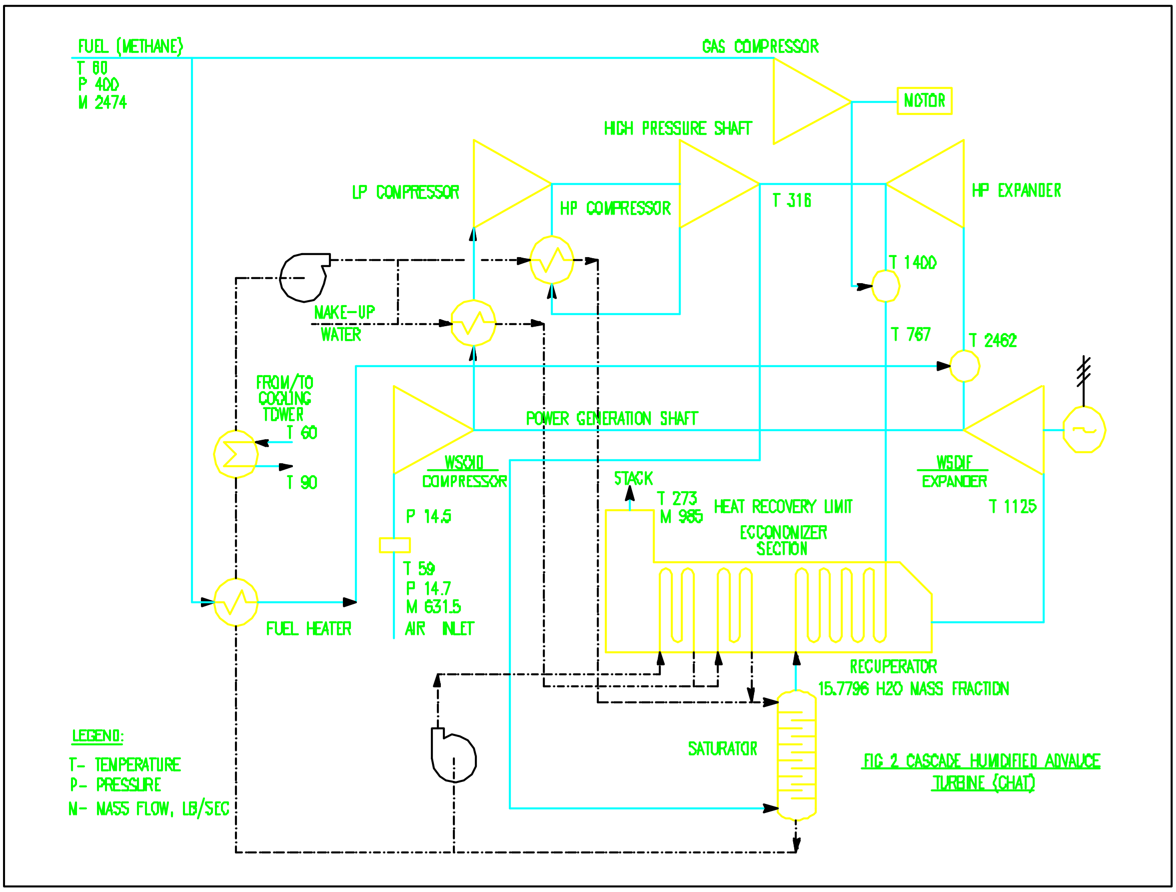


Fig. 2 – Cascade Humidified Advance Turbine (CHAT)

c. Fuel Cell

A more advanced system for power generation is the fuel cell. In a combination with coal gasification the electrical efficiency can be 50% or more.

Both the molten carbonate fuel cell, operating at 600-650°C, and the solid oxide fuel cell, operating at 900-1000°C are possible options for converting syngas to electricity. Heat rejected from these fuel cells is at sufficiently high temperature to permit its recovery in a steam bottoming cycle, generating approximately 30% of total power output.

Solid oxide fuel cells are less sensitive to sulphur poisoning, thus a less expensive syngas purification can be used, compared to the requirements of molten carbonate fuel cells.

The manufacturing cost of fuel cells is at present too high (3000 $/kW minimum) to make the IGCC fuel cell combination commercially attractive. However the intense R/D activities in this area may provide, in the future, important technological breakthroughs to make possible the production of low cost electricity with very low emissions.

4.0 Gasifier

As reported by USA DOE at the recent 5th Gasification Conference in the Netherland (April 8-10, 2002), the priorities for the gasification technology is to reduce the capital cost and to improve the reliability.
A route, common to all technologies, to reduce capital cost is an increase of the single line capacity.
Entrained flow gasifiers, currently the most successful, have demonstrated coal capacity throughputs equal to 2000 t/d and higher (see Table 1).

Table 1

Gasifier	Location	Coal t/d	MW
Texaco	Tampa-Florida	2000	250
Shell	Buggenum (NL)	2000	250
Preflow	Puertollano	2400	300
E-Gas	Wabash	2000	250

Capacity scale-up to 3000-5000 t/d is offered by the Licensors for new projects. This level of scale up should not present great risk. Gasifiers, in fact, are sized on the base of residence time, but designer must take into account that carbon conversion deteriorates when gasifier volume is increased. This can be compensated by increasing the temperature and/or choosing, for a given volume, a higher gasifier length/diameter ratio, to provide more gasifier surface wall, thus more chances for the molten ash slag (carbon trap) to run on the gasifier walls, with more residence time at high temperature.
At the capacity levels, above indicated a further capacity increase is no longer a priority. As a matter of fact many believe that the use of multiple parallel gasifiers of medium capacity is preferable to achieve better reliability. Eastman Chemical propose in their paper, presented at the 5th Gasification Conference (Netherland, April 2002), the use of a stand-by gasifier.

Higher reliability is the other priority for the gasification island. DOE identified a number of components of the current gasifiers requiring further improvements:

a. Feed injectors: Feed injectors are weakest item of the process for achieving a high on-stream factor. Typical life registered in existing plants goes from 1 to 6 months, while a minimum life of 12 months is desired.
   Developments should focus not only on fluodynamics, to achieve better dispersion, but also on metallurgy and cooling systems to increase operating life.

b. Refractory: Refractory liners, where applied, in high temperature slagging gasifiers, are subject to sever attack. Reported life is 12-24 months while a desired life would be 3 years or more in consideration of the cost and downtime required for relining the gasifier.
   New materials need to be developed, less prone to degradation. Ultimately, however, the elimination of refractory is the most beneficial solution.

c. Thermocouples: Gasifier internal temperature registration is a key information for operators. Unfortunately thermocouples fail after few weeks, leaving the operator blind. Consequently there is the need to develop temperature reading devices more endurable.

d. Coal feeding system: Dry coal feed gives a higher cold gas efficiency and lower oxygen consumption but is costly and limited in the achievable delivery pressure. Current dry coal feed is based on lock hoppers, that are limited in the operating pressure, about 40 bar, which limits the maximum pressure of the gasification.
   On the contrary the water-coal slurry feed, based on slurry pumping, has a lower cold gas efficiency, higher oxygen consumption but can be designed for higher delivery pressure, 70 bar, as demonstrated by the Eastman (Tennessee) Texaco coal gasification (gasifier pressure 1000 psig).
   An interesting improvement of the coal feeding system would be to develop a design offering the advantages of dry and wet feed, i.e., high pressure and high cold gas efficiency.
   Different concepts have been suggested:
   - slurry pumping, followed by heating, flashing and solid separation (cyclone); solid is fed to the gasifier while steam is added to the raw syngas;
   - inject slurry in the raw syngas to evaporate the water; separate the solid, fed to the gasifier;
   - use a coal-liquid CO_2 slurry.

So far none of these concepts have been tested, with the exception of coal-liquid CO_2 slurry, which has been tested, to determine the fluodynamic, in a 200 ft pipe loop by EPRI. The coal-CO_2 slurry is pumpable up to 88% coal content; furthermore CO_2 has the advantage of a latent heat of vaporization only 25% that of water. Texaco has calculated the cold gas efficiency for lignite gasification and found 67% for lignite-water slurry feed and 83% for lignite-liquid CO_2 slurry feed.

e. Slag-ash removal

All entrained flow gasifiers remove the slag with lock hoppers, which are costly, require maintenance and add height to the gasification structure. Only E-Gas gasifier uses a proprietary continuous slag removal system which requires less height and cost. This concept should be further developed and used for other gasification technologies.

f. Entrained flow gasifier design optimization: the most successful entrained flow gasifier have the following design features:

Texaco	:	wet feed – single stage
Shell	:	dry feed – single stage
E-Gas	:	wet feed – double stage

Superior cold gas efficiency is obtained by the combination of dry feed and double stage, which currently is not used.
So an expected improvement of the gasification island is to develop this design. In Japan it has been announced by Mitsubishi the plan to construct a 250 MW air blown, demonstration gasifier, which will adopt dry feed and 2 stages of gasification (two points of feed injection).
In an entrained flow gasifier the second stage extends the progress of gasification at the expense of first stage thermal output and cools down the gasifier outlet temperature in order to enter the syngas cooler below the ash melting point, thus avoiding quick fouling of the syngas cooler.

g. Fluidized bed gasifier: the fluidized bed gasifier is more suited than entrained flow gasifier to process a variety of solid fuels, coal, wood, biomass, wastes and coal with high ash content.So the development of a commercial fluid bed gasifier is desired.

Several technologies have been proposed:
HT Winkler
KRW
IGT
Foster Wheeler partial gasifier
KRB Transport gasifier
None, so far, has gone truly commercial.

The most promising design is the circulating fluid bed, which can reach capacities similar to the entrained flow gasifiers, while the bubbling bed, for the same capacity, requires multiple parallel units.
Fluid bed gasifier are generally air-blown. Carbon conversion is lower than in entrained flow gasifier, but can reach 97-98% by increasing the temperature. A limit is posed by the ash melting point. If ash melts the consequent agglomeration of solids would be a disaster for the fluid bed regime.
Often fluid bed gasifier are partial gasifier, assisted by a combustion boiler to burn the char discharged from the gasifier.
Fluid bed gasifiers are based on lock hoppers for the feed and ash discharge. This is an area of improvement in order to provide a truly continuous system to have a better control of the flowrates, reduce local temperature variations and avoid agglomeration and fouling.
Fluid bed gasifier are less suited for CO_2 capture because they are, generally, air blown, which causes a significant dilution of the syngs with nitrogen.

5.0 Syngas cooler

Heat recovery from hot raw syngas involve a sizeable quantity of thermal energy, equivalent to 15% or more of the energy in the feed coal.
Heat recovery can be radiant and/or convection heat exchange. With Texaco gasifier raw syngas exists the gasifier at the maximum temperature, so heat recovery involve a radiant gasifier followed by a fire tube convective gasifier. In the Shell process the raw gas at the gasifier exit, is cooled with a recycle of cool and filtered syngas, below the ash slagging temperature, so Shell uses only a proprietary water tube convective exchanger. Also in the E-Gas process only a convective, fire tube, exchanger is used because raw syngas is cooled by the second gasification stage.

Convective fire tube exchanger, as used in the E-Gas, Wabash plant, are less costly than water tube design, as used by Shell in the Buggenum plant, because there are significant steel and weight savings associated with containing the hot, high pressure coal gas in small tubes.
Steam superheating can be done in the syngas cooler (Shell-Buggenum), but it is more economical to superheat the steam in the HRSG of the combined cycle.

6. Hot gas clean-up

Removal of particulate in syngas at high temperature, 350°-700°C, has been practised in several plants of commercial size. Initially this process components were one of the primary causes of repeated shutdowns and maintenance. Over the year the technology has improved and competion amongst Vendors has also reduced the cost.

Two materials are proposed as filtration media: ceramic and sintered metals.

Ceramic has almost no temperature limitation but is more prone to rupture. Metallic filter are more costly but mechanically stronger.
A complete removal of solid particles is mandatory because these particles, containing sulfides, chlorides and alkaly, pose an abrasive and corrosive threat to the turbine. Effluent concentration of 0.0001÷0.1 mg/m^3 have been demonstrated with flyash at the entrance at concentrations of 1÷30 g/m^3.

The removal, at high temperature, of other contaminants in the syngas, like sulphur compounds, halogens, trace elements and alkali metals, is another important option to improve the IGCC efficiency; theoretical calculations have demonstrated a possible improvement of 1.0÷1.5% point.
Unfortunately the problem is complex and difficult to be solved.
Sulphur compounds, H_2S and COS can be captured at high temperatures, 300-600°C, by metallic oxides; the resulting metal sulfides can be regenerated with air producing SO_2, which can be converted to sulphuric acid or to elemental sulphur.
Alogens can be removed, at similar temperatures, with chemicals, such as $Ca(OH)_2$ or Na_2CO_3, either with pneumatic injection of powder or with a fixed bed of granular material.
No hot gas process is available to remove trace elements, such as zinc, lead and alkali metals, although some indirect removal is obtained by separation of submicron particulate with filtration.
The complex hot gas clean-up involve complicated multiple treatments. A compromise solution proposed is a combination of conventional wet scrubbing, for the removal of alogens, alkali, volatile metals, NH_3, HCN and residual particulate, followed by hot gas clean-up, at 250-400°C, for the removal of sulphur compounds by adsorption on metal oxides.
General Electric developed a process based on zinc ferite. IHI in Japan and Kema in Europe developed a process based on iron oxide promoted by other metal oxides (Mo). In spite of many investigations and pilot testings the development of a sorbent with the necessary attrition resistant properties has been very elusive. For this reason the planned hot gas desulphurization tests at Tampa and Sierra Pacific IGCC plants, have never been made, in spite of DOE financial support.

A further development of this technology does not warrant an acceptable return. The complication and costs of treatments at high temperatures are not expected to be justified by the modest increase of efficiency. Further the hot gas treatments, based on gas-solid contact and solid transportation, would possibly be a source of operating problems, worsening the reliability of the IGCC.

7. Mercury and other trace elements

Mercury is present, at trace level, in several coals. Environmental authorities are paying increasing attention to this problem and limits are expected to be imposed on coal based power stations.

The capture of mercury can be done by passing cold syngas through a bed of granular activated carbon at 30°C. Eastman Chemical report a 90-95% removal of mercury in their coal partial oxydation plant (Tennessee). This appears to be a fairly low cost and effective method for mercury removal. Active carbon at room temperature is also a good trap for nickel and iron carbonyls, sometimes present in syngas, specially with quench gasification.

There is certainly much additional benefit to be obtained from a comprehensive development and testing program with different sorbents to stop not only mercury but also other trace elements and poisons such as As, Cd, Se, PBT etc. The need to control these contaminants is expected to become more and more important. If adsorption at low temperature is confirmed to be the right solution, there will be a further reason to consider without future the hot gas clean-up.

8. Acid gas removal (AGR)

Scrubbing H_2S and CO_2 from syngas, separately or together, has been studied and developed by the Chemical Industry for decades. Well over 30 different processes are in commercial use, based o either chemical solvents or physical solvents or mixed chemical/physical.

The key technical and economical problem is to choose the right process, case by case, taking into account:

- total and partial pressure of acid gases;
- allowable residual acid gas in syngas;
- relative quantities of CO_2 and H_2S;
- low level heat available for regeneration.

In conclusion the technology of removal of acid gases is rather mature and well developed. However opportunities exist to improve the cost and performance of conventional solvent based processes. The areas of possible and desired improvements are:

a. <u>Heat Stable Salts</u>: the high carbon monoxide environment produced by the gasifier, promotes the formation of heat stable salts in amine based systems, one of the most common solvent. These salts not only reduce the effectiveness of the solvent, but also enhances the corrosion.

Heat stable salts are removed today with special regenerable ion exchange resins or with a reverse osmosis process. The development of a new and more cost effective technology to remove heat stable salts is desirable.

b. Carbonyl Sulphide (COS): to achieve the required sulphur emission levels, it is necessary to remove not only H_2S but also COS. Acid gas removal processes in use, have no or modest capacity to capture COS. For this reason IGCC plants have to install a costly hydrolysis step to convert COS to H_2S upstream the H_2S scrubbing. A cost effective improvement would be to hydrolize COS to H_2S in the scrubbing process by adding a suitable activator in the solvent. Research is progressing in this direction and preliminary successes have been announced by Linde.

c. Coal gasification provides a potential option for removal of CO_2 from the syngas in order to reduce CO_2 emission of coal fired plant. This option is more cost effective than post combustion CO_2 removal proposed for combustion power plants.
CO_2 removal is achieved in two steps. First the syngas is shifted to convert catalytically CO to CO_2; then CO_2 is recovered in the AGR.
Due to the large quantities involved, physical solvents, such as Selexol, Purisol or Rectisol, are favoured to reduce the energy input for the solvent regeneration. To use effectively a physical solvent the gasification pressure should be as high as possible.
New approaches should be pursued to separate H_2 from CO_2. Selective, high temperature membranes are first on the list. This technology is under development at the Oak Ridge National Laboratory.
A serious disadvantage is that the permeated gas, hydrogen, is delivered at low pressure and will absorb energy for ricompression, before entering the gas turbine.

9. Air separation unit (ASU)

Cryogenic separation of oxygen and nitrogen is a mature technology, in existance since over 100 years. In the recent years, following the demand of large capacities and lower O_2 purity, coming from the IGCC and Gas to Liquid Industry, cryogenics Vendors have developed improvements to satisfy these specific requirements. These improvements are generally directed to make ASU less complex, less costly and less energy intensive than old industrial gas production facilities, required to produce smaller quantities, high purity products and recovery of noble gases. The most important changes of the cryogenic technology for IGCC applications are:

a. Capacity: capacity of a single line facility has been increased dramatically. Two plants are in operation in Belgium an Malaysia with a capacity of 3200 t/d oxygen.

b. Front end purification: special radial double bed reactors have been developed to purify very large flow of feed air, by removing H_2O, CO_2 and hydrocarbon traces with alumina and molecular sieve. Old conventional horizontal bed reactors would have not permitted similar flowrates coupled with low pressure drop.

c. Distillation packing: structured packing has substituted old sieve trays in the HP and LP columns of fractionation, to reduce pressure and liquid hold-up thus permitting a quicker response to load variations. This technology resulted in 5% energy savings.

d. ASU- IGCC Integration: Various concepts have been developed to integrate ASU and IGCC, such as:

- total or partial supply of air feed from the gas turbine compressor;
- high pressure ASU delivering O_2 and N_2 at approximately 3-5 bar, instead of 0.5 bar, thus reducing subsequent compression energy;
- combination of liquid O_2 pumping and subsequent compression to overcome current limitations of O_2 compressor delivery pressure;
- new control technics to operate floating pressure ASU, receiving air feed from the gas turbine at pressures variable with the gas turbine load.

e. Oxygen purity: the purity of O_2 is not a priority for IGCC. On the contrary a low energy consumption is much more important. Fig. 3 provides an indication of the energy consumed by ASU as function of the purity of oxygen.
The shape of the curve explains why the majority of IGCC designs has chosen an O_2 purity of 95%.

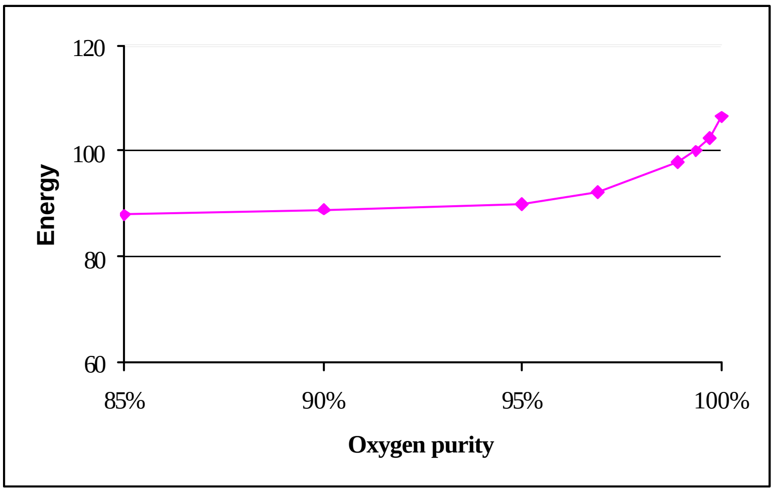


Figure no. 3
Energy vs. O_2 purity

However, in spite of all above described modifications/improvements, the energy demand of ASU is still equivalent to 15% of the gross IGCC power output and its investment cost 10% or more of the total IGCC cost.
So there are ample justifications to search for new concepts to separate O_2 and N_2 in a more cost effective way. The most promising new process is the Air Products-DOE process, called Ion Transport Membrane Oxygen (ITM Oxygen). Another process has been announced sponsored by Praxair and based on a similar Ion Transport Membrane (OTM).

