IEA GREENHOUSE GAS R&D PROGRAMME

The IEAGHG Power Plant Assessment Program (PPAP)

Development and testing June 2002 –October 2005

Report Number 2005/7
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IEA GHG POWER PLANT ASSESSMENT PROGRAM FOR NOVEL CO_2 CAPTURING ELECTRICITY GENERATING PROCESSES

Background to the study

The IEA Greenhouse gas R&D programme has conducted many studies on CO_2 capture from large power stations. Such studies are normally conducted by an experienced contractor and typically cost upwards of £40,000. In order to perform such studies leading to a capital costs estimate within +-30% it is necessary to have a reasonably detailed description of the process and all of the main equipment which is required. In addition the contractor needs to have a reliable database of cost information on the equipment. From time to time novel schemes are put forward but detailed evaluation is inhibited by the high cost of a full study. Furthermore factors other than cost may be important in determining how interesting a novel system is and it may be difficult to predict the cost of exotic equipment. IEAGHG thus developed a simple assessment program in order to be able to carry out a first screening of novel process without incurring large costs. This report summarises the work which has been done on the development of this computer program and the experience with using it on a number of novel schemes.

Approach adopted

The program was written in Excel using a consultant from CRE, a consultancy company based in the UK. Testing of the program and a number of process evaluations were carried out by a small independent consultancy, GasConsult, based in Reading UK.

Results and Discussion

The Power Plant Assessment Program (PPAP) was first completed in April 2002. It was used on several processes including conventional capture processes in order to test and calibrate it. A number of revisions were made and additional processes were evaluated to check how the program performed. A major change was to make it possible to input heat and material balance information produced by external process simulators as an alternative to relying on the rather simple routines in PPAP. The tool has been useful in gaining insight into the merits of novel processes and has proved useful in discussions with process developers. Simple evaluations leading to a consistent analysis of the performance and risks of a novel process can be carried out by experienced process engineers at commercial rates at a cost of £2000-£4000.

The program uses a weighted multi-criteria analysis to take into account factors other than electricity price in assessing the performance of CO_2 capturing power plant. It also includes a simple but systematic evaluation of the risks which could be involved in developing each technology. The analysis enables a simple strategic view to be formed of the competing novel technologies and also appears to assist process developers in better appreciation of the main barriers to successful commercial development in a competitive world.

Major Conclusions

There are factors relating to CO_2 capturing power plant which cannot easily be expressed in purely monetary terms. Multi-criteria analysis as applied in PPAP forces consideration of these factors in monetary terms. From the novel processes which have so far been evaluated it would seem that the effect of these factors could range from being almost nothing to the equivalent of several ¢/kWh on the electricity price. The methodology promotes objective comparison of competing processes. Some of the innovative evaluated processes could mount a serious challenge to conventional capture processes. However none of those evaluated so far would appear to have a clear lead.

Recommendations

PPAP has been used exclusively “in house” giving IEAGHG the ability to systematically screen novel capture processes at low cost. The program is only suitable for use by experienced Chemical Engineers preferably with access to process simulation software. It is recommended that the tool be retained for “in house” use in the first screening of novel capture processes as and when these come to our attention prior to making proposals for in depth studies.

PPAP - POWER PLANT ASSESSMENT PROGRAM -

IEA GREENHOUSE GAS R&D PROGRAMME

The development of a Power Plant Assessment Program (PPAP)

Summary of development work from June 2002 through October 2005

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1 Summary

Novel schemes for generating power from fossil fuel with CO2 capture are underdevelopment and from time to time new schemes are proposed. Development of this sort of technology is both costly and potentially risky. A tool to screen such novel proposals in order to assess their performance and viability on a consistent basis has been developed. The tool uses standardised basic data on costs for common components and performs simplified calculation of basic gas and steam cycles if detailed information is not available. The program also manages the input of the overall heat and mass balance to ensure that losses and auxiliary power consumption are treated on a consistent basis. Where detailed heat and mass balances are available from a simulation program the tool allows key results to be input.

The viability of a proposed technology is assessed in two ways using standardised questions about the state of development of the process, the complexity of the flow scheme, the type of materials, severity of process conditions, safety and environmental aspects. Answering these questions relies to some extent on sound chemical and mechanical engineering judgment and the tool is thus intended for use by professionals experienced in the power generation and heavy chemical process field. The program assesses the overall commercial performance on a multi-criteria scoring basis taking into account, CO2 emissions, fuel consumption, capital and operating costs as well as the process complexity and severity, construction material and natural resource requirements, development requirements, safety and environmental impacts. Credit is given in the scoring for good performance whilst use of exotic materials, extreme process conditions, dangerous processes or toxic materials is penalised.