ITM is based on ceramic membranes that selectively transport oxygen ions when operated at high temperature, typically 800-900°C.
The conductors, within the crystalline ceramic structure, are mixed inorganic metal oxides, deficient of oxygen, which permit only the migration of oxygen ions from one side to the other side of the membrane. The result is that the permeated gas is extremely pure oxygen; nitrogen contaminant in the oxygen is an indication of membrane cracks or defects.
Oxygen is delivered at membrane temperature (800-900°) and typically at a pressure less than 1 bar. The non permeated stream is air, somewhat depleted in oxygen, delivered at membrane temperature (800-900°C) and at pressure close to the air feed delivery pressure, typically 10-30 bar, depending on air feed supply pressure.
Membrane temperature is kept by feeding air heated at the desired temperature (800-900°C).

ITM-Oxygen process is particularly suited for integration with IGCC. Fig. 4 shows schematically an IGCC - ITM Oxygen complex, fully integrated.
All the air compressed in the gas turbine is extracted, preheated against the oxygen depleted air coming from ITM at 800-900°C. Air is further heated to ITM temperature with an in-line burner by direct combustion with clean syngas.
Hot, low pressure, pure oxygen is cooled by raising medium pressure steam, along with other low-level heat recovery, before compression to the gasifier pressure.
Hot, high pressure, O_2 depleted air, after heat recovery in the gas-gas economizer is returned to the gas turbine where it is used as combustion air in the syngas burners. The gas turbine air circuit above described, generates some additional pressure drop and loss of the sensible heat of the separated oxygen, compared to conventional gas turbine arrangement. These losses are compensated by increasing somewhat the syngas fuel to achieve the maximum gas turbine power output. This extra syngas to the gas turbine plus the syngas used in the inline burner to preheat the ITM air feed, require a slight increase of the gasification and 4,7 % more coal and oxygen than an equivalent IGCC based on cryogenic ASU.

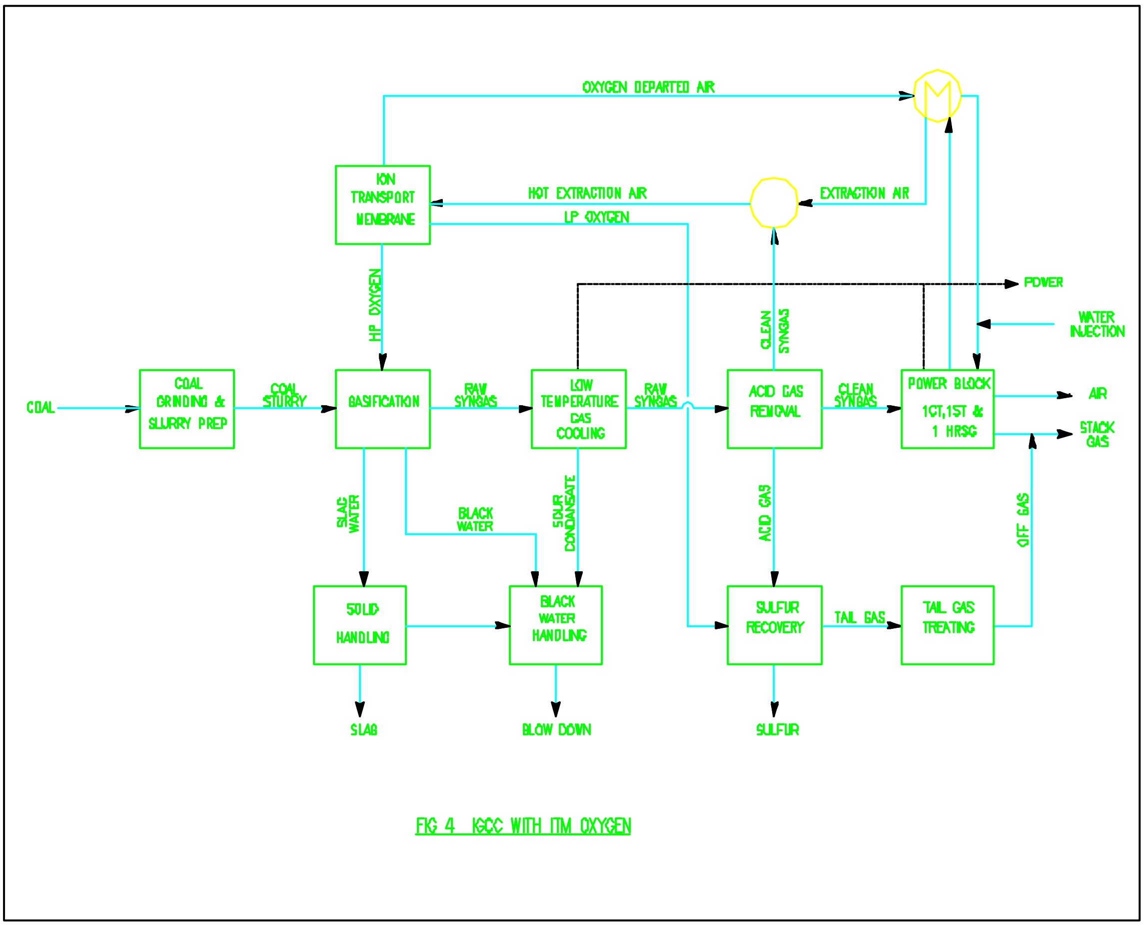


Figure no. 4
IGCC with ITM Oxygen

The following Table 2 reports performance and cost data from a study presented by Air Products at the 5^{th} Gasification Conference in the Netherland (8-10 April 2002). This study compare a coal IGCC based on Westinghouse gas turbine W501G, deriving O_2 from ITM and a similar IGCC based on traditional cryogenic ASU. Both IGCC use, for gasification, a Texaco quench gasifier and 100% air/N_2 integration between gas turbine and O_2 plant.

Table 2

		IGCC+ITM	IGCC+Cryogenic
Coal (HHV)	MMBTU/h	3704	3539
O_2 (100%)	t/d	2900	2760
Power Production			
W501G	MW	272	272
Steam Turbine	MW	189	172
Expander	MW	14	13
Total	MW	475	457
Power Consumption			
O_2	MW	19.5	29.8
IGCC	MW	17.5	18.2
Total	MW	37.0	48.0
IGCC net P.O.	MW	438	409
IGCC eff. (HHV)	%	40.4	39.5
O_2 plant cost	MM$	41.6	61.2
Balance of Plant	MM$	405.4	386.8
Total Investment	MM$	447.0	448.0
$ per kW		1020	1094

The additional 29 MW produced by the IGCC-ITM are obtained at no additional capital cost; their cost is only the sum of additional coal and O_2 costs.
Table 2 gives for the cryogenic ASU a power consumption of 29.8 MW which is equivalent to 6.5% of the total power output of the IGCC and corresponds to 259 kW h per ton of O_2. Both numbers appears rather optimistic, even considering the 100% integration of ASU with the gas turbine; in fact the power saving due to the absence of the ASU air compressor is normally compensated by the power of a large N2 compressor required to replenish the gas turbine to its maximum power output. With a higher and more realistic power requirement of the cryogenic ASU the advantages of ITM would have been even greater.

10. Shift of CO to H_2 and CO_2

The shift of CO to H_2 and CO_2 is a catalytic step necessary when the IGCC must reduce the CO_2 discharged to the atmosphere. However CO shift may also be considered for quench IGCC not recovering CO_2. In fact when the reference of the comparison is a quench gasifier, the addition of CO shift brings the following benefits:

- CO shift reaction is exothermic and eliminates part of the syngas water coming from the quench. This results, downstream, in more availability of high temperature heat, for HP steam production, and less low temperature heat for LP steam production.
  With a quench gasifier without shift, heat can only be recovered as MP and LP steam.
- CO shift catalyst also hydrolysis COS to H_2S and there is no need of a separate COS hydrolysis system.
- The greater mass flow of syngas, due to CO_2, increases the energy recoverable from the expander.
- More CO_2 in the gas turbine reduces the quantity of H_2O to be added to saturate the expander and, at the same time, contributes to NOx reduction.

In the case of a gasifier followed by a syngas cooler (no quench) the CO shift step would be negative because the large majority of heat from gasification is recovered as HP steam and the exothermic heat of the shift reaction is a net loss of syngas chemical energy to the gas turbine. Further to operate the shift, downstream a non quench gasifier, would require the addition to the syngas of a large quantity of steam, degrading the IGCC efficiency.

The catalysts for the shift reaction have been developed and progressively improved by the chemical industry (H_2 and NH_3).
The first catalyst used was a high temperature catalyst based on Fe-Cr oxydes. In the syngas reducing atmosphere Fe_3O_4 may be reduced to FeO and Fe, which are effective catalysts for Bondouard (carbon formation) and Fischer-Tropsch (hydrocarbon formation) reactions. To prevent these side reactions old HT shift catalyst required, in the entering syngas, a large excess of steam; steam/dry gas ratio vol. = 2.5, equivalent to 5 times the stechiometric water used in the shift.
Subsequently Tops?e and Süd Chemie introduced the copper promoted HT catalyst, permitting operation with a lower steam to dry gas ratio, 2 v/v, equivalent to four times the stechiometric water.
Since the CO shift reaction is favoured by low temperatures, the LT shift catalyst was introduced, based on copper-zinc, which can operate with a water/dry gas ratio equal to 1.5.
In connection with the production of ammonia and hydrogen with heavy oil partial oxydation, BASF developed a shift catalyst which can stand high concentration of H_2S, contrary to the HT and LT catalyst, above described, which must operate in absence of

sulphur compounds. This catalyst, called dirty shift catalyst, is based on Co-Mo, operates at medium high temperatures and requires a steam/dry gas ratio=1.5.
All these developments have taken place over the past 50-60 years. The technology has to be ranked mature with little chances of further improvements.
The catalyst life is typically 3-5 years for HT shift and dirty shift catalysts, while for LT shift catalyst a 2 life years is the standard.

11.0 Expected Benefits from 2020 IGCC Best Available Technologies

Coal IGCC Best Available Technology (B.A.T.), currently demonstrated, is based on the following key processing steps:

- gasifier: entrained, O_2 blown, high pressure with single line capacity in the 2000-3000 t/d coal range;

- air separation: cryogenic, high pressure, integrated, with single line capacity up to 3000 t/d oxygen;

- gas turbine: F class, 1300°C firing temperature and power output close to 300 MW.

This current IGCC B.A.T. is basically represented by Cases A1 and B1 of this study.

This technology is expected to improve in the future, as indicated in the previous paragraphs of this Section G. To predict the extent of these improvements in the next 20 years, is difficult and uncertain because 2020 is well beyond any planning horizon of the industry.
In the following Table G.11 we have attempted, for each technology sector, to quantify the extent of improvements, compared to the technologies available today. The improvement values shown in this Table are, obviously, stretch goals, reflecting an educated guess of what may be the technology development in the future years.
In the same Table we have also indicated, for each improvement of the technologies, an expected probability of achievement of the specified gain over the performance of the IGCC Technology today available.

Table G.11
Improvements of the Technologies

	IGCC Net Effic. % gain		IGCC Capital Euro/kW reduction		IGCC Availability gain		NOTES
	Efficiency Gain	Probability	Capital Reduction	Probability	Availability	Probability	
1. GT	min 3 max 6	High Medium	min 20 max 50	High Medium	Superior	high	H class + air compressor staging and multiple firing
2. HRSG	min 1 max 2	High Medium	Marginal (*)	High	Superior	High	Once through supercritical
3. HAT-CHAT	Min 0.5 Max 2.0	Medium Low	min 20 max 40	Medium Low	Unpredictable	-	
4. FUEL CELL	min 3 max 7	High Medium	Unpredictable	-	Unpredictable	-	Solid oxide
5. GASIFICATION	min 1 max 2	High Medium	min 10 max 30	High Medium	Superior	High	Dry feed, double stage, large capacity, no refractory
6. SYNGAS COOLER	Marginal	High	Marginal	High	Superior	High	
7. HOT GAS CLEAN UP	Min 0.5 Max 1.5	Low Low	Unpredictable	-	Unpredictable	-	Not promising development
8.1 AGR	Marginal	High	Marginal (*)	High	Superior	High	Physical solvent, active for COS and Trace Contaminants for cases w/o CO_2 capture
8.2 AGR	Marginal	High	Min 30 Max 50	High	Marginal	High	Optimisation of washing with physical solvents like Rectisol, Selexol etc.. for cases w CO_2 capt.
9. ASU	Min 0.5 Max 1.5	Medium Medium	min 20 max 40	Medium Low	Unpredictable	-	ITM technology
10. SHIFT + SOUR EXPANDER	Min 0.5 Max 1.0	High High	Marginal (*)	High	Marginal	High	

(*) With respect to the overall IGCC Capital Cost

The amount of effort required to develop and commercialize the technologies listed in Table G.11, is uncertain, as it is the case for any research and development program.
However we have attempted to provide in the following paragraphs, a qualitive estimate for each technology.

Gas Turbine: the development of gas turbine has been for many years an important feature of the industries involved, specially driven by the military sector and by governmental energy agencies. This trend will stay in place in the future, even stronger, thanks to the strategic importance of this sector. Investment involved are enormous and often require public financing to progress.

HRSG: the development of HRSG technology is in the hands of the boiler industry, and is a natural evolution coming from the fired boiler technology. So most of the technology advancements are already available and commercialized with the large fired boilers. Consequently the development effort required is limited but time is necessary to prove the new technologies and make it commercial.

HAT-CHAT: these power cycles are undoubtly of great interest, but unfortunately they require the development of large rotating machinery, which would be extremely costly and not justified by the number of potential applications. For this reason we do not see, in the next twenty years, a future for this technology.

FUEL CELL: this technology is one of the list of the research programs of many industrialized countries. Public and private money invested in fuel cell development is very large.
This technology will certainly become commercially available in the next 20 years and will find in the gasification technology a natural partner.

GASIFICATION: this technology is already fairly advanced but improvements in performance and cost have to be expected. The most important development efforts are today taking place in USA, Europe and Japan.
The size of the efforts involved can be classified medium.

SYNGAS COOLER: this costly item, part of the heat recovery gasification, is commercially available in different designs. Only marginal improvements are expected in the future and the development effort required is limited.

HOT GAS CLEAN-UP: this technology was studied and tested with great interest, by many entities in different countries during the 90’s. The difficulties encountered have discouraged most of the R/D programs to invest further money and resources.

AGR: this is a mature technology, developed by the chemical industry. Improvements of the solvent characteristics and optimization of the process are however required to meet specific IGCC requirements, such as capture of COS and other trace contaminants.
Development efforts required are low to medium size.

ASU: the large demand of power and capital of the cryogenic technology has driven the research to develop other technologies. The membrane technology appears to be the most promising. The effort required to develop and commercialize this new process is large and is currently supported by the private U.S. Industry and DOE Government Agency. This large effort is however justified by the great commercial potential of this technologies in various fields and IGCC.

SHIFT AND SOUR EXPANDER: this technology is mature and does not require substantial development efforts. The only need is to demonstrate commercially its application.

12.0 Expected Performance of the IGCC Best Available Technology in Year 2020

The improvements of the various technology components of an IGCC, expected in the next years (see Table G.11), cannot be all simultaneously applied to an hypothetical IGCC scheme of the year 2020. However, in the assumption that all the technology improvements of Table G.11, will be available in year 2020, it is possible to combine a discrete number of them in a logical scheme in order to arrive to an optimized IGCC, representing the Best Available Technology of Year 2020 (2020 B.A.T. IGCC).
In this paragraph we have attempted to develop the year 2020 B.A.T. IGCC, without and with capture of CO_2. These two schemes are referred, respectively, as:

- Case G.1 : 2020 IGCC without CO_2 capture
- Case G.2 : 2020 IGCC with CO_2 capture (CO_2 removal efficiency 85%)

The main features of Case G.1 are:

- coal dry feed;
- gasification: entrained flow, high pressure, double stage;
- gasifier heat recovery type, large capacity, no refractory;
- syngas purification: hot filtration, water scrubbing, A.G.R. based on selective physical solvent able to capture H_2S, COS and other trace contaminants, such as as carbonyls, HCN, NH_3, CS_2, mercury, As, Cd, etc.;
- Gas turbine of 2020 generation (see paragraph G.1);
- HRSG once through, supercritical.;
- ASU based on ITM technology;

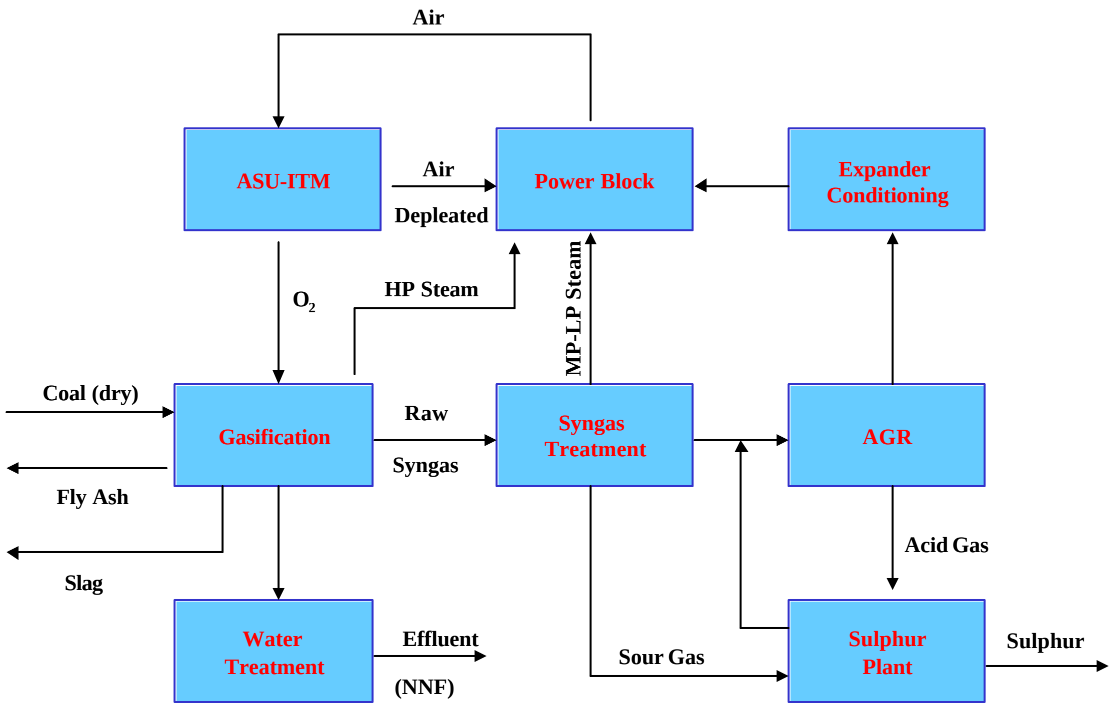
- Sulphur recovery based on SCOT type process.

The main feature of Case G.2 are:

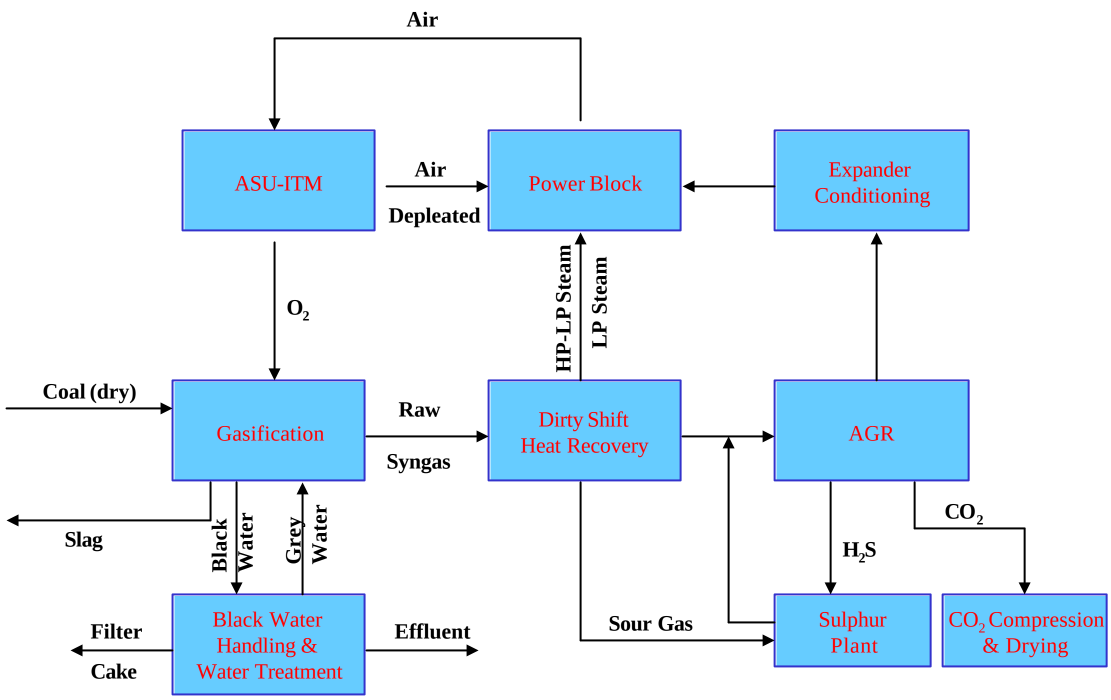
- coal dry feed;
- gasification: entrained flow, high pressure, double stage;
- gasifier quench type, large capacity, no refractory (Lower cold gas efficiency and lower investment costs with respect to heat recovery type);
- CO shift: dirty shift type, single stage (sufficient for 85% CO_2 removal);
- AGR: H_2S and CO_2 separate absorptions, based on a physical solvent able to capture H_2S and COS and all trace contaminants. For the purpose of evaluating Case G.2 performance the characteristics of the solvent have been assumed to be similar to methanol characteristics;
- Solvent regeneration: thermal for H_2S, flash for CO_2;
- Gas turbine of 2020 generation (see paragraph G.1);
- HRSG once through, supercritical;
- ASU based on ITM technology;
- Sulphur recovery based on SCOT type process.

The attached Block Flow Diagrams schematically show the process schemes of Case G.1 and G.2.

Block Flow Diagram – Case G.1



Block Flow Diagram – Case G.2



The coal processing rate chosen for Case G.1 and G.2 is 250 t/h, which is equal to the capacity of Case A.1, the IGCC scheme with the highest net electrical efficiency (43.1%) amongst those examined in Section D. Case A.1 may be ranked as the most close to the B.A.T. of Year 2000, from the point of view of efficiency (43%), but not of the investment (1371.5 Euro/kW instead of 1200). Since Case G.1 and G.2 are based on advanced gas turbines of the Year 2020, whose capacity is not defined, no consideration has been given to the saturation of these gas turbines capacity, leaving the coal throughput (250 t/h) as the only design parameter for the definition of the IGCC capacity. The quality of coal is the same used for Case A.1, as defined in Section B, para 2.0.

The environmental impact of Case G.1 and G.2 is expected to be equal or better than that of the Cases examined in Section D.
The recovery of CO_2 of Case G.2 is equal to 85%.
The performance of Cases G.1 and G.2 is given in the following Table. The values shown in this table are an educated guess of the performance of the various IGCC components in

Year 2020, therefore they include all the uncertainties connected with the speculation of what will be in the future the progress of the selected IGCC components.

Table G.12.1

Overall Performance of Cases G.1 and G.2

		Case G.1	**Case G.2**
Coal Feed rate	t/h	250	250
	MWt (LHV)	1797	1797
Raw Syngas ex Scrubber	MWt (LHV)	1509	1474
Cold Gas efficiency	%	84	82
Clean Syngas	MWt (LHV)	1503	1341
Syngas Treatment Efficiency	%	99.6	91
Clean Syngas to ASU-ITM	MWt (LHV)	60	60
Clean Syngas to GT	MWt (LHV)	1443	1281
Gas Turbine Power Output	MWe	600	533
Steam Turbine Power Output	MWe	340	355
Expander Power Output	MWe	10	8
Gross Electric Power Output	MWe	950	896
ASU Power Consumption	MWe	35	35
Process Units Consumption	MWe	16	35
Utility – Offsite Consumption	MWe	7	7
Power Island Consumption	MWe	13	13
CO_2 compression/drying	MWe	-	30
IGCC Auxiliary Consumptions	MWe	71	120
IGCC Net Electric Power Output	**MWe**	**879**	**776**
Net Electrical Efficiency (LHV)	**%**	**48.9**	**43.2**

The investment cost of Cases G.1 and G.2 has been developed on the same bases defined in Section E. The same contingencies, fees, cost of land and factors for bulk materials, construction, site preparation, etc. have been used. The values are expressed in today Euro, with no account for inflation.

	Case G.1 10^6 **€**	**Case G.2** 10^6 **€**
Coal Handling Storage	8	8
Gasification Section	400	300
ASU	73	73
Syngas Treatment and Conditioning	17	47
AGR	16	60
SRU and TGT	16	16
CO_2 compression and drying	-	22
Power Island	350	330
Utilities/Offsites	113	113
Total Investment	**993**	**969**
Specific Investment Cost, €/kW	**1129**	**1248**

The C.O.E. and Cost of CO_2 removal at 10% DCF for cases G.1 and G.2 are derived from the attached Tables G.12.2 and G.12.3 respectively.

The following Table compares the net electrical efficiencies, the specific investment costs, the C.O.E. and the cost of CO_2 removal of Cases G.1 and G.2 vs. Case A.1 and B.1.

ALTERNATIVE		**G.1** (no CO_2 capture)	**A.1** (no CO_2 capture)	**G.2** (w CO_2 capture)	**B.1** (w CO_2 capture)
Net Electric Efficiency	%	**48.9**	43.1	**43.2**	34.5
Specific Cost	Euro/kW	**1129**	1371.5	**1248**	1860
Cost of Energy	Euro/kWh	**0.040**	0.048	**0.045**	0.063
CO_2 removal cost	Euro/t	**-**	-	**9.0**	24.2

If all the improvements incorporated in the two schemes G.1 and G.2 will become a reality the cost and performance benefits will be very large. At this point the IGCC will become a winning choice in the power industry. Consequently other cost benefits will come from the larger number of applications of the IGCC technology.

References

EPRI : Reports TR-106905-TR102034

TEXACO-GE-PRAXAIR : IGCC Study on H class Turbines

IST : Once through HRSG

US-DOE : 5th Gasification Conference (Netherland)

Eastman Chemical : 5th Gasification Conference (Netherland)

Air Products-DOE : ITM O_2 Process – 5th Gasification Conference (Netherland)

FOSTER WHEELER ITALIANA

TABLE G.12.2 - G.1 - Cost Evaluation - Discount Rate = 10%

Rev. : 1
Date : March 2003

Production		
Coal Florate	####	t/h
Net Power Output	####	MW
Sold Sulphur	2,14	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures	**MM Euro**	
Installed Costs		873,7
Land purchase; surveys	5%	43,7
Fees	2%	17,5
Average Contingencies	6,6%	57,8
Total Investment Cost		992,7

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	72,2
Maintenance	34,2
Waste Disposal (7€/t)	1,9
Chemicals + Consumabl	1,7
Insurance and local taxe	17,5

Working Capita		**MM Euro**
30 days Chemical Storag		0,2
30 days Coal Storage		7,0
Total Working capital		7,2
Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,040	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	263,1	MM Euro/year
NPV	**0,00**	
IRR	**######**	

CASH FLOW ANALYSYS Millions Euro	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				138,4	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5
Sulphur				0,9	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6
Operating Costs															
Fuel Cost				-38,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2
Maintenance				-22,8	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3
Chemicals & Consumables				-0,9	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7
Waste Disposal				-1,0	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9
Insurance				-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5
Working Capital Cost				-7,2											
Fixed Capital Expenditures	-198,5	-446,7	-347,4												
Total Cash flow (yearly)	-198,5	-446,7	-347,4	43,4	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2
Total Cash flow (cumulated)	-198,5	-645,3	-992,7	-949,3	-822,1	-694,9	-567,7	-440,5	-313,3	-186,1	-58,9	68,3	195,6	322,8	450,0
Discounted Cash Flow (Yearly)	-180,5	-369,2	-261,0	29,6	79,0	71,8	65,3	59,3	53,9	49,0	44,6	40,5	36,8	33,5	30,5
Discounted Cash Flow (Cumul.)	-180,5	-549,7	-810,7	-781,1	-702,1	-630,3	-565,0	-505,7	-451,7	-402,7	-358,1	-317,6	-280,7	-247,2	-216,8

CASH FLOW ANALYSYS Millions Euro	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	261,5	
Sulphur	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	
Operating Costs														
Fuel Cost	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	
Maintenance	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	-34,2	
Labour	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	-1,7	
Waste Disposal	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	
Insurance	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	-17,5	
Working Capital Cost														7,2
Fixed Capital Expenditures														
Total Cash flow (yearly)	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	127,2	7,2
Total Cash flow (cumulated)	577,2	704,4	831,6	958,8	1086,0	1213,2	1340,4	1467,7	1594,9	1722,1	1849,3	1976,5	2103,7	2110,9
Discounted Cash Flow (Yearly)	27,7	25,2	22,9	20,8	18,9	17,2	15,6	14,2	12,9	11,7	10,7	9,7	8,8	0,5
Discounted Cash Flow (Cumul.)	-189,1	-163,9	-141,0	-120,2	-101,3	-84,1	-68,5	-54,3	-41,4	-29,6	-19,0	-9,3	-0,5	0,0

FOSTER WHEELER ITALIANA

TABLE G.12.3 - G.2 - Cost Evaluation - Discount Rate = 10%

Rev. : 1
Date : March 2003

Production		
Coal Florate	####	t/h
Net Power Output	####	MW
Sold Sulphur	2,14	t/h
Fuel Price	38,8	USD/t (*)
Insurance and local taxes	2%	Installed cost

(*) 1 USD= 1.00 Euro

Capital Expenditures		**MM Euro**
Installed Costs		853,3
Land purchase; surveys	5%	42,7
Fees	2%	17,1
Average Contingencies	6,6%	56,0
Total Investment Cost		969,1

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	72,2
Maintenance	32,3
Waste Disposal (7€/t)	1,9
Chemicals + Consumabl	2,6
Insurance and local taxe	17,1

Working Capit	**MM Euro**
30 days Chemical Storag	0,3
30 days Coal Storage	7,0
Total Working capital	7,2

Labour Cost		**MM Euro/year**
# operators		128
Salary		0,05
Direct Labour Cost		6,4
Administration	30% L.C	1,9
Total Labour Cost		8,3

Electricity Production Co	0,045	Euro/kWh
Sulphur Price	103,3	Euro/t
Inflation	0,00	%
Taxes	0,00	%
Discount rate	10,00	%
Revenues / year	258,7	MM Euro/year

NPV **0,00**
IRR **######**

CASH FLOW ANALYSYS Millions Euro	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				136,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1
Sulphur				0,9	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6
Operating Costs															
Fuel Cost				-38,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2
Maintenance				-21,6	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3
Labour				-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3
Chemicals & Consumables				-1,4	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6	-2,6
Waste Disposal				-1,0	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9
Insurance				-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1
Working Capital Cost				-7,2											
Fixed Capital Expenditures	-193,8	-436,1	-339,2												
Total Cash flow (yearly)	-193,8	-436,1	-339,2	42,1	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2
Total Cash flow (cumulated)	-193,8	-629,9	-969,1	-927,0	-802,8	-678,6	-554,4	-430,1	-305,9	-181,7	-57,5	66,7	190,9	315,1	439,3
Discounted Cash Flow (Yearly)	-176,2	-360,4	-254,8	28,8	77,1	70,1	63,7	57,9	52,7	47,9	43,5	39,6	36,0	32,7	29,7
Discounted Cash Flow (Cumul.)	-176,2	-536,6	-791,4	-762,7	-685,5	-615,4	-551,7	-493,8	-441,1	-393,2	-349,7	-310,1	-274,1	-241,4	-211,7

CASH FLOW ANALYSYS Millions Euro	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	257,1	
Sulphur	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	1,6	
Operating Costs														
Fuel Cost	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	-72,2	
Maintenance	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	-32,3	
Labour	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	-8,3	
Chemicals & Consumables	-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	
Waste Disposal	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	-1,9	
Insurance	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	-17,1	
Working Capital Cost														7,2
Fixed Capital Expenditures														
Total Cash flow (yearly)	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	124,2	7,2
Total Cash flow (cumulated)	563,5	687,7	811,9	936,1	1060,3	1184,5	1308,7	1432,9	1557,1	1681,3	1805,5	1929,8	2054,0	2061,2
Discounted Cash Flow (Yearly)	27,0	24,6	22,3	20,3	18,5	16,8	15,3	13,9	12,6	11,5	10,4	9,5	8,6	0,5
Discounted Cash Flow (Cumul.)	-184,6	-160,1	-137,7	-117,4	-99,0	-82,2	-66,9	-53,0	-40,4	-29,0	-18,5	-9,1	-0,5	0,0

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : BASIC INFORMATION FOR EACH ALTERNATIVE

ISSUED BY : R. DOMENICHINI
CHECKED BY : R. DOMENICHINI
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
October 2002		R. Domenichini	R. Domenichini	R. Domenichini

SECTION H

ATTACHMENTS

INDEX

SECTION H

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : GASIFICATION POWER GENERATION STUDY
DOCUMENT NAME : GASIFICATION TECHNOLOGIES REVIEW

ISSUED BY : G.L. FARINA/R. DOMENICHINI
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GASIFICATION TECHNOLOGIES REVIEW

I N D E X

1.0 INTRODUCTION

Gasification is the conversion of a solid (coal, biomass, wastes) or liquid (oil) fuel to a gas, often identified as syngas, in which the major components are hydrogen (H_2) and carbon monoxide (CO). This report is aimed at describing the main coal gasification technologies.

Gasification entails partial oxidation reactions; combustion, instead, involves complete oxidation, while pyrolysis is a thermal degradation in absence of oxygen (O_2).
The gasification agents used in gasification are oxygen or air and, usually, steam. The choice of O_2 or air depends on a number of factors such as the reactivity of the feed material, the purpose for which the gas is to be used and the type of gasifier. Steam helps the mixing of feed and oxidant and acts as a temperature moderator, as the reactions of steam with carbon are endothermic.

The first major application of gasification was to convert coal into fuel gas for domestic heating and lighting. In the early part of the last century a large number of coal gasifiers operated commercially to produce residential and industrial fuel gas. By the mid 1950s, the availability of abundant and low cost natural gas led to the abandonment of most coal gasification units. In the last few decades of the past century, the main application of gasification has been the petrochemical industry to convert different hydrocarbon streams into synthesis gas, for the manufacture of ammonia, methanol and hydrogen, used in hydrodesulphurization and hydrocracking of oil stocks.

The two oil price shocks of the 1970s renewed interest in the gasification technology for the power generation industry. Gasification, in fact, acts as a bridge between coal or heavy fuel oils and the gas turbines. Gasification of such fuels generates a fuel gas which, after cleaning, can be used in a gas turbine combined cycle power plant. The resulting process configuration (Integrated Gasification Combined Cycle – IGCC) is the only coal based power technology that can approach the environmental performance of natural gas fired systems, because the syngas, before firing in the gas turbine, can be cleaned to reduce to very low levels contaminants such as sulphur compounds and particulates. Furtherly the syngas can be mixed with nitrogen and/or saturated with water to reduce similarly the nitrogen compounds.

2.0 GASIFICATION PROCESSES

A large number of gasification processes exist. The most convenient way of classifying all these different processes is by the regime of flow inside the gasifier. In this way gasifiers fall in one of the following three categories:

- Moving bed;
- Fluidized bed;
- Entrained flow.

2.1 Moving bed gasifiers

In a moving bed gasifier the gasification agents, O_2 and steam, are injected into the bottom of the reactor. The generated gas moves upward, while the solid fuel, fed at the top, gradually moves down, as the solid fuel at the bottom of the bed is consumed. The raw fuel gas, flowing countercurrent through the bed, is cooled by the incoming feed, which, in turn, is dried and heated to progressively higher temperatures.
The temperature profile inside the gasifier goes from 400-500°C, at the top, to around 1000°C or more at the bottom. Moving down the bed different zones are identified:

- drying zone;
- devolatization zone;
- gasification zone;
- combustion zone.

The ash below the combustion zone cools by giving up heat to the entering steam and O_2 (or air).
The raw fuel gas, flowing through the devolatization and drying zones picks up significant amounts of volatile tarry compounds, light hydrocarbons and methane. The raw fuel gas is therefore washed at the outlet with water to remove the tars.
Moving bed gasifiers process only solid fuels (coal), with size ranging from 5 to 50 mm. The tolerance for fines (< 5 mm) in the coal feed is limited. Run-of-mine coals contain typically 30-50% fines by weight , which must be screened and briquetted with bitumen before entering the gasifier.
The residence time inside the gasifier is long, from 15 to 30 minutes.
The syngas outlet temperature is low, 400-600°C, depending on the feed coal moisture content.

A prominent example of moving bed gasifier is the Lurgi gasifier (Figure 1).
The Lurgi dry-ash gasifier was developed in the 1930s and has been used extensively for producing town gas and, in South Africa, for synthesizing chemicals and transportation fuels. The temperature at the bottom is kept below the ash fusion point so that ash is discharged as solid. In 1970 British Gas and Lurgi developed the slagging version, in which the temperature at the bottom is sufficient to melt the ash. The BGL slagging gasifier achieves a higher carbon conversion than the dry ash Lurgi gasifier.

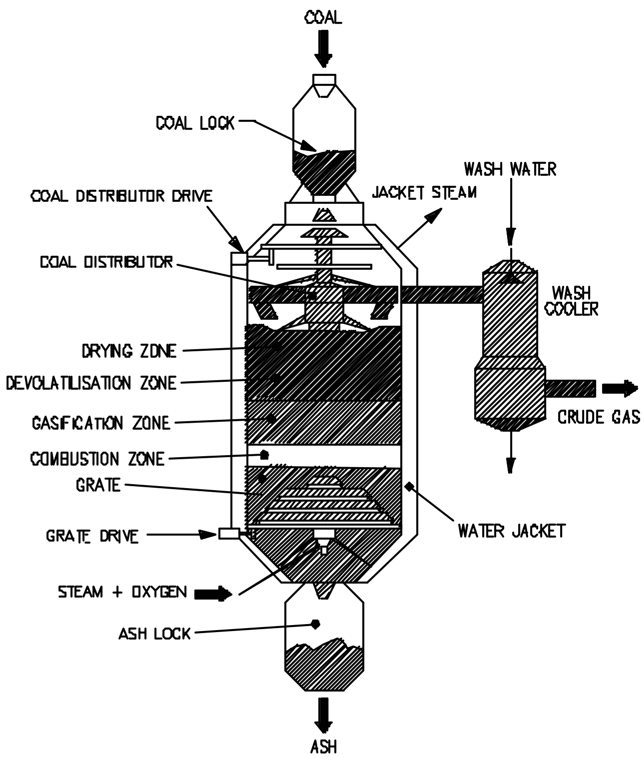


Figure 1
Lurgi Dry Ash Gasifier

2.2 **Fluidized bed gasifier**

Fluidized bed gasifiers can be bubbling bed type or circulating bed type (Figure 2). Solid coal and ash are suspended in an upward flowing gas stream. The fluidized bed stays at constant temperature below the ash initial fusion temperature, in order to avoid formation of clinker and possible defluidization of the bed.

Coal particles shrink in size during gasification and are entrained with the hot raw gas to the top outlet. Char and ash particles are recovered in the external cyclone and recycled to the gasifier, while the raw gas proceeds to the downstream treatment facilities. Bottom ash is discharged through lock hoppers.

Fluidized bed gasifiers may produce dry ash or agglomerated ash. Agglomerated ash is obtained when the gasifier design provides a higher bottom temperature, thus improving the char utilization.

The processing of highly caking bituminous coal in fluidized bed gasifiers may cause fluidization problems, although most modern fluid bed gasifiers have resolved this problem.

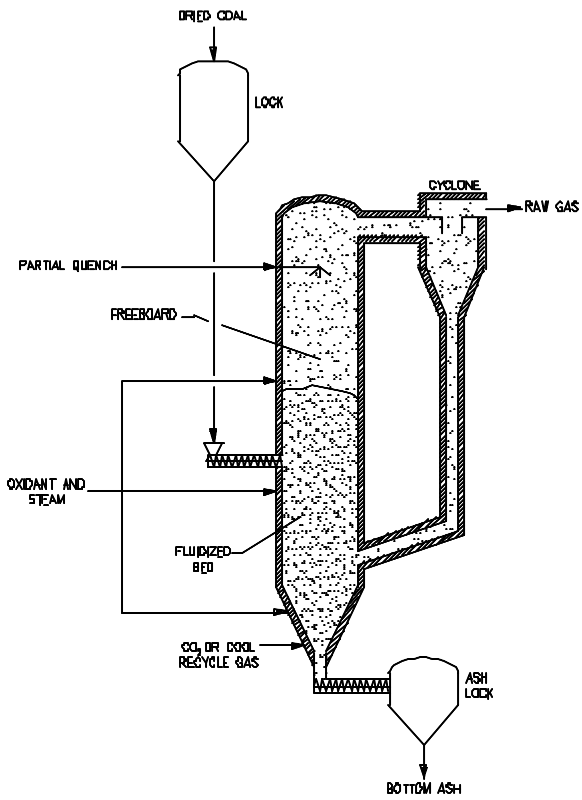


Figure 2
HTW Fluidized Bed Gasifier

Fluid bed gasifiers process only solid fuels (coal), with size ranging from 0.5 to 5 mm, therefore with adequate tolerance for coal fines. They are not suitable for liquid fuels.
The residence time inside the gasifier can range from 10 to 50 seconds.
The raw syngas outlet temperature is usually within the range 700-900°C, with the exception of the High Temperature Winkler (HTW) process, where the raw syngas temperature is increased by 150-200°C by injecting a portion of oxidant above the fluidized bed (Figure 2).