The tool also makes an assessment of the likelihood of success on a comparative, (i.e not absolute) scale. This allows results to be plotted in a two dimensional way so that the competitive position of process can be visualised both in terms of likely commercial performance and risk. The tool has been calibrated with several conventional baseline processes both with and without capture. This provides a backdrop on which novel competitors for the next generation of CO2 capturing power plant can be plotted. The tool is offered as a means of screening out novel processes which have little chance of commercial success and also helping those which are more competitive to understand their potential strengths and weaknesses from a commercial as well as a technical viewpoint.

2 Introduction

Capture of CO_2 from large power plant and its geological sequestration is a technology which has the potential to contribute large reductions in the emission of CO_2. Power is generated on a very large scale, power station operators would be able to manage the operation of the required technology and, although the CO_2 is quite dilute, the quantities available at each emission point give good economies of scale.

There are a host of potential CO_2 capture processes ranging from those based on existing technology to exotic systems using for example chemical looping, high temperature membranes, rocket fuel burning technology and fuel cells. Detailed analysis and comparison of options is expensive and time consuming. The IEA GHG programme has along with other research organisations conducted such assessments for a variety of processes in varying degrees of detail. Cost for such evaluations can range from tens to hundreds of thousands of dollars. Evaluation of more exotic processes which may offer a breakthrough in cost or performance but equally may prove to exhibit serious technical or commercial drawbacks, is inhibited by this high cost of assessment.

For this reason IEAGHG R&D programme sought to develop a simpler and cheaper screening system. The latest version of this development and further results are presented in this report.

3 Description of the assessment programme

3.1 Programme platform

The programme is Excel spreadsheet based, and makes extensive use of macros. There are also a number of visual basic routines for thermodynamic property calculations. The input and output are in the form of a set of worksheets through which the user is guided by interlinks. One of the disadvantages of using the Excel platform is the need to update when newer version of Excel are released. This has been partially alleviated in the latest version by having a facility to import data from earlier versions on the basis of data labels. The programme presents results in two output worksheets as well as a worksheet with a complete vector of all inputs and outputs which is useful for detailed comparisons and cross checking.

3.2 Programme capabilities

The programme performs the following main tasks on the basis of the data input by the user.

Overall heat and material balance reconciliation
Capital cost estimate
Thermodynamic calculations of simple steam and gas turbine cycles
Multicriteria assessments of the proposed process
Performance and unit cost calculations for the complete power plant

The programme checks for a full reconciliation of the overall fuel and energy flows for the power plant under assessment. This ensures that where fuel and energy is split between different devices and working cycles that the overall energy balance is not violated. Power and heat consumed in auxiliary systems has to be accounted and default values for common items such as mechanical and generator losses are automatically applied. This ensures that as far as possible every process is evaluated on a common basis and that all assumptions regarding losses and efficiencies are clearly highlighted.

The capital cost estimate is built up partly from standard data held in the programme and partly from external inputs. Costs and scaling factors are available for a variety of standard elements such as gas turbines, heat recovery generators, oxygen plant, combustors and boilers. For other elements the user has to enter appropriate data but can specify and use scaling factors if only a single cost/capacity datum is available. This allows the basic table of standard costs to be built up to include other types of equipment. Multiple trains can be specified for any of the costed units and the programme automatically applies the appropriate scaling factor. Standard costs can be altered by specifying a multiplier but when this is done it is clearly visible on the cost data entry sheet. At present the cost database is populated with a few costs extracted from earlier studies and could benefit from further extension. A systematic way of escalating cost data from the year in which they were estimated to a later reference date would also be useful but is not yet included.

Most processes for power generation make use of steam or gas turbine cycles. The programme therefore contains simple routines for calculating the efficiency of these cycles. However where better data is available, perhaps from a more detailed simulation, the programme values can be overridden. In practice the efficiency of more sophisticated steam cycles tends to be slightly higher than the simpler ones which are calculated by the program. After a first assessment it may pay to refine the results by inputting a more accurate simulation.
There is no particular control on the efficiencies specified for compressors and expanders. Those using the program have to have the competence to assess these realistically, although conservative defaults are included where no such data is known.

A multicriteria analysis is included in the program. This assesses several attributes. Some of these are strictly related to the predicted performance of the plant as calculated by the programme. These include the power cost, the CO_2 emission per Kw and the specific fuel consumption. Other parameters are assessed on a descriptive basis and include safety, environmental impact, materials of construction, severity of process and process complexity. In order to standardise the assessment of these attributes there is a set of standard questions and multiple choice answers. The user simply chooses the most appropriate answer to each question. There are two questions for each attribute, one is aimed at understanding the likely degree of cost escalation presuming that the process will be technically possible. Scores thus reflect the need for greater or less financial input to complete development of a fully commercial product. The second set of questions is designed to assess the likelihood that the process will be technically workable and commercially saleable. Most of the emphasis here is on the technical track record with the development. Some attributes such as those relating to safety and environment may be controllable technically but still reduce the chance of successful deployment for example because of public or institutional resistance.