The most prominent examples of fluidized bed gasifier are:

- the above mentioned High Temperature Winkler (HTW)
- Tampella – U-Gas
- Kellogg Rust Westinghouse (KRW).

2.3 Entrained Flow Gasifiers

In this type of gasifier (Figure 3) the feed, pulverized coal or atomized oil, flows co-currently with the gasification agents (O_2 and steam). Residence time is very short, between 0.5 and 5 seconds; the temperature inside the gasifier is uniform and very high, from 1300°C to over 1500°C, well above the ash fusion temperature. At these temperature conditions the syngas product contains only very small amounts of methane (0.1-0.3% vol.); for this reason entrained gasifiers are preferred when syngas is used in chemical synthesis.
Entrained flow gasifiers are suited to process both solid and liquid feed, provided that they can be atomized to very small particles, less than 200-300 micron. They are not suited to process solid wastes, which cannot be readily pulverized. Gasification reactions are extremely fast due to the high temperature and great surface of the atomized feed.
Ash in the feed is melted and extracted, together with the unconverted carbon, part from the gasifier bottom and part with the gas to be captured in the gas clean-up facilities downstream of the gasifier.

Entrained flow gasifiers may differ in the coal feed system and in the configuration recovering the large amount of sensible heat in the raw gas.
Two types of feed systems are in use. The wet type is based on pumping a slurry of pulverized coal in water; the dry type is based on pneumatic transport of pulverized coal.
Recovery of gasifier sensible heat can be made in a waste heat boiler, downstream of the gasifier, generating high pressure steam, or through a water quench inside the

gasifier and subsequent recovery of the degraded heat in external waste heat boilers, producing medium and low pressure steam.

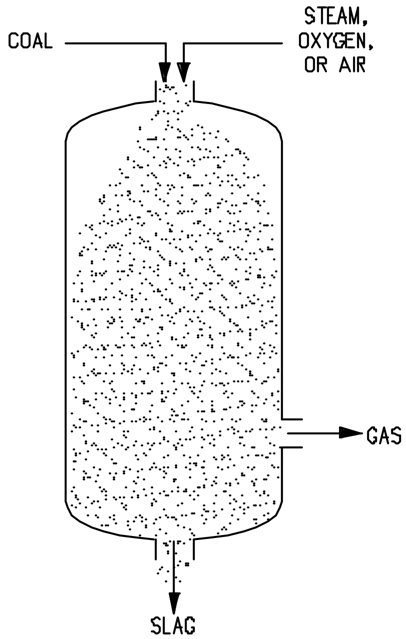


Figure 3
Entrained Flow Gasifier

The waste heat boiler system improves energy efficiency, but the quench system permits to remove efficiently solids from the raw gas before entering the downstream facilities. In addition water quench is attractive when syngas requires CO shifting, to increase the H_2/CO ratio.

In fact CO shift requires the addition of large amounts of water in the gas, which can be done conveniently in the quench.

Entrained flow gasifiers have been selected for nearly all the most recent gasification projects because of their flexibility in processing a large variety of fuels, solid and liquid, and because they can achieve in a single train large capacities, thus better scale economy.

The most prominent examples of entrained flow gasifiers are:

- Texaco
- Shell
- Prenflo (Krupp – Uhde)

- E-Gas (Global Energy)
- Noell (Babcock Borsig Power).

3.0 DESCRIPTION OF SPECIFIC GASIFIERS

The most important and well-known gasifiers are described in this paragraph.

3.1 Lurgi Dry Ash Gasifier (moving bed)

This gasifier was developed in the 1930s. The first commercial plant was constructed in 1936 (A.G. Sachsische Werke – Dresden – Germany) to gasify lignite and produce town gas.

After the world war the design was improved to accept bituminous coal (caking). Since then the Lurgi Dry Ash gasifier has become the technology leader, used worldwide for a variety of applications: town gas, ammonia, methanol, synthetic natural gas (SNG) and synfuels (Fischer – Tropsch).

The most significant commercial installations of the Lurgi Dry Ash Gasifier are listed in Table 1.

In total 164 Lurgi Dry Ash Gasifiers have been constructed.

The gasifier is shown schematically in Figure 1 (see para. 2.1). Coal is fed, in lumps of controlled size (5-50 mm), through lockhoppers at the top of the gasifier and pressurized before entering the reactor. A rotating distributor feeds evenly the coal around the gasifier. The coal moves slowly down, warming up by heat transfer from the upward flowing hot gas. Thus coal is subsequently dried, devolatilised, gasified and combusted. The devolatilization forms phenols and tars ending up in the raw syngas.

The hottest part is the bottom (~1000°C) where the remaining coal is combusted. The CO_2 produced reacts, in the higher section, with carbon to form CO. Ash is removed by a revolving grate and depressurized in lockhoppers. Steam and O_2 are blown through the grate to provide the gasification agents.

The steam to oxygen weight ratio is kept high, close to 4.5, to maintain the bottom temperature sufficiently low to avoid ash fusion, so that ash is removed as a solid.

The gas product leaves the gasifier at low temperature, 300-500°C, and contains tars and light hydrocarbons (methane) in quantities greater than other gasifiers; so the cold gas efficiency of this gasifier is higher and gas sensible heat lower than in other gasifiers of fluid bed and entrained flow types, operating at much higher temperatures.

Product gas is cooled and washed with water to remove tars and most heavy hydrocarbons.

The gasifier is surrounded by a water jacket, raising steam.

TABLE 1

Lurgi Dry Ash Gasification Process

Customer	Location	No. of Gasifiers Op/spare	Fuel Input/ Syngas Out (MWt)	Coal t/d	Product	Start Date
Sasol I	Sasolburg - South Africa	17/2	1169/971	Sub-bituminous/10,000	FT liquid	1955
Gas Board	Westfield – Scotland (UK)	4/0 (1)	--	Sub-bituminous/1000	Towngas	1960
SVZ Schwarze Pump	Lausitz – Germany	24/0 (2)	1113/848	Briquetted Brown Coal	Towngas	1964
Sokolovska Uhelna	Vresova - Czech Republic	26/1	796/636	Coal	Power (3)	1970
Sasol II	Secunda - South Africa	36/4	5435/4511	Sub-bituminous/30,000	FT liquid	1977
Sasol III	Secunda - South Africa	36/4	5435/4511	Sub-bituminous/30,000	FT liquid	1982
Dakota Gasification	Bismark, ND – USA	12/2	1861/1500	Lignite/14,000	SNG	1984
CNTIC	Shaanxi – China	3/1	367/312	Coal	Chemicals	1987
Henan	Puyang – China	3/1	367/312	Coal	Chemicals	2000

(1) Not yet operated
(2) Presently seven gasifiers are in operation
(3) Initially Town Gas

The average lower temperatures prevailing in the Lurgi Dry Ash Gasifier make this gasifier more suited to process reactive coals, lignite and bituminous coals, and less suited for refractory fuels, such as anthracites and petroleum coke.
A disadvantage of the Lurgi Dry Ash Gasifier is the maximum capacity of the single gasifier. The most widely used model, the Mark IV, with a diameter of 4 m can process around 700 t/d coal, much less than the most modern entrained flow gasifiers, 2000 t/d or more. This is a penalty for the investment cost of large plants.
To mitigate this limitation Lurgi has developed and installed in SASOL I the new Mark V gasifier with a diameter of 5 m; this gasifier has a capacity of 1000 t/d moisture and ash free coal.

3.2 British Gas-Lurgi Slagging Gasifier (moving bed)

This gasifier is a development of the dry ash version, which took place in the 1970s, sponsored by the British Gas Development Center in Westfield (Scotland), to produce town gas and SNG more efficiently.
This gasifier is shown schematically in Figure 4. Lump coal and limestone, as fluxing agent, are fed into a lockhopper, which, after pressurization, periodically discharges into the top of the gasifier. A rotating distributor plate spreads the coal across the top section of the vessel. For caking coals a stirrer is added to the rotating plate to prevent coal agglomeration.
As in the dry ash version the descending bed encounters four zones: drying, devolatilization, gasification and combustion. O_2 and steam are added through nozzles; the weight ratio, steam over O_2, is much lower than in the dry ash gasifier, from 0.5 to 1.0. In this way the bottom temperature is kept higher than the ash melting point. The molten slag produced is quenched in water and discharged by a lockhopper. The gasifier is refractory lined to reduce heat losses. The gas leaves the gasifier at low temperature, 400-500°C, and contains tars and hydrocarbons. This raw gas is cooled and scrubbed with water to remove tars, heavier hydrocarbons and coal dust which are recycled back to the gasifier.
As the dry ash gasifier the BGL slagging gasifier has a very high cold gas efficiency compared with other gasifiers.

The BGL gasifier at Westfield is a demonstration unit, designed to process 500 t/d bituminous coal, in a vessel of 2.3 m diameter. In a 4 m diameter design BGL would expect a coal feed rate of about 1200 t/d. The gasifier began operation in 1984 and was shutdown in 1990 after successfully completing extensive coal testing.

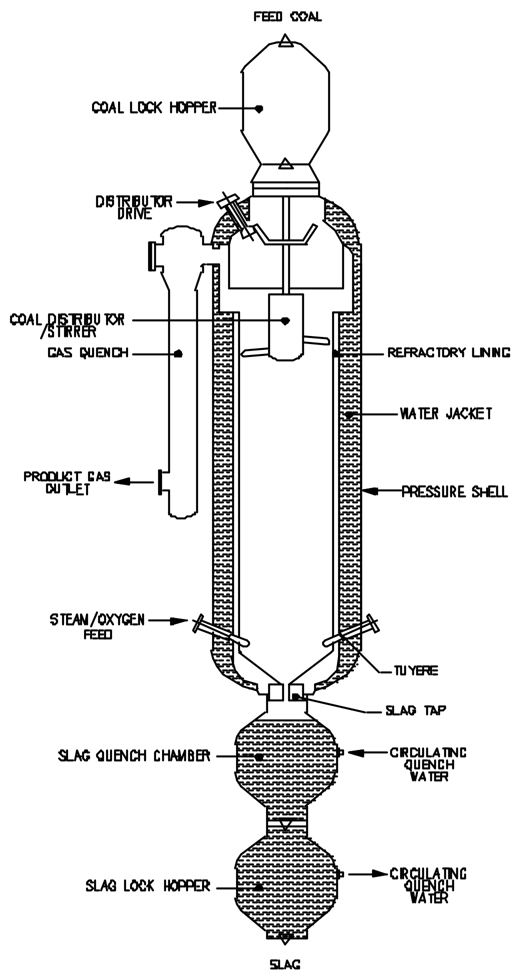


Figure 4
BGL Slagging Gasifier

In 1999 a BGL gasifier was started up at SVZ Schwarze Pumpe Plant, Germany, to gasify waste. The gasifier design capacity is 30 t/h, while the actual capacity depends on properties and composition of waste. Also this gasifier is a demonstration unit supported by the THERMIE programme.

The BGL gasification technology has been selected for two 540 MWe IGCC projects under development in USA, the Kentucky Pioneer Energy Project and the Lima Energy Project, as well as for the Global Energy/Fife Power 400 MWe project in Cardenden, Fife, Scotland (UK), which is presently deferred.

3.3 High Temperature Winkler (fluidized bed)

The High Temperature Winkler (HTW) gasifier is a development of the old Winkler atmospheric pressure gasifier used in the 1920s.
The high temperature feature of the HTW is accomplished by injecting a portion of the oxidant above the fluidized bed to obtain a much higher temperature over the original Winkler with the following advantages:

- increased carbon conversion (less char)
- reduced methane and heavier hydrocarbons formation.

Rheinbraun, a major producer of lignites, developed the HTW gasifier for lignite gasification.
A first demonstration unit was built in 1985 at Berrenrath (Germany) to gasify 700 t/d brown coal, at 10 bar pressure, with minimum content of methane to meet the requirements of a downstream methanol synthesis.
In 1989 a second demonstration unit, optimized for IGCC power generation, was started in Wesseling. This unit, having a capacity of 170 t/d coal, operates at 25 bar, and can be operated either as a bubbling or circulating bed, using either air or O_2. This unit was the demonstration step for a 350 MW IGCC project, called KoBRA, which was dropped later, for economical reasons. The KoBRA plant was expected to gasify 3600 t/d coal in an air blown gasifier.
The HTW gasifier is shown schematically in Figure 2 (see para 2.2).
Fuel is pressurized in a coal hopper and fed to the gasifier by a screw conveyor.
The gasifier vessel is refractory lined; the bottom is occupied by the fluid bed, fluidized by steam, O_2 or air. Generated gas is further heated in the upper zone by injection of oxidant. Entrained solids at the outlet of the gasifier are separated in a cyclone and recycled to the gasifier for further char conversion. The gasifier bottom temperature is kept at about 800-900°C to avoid ash melting, while the freeboard temperature can be 150-200°C higher.
Ash and residual char are removed from the base of the gasifier. Depending on the char content, the ash may be sent to an external fluid bed boiler for full combustion of char. When high rank, low reactive, coals are gasified additional combustion is necessary; whereas this may not be required with highly reactive lignites.

HTW gasification technology has been selected for the substitution of the 26 old Lurgi dry ash gasifiers installed in the Sokolovska Uhelna plant, Vresova (Czech Republic). This project is presently in the development phase.

3.4 Tampella U-Gas and KRW (fluidized bed)

Tampella U-Gas and KRW gasifiers are similar. Both processes are using a bubbling bed regime and air is the oxidizing agent.
These two gasifiers have a hot ash agglomeration zone, close to the bottom of the gasifier. This approach produces higher carbon conversion then in conventional fluid beds, an advantage particularly important when processing low reactivity bituminous coal.
The key difference between these two gasifiers is that the KRW uses recycle gas for velocity and temperature control in the critical ash agglomeration zone, whereas the U-Gas uses steam.

Both KRW and U-Gas have undergone testing with limestone addition for in situ sulphur removal. However in reducing conditions the sulphur reacts with limestone to form calcium sulphide. Whether the calcium sulphide can be transformed into the more desirable calcium sulphate in the agglomeration zone or in an external oxidizing reactor is not clear.

The U-Gas gasifier was developed, in the late 70s, by the Institute of Gas Technology (Chicago). The technology was later purchased by Tampella, a large boiler manufacturer in Finland. Eight gasifiers (six in operation, two spare), 100 t/day each, have been in operation on bituminous coal at Wujing, Shanghai (China) since 1994. The plant produces gaseous fuels. The technology has been proposed for many other projects supported by the U.S. Clean Coal Program, but none have been built.
This gasification technology has been selected for the IBIL Energy Systems (IES) IGCC project in Kutsch, Gujarat (India). The project is in the engineering phase.

The KRW gasifier was developed, in the late 70s, by Westinghouse in a 30 t/d pilot plant located in Pittsburgh. The technology obtained support from US D.O.E, during development. Later, in the 90s, a 100 MWe IGCC plant (the Pinön Pine Project) was built at Reno (Nevada), with financing provided by U.S. Clean Coal Program. Start up was long and difficult; currently this plant generates power firing natural gas.

3.5 Texaco Gasification (entrained flow)

Texaco is the foremost name in the gasification technology. The process was developed in the late 1940s at Montebello Texaco Laboratories (California), initially to reform natural gas to syngas and later to gasify oil and coal.

Over 100 commercial partial oxydation plants have been licensed, worldwide, to convert gas and oil feeds to chemicals (ammonia, methanol, hydrogen).
The oil price increases in the 1970s renewed the interest in coal gasification. Two demonstration units were built; the first was a 165 t/d coal gasification at Ruhrchemie – Oberhausen (Germany); the second was an ammonia plant based on gasification of 190 t/d coal, at TVA plant, Muscle Shoals (Alabama).
The first commercial unit was built in 1983 to generate oxosyngas from coal at the Tennessee Eastman Chemical Complex. But the most significant commercial plant, based on coal gasification, was the Cool Water IGCC, generating 120 MW from 1000 t/d bituminous coal. This was a successful demonstration for the power industry that electric energy can be generated reliably by IGCC.
Most recent designs of Texaco coal gasifier can handle 2000 t/d coal (dry), as demonstrated in the Polk (Tampa-Florida) 250 MW IGCC, operational since 1996, and in the Delaware 255 MW IGCC, operating on petroleum coke since 1999.

Figure 5 provides a schematic description of the pressurized, downflow, entrained Texaco gasifier in the two versions: direct quench and syngas cooler.
Texaco use a wet type feed system. Coal is crushed and slurried with water in wet rod mills, producing a slurry containing 60-70%wt coal.
The coal water slurry is pumped into the gasifier burner, together with O_2. The water in the coal slurry acts as a moderator of the gasification temperature. When oil is gasified temperature moderation is obtained with injection of steam.
The raw gas leaving the gasifier at 1300-1400°C contains molten ash and a small quantity of unburned carbon (soot). This stream is either directly quenched in water, to cool the gas and remove solidified particles, or is indirectly cooled in radiant and convection boilers, to recover sensible heat in the form of high pressure steam, prior to water scrubbing.

The Texaco gasifier is a refractory lined pressure vessel, operating at pressures variable from 30 to 80 bar, depending on the requirement of the final syngas use.

The major advantages of the quench variant is a lower cost and higher reliability. When CO shift is required the quench provides in the syngas all the water needed by the shift reaction. The major disadvantage of the quench variant is the lower energy efficiency.

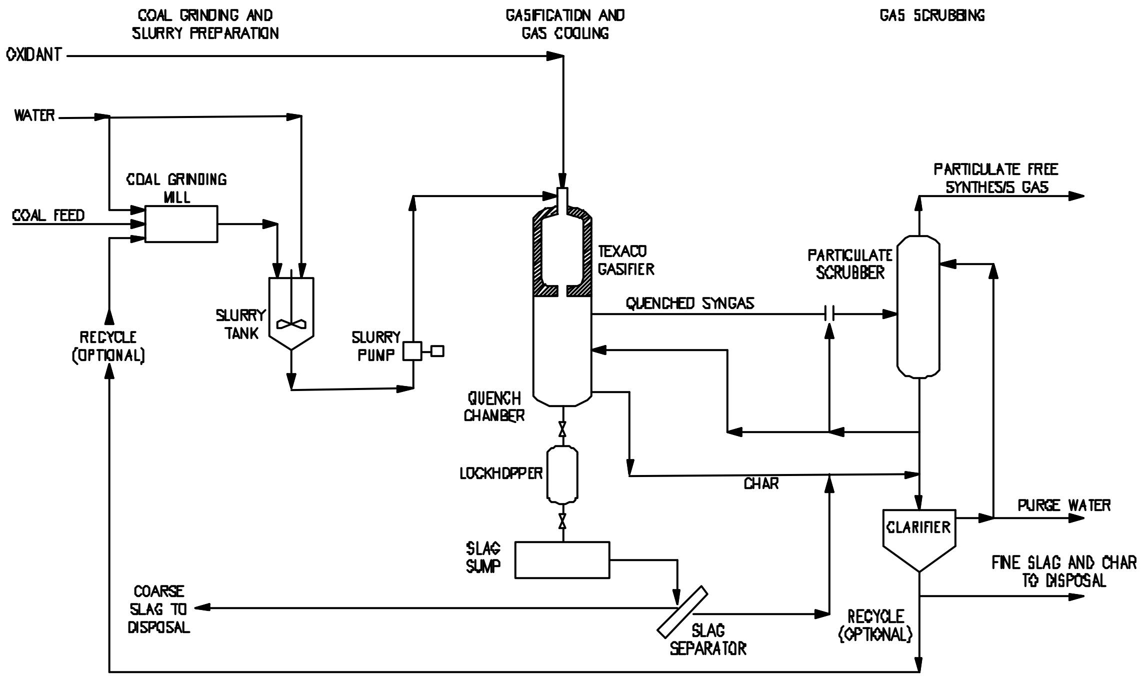
As of January 2001 the total plants licensed by Texaco are 127, with a total of 69 plants in operation and engineering, construction or start-up phases.
Table 2 shows the split among different feedstock for the 69 plants in operatin and enginieering.

TABLE 2

Feedstock	Plants in operation	Plants in Eng./ Constr./Start-up Phases	Total
Coal/Petcoke	13	2	15
Liquid	20	12	32
Natural Gas	19	3	22
TOTAL	49	20	69

Table 3 lists coal gasification plants presently in operation.

Direct Quench Mode



Full Heat Recovery

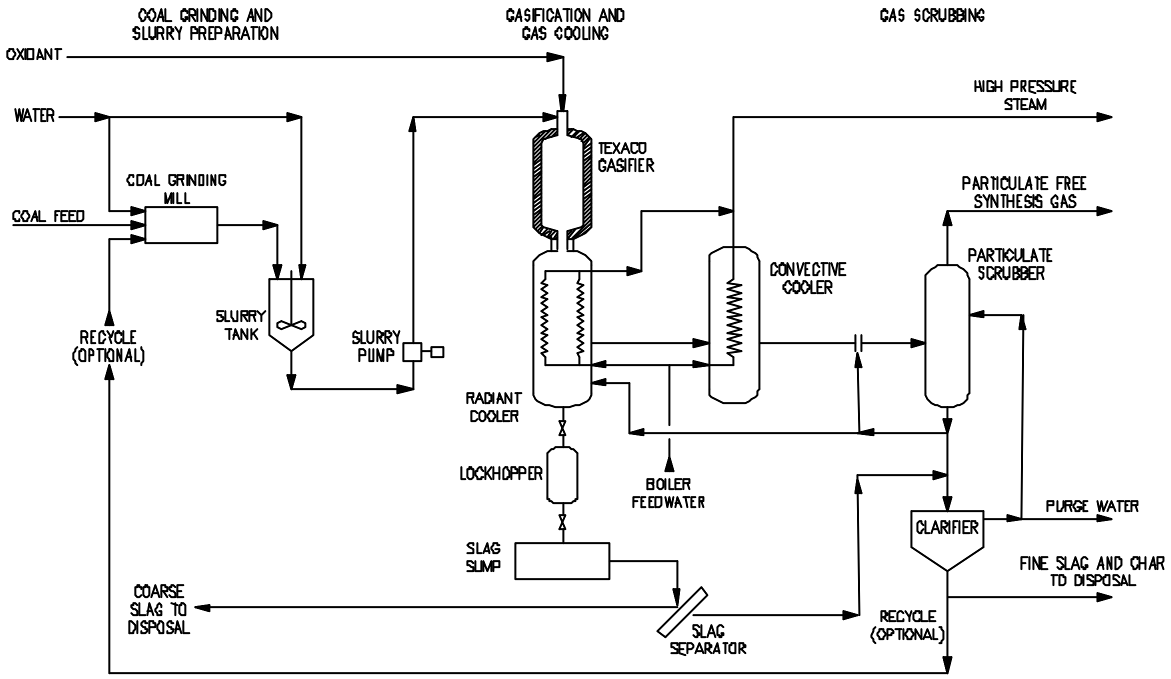


Figure 5
Texaco Gasification

TABLE 3

Texaco Coal/Petcoke Gasification Process

Customer	Location	No. of Gasifiers Op/spare	Type Quench (Q) WHB (FHR)	Solid Feedstock	Product	Start Date
Eastman Chemical	Kingsport, TN – USA	1/1	Q	Bituminous Coal	Oxochemicals	1983
Ube Ammonia Industry	Ube City – Japan	3/1	Q	Coal/Petcoke	Ammonia	1984
Rheinbraun	Ville – Germany	3/0	Q/FHR	Coal/oil	Methanol	1986
Lu Nan Chemical Industry	Tengxian, Shandong – China	2/0	Q	Bituminous Coal	Ammonia	1993
Shanghai Pacific Chemical	Wujing, Shanghai – China	3/1	Q	Anthracite Coal	Methanol/ Town gas	1995
Tampa Electric	Lakeland, FL – USA	1/0	FHR	Coal	Electricity	1996
Texaco Gasification Power Systems	El Dorado, KS – USA	1/0	Q	Petcoke	Electricity/ Steam	2000
Weihe Fertilizer	Xian, Shaanxi – China	2/1	Q	Coal	Acetic Acid	1996
Farmland Industries	Coffeyville, KS – USA	1/0	Q	Petcoke	Ammonia/ UAN	2000
Huainan	Anhui – China	2/1	Q	Coal	Ammonia	2000
Motiva Enterprises	Delaware City, DE – USA	2/0	Q	Petcoke	Electricity/ Steam	2000

3.6 Shell Gasification (entrained flow)

Shell Gasification by partial oxydation of oil and gas was developed in the 1950s. More than 50 commercial plants have been built to convert liquid and gaseous hydrocarbons to ammonia, methanol and hydrogen, using a downflow entrained gasifier. This gasifier is offered only in the syngas cooler version without a quench variant.
In the 70s, after the first oil crisis, Shell started to work on coal gasification, in a 165 t/d pilot plant built in the Shell Hamburg refinery (Germany).
Initially Shell cooperated with Krupp Koppers, owner of the old Kopper-Totzek gasification technology. In 1981 this partnership terminated; Shell and Krupp Koppers continued to develop separately their own technology. Shell proved its coal gasification technology in a 250-400 t/d demonstration unit at Deer Park (Texas), while Krupp Koppers built a smaller demonstration plant, 50 t/d, at Fürstenhausen (Germany), calling their technology Prenflo (Pressurized Entrained Flow).
Due to this common origin (Kopper-Totsek) the Shell and Prenflo technologies have many similarities.
In 1989 the Shell gasifier was selected for the 250 MW IGCC plant at Buggenum (Netherland), gasifying in a single vessel 2000 t/d coal. This plant started up in 1994, entered the commercial operation at the beginning of 1998 experiencing some operating problems during the first years.

The Shell gasification is schematically shown in Figure 6.
The gasifier vessel is a membrane carbon steel pressure shell, internally lined with refractory and enclosed inside a carbon steel pressure vessel. Water circulated in the membrane wall cools the gasifier and raises saturated steam.
Pulverized coal is pressurized in lockhoppers and transported pneumatically by pressurized nitrogen to opposite burners, located at the bottom of the gasifier. The high temperature (1400°C) converts ash into molten slag, which runs down the refractory lined membrane wall of the gasifier into a bottom water bath, from where a slag-water slurry is discharged with lockhoppers. A portion of slag adheres to the refractory lined wall forming a protective layer.
The hot raw gas leaving the gasifier top entrains some molten slag and unburned carbon. To make the ash non sticky, this gas is partially cooled, to about 900°C, by quenching with cooled, filtered syngas. In this way fouling of the downstream syngas cooler is avoided. The syngas cooler is a Shell proprietary design, based on water-tube, contrary to the syngas cooler used in Shell oil gasifiers which is a fire-tube.

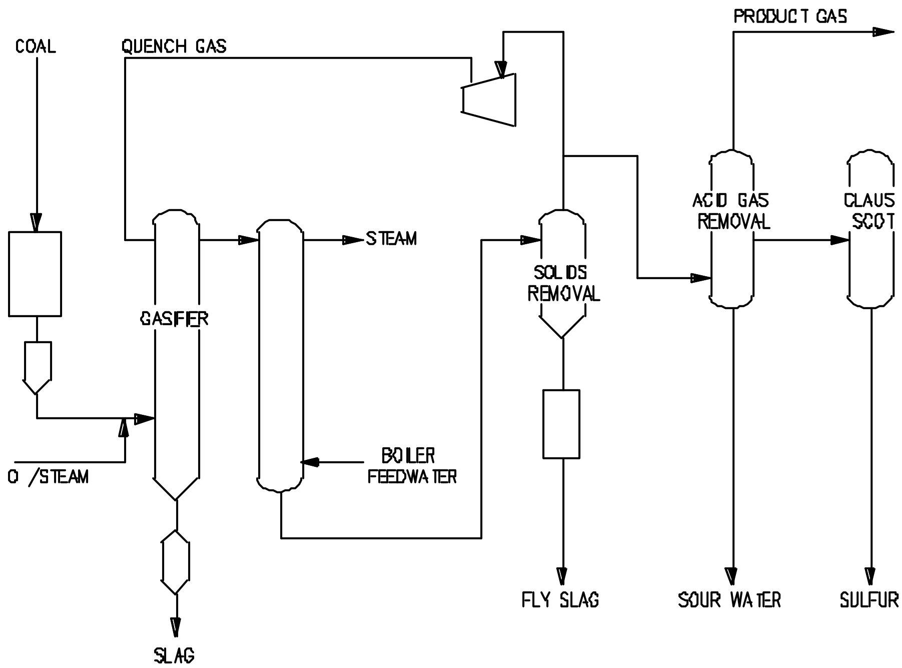


Figure 6
SHELL Gasification

The dry feed used in the Shell gasifier minimizes the O_2 requirement and makes the Shell gasifier somewhat more efficient than entrained flow gasifiers using wet feed systems. This is reflected in the much lower CO_2 content of the syngas. A penalty is however paid because the dry feed is more costly and operationally more complex.

Currently there are six large coal/coke gasification projects adopting Shell technology in different phases of development, design and engineering.

3.7 Prenflo Gasification (entrained flow)

The Prenflo gasifier, following the demonstration in the Fürstenhausen pilot plant, was selected for the Puertollano, 300 MW IGCC Plant, sponsored by the European Community within the Thermie Program. This plant became operational in 1998, but has reported several problems during commissioning and disappointing service factors in the first years of operation.

The Prenflow gasifier is shown in Figure 7. This gasifier is similar to the Shell gasifier (see paragraph 3.6). Both use pressurized dry feed, bottom opposed burners and upward entrained flow. The gasifier vessel is water cooled.
The key difference is the heat recovery system. Shell partially cools the raw gas before the heat recovery with cooled and filtered recycle gas. The Prenflo gasifier uses a radiant water wall boiler, directly connected with the gasifier to form one vessel. The developers of this design claim to obtain a thermal efficiency advantage.

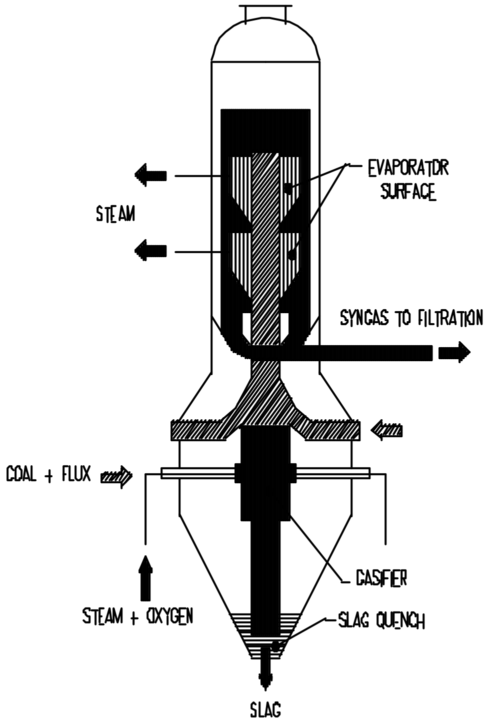


Figure 7
PRENFLO Gasifier

3.8 E-Gas Gasification (entrained flow)

This technology was originally developed by Dow Chemical in the 70s through pilot plant tests. In 1984 the decision was taken to build a commercial gasifier, processing 1600 t/d subbituminous coal, to produce syngas to be fired in an existing combined cycle together with natural gas, and generate 185 MW. This plant was built in the Dow Chemical Complex of Plaquemine (Louisiana) and operated successfully until the early 90s when the technology was chosen for a repowering IGCC project of

250 MW, at Wabash River (Indiana), processing 2000 t/d bituminous coal. The plant was started up in 1995.
The technology was originally under the name Destec, later changed to E-Gas when the technology was purchased by Global Energy.
Figure 8 provides a schematic description of the E-Gas gasifier. This gasifier is a pressure vessel internally lined with refractory, not cooled. Two gasification burners are located in the lower section of the gasifier with a further feed injection in the upper section of the gasifier. So this gasifier is classified as a two stage gasifier, a feature which improves the cold gas efficiency.
The feed is wet type; pulverized coal is slurried in water and pumped to the three injection points. Oxygen is fed only to the first stage, where partial oxidation takes place at temperatures close to 1400°C and 30 bar pressure. The ash in the coal melts and runs down the vessel and is removed through a tap hole into a water quench, from where it is discharged as a water slurry.
The hot raw gas, formed in the first stage, flows upward into the upper second stage, where the coal slurry is injected. This second stage feed undergoes pyrolysis and gasification, cooling the product gas from 1400°C to about 1050°C. Outside the gasifier the gas is cooled in a fire-tube syngas cooler, generating high pressure steam, and then washed in a water scrubber.
The Wabash River plant is operating successfully, testing a large variety of coal and petroleum coke.

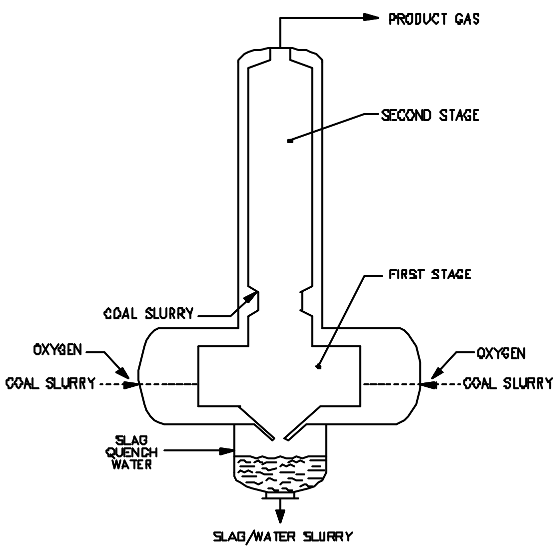


Figure 8
E-Gas Gasifier

3.9 Noell Gasification (entrained flow)

The Noell entrained flow gasification is a technology that was originally developed by Deutsches Brennstoffinstitut Freiberg in 1975 for the gasification of pulverized low grade brown coal, becoming known under the name "GSP (Gaskombinat Schwarze Pumpe) Process". Beginning in the nineties the technology has been developed, allowing to accept waste materials, residues, black liquor and sludges and to operate at different pressures. Presently the Noell technology belongs to Babcock Borsig Power.

This gasifier is a dry feed, pressurized downflow reactor. Two variants are available:

- Cooling Screen for high ash containing streams; the reactor chamber is enclosed by a cooling screen of water cooled tubes.
- Refractory lined reactor for non-ash or low ash containing stream combined with a cooling wall to cool the external shell.

The two variants, quench and WHB, are both available for the heat recovery downstream the reaction.

The first application of Noell gasification technology has been successfully operated in SVZ Schwarze Pumpe Plant, Lausitz (Germany), since 1994. The gasifier was initially fed with brown coal (600 t/day) and then with a mixture of 50% coal and 50% sludge, ash containining oils and waste plastics.
A second unit, presently entering the commercial operation, is installed at the BASF plant of Seal Sands (UK) and receives as gasification feedstock the nitrogen organic compounds generated by the Acrylonitrile synthesis.

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REVISION	DRAFT	01	02	03	04	05
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CONTRACT NO. :	1-17-12001	REV :	0
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AGRU TECHNICAL COMPARISON AND OPTIMISATION REPORT

Distribution

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CONTENTS

1.0 INTRODUCTION

The IEA Greenhouse Gas R&D Programme has retained Foster Wheeler to investigate gasification based power generation from coal with and without capture of the produced CO_2. The study primary aim is therefore to evaluate technologies that could be used to avoid emissions of greenhouse gas, particularly from the use of fossil fuels.

The study is based on the current state-of-the-art technology, evaluating costs and performances of plants which can be presently engineered and built. The study does however consider possible improvements to current technology and also potential future technologies in order to assess the likely performance of a plant in the year 2020.

The study plant is fed with coal and produces electric power to be delivered to the national grid. The nominal net power production capacity is 800 MWe.

This report details the technologies available for capture of the acid gas (AGRU : Acid Gas Recovery Unit). The study as a whole has considered Shell and Texaco based coal gasification technologies, and the impacts of pressure, shift stages and nature of the acid gas capture. This in turn leads to several cases which have been investigated, the case definitions of which are detailed in section 2. The basic schemes investigated are therefore:

- Base case plant : no CO_2 capture, AGRU captures H_2S only
- With CO_2 capture : separate production of H_2S and CO_2 rich streams
- With CO_2 capture : production of a combined H_2S / CO_2 stream

For alternatives which produce a separate H_2S stream, sulphur is recovered from the acid gas by a separate oxygen Claus Sulphur Removal Unit (SRU) so as to minimise sulphur emissions from the facility.

2.0 DESIGN BASIS

The following sections detail the design basis for the AGRU which has been used both in licensor enquiries and also for development of the open-art MDEA unit.

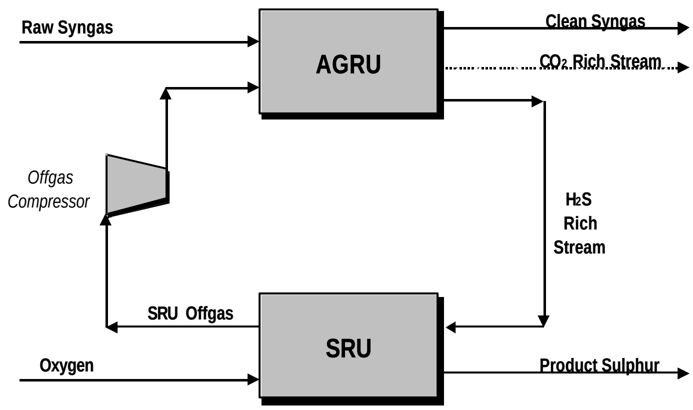
2.1 CASE DEFINITION

The following cases have been investigated:

Case	Gasification	Pressure	Shift	CO_2 Capture	Combined
A1	Shell	Low	no	no	no
C1	Texaco	High	no	no	no
B1	Shell	Low	Sour x2	yes	no
B2	Shell	Low	Clean x3	yes	no
B3	Shell	Low	Sour x2	yes	yes
D1	Texaco	High	Sour x1	yes	no
D2	Texaco	High	Sour x1	yes	yes
D3	Texaco	High	Sour x2	yes	no

2.2 FEEDSTOCK DEFINITION

The AGRU has been specified to also treat the offgas from the SRU to (alternatives without H_2S/CO_2 combined removal) minimise emissions from the complex:



As a result, there are two feedstocks to the AGRU as detailed below:

2.2.1 Raw Syngas

		Case A1	Case C1	Case B1	Case B2	Case B3	Case D1	Case D2	Case D3
H_2	mol.%	31.81	38.75	56.41	31.85	56.41	55.04	55.04	55.85
N_2	mol.%	4.92	0.93	3.09	4.83	3.09	0.68	0.68	0.67
CO	mol.%	60.43	40.07	2.51	60.48	2.51	2.84	2.84	0.99
Ar	mol.%	0.75	1.07	0.48	0.75	0.48	0.79	0.79	0.78
CH_4	mol.%	0.00	0.02	0.00	0.00	0.00	0.02	0.02	0.02
CO_2	mol.%	1.52	18.65	37.02	1.52	37.02	40.22	40.22	41.29
H_2S	mol.%	0.28	0.31	0.18	0.28	0.18	0.22	0.22	0.22
H_2O	mol.%	0.29	0.20	0.31	0.29	0.31	0.19	0.19	0.19
COS	vppm	11	4	1	0	1	1	1	1
HCN	vppm	5	5	5	5	5	5	5	5
NH_3	vppm	49	10	45	49	45	10	10	10
Mol Wt		20.06	21.05	19.31	20.06	19.31	20.22	20.22	20.18
Flowrate	kmol/h	22750	26437	36998	23507	36998	37276	37276	38153
Pressure	barg	29.5	54.0	26.0	29.5	26.0	56.2	56.2	55.6
Temp	°C	38	38	38	38	38	38	38	38

2.2.2 Recycle Gas From SRU

		Case A1	Case C1	Case B1	Case B2	Case D1	Case D3
H_2	kmol/h	13.8	17.7	13.6	14.2	17.4	18.1
N_2	kmol/h	59.6	76.7	59.0	61.6	75.6	78.3
CO	kmol/h	1.5	1.2	0.1	1.6	0.2	0.1
Ar	kmol/h	0.6	0.8	0.6	0.7	0.8	0.9
CO_2	kmol/h	5.2 + XA1	73.4 + XC1	208.0 + XB1	5.3 + XB2	216.0 + XD1	226.0 + XD3
H_2S	kmol/h	2.4	3.1	2.4	2.5	3.1	3.2
H_2O	kmol/h	sat	sat	sat	sat	sat	sat
Flowrate	kmol/h	83.1 + XA1	172.9 + XC1	283.7 + XB1	85.9 + XB2	313.1 + XD1	326.5 + XD3
Pressure	barg	As required	As required	As required	As required	As required	As required
Temp	°C	38	38	38	38	38	38

Xi = quantity of CO_2 leaving the AGRU in the H_2S rich gas.