The unit costs of electricity, total capital cost, operating cost, efficiency, fuel consumption CO_2 emissions are all calculated and presented by the program. These along with the multi-criteria analysis results form the output of the assessment. Full details of the questions and answers used in the multi-criteria analysis are given in appendix A.

3.3 Use of externally calculated heat and material balance simulation programs

For those in possession of licences to chemical engineering simulation programs such as Hysis, Gatecycle, Aspen and Pro-vision the marginal cost of simulating a power plant cycle may be quite low. In order to facilitate the transfer of key results from this type of simulation program an additional input option which bypasses the internal calculation of steam and turbine cycles is incorporated in the latest version. The key efficiencies and powers are entered here excluding allowances for certain specified mechanical and electrical losses. Such losses are assessed by the program. A check is made to ensure that the values entered are consistent with the specified fuel quantities.

3.4 Calibration of the multicriteria analysis

One way to appreciate the multi-criteria analysis is to consider the assigned weightings as painting a scenario about commercial power generation at a future date when carbon capture and sequestration is commonplace. In this future world there is a value to not emitting CO_2, just as there is to having a low electricity price. The parameters are currently set so that this value is \$50/ton CO_2. Additional value is also placed on low fuel consumption. A premium of an extra \$1.5/Mbtu for coal and \$3/Mbtu for gas is applied which effectively applies a penalty for any fuel consumption higher than that of conventional state of the art power plants. The other attributes feed in to the score through their weighting in effect by loading the technology with extra development costs which have to be recovered. Low scores effectively increase the capital cost per Kw over and above that derived from the basic capital cost estimate. The figure 1 illustrates how the weightings are built up. Note that the multi-criteria performance score is intended to bear a close relationship to overall cost.

The weightings chosen for any multi-criteria analysis are inevitably based on choice and an appreciation of the relative value of the different attributes. The choice of the attributes themselves is also an issue of debate. The attributes used in the program were chosen by a group of experts invited to a forum. The same experts also suggested weightings but these were set without the transparency of converting them to equivalent costs and some of the values chosen initially were clearly anomalous.

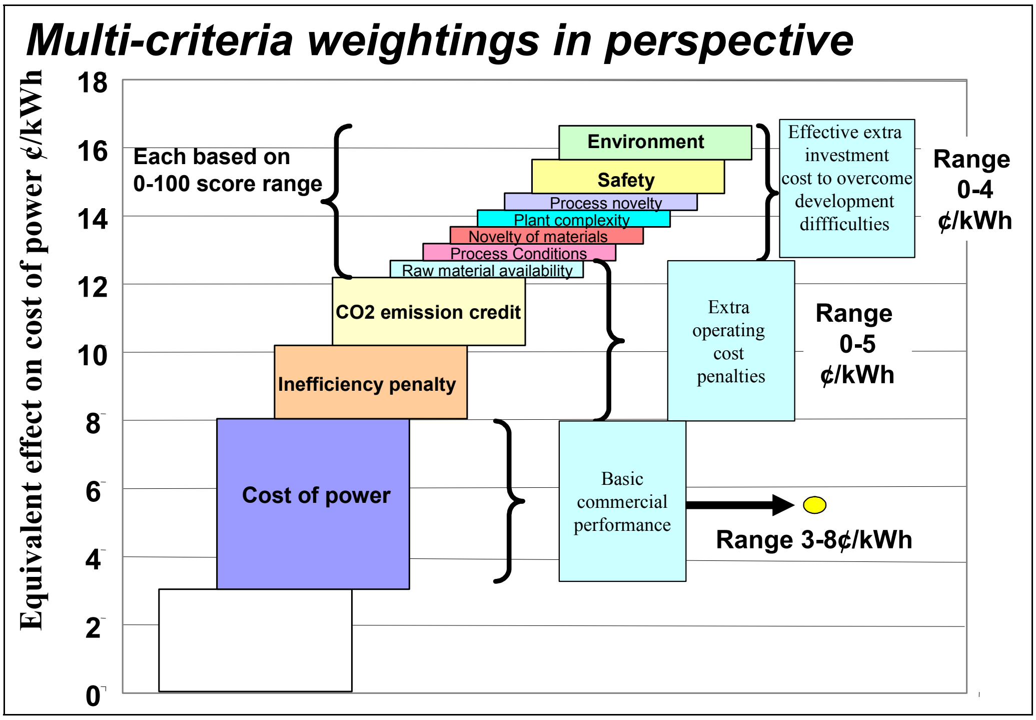


Figure 1 Multi-criteria weightings

The second dimension of the multi-criteria analysis is the risk that the technology will not succeed. This could be either for technical or non-technical reasons