2.3 PRODUCT & PERFORMANCE SPECIFICATIONS

Product specifications are provided for the "clean" syngas and the recovered CO_2 and H_2S streams. In addition to these, there is also a recovery specification against CO_2 to ensure the overall facility target of 85% CO_2 capture is achieved. Case D3 requires a lower CO_2 washing-unit removal efficiency as the required facility target of CO_2 capture is 80%.

2.3.1 Clean Syngas

		Case A1	Case C1	Case B1	Case B2	Case B3	Case D1	Case D2	Case D3
H_2S+COS concentration	ppmv	< 40	< 40	< 40	<10	< 40	< 40	< 40	< 40
CO_2 Washing-unit removal efficiency	%	n/a	n/a	91	91	91	91	91	81
Solvent content	ppmv	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1

- Max pressure drop 0.5 bar (raw syngas inlet to clean syngas outlet) including entrance/exit losses for cases A1 and C1.
- Max pressure drop 1.0 bar (raw syngas inlet to clean syngas outlet) including entrance/exit losses for other cases.
- Carbon Dioxide slippage maximized for cases A1 and C1.
- Definition of CO_2 washing unit removal efficiency as follows:

$$\frac{CO_2 \text{ flow rate to B.L.}}{CO_2 \text{ flow rate in raw syngas to AGR}} \times 100$$

2.3.2 Acid Gas (H_2S Rich)

For this stream the Hydrogen Sulphide concentration is maximized such that the composition and operating conditions are suitable for downstream treatment in an Oxygen Claus Sulphur Recovery Unit. For purposes of design, this has been interpreted as a minimum target H_2S content of 15-20 mol%.

Note not all licensors agree with this interpretation and several cases are below 10 mol% H_2S.

2.3.3 Acid Gas (CO_2 Rich)

For cases where separate H_2S and CO_2 rich streams are produced, a specification of max 100ppm H_2S in CO_2 has been adopted. Its worth noting that this specification if fairly arbitrary, and has been adopted to ensure a "sensible" separation between the two acid gases.

For cases where a combined stream is produced there are no equivalent specifications.

No hydrogen slippage specification was imposed, and the results from several licensors have shown this to be a significant loss to the complex in terms of equivalent power production.

2.4 UTILITY CONDITIONS

The AGRU is a user of steam, electrical power, and cooling water.

For electrical power and steam, no limitations were put on designs in terms of quantities, but LP steam was specified at 3.5 barg.

2.5 TURNDOWN AND AVAILABILITY

Turndown required is specified at 50%. The availability of an AGRU is expected to be higher than the remainder of the IGCC facility, and so no special considerations are required in the design.

2.6 SITE AND PLOT DATA

No limitations were specified.

2.7 ENVIRONMENTAL STANDARDS

There are no direct emissions to the environment from an AGRU, o no environmental limits were specified. Sufficient tankage is specified for the total inventory of solvent.

2.8 CLIMATIC DATA

The following relevant data has been used in specification of the units:

2.8.1 Air

Relative Humidity:	average	60%
	maximum	95%
	minimum	40%
Temperature	minimum	-10°C
	maximum	30°C
	average	9°C

2.8.2 Cooling Water

Supply temperature:	maximum	17°C
	minimum	13°C
	max 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	60°C
Fouling Factor	0.0002 h °C m^2/kcal

3.0 PROCESS/SOLVENT SELECTION

For removal of acid components from gas streams several methods are possible:

- Cryogenic separation
- Membrane separation
- Solvent processes:
  - Physical absorption
  - Chemical absorption

The first two processes, cryogenic and membrane separation, have not found yet commercial operation. Solvent processes have dominated the market.

The choice between physical and chemical solvent has been the subject of several studies and evaluation of many projects in the chemical industry. As a general rule chemical solvents, such as Amine, Potassium Carbonate etc., are that suited when the acid gas partial pressure is low whereas physical solvents have generally a superior performance when the acid gas partial pressure is high.

Chemical solvents require more thermal energy for regeneration because the acid gas capture takes place through a foundation of a chemical bond between the acid gas and the solvent molecule. During regeneration, this chemical bond is broken with the use of thermal energy.

On the contrary, physical solvents require little or no thermal energy for regeneration because the Acid gas is physically de-solved in the solvent and can be recovered during regeneration by a reduction of the pressure, possibly with the final thermal step only to regenerate more deeply the solvent.

In some of the IGCC process schemes considered in the study, it is interesting to exploit solvent selectivity properties in order to capture separately H_2S and CO_2. Chemical solvents selectivity is obtained by controlling the solvent acid gas contact time; with amine solvent a short time of contact permits to absorb preferentially H_2S instead of CO_2. With a physical solvent the selectivity is a physical characteristic of the solvent which entails a greater solubility of one acid gas versus the other.

4.0 LICENSOR INFORMATION

The process selection in the previous section suggested that the following two main process areas needed to be concentrated on:

- Physical solvents
- Hindered/activated amines

As a result numerous licensors were contacted to obtain the required information for the study. The responses and licensor designs are reported here.

4.1 LURGI (Rectisol)

Reference : www.lurgi-oel.de

4.1.1 General Information

The Rectisol process is a physical solvent based process which can be configured with high selectivity for target components. Cold (refrigerated) methanol is used as the solvent. The target components, such as CO_2, H_2S, COS, HCN, NH_3, organic sulfur compounds, iron carbonyls as well as hydrocarbons are physically absorbed from the raw gas by this solvent. These components are then desorbed by reducing the pressure of the solvent and reboiling it to liberate the removed components. The solubility of the different components in the methanol varies considerably thus allowing for the selective removal of these components. In addition, the solubility of CO_2 in the methanol is higher with respect to Selexol or Purisol, thus allowing to reduce the solvent flow rate and therefore reducing the power requirement.

As a consequence, the Rectisol process is highly flexible and can be adjusted to meet very specific requirements and plant conditions. Due to the high purity that can be achieved in a single process stage, the Rectisol process is particularly suited for the conditioning of synthesis gases. Other syngas applications include two stages, with the first stage is used for selective desulfurization and the second stage for the removal of CO_2 .

4.1.2 Typical Process Performance (information from public domain)

Typical purity of synthesis gas:

< 0.1 ppm (vol.) total sulfur
< 10 ppm (vol.) CO_2

Typical consumption for synthesis gas treated for a 2000 t/d methanol plant:

Electric power (not incl. cooling unit)	1,640 kW
LP steam	5.5 t/h
Cooling water (Delta T = 10 K)	133 m³/h
Cooling (refrigeration) @ -31°C)	4,200 kW

4.1.3 Study Specific Information

Lurgi declined to assist with the study due to workload commitments at the time.

4.2 BASF (aMDEA)

Reference : www.basf-de.com

4.2.1 General Information

The BASF aMDEA process is a conventional amine type system, but using a proprietary activated (hindered) amine which allows high selectivity to the target acid gas components. As a result the process is extremely flexible, especially when coupled with an AGE process (Acid Gas Enrichment) and has low regeneration utility requirements.

The process typically is configured as a conventional amine absorption system, with an absorber, HP/LP flash stages and regenerator/stripper with associated heat exchangers and reboilers. Depending on the process configuration selected, the performance of the solvent is such that it can be targeted to produce a H_2S rich stream from a raw syngas containing large amounts of CO_2, without the need for AGE. The process can also produce CO_2 and H_2S rich streams separately via use of 2-stage absorption.

4.2.2 Typical Process Performance (information from public domain)

No public domain typical performance data is available.

4.2.3 Study Specific Information

BASF declined to assist with the study due to workload commitments at the time.

4.3 UOP (AmineGuard / Selexol)

Note that UOP now offer the Dow processes as a result of the Dow merger. In most cases, a combined UOP/Dow response was received.

4.3.1 General Information

UOP provided for each case a set of information which allowed FW to fully evaluate the performance and investment costs of the AGRU and how this section meets the technical and economic targets of the entire IGCC plant. This information has been provided under a non-disclosure agreement between FW and UOP. As a consequence, this report includes only the data that UOP allows to be disclosed to IEA without a non-disclosure agreement between IEA and UOP. The workup of the data presented here is though based on a full set of data provided by UOP to FW.

Please note that data for these alternatives was provided by UOP at a early stage of the study before all options had been evaluated or for which data was available. As a result, in the evaluation of the overall IGCC performances in the main Study Report, some minor modifications were made to this data in order to match them with the required coal flow rate of each alternative.

As UOP provided a full set of study specific data, no comparison of public domain information was made.

Note that for most cases, UOP, who now offer the DOW MDEA process, carried out an internal assessment as to which process would be most applicable, so in a lot of cases, a full set of data for both Selexol (or AmineGuard) and DOW are not available.

4.3.2 Case A1

In this case the untreated syngas is at low pressure (29.5 barg), and the CO_2/H_2S ratio is only 5.5/1, since this is a Shell gasifier that produces minimal CO_2. UOP see this separation as relatively easy, and propose a UCARSOL MDEA-based chemical wash. Hence no further Selexol or AmineGuard information is available for this case.

4.3.3 Case C1

Process Description

This case is characterized by a high syngas pressure (54 barg) and a high CO_2/H_2S ratio (60/1). Selexol was offered by UOP for this case : a single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	49	
Cooling Water, m^3/h	1264	(Delta T 12 °C)
Purge Water, m^3/h	0.3	
Electric Power, kW	3107	
Solvent Make-up, m^3/yr	85	

Scheme Performance

	Untreated Gas	Recycle Gas SRU	Nitrogen	Treated Gas Exp.	Treated Gas GT	Acid Gas to SRU
kmol/h						
CO_2	4930.50	141.5	0.0	3882.9	1121.0	68.1
H_2S+COS	82.06	3.1	0.0	0.8	0.2	84.1
H_20	52.87	0.6	0.0	27.4	6.4	16.4
N_2	245.86	76.7	1200.0	244.2	1150.8	127.6
CO	10593.31	1.2	0.0	10435.8	158.7	0.0
H_2	10244.34	17.7	0.0	10149.2	112.8	0.0
Ar	282.88	0.8	0.0	278.9	4.7	0.0
Others	5.68	0.0	0.0	5.3	0.2	0.4
Total Flow, kmol/h	26437.5	241.6	1200.0	25024.5	2554.8	296.6
Total Flow, kg/h	556396	8594	33600	502257	86562	9744
Pressure, bar g	54.0	25.0	26.0	53.8	25.0	1.0
Temperature, °C	38.0	38.0	149.0	44.0	46.0	49.0

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 32 ppm, the second one of 78 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 use of Nitrogen 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.

4.3.4 Case B1

Process Description

For this case, the untreated gas is at low pressure (26 barg), but the CO_2/H_2S ratio is very high (206/1). UOP believes that again a selective amine has no chance of meeting the minimum H_2S concentration suitable for the SRU. Despite the lower pressure, the same two configurations proposed for case D1 (see section 4.3.7) have been evaluated, one enhancing the acid gas H_2S concentration by using part of Nitrogen produced by the ASU, the other one adopting a more complicated and electric power consuming process scheme. The result of case D1 investigation was not considered directly applicable to case B1, due to the shortage of Nitrogen deriving from its use for coal pneumatic transport, which marks the Shell cases with respect to Texaco cases. Both options are based on a two twin trains configuration equipped with a refrigeration package.

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment Costs and on the Operating Costs of the two options (see section 5). Based on these results, the option without Nitrogen use is finally selected, for which all the following data refers to for this case.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	82
Cooling Water, m^3/h	4242 (Delta T 12 °C)
Purge Water, m^3/h	1.0
Electric Power, kW	32630 (Refrigeration Package: 41%)
Solvent Make-up, m^3/yr	120

Scheme Performance

kmol/h	Untreated Gas	Recycle Gas SRU	Treated Gas GT	CO_2 to Compr.	Acid Gas
CO_2	6848.33	225.7	708.0	6244.9	121.1
H_2S+COS	33.32	1.2	0.04	0.6	33.9
H_20	57.35	0.7	3.1	17.6	10.8
N_2	571.62	29.5	596.9	4.2	0.0
CO	464.32	0.1	452.5	11.8	0.1
H_2	10435.29	6.8	10331.7	109.9	0.5
Ar	88.8	0.3	87.1	2.0	0.0
Others	0.92	0.0	0.0	0.0	0.9
Total Flow, kmol/h **Total Flow, kg/h**	18499.9 357181	264.3 10839	12179.3 84919	6391.0 275928	167.3 6696
Pressure, bar g	26.0	26.0	25.2	(1)	0.8
Temperature, °C	38.0	38.0	34.0	(1)	49.0

Note: CO_2 stream is the combination of three different streams delivered at Unit B.L. at different conditions.

The proposed process reaches an H_2S+COS concentration of the treated gas exiting the Unit of 3 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. 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 more than 22 % dry basis, suitable to feed the oxygen blown Claus process.

Together with CO_2, the following quantities of other components are sent to the final CO_2 destination, after compression:

- 220 kmol/h of Hydrogen, corresponding to 1.7% vol and to an overall thermal power of 14.8 MWt, i.e more than 5 MWe.
- a very low quantity of H_2S, corresponding to a concentration of 90 ppm.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

4.3.5 Case B2

The untreated gas is at low pressure (29 barg), and the CO_2/H_2S ratio is low (5.5/1). The inlet raw syngas flows from the COS Hydrolysis section for the removal of H_2S to avoid poisoning the downstream shift catalyst. After the removal of the H_2S, the clean gas is shifted and finally fed again to the AGR Unit for the removal of the CO_2.

For this alternative, UOP/DOW believe that the separate removal of H_2S from raw syngas and CO_2 from shifted syngas can be obtained by a UCARSOL MDEA based chemical wash. Hence no further Selexol or AmineGuard information is available for this case.

4.3.6 Case B3

Process Description

For this case, the untreated gas is at low pressure (26 barg) and the CO_2/H_2S partial pressure is high. As UOP see this separation relatively easy, only an Amine Guard chemical wash has been proposed.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	148	
Cooling Water, m^3/h	5265	(Delta T 12 °C)
Purge Water, m^3/h	0.3	
Electric Power, kW	12560	
Solvent Make-up, m^3/yr	60	

Scheme Performance

	Untreated Gas	Treated Gas to GTs	CO_2/H_2S to Compr.
Kmol/h			
CO_2	4565.55	385.2	4180.4
H_2S + COS	22.21	0.02	22.2
H_20	38.23	51.8	297.3
N_2	381.08	380.0	1.1
CO	309.55	308.3	1.2
H_2	6956.86	6924.2	32.7
Ar	59.20	59.0	0.2
Others	0.61	0.61	0.0
Total Flow, kmol/h	12333.3	8109.1	4535.1
Total Flow, kg/h	238156	53484	190227
Pressure, bar g	26.0	25.7	0.8
Temperature, °C	38.0	43.0	49.0

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 3 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.

The CO_2 removal rate is 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 steam consumption.

Together with CO_2/H_2S exiting the Unit, the following quantities of hydrogen are sent to the final destination, after compression:

- 98 kmol/h, corresponding to 0.7% vol and to an overall thermal power of 6.6 MWt, i.e. more than 2 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

4.3.7 <u>Case D1</u>

Process Description

For this case UOP believes that, due to the high syngas pressure (56 barg), and the extremely high CO_2/H_2S ratio (183/1), only an optimised Selexol Process is able to achieve an acceptable Claus Plant acid gas. With this high ratio, even a double amine configuration (AGR plus Acid Gas Enrichment (AGE)) cannot meet the minimum H_2S concentration of Acid Gas (15-20% vol). In addition, the high steam requirement of the amine process would entail a drastic reduction of the Steam Turbine power production. The same two configurations proposed for case B1 (see section 4.3.4) have been evaluated, both based on a single train configuration equipped with a refrigeration package, one enhancing the acid gas H_2S concentration by using part of Nitrogen produced by the ASU, the other one adopting a more complicated and electric power consuming process scheme.

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment Costs and on the Operating Costs of the two options (see section 5). Based on these results, the option with Nitrogen use is the best alternative to reduce both the investments and operating costs. However, it was later known that high N_2 concentration in the product CO_2 stream has a negative impact for CO_2 storage, particularly if CO_2 is used for enhanced oil recovery. Therefore Option 2, without Nitrogen stripping, was finally selected.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	70.3	
Cooling Water, m^3/h	2966	(Delta T 12 °C)
Purge Water, m^3/h	0.3	
Electric Power, kW	32100	(refrigeration Package: 32%)
Solvent Make-up, m^3/yr	120	

Scheme Performance

	Untreated Gas	Treated Gas Exp.	CO_2 to Compr.	Recycle GAS SRU	Acid Gas
kmol/h					
CO_2	14992.41	1512.24	13695.26	569.36	354.26
H_2S+COS	82.05	0.1	1.3	3.1	83.78
H_2O	70.82	3.71	43.02	1.57	30.63
N_2	253.48	251.37	77.69	75.6	0.01
CO	1058.64	1035.09	23.56	0.2	0.2
H_2	20516.71	20277.89	254.46	17.4	1.76
Ar	294.48	288.31	6.92	0.8	0.05
Others	8.02	7.17	0.29	0	0.54
Total Flow, kmol/h	37276.61	23375.88	14102.5	668.03	471.23
Total Flow, kg/h	753892	155167	607182	27381.81	19020.75
Pressure, bar g	57.2	56.2	(1)	28.3	1.8
Temperature, °C	38	35.7	(1)	38	48.9

Note: CO_2 stream is the combination of three different streams delivered at Unit B.L. at different conditions.

The proposed process reaches an H_2S+COS concentration of the treated gas exiting the Unit of 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 refrigeration package. 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 the 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, the following quantities of other components are sent to the final CO_2 destination, after compression:

- 254.5 kmol/h of Hydrogen, corresponding to 1.8% vol and to an overall thermal power of 17.2 MWt, i.e. more than 5.6 MWe.
- a very low quantity of H_2S, corresponding to a concentration of 92 ppmdv.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and other components at super-critical

CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

4.3.8 Case D2

Process Description

For this case UOP believes that, due to the high syngas pressure (56 barg), and the extremely high CO_2/H_2S partial pressure, the Selexol Process is best choice to achieve the required removal of H_2S and CO_2. UOP proposed only an alternative that uses part of the Nitrogen produced by the ASU to enhance the stripping of the rich solvent.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	65	
Cooling Water, m^3/h	5330	(Delta T 12 °C)
Purge Water, m^3/h	0.4	
Electric Power, kW	31220	(Refrigeration Package: 54%)
Solvent Make-up, m^3/yr	120	

Scheme Performance

	Untreated Gas	Nitrogen	Treated Gas to GTs	CO_2/H_2S to Compr.
kmol/h				
CO_2	7496.20	0.0	616.3	6880.0
H_2S+COS	41.02	0.0	0.08	40.9
H_20	35.41	0.0	1.0	21.7
N_2	126.74	1500.0	125.9	1500.8
CO	529.32	0.0	515.1	14.2
H_2	10258.36	0.0	10140.3	118.1
Ar	147.24	0.0	143.6	3.6
Others	3.93	0.0	3.5	0.4
Total Flow, kmol/h	18638.3	1500.0	11545.8	8579.7
Total Flow, kg/h	376946	42020	71332	347410
Pressure, bar g	56.0	30.0	55.0	(1)
Temperature, °C	38.0	149.0	36.0	(1)

Note: CO_2 stream is the combination of two different streams delivered at Unit B.L. at different conditions.

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 7 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 refrigeration package.

The CO_2 removal rate is 91% as required, allowing to reach an overall CO_2 capture of 85% with respect to the carbon entering the IGCC.

In any case, this alternative requires a higher steam and electrical consumption with respect to the corresponding Case D1, thus making the alternative of combined removal of H_2S and CO_2 less efficient than the separate removal. This is against what can be conceptually expected. So a further optimisation was discussed with UOP. UOP agreed with FW that a process flow scheme derived from Case D1 may be proposed which eliminates some equipment not yet necessary as acid gas is not sent to the Sulphur Recovery Unit and tail gas is not recycled back. Performance data for this modified scheme have been evaluated by FW based on the corresponding data provided by UOP for Case D1. The use of Nitrogen as stripping medium was avoided also for this alternative, thus improving the effect of the CO_2 stream in case it is used for enhanced oil recovery.

4.3.9 Case D3

Process Description

For this case, due to the high syngas pressure (55.6 barg), and the extremely high CO_2/H_2S ratio (188/1), UOP believes that only an optimised Selexol Process is able to achieve an acceptable Claus Plant acid gas, using nitrogen as before. Two configurations, both based on a single train have been evaluated, one increasing the inlet pressure to the downstream CO_2 compression Unit, thus reducing its power consumption, the other one decreasing the solvent flow rate, thus reducing the power consumption of the AGR.

A technical/economical evaluation was performed to select the most suitable option, taking into account the different impacts on the Investment Costs and on the Operating Costs of the two options (see section 5). Based on these results, the option with the lower solvent flowrate is finally selected, for which all the following data refers to for this case.

Equipment Sizes

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

Utility Consumptions

LP Steam, t/h	73.2	
Cooling Water, m^3/h	3571	(Delta T 12 °C)
Purge Water, m^3/h	0.3	
Electric Power, kW	25652	(Refrigeration Package: 44%)
Solvent Make-up, m^3/yr	122	

Scheme Performance

	Untreated Gas	Recycle Gas SRU	Nitrogen	Treated Gas Exp.	CO_2 to Compr.	Acid Gas
kmol/h						
CO_2	15753.4	302.7	0.0	3332.8	12646.6	76.8
H_2S+COS	84.0	3.2	0.0	0.1	1.3	85.8
H_20	72.5	0.6	0.0	4.9	33.6	19.5
N_2	255.6	78.3	1500.0	253.5	1462.8	117.7
CO	377.7	0.1	0.0	369.6	8.2	0.0
H_2	21308.5	18.1	0.0	21065.0	261.5	0.0
Ar	297.6	0.9	0.0	291.6	6.9	0.0
Others	8.2	0.0	0.0	7.4	0.3	0.5
Total Flow, kmol/h **Total Flow, kg/h**	38157.43 770189	404.9 15718	1500.0 42020	25324.8 218452	14421.3 599244	300.3 9962
Pressure, bar g	55.6	28.0	30.0	54.6	(1)	0.8
Temperature, °C	38.0	38.0	149.0	41.0	(1)	49

Note: CO_2 stream is the combination of three different streams delivered at Unit B.L. at different conditions.

Case D3, with the lower capture specification is most closely compared with case D1 which has a similar process configuration for the IGCC complex. The CO_2 content in the feed is higher because two shift converters for case D3 were selected. If a single shift converter was considered, the required CO_2 removal rate is 87% vs 91% of case D1. UOP believe that this small difference would not seriously affect the AGRU performances. As a consequence, the adoption of two shift stages was needed to increase the CO_2 content in the feed, thus reducing the required CO_2 capture rate.

The proposed process reaches an H_2S+COS concentration of the treated gas exiting the Unit of 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 refrigeration package. The CO_2 removal rate is more than 80% as required, allowing to reach an overall CO_2 capture of 80% with respect to the carbon entering the IGCC.

These excellent performances on both the H_2S removal and the CO_2 capture are achieved with a large power consumption, only marginally lower than consumption of Case D1 (reduction of power consumption = 7.4%). The steam consumption of the two cases is very similar. UOP stated that the reason is due to the fact that the thermal regeneration section is more sensitive to the H_2S removal, while the CO_2 capture rate mainly affects the design of the flash section of the unit.

The acid gas H_2S concentration is 31% dry basis, more than suitable to feed the oxygen blown Claus process.

Together with CO_2, the following quantities of other components are sent to the final CO_2 destination, after compression:

- almost 100% of Nitrogen used to enhance the acid gas H_2S concentration
- 261.5 kmol/h of Hydrogen, corresponding to 1.8% vol and to an overall thermal power of 17.5 MWt, i.e. more than 6 MWe.

- a very low quantity of H_2S, corresponding to a concentration of 90 ppmdv.

The feasibility to separate and recover H_2 and N_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and other components at super-critical CO_2 conditions, this separation is unfeasible, thus constituting a disadvantage of the process.

However, it was later known that high N_2 concentration in the product CO_2 stream has a negative impact for CO_2 storage, particularly if CO_2 is used for enhanced oil recovery. Therefore, it was decided to use a flow scheme derived from case D1, without Nitrogen stripping.

4.4 DOW (Ucarsol)

Please see section 4.5 for information on the GAS/SPEC processes previously offered by Dow. The following information relates to Ucarsol, which is still offered by Dow.

Note that for most cases, UOP, who now offer the DOW UCARSOL MDEA-based chemical wash, carried out an internal assessment as to which process would be most applicable, so in a lot of cases, a full set of data for both Selexol (or AmineGuard) and DOW are not available.

4.4.1 Case A1

Process Description

In this case the untreated syngas is at low pressure (29.5 barg), and the CO_2/H_2S ratio is only 5.5/1, since this is a Shell gasifier that produces minimal CO_2. This separation as relatively easy, and a UCARSOL MDEA-BASED chemical wash can easily achieve the requirements. A single-stage absorption is suitable to accomplish all objectives, i.e. no acid gas enrichment is required. Therefore the tail gas coming from the Sulphur Recovery Unit is mixed with the raw syngas before entering the AGR section.

Equipment Sizes

Due to reasons of secrecy, Dow/UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with Dow/UOP.

Utility Consumptions

LP Steam, t/h	17	
Cooling Water, m^3/h	2620	(Delta T 12 °C)
Purge Water, m^3/h	0.3	
Electric Power, kW	250	
Solvent Make-up, m^3/yr	60	

Scheme Performance

	Untreated Gas	Recycle Gas SRU	Treated Gas to GTs	Acid Gas to SRU
kmol/h				
CO_2	345.8	73.1	351.0	67.9
H_2S+COS	63.9	2.4	0.5	65.8
H_2O	65.9	0.1	63.5	10.9
N_2	1119.3	59.6	1178.8	0.1
CO	13747.8	1.5	13747.7	1.6
H_2	7236.7	13.8	7249.7	0.8
Ar	170.6	0.6	171.1	0.1
Others	1.2	0.0	1.1	0.1
Total Flow, kmol/h	22751.2	151.1	22763.4	147.3
Total Flow, kg/h	456133	5062	455872	5473
Pressure, bar g	29.5	29.5	29.4	1.7
Temperature, °C	38.0	38.0	41.0	49.0

The proposed process matches the process specifications with reference to H_2S+COS concentration of the treated gas exiting the Unit and fed to the Combined Cycle Unit. The treated gas feeding the gas turbines has an H_2S+COS concentration of 22 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.

The acid gas H_2S concentration is 49% dry basis, more than suitable to feed the oxygen blown Claus process.

4.4.2 Case B2

Process Description

The untreated gas is at low pressure (29 barg), and the CO_2/H_2S ratio is low (5.5/1). The inlet raw syngas flows from the COS Hydrolysis section for the removal of H_2S to avoid poisoning the downstream shift catalyst. After the removal of the H_2S, the clean gas is shifted and finally fed again to the AGR Unit for the removal of the CO_2. For this alternative, UOP/DOW believe that the separate removal of H_2S from raw syngas and CO_2 from shifted syngas can be obtained by a UCARSOL MDEA-based chemical wash.

The H_2S removal can be accomplished in single-stage absorption process, i.e. no acid gas enrichment is required. Therefore the tail gas coming from the Sulphur Recovery Unit is mixed with the raw syngas before entering the AGR section. The CO_2 is also accomplished in a single stage absorption process, similar to the H_2S removal.

Equipment Sizes

Due to reasons of secrecy, Dow/UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with Dow/UOP.

Utility Consumptions

LP Steam, t/h	815.3
Cooling Water, m^3/h	133,200 (Delta T 12 °C)
Purge Water, m^3/h	2.0
Electric Power, kW	500
Solvent Make-up, m^3/yr	120

Scheme Performance

	Untreat. Gas	Recycle Gas	Acid Gas to SRU	Gas to Shift	Shifted Gas	CO_2 to Compr	Treated Gas GT
kmol/h							
CO_2	353.43	185.7	180.4	358.7	12996.7	12996.6	0.1
H_2S+COS	64.49	2.5	65.4	1.6	1.6	1.5	0.1
H_2O	66.52	0.1	18.0	48.6	115.5	1064.7	89.8
N_2	1128.42	61.6	0.0	1190.6	1190.0	232.3	957.7
CO	14051.51	1.6	0.3	14052.8	1414.8	2.7	1412.1
H_2	7398.22	14.2	0.2	7412.3	20050.3	59.4	19990.9
Ar	174.37	0.7	0.0	175.1	175.1	0.0	175.1
Others	0.04	0.0	0.0	0.04	0.04	0.0	0.04
Total, kmol/h	23238.8	266.4	264.3	23239.1	35944.0	14357.4	22625.6
Total, kg/h	465751	10084	10496	465339	694028	597772	114957
Press., barg	29.5	29.5	1.7	28.8	26.0	1.5	25.5
Temp.,°C	38.0	38.0	49.0	38.0	38.0	49.0	38.0

The proposed process reaches an H_2S+COS concentration of the treated gas exiting the Unit of 4 ppm. The CO_2 removal rate is virtually 100% with reference to flow rate feeding the CO_2 removal section, thus allowing to reach an overall CO_2 capture of 85% with respect to the carbon entering the IGCC.

The acid gas H_2S concentration is more than 26 % dry basis, suitable to feed the oxygen blown Claus process.

However, these excellent performances on both the H_2S removal and CO_2 capture are achieved with a very large steam consumption. In fact, the very high steam requirement, 815.3 t/h, makes this alternative unfeasible as most of steam generated by the Power Island should be used with a consequent the Steam Turbine power production drastically reduced.

Because of the above consideration, a different process alternative has been built by FW based on information provided by UOP/DOW for another alternative of the study, i.e. for Case B1. The process scheme selected for this alternative corresponds to Case B1 process configuration, one Selexol train, where downstream of the H_2S absorber, syngas is fed to the clean shift reaction section and furtherly to the CO_2 absorbers. Only the H_2S absorber operating pressure and consequently the pressure of the associated equipment are different in this modified case with respect to Case B1.

4.5 INEOS (GAS/SPEC)

References : www.ineos.com
www.gasspec.com
www.dow.com/alkanolamines/

4.5.1 General Information

As a result of the merger between Dow Chemical Company and the Union Carbide Corporation (who own UOP), the US Federal Trade Commission and European Commission ruled that certain aspects of the Dow Chemical Company's assets must be divested as a condition of the merger (ref http://www.dow.com/dow_news/corporate/2001/20010205a.html).

As a result, INEOS plc purchased both Dow's Ethanolamines and GAS/SPEC MDEA based speciality amines business as of 12 February 2001. INEOS also acquired the GAS/SPEC technology group and the key personnel. All GAS/SPEC products, technology and know-how is the exclusive property of INEOS on a global basis.

Dow still retain the Ucarsol process which is marketed under the Speciality Alkanolamines brand. The Dow gas treating website now lists all UOP and retained Dow technologies.

4.5.2 Study Specific Information

At the present time INEOS are happy to offer the full range of GAS/SPEC solvents for purchase:

- CS-1, CS-3, CS-2000, CS-Plus : general gas cleanup and bulk CO_2 removal
- SS, SS-3, SRS : sulphur removal and acid gas enrichment
- TG-10 : tail gas treating

They also offer design assistance for revamp of existing units or other technology units for use with GAS/SPEC solvents. However INEOS are still looking for a "strategic partner" to offer GAS/SPEC unit designs using the solvent technology.

4.6 MHI (Mitsubishi Heavy Industries)

Reference : www.mhi.co.jp/machine/recov_co2/

Mitsubishi Heavy Industries supplies large scale energy-efficient flue gas CO_2 recovery plant. The technology was jointly developed by MHI and the Kansai Electric Power Co. (KEPCO) and is targeted at CO_2 recovery from power station flue gases. In this regard therefore it is not suited for in-process CO_2 capture from syngas.

The process is amine-based, with a proprietary amine mixture which is resistant to the impurities found in power station flue gases. It has a low pressure-drop absorber design, which is designed to vent directly to atmosphere in flue-gas treatment applications. The flowscheme is similar to a conventional amine system, with an absorber-regenerator configured scheme with associated heat exchangers.

The process has attractions for the IGCC scheme under consideration due to the very large single-train sizes that can be achieved with the MHI process, which could have cost benefits over more conventional CO_2 capture schemes which would use multiple trains. However, MHI have no direct experience in applying their technology to syngas cleanup and doubt whether the process could compete with alternative technologies (the main attraction of their process is the robustness of the solvent to impurities in flue gases which are absent here).

4.7 GTC

At the time of the report, a response is still awaited from GTC.

GTC have an amine based technology which is designed for CO_2 recovery from flue gases. Their process has a special design of contacter/absorber which has a very low pressure drop, which is ideally suited to flue gas applications. It is unknown whether their technology is applicable cost-effectively for acid gas capture from syngas, where a high impurity resistant solvent is not required.

4.8 SHELL (Sulfinol)

Shell have agreed to provide the required information for Sulfinol for the study, but this information will not be available until the middle of September due to current workload commitments.

As a result, a final report addendum will be issued once the information has been received and screened.

Rev01 addendum : Shell ultimately declined to offer assistance due to current workload commitments.

5.0 RESULTS COMPARISON

5.1 SCHEME PERFORMANCE

Due to differences in interpretations of the specifications by the licensors, and different abilities of the processes, each of the schemes has different performances in terms of acid gas compositions and syngas compositions when compared. The following tables show these differences for the process scheme selected for each alternative of the project.

5.1.1 Clean Syngas

H_2S + COS concentrations (specification < 40ppmv) :

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case A1	-	-	22.0
Case C1	36.3	-	19.9
Case B1	3.3	-	-
Case B2	-	-	4.4
Case B3	-	2.5	-
Case D1	4.3	-	-
Case D2	6.9	-	-
Case D3	3.9	-	-

CO_2 removal (mol%) (specification 91%):

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case B1	91.2	-	-
Case B2	-	-	99.9
Case B3	-	91.6	-
Case D1	91.3	-	-
Case D2	91.7	-	-
Case D3	80.3$^{(1)}$	-	-

Note (1): CO_2 removal specification = 81%

5.1.2 Acid Gas (H_2S Rich)

H_2S concentration (cases without combined removal: target specification 15-20 mol%):

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case A1	-	-	48.2
Case C1	30.0	-	22.4
Case B1	21.7	-	-
Case B2	-	-	26.6
Case D1	19.0	-	-
Case D3	30.6	-	-

5.1.3 Acid Gas (CO_2 Rich or Combined Cases)

H_2S concentration (cases with CO shift: specification 100ppm max for non-combined cases):

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case B1	94.1	-	-
Case B2	-	-	112.8
Case B3	-	5238	-
Case D1	92.2	-	-
Case D2	4767	-	-
Case D3	90.4	-	-

5.2 EQUIPMENT SIZES

Due to reasons of secrecy, UOP has issued FW with a full equipment list for each case for the purposes of costing, but this information cannot be released any further without the third parties signing a secrecy agreement with UOP.

For this reason a full comparison of the equipment cannot be made for each case and so no analysis is presented here.

Capital costs are compared within section 5.4 which reflect the equipment intensity and service for each case.

5.3 UTILITY CONSUMPTIONS

The following tables summarise the utility consumptions (all trains) for the various technologies for each case as appropriate:

5.3.1 Steam

All flows in tph

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case A1	-	-	17.0
Case C1	49.0	-	73.8
Case B1	82.0	-	-
Case B2	-	-	815.3
Case B3	-	148.0	-
Case D1	70.3	-	-
Case D2	65.0	-	-
Case D3	73.2	-	-

5.3.2 Power

All consumptions in kW.

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case A1	-	-	250
Case C1	3107	-	1107
Case B1	32630	-	-
Case B2	-	-	500
Case B3	-	12560	-
Case D1	32100	-	-
Case D2	31220	-	-
Case D3	25652	-	-

5.3.3 Cooling Water

All flows in m^3/hr (12^{o}C temperature rise).

	UOP (Selexol)	**UOP** (AmineGuard)	**Dow** (Ucarsol)
Case A1	-	-	2620
Case C1	1264	-	air cooled
Case B1	4242	-	-
Case B2	-	-	133,200
Case B3	-	5265	-
Case D1	2966	-	-
Case D2	5330	-	-
Case D3	3571	-	-

5.4 CAPITAL COSTS

The following are the cost comparisons for each case, which compare UOP Selexol, UOP AmineGuard and Dow schemes, with sub-options, for the basis of selection.

Note that this section does not compare costs between cases, only for options within each individual case. Please refer to the main study report for costing information between cases.

5.4.1 Case A1

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.4.2 Case C1

Comparison of UOP Selexol vs Dow UCARSOL MDEA-based chemical wash.

- **Option 1 - Selexol**: a single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit.
- **Option 2 - UCARSOL MDEA-based**: an Acid Gas Removal system (two twin parallel trains) followed by an Acid Gas Enrichment section (one train).

CAPEX	**Option 1 Selexol**	**Option 2 UCARSOL MDEA-based**
AGR Investment Cost	+6.3 MM€	Base
SRU Investment Cost	Base (30% H_2S conc.)	+6.3 MM€ (21% H_2S conc.)
ASU Investment Cost	+2.6 MM€ high purity/high press. N_2	Base
TOTAL, MM €	+8.9	+6.3

The CAPEX comparison is in favour of Option 2 – UCARSOL MDEA-based (2.6 MM € saving).

5.4.3 Case B1

Comparison of nitrogen stripping vs alternate without nitrogen, for Selexol.

CAPEX	**Option 1 Use of N_2**	**Option 2 No use of N_2**
AGR Investment Cost	base	+1.5 MM€ (due to more equipment)
SRU Investment Cost	base (23% H_2S conc.)	+1.3 MM€ (20% H_2S conc.)
ASU Investment Cost	+2.9 MM€ high purity/high press. N_2	base
TOTAL, MM €	+2.9	+2.8

The CAPEX comparison is in favour of no use of Nitrogen (0.1 MM € saving)

5.4.4 Case B2

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.4.5 Case B3

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.4.6 Case D1

Comparison of nitrogen stripping vs alternate without nitrogen, for Selexol.

CAPEX	**Option 1 With Nitrogen**	**Option 2 No Nitrogen**
AGR Investment Cost	Base	+1.0 MM€
SRU Investment Cost	Base (30% H_2S conc.)	+6.5 MM€ (19% H_2S conc.)
ASU Investment Cost	+3.0 MM€ high purity/high press. N_2	Base
TOTAL, MM €	+2.0	+7.5

The CAPEX comparison is in favour of use of Nitrogen (5.5 MM € saving)

5.4.7 Case D2

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.4.8 Case D3

Comparison of high pressure vs lower solvent rates, for Selexol.

CAPEX	**Option 1 High Pressure**	**Option 2 Low solvent**
AGR Investment Cost	+1.0 MM€	base
TOTAL, MM €	+1.0 MM€	0

The CAPEX comparison is in favour of use of Option 2 (1.0 MM € saving).

5.5 OPERATING COSTS & OPTION SELECTION

See comments in section 5.4

The operating costs have been evaluated on the following basis:
- Hours of operation: 7446 h/year.
- Years of operation: 6 years.
- Power cost: 0.03 €/kWh

5.5.1 Case A1

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.5.2 Case C1

Comparison of UOP Selexol vs Dow UCARSOL MDEA-based chemical wash.

- **Option 1 - Selexol**: a single train configuration that enhances the H_2S concentration by using part of Nitrogen produced by the Air Separation Unit.
- **Option 2 - UCARSOL MDEA-based**: an Acid Gas Removal system (two twin parallel trains) followed by an Acid Gas Enrichment section (one train).

The OPEX difference is mainly due to the different power consumption of the Process Units like AGR, ASU, SRU and to the reduction of ST power production because of the different steam consumption of the AGR section. Use of nitrogen for the UOP alternative has no effect on Gas Turbine power production because most of the nitrogen used for H_2S concentration is recovered and recycled back to the Gas Turbine. In fact it is part of the syngas out-coming from the AGR system.

OPEX	**Option 1 Selexol**	**Option 2 UCARSOL MDEA-based**
ASU N_2 compression	710 kW	Base
AGR Power Consumption	2000 kW	Base
Tail Gas Recycle compression	550 kW	Base
ST Power Decrease	base	12200 KW
TOTAL	3260 kW	12200 KW

- The difference of the IGCC net power production is very high (8940 kW) in favour of Option 1 – Selexol.

The net additional operating cost of Option 2 – UCARSOL MDEA-based is as follows:

- Net additional cost for power consumption: 12.0 MM €

A saving of 0.3 MM Euro per year is estimated for solvent make-up for Amine case, resulting in 1.8 MM € over 6 years. Finally the Opex difference is 10.2 MM € in favor of Selexol alternative.

The above additional cost clearly compensates the difference of the Capex (see Section 5.4.2).

Option 1 – Selexol is finally selected (- 7.6 MM Euro).

5.5.3 Case B1

Comparison of nitrogen stripping vs alternate without nitrogen, for Selexol.

The OPEX difference may be only guessed due to the effects of dilution Nitrogen flow rate on Gas Turbine and Steam Turbine power production: decrease of Nitrogen available for syngas dilution must be compensated by Nitrogen saturation with water in order to meet the same NOx emission. This results in an increase of GT power production, as approx a double quantity of moisture with respect to Nitrogen is expanded through the gas turbine, and in a reduction of ST power production due to the decrease of LP steam admitted to the machine.

OPEX	**Option 1** Use of N_2	**Option 2** No use of N_2
ASU N_2 compression	1650 kW	base
GT Power Increase	- 5700 kW	base
ST Power Decrease	20000 kW	base
AGR Power Consumption	base	5100 kW
Tail Gas Recycle compr.	base	300 kW
N_2 in CO_2 stream compr.	5000 kW	base
TOTAL	20950 kW	5400 kW

The difference of the IGCC net power production is very high (15550 kW) in favour of no use of N_2, with an impressive difference in the economical revenues. Even if these impacts are overestimated, the final selection should be in favour of no use of Nitrogen.

The option without Nitrogen use is finally selected.

5.5.4 Case B2

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.5.5 Case B3

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.5.6 Case D1

Comparison of nitrogen stripping vs alternate without nitrogen, for Selexol.

OPEX	**Option 1** Use of N_2	**Option 2** No use of N_2
ASU N_2 compression	840 kW	base
GT Power Reduction	2100 kW (due to less N_2 to GT)	base
AGR Power Consumption	base	4400 kW
Tail Gas Recycle compr.	base	1200 kW
N_2 in CO_2 stream compr.	2500 kW	base
TOTAL	5540 kW	5600 kW

The difference of the IGCC net power production is only marginal (160 kW), but again in favour of use of N_2 (see Section 5.4.6).

Therefore the option with Nitrogen use is finally selected.

5.5.7 Case D2

Only a single licensor case is available for this option so no comparison economics between options was developed for this case.

5.5.8 Case D3

Comparison of high pressure vs lower solvent rates, for Selexol.

OPEX	**Option 1** High Pressure	**Option 2** Low solvent
AGR Power Consumption	2760 kW	base
ST Power Decrease	base	+80 kW
CO_2 Compression Power Consump.	base	+600 kW
TOTAL	2760 kW	+680 kW

The difference of the IGCC net power production is 2080 kW, again in favour of Option 2 (see Section 5.4.8). Therefore the Option 2 with a lower solvent flow rate is finally selected.

7.0 CONCLUSIONS

The following technology options have been selected based on overall economic performance (capital cost, operating cost and cost impacts on overall IGCC scheme in terms of utility consumption and impact on power generated) and process constraints:

- Case A1 UOP/Dow UCARSOL MDEA-based chemical wash, single train, single stage without AGE;
- Case C1 UOP/Dow Selexol, single train with nitrogen;
- Case B1 UOP/Dow Selexol, 2 trains without nitrogen;
- Case B2 UOP/Dow Selexol, 2 trains without nitrogen;
- Case B3 UOP Amineguard, three trains;
- Case D1 UOP/Dow Selexol, single train without nitrogen;
- Case D2 UOP/Dow Selexol, 2 trains without nitrogen;
- Case D3 UOP/Dow Selexol, single train without nitrogen.

APPPENDIX A1 – AGRU Licensor Enquiry

Attached is the enquiry document sent to all licensors for the AGRU review. Note at all time, licensors worked off identical and consistent information.

Note that the following correspondence reflects the definition of the IGCC complex cases used at early stage of the project, when the enquiry document was issued:

IGCC Facility Case	AGRU Review Case
A1	1b
C1	1a
B1	2c
B2	2d
B3	2f
D1	2a
D2	2e
D3	2b

CLIENT: IEA GREENHOUSE R&D PROGRAMME
PROJECT NAME: GASIFICATION POWER GENERATION STUDY
CONTRACT NO.: 1-BD-0119A
UNIT NO.:
UNIT NAME: ACID GAS REMOVAL / CO_2 CAPTURE FUNCTIONAL SPECIFICATION

ISSUED BY: S. TERENZONI
CHECKED BY: S. ANDREOLA
APPROVED BY: R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by
April 2002	First issue	S. Terenzoni	S. Andreola	R. Domenichini
May 2002	11,13	S. Terenzoni	S. Andreola	R. Domenichini

INDEX

INTRODUCTION

IEA Greenhouse Gas R&D Programme (IEA GHG) charged Foster Wheeler to execute a study aimed at comparing two different gasification technologies (Texaco and Shell) that can be applied in a Coal Integrated Gasification Combined Cycle (IGCC) plant with and without capture of CO_2.
IEA GHG is an international organization supported by sixteen countries world-wide, the European commission and several industrial organizations, established in 1991 to evaluate technologies that could be used to avoid emissions of greenhouse gas, particularly from the use of fossil fuels.

The study shall be based on the state-of-the-art technology, evaluating costs and performances of plants which can be presently engineered and built.
However the study shall include an assessment of the opportunities for future improvements.

The plant will be fed with coal and will produce electric power to be delivered to the national grid. The net electric power nominal capacity is 800 MWe. The standard site is on the NE cost of the the Netherlands.

Purpose of this Functional Specification is the definition of the design bases and technical requirements to define the Acid Gas Removal/CO_2 Capture process adopted for each Integrated Gasification Combined Cycle (IGCC) alternatives to be evaluated as part of the IEA Gasification Power Generation Study.

The technical requirements and specifications for the different alternatives are defined in the following sections:

1. Section 1: IGCC without CO_2 Capture; before entering the AGR system syngas is treated in order to convert COS to H_2S in a COS Hydrolysis reactor.

2. Section 2: IGCC with CO_2 Capture; syngas shall be treated in order to convert syngas CO content to CO_2 in a shift reaction section. Both sour and clean gas shift options are evaluated:
   - in case of sour gas shift this section is put upstream of the AGR/CO_2 capture;
   - in case of clean gas shift, first syngas is fed to a COS Hydrolysis section and to the AGR, then it is shifted and finally fed to the CO_2 capture section.

For alternatives without CO_2 capture the AGR system must remove from syngas H_2S only, in order to allow the IGCC plant to meet the environmental limits for sulphur emissions to atmosphere.
For alternatives with CO_2 capture, CO_2 is removed, compressed and delivered to its final destination, in order to minimize the CO_2 emissions to atmosphere.
In both main alternatives, H_2S and/or CO_2 are removed from raw syngas by means of a solvent wash.

For alternatives, with CO_2 Capture, two cases shall be studied:

- Separate removal of H_2S and CO_2.
- Combined removal of H_2S/CO_2 producing a single stream to be delivered at plant B.L.

For alternatives which adopt a separate H_2S removal section, sulphur is recovered from acid gas downstream to the AGR by an Oxygen Claus Sulphur Removal Unit.

In summary the following cases shall be evaluated:

1a IGCC w/o CO_2 capture, Texaco gasification process, high pressure, H_2S removal only.
1b IGCC w/o CO_2 capture, Shell gasification process, low pressure, H_2S removal only.
2a IGCC with CO_2 capture, Texaco gasification process, high pressure, sour gas shift (1 bed), separate removal of H_2S and CO_2.
2b IGCC with CO_2 capture, Texaco gasification process, high pressure, sour gas shift (2 beds), separate removal of H_2S and CO_2.
2c IGCC with CO_2 capture, Shell gasification process, low pressure, sour gas shift, separate removal of H_2S and CO_2.
2d IGCC with CO_2 capture, Shell gasification process, low pressure, clean gas shift, separate removal of H_2S and CO_2.
2e IGCC with CO_2 capture, Texaco gasification process, high pressure, sour gas shift, combined removal of H_2S and CO_2.
2f IGCC with CO_2 capture, Shell gasification process, low pressure, sour gas shift, combined removal of H_2S and CO_2.

1 ALTERNATIVES WITHOUT CO_2 CAPTURE

1.1 SCOPE OF WORK

The Supplier shall design and select the AGR process for the two alternatives described below and referred to the IGCC configurations without CO_2 Capture:

1.a Texaco Gasification process: High Pressure case

1.b Shell Gasification process: Low Pressure case

The purpose of Acid Gas Removal System is the removal of H_2S from syngas by means of a solvent wash, in order to allow the IGCC Plant to meet the environmental limits for sulphur emissions to atmosphere.
Sulphur is recovered from the acid gas downstream to the AGR by an Oxygen Claus Sulphur Revovery Unit.

The Acid Gas Removal solvent is required be selective removing the Hydrogen Sulphide and maximizing the Clean Syngas Carbon Dioxide slippage.

The Acid Gas Removal is fed also by the Hydrogenated Tail Gas produced by the Sulphur Recovery Unit (SRU).
The supplier shall optimize the AGR configuration with respect to the tail gas recycle, taking into account the need to treat this stream for H_2S removal. In case an Acid Gas Enrichment section is adopted downstream to the AGT, the tail gas from SRU can be recycled back to the Acid Gas Enrichment Absorber.

1.2 BASIS OF DESIGN

1.2.1 FEED DATA

Raw Syngas

The following table details flow rate and characteristics of syngas coming from the "Syngas Treatment and Conditioning Unit" and fed to AGR for the two cases indicated in paragraph 1.1 :

CASE/ Raw Syngas		**Case 1.a**	**Case 1.b**
Gasification Technology		Texaco	Shell
Pressure		High	Low
H_2	Mol.%	38.75	31.81
N_2	Mol.%	0.93	4.92
CO	Mol.%	40.07	60.43
Ar	Mol.%	1.07	0.75
CH_4	Mol.%	0.02	-
CO_2	Mol.%	18.65	1.52
H_2S	Mol.%	0.31	0.28
H_2O	Mol.%	0.2	0.29
COS	Vppm	4	11
HCN	Vppm	5	5
NH_3	Vppm	10	49
MW		21.05	20.06
Flowrate (1)	Kmol/h	26437	22750
Pressure	Barg	54	29.5
Temperature	°C	38	38

Note: (1) This value corresponds to the total syngas flow rate.
The Syngas Treatment and Conditioning Units upstream of the AGR section are divided into two twin parallel trains; the supplier shall optimize the number of trains taking into account possible constraints on equipment size, the operating flexibility and the investment cost.

1.2.2 RECYCLE GAS FROM SRU UNIT

The following compositions are preliminary.

- Temperature, °C 38.0
- Pressure, barg As required

Supplier shall advise acceptable limits of tail gas contaminants, if any.

Tail gas

CASE		**Case 1.a**	**Case 1.b**
Gasification Technology		Texaco	Shell
Pressure		High	Low
H_2	kmol/h	17.7	13.8
N_2	kmol/h	76.7	59.6
CO	kmol/h	1.2	1.5
Ar	kmol/h	0.8	0.6
CO_2	kmol/h	73.4 + $X_{1.a}$	5.2 + $X_{1.b}$
H_2S	kmol/h	3.1	2.4
H_2O	kmol/h	sat.	sat.
Flowrate(dry)	kmol/h	172.9 + $X_{1.a}$	83.1 + $X_{1.b}$
Pressure	barg	As required	As required
Temperature(1)	°C	38	38

where

X_i = quantity of CO2 leaving the Acid Gas Removal system (to be defined by the AGR supplier).

1.3 PROCESS SPECIFICATIONS

Clean Syngas

Case		**Case 1.a**	**Case 1.b**
H_2S+COS concentration	ppm vol.	< 40	< 40
Solvent content	ppm vol.	< 1	< 1

Outlet pressure to be 0.5 bar max less than the Syngas inlet pressure (including entrance/exit losses).
Carbon Dioxide slippage shall be maximized for each case.

Acid Gas

Hydrogen Sulphide concentration is to be maximized. The composition and operating conditions must be suitable for the downstream treatment in an Oxygen Claus Sulphur Recovery Unit.

2 ALTERNATIVE WITH CO2 CAPTURE

2.1 SCOPE OF WORK

The Supplier shall design and select the AGR CO_2 capture process for the six alternatives described below and referred to the IGCC configuration with CO2 Capture:

2a IGCC with CO_2 capture, Texaco Gasification, high pressure, sour gas shift (1 bed), separate removal of H_2S and CO_2.
2b IGCC with CO_2 capture, Texaco Gasification, high pressure, sour gas shift (2 beds), separate removal of H_2S and CO_2.
2c IGCC with CO_2 capture, Shell Gasification, low pressure, sour gas shift, separate removal of H_2S and CO_2.
2d IGCC with CO_2 capture, Shell Gasification, low pressure, clean gas shift, separate removal of H_2S and CO_2.
2e IGCC with CO_2 capture, Texaco Gasification, high pressure, sour gas shift, combined removal of H_2S and CO_2.
2f IGCC with CO_2 capture, Shell Gasification, low pressure, sour gas shift, combined removal of H_2S and CO_2.

Purpose of Acid Gas Removal/CO_2 capture System in all the six alternatives, is the removal of H_2S and CO_2 from syngas by means of a solvent wash, in order to allow the IGCC Plant to meet the environmental limits for sulphur emissions to atmosphere and to minimize the CO2 emissions to atmosphere.

For cases **2.a**, **2.b**, **2.c**, **2.d** Sulphur is recovered downstream to the H2S removal system by an Oxygen Claus Sulphur Reactor Unit.
In these cases the solvent is required to be selective removing the Hydrogen Sulphide maximizing the Carbon Dioxide slippage.

The Acid Gas Removal is fed also by the Hydrogenated Tail Gas produced by the Sulphur Recovery Unit (SRU).
The supplier shall optimize the AGR configuration with respect to the tail gas recycle, taking into account the need to treat this stream for H_2S removal. In case an Acid Gas Enrichment section is adopted downstream to the AGT, the tail gas from SRU can be recycled back to the Acid Gas Enrichment Absorber/Tower.

2.2 BASIS OF DESIGN

2.2.1 FEED DATA

Raw Syngas

The following table details flowrate and characteristics of the syngas fed to AGR for the different cases indicated in paragraph 2.1 :

CASE/Raw Syngas		Case 2.a	Case 2.b	Case 2.c	Case 2.d	Case 2.e	Case 2.f
Gasification Technology		Texaco w/ CO2capture	Texaco w/ CO2capture	Shell w/ CO2capture	Shell w/ CO2capture	Texaco w/ CO2capture	Shell w/ CO2capture
Pressure		High	High	Low	Low	High	Low
Shift stages		1 BED dirty	2 BEDS dirty	2 BEDS dirty	clean	1 BED dirty	2 BEDS dirty
H2S – CO2 removal		Separate	separate	separate	separate	combined	combined
H_2	mol.%	55.04	55.85	56.41	31.85	55.04	56.41
N_2	mol.%	0.68	0.67	3.09	4.83	0.68	3.09
CO	mol.%	2.84	0.99	2.51	60.48	2.84	2.51
Ar	mol.%	0.79	0.78	0.48	0.75	0.79	0.48
CH_4	mol.%	0.02	0.02	-	-	0.02	-
CO_2	mol.%	40.22	41.29	37.02	1.52	40.22	37.02
H_2S	mol.%	0.22	0.22	0.18	0.28	0.22	0.18
H_2O	mol.%	0.19	0.19	0.31	0.29	0.19	0.31
COS	vppm	1	1	1	-	1	1
HCN	vppm	5	5	5	5	5	5
NH_3	vppm	10	10	45	49	10	45
MW		20.22	20.18	19.31	20.06	20.22	19.31
Flowrate (1)	kmol/h	37276	38153	36998	23507	37276	36998
Pressure	barg	56.2	55.6	26	29.5	56.2	26
Temperature	°C	38	38	38	38	38	38

Note (1) This value corresponds to the total syngas flowrate. The Syngas Treatment and Conditioning Unit upstream of the AGR section is divided into two twin parallel trains; the Supplier shall optimize the number of trains taking into account possible constraints, on equipment size, the operating flexibility and the investment cost.

2.2.2 RECYCLE GAS FROM SRU UNIT

The following compositions are preliminary.

- Temperature °C 38.0
- Pressure, barg As required

Supplier shall advise acceptable limits of tail gas contaminants, if any.

Tail gas

CASE		Case 2.a	Case 2.b	Case 2.c	Case 2.d
Gasification Technology		Texaco w/ CO2capture	Texaco w/ CO2capture	Shell w/ CO2capture	Shell w/ CO2capture
Pressure		High	High	Low	Low
Shift stages		1 BED dirty	2 BEDS dirty	2 BEDS dirty	Clean
H2S - CO2 removal		Separate	separate	separate	separate
H_2	kmol/h	17.4	18.1	13.6	14.2
N_2	kmol/h	75.6	78.3	59.0	61.6
CO	kmol/h	0.2	0.1	0.1	1.6
Ar	kmol/h	0.8	0.9	0.6	0.7
CO_2	kmol/h	216.0 + $X_{2.a}$	226.0 + $X_{2.b}$	208.0 + $X_{2.b}$	5.3 + $X_{2.c}$
H_2S	kmol/h	3.1	3.2	2.4	2.5
H_2O	kmol/h	Sat	sat	sat	sat
Flowrate (dry)	kmol/h	313.1 + $X_{2.a}$	326.5 + $X_{2.b}$	283.7 + $X_{2.c}$	85.9 + $X_{2.d}$
Pressure	barg	As required	As required	As required	As required
Temperature(1)	°C	38	38	38	38

where

X_i = quantity of CO2 leaving the Acid Gas Removal system (to be defined by the AGR supplier).

2.3 PROCESS SPECIFICATIONS

Clean Syngas

Case		**Case 2.a**	**Case 2.b**	**Case 2.c**	**Case 2.d**	**Case 2.e**	**Case 2.f**
H_2S+COS concentration	ppm vol.	< 40	< 40	< 40	< 0.2	< 40	< 40
CO2 Washing-unit removal efficiency	%	91**(1)**	87	91**(1)**	91**(1)**	91**(1)**	91**(1)**
Solvent content	Ppm vol.	< 1	< 1	< 1	< 1	< 1	< 1

Note(1) : desired value for *CO2 washing unit removal efficiency* if feasible. Definition of *CO2 washing unit removal efficiency* as follows:

$$\frac{CO_2 \text{ flow rate to B.L.}}{CO_2 \text{ flow rate in raw syngas to AGR}} \times 100$$

Supplier to comment and decrease the specification if considered unfeasible or uneconomic.

If case **2.a** specification (91%) is achieved with performances and investment cost considered acceptable by Vendor, case **2.b** can be neglected.

Outlet pressure of Syngas of AGR system (including CO2 and H2S wash), to be a 1 bar max less than the Syngas inlet pressure (including entrance/exit losses).

Acid Gas (for cases 2.a, 2.b, 2.c, 2.d)

Hydrogen Sulphide concentration is to be maximized. The composition and operating conditions must be suitable for downstream treatment in an Oxygen Claus Sulphur Recovery Unit.

3 SCOPE OF SUPPLY

The Unit shall include in addition to the Absorption and Regeneration facilities the following items:

- Solvent storage and supply system.
- A dedicated closed drain system including the closed drain sump, sump pump etc.
- Antifoam injection and any other chemical injection and storage facilities if required.

If there are particularly "sensitive" areas in the design, for example recovery and elimination of trace components, the supplier is requested to advise FW of and the likely impact of changes upon equipment and solvent cost such areas be relevant.
Certain solvents, although not all, may be susceptible to the build up of heat Stable Salt (HSS). In cases such as this the reclamation package is required within the suppliers scope. Salts that could possibly build up are formates, acetates, cyanides, etc.

3.1 INFORMATION REQUIRED

The following documentation/information, as a minimum, shall be provided for the each alternative specified in para.1(see Introduction):

- Unit description
- Process Flow Diagram;
- Heat and Material Balances;
- Utilities, and Chemicals Consumption (see para. 3.2 for characteristics):

Cooling Water Flowrates	m^3/h
Power	kW
Make up Water	m^3/h
LP Steam	t/h

- Solvent Make up Flowrate and Monthly Consumption;
- Equipment list and Package Duty specifications, with major of equipment sizing
- Investment cost;

If justified by economics a Power Recovery Turbine shall be used on the high pressure/low pressure rich solvent interface, driving lean solvent booster pumps or similar.

3.2 UTILITY CHARACTERISTICS AND CONSUMPTIONS

The Utilities characteristics are detailed in the BEDD.

Basic Engineering Design Data attached to this specification. Note that information presented in this specification shall be used in preference to the BEDD where differences exist.

The supplier may deviate from the guidelines provided as their experience dictates, however all deviating areas must listed and reasons explained.

Cooling Water flowrates	m3/h	By Supplier
Power:	kW	By Supplier
Make up Water:	m3/h	By Supplier
LP Steam:	t/h	By Supplier

3.3 EQUIPMENT DESIGN

The following design suggestions shall be reviewd and commented by the Supplier.

Pumps are 100% spared (1operating) except for the Solvent Sump pump(not spared).

Exchangers are to be specified as plate exchangers wherever possible to minimize investment cost.

The regenerator reboilers are 2 x 70% capacity parallel items.

Solvent storage is to be provided with capacity for the twice the entire solvent inventory and twice and twice the 12 months make-up requirements, split between 2 tanks. One tank will contain solvent at any given time with the other empty for containment of possible contaminated solvent. The supplier can assume a distance of 250 m from the storage area to the process train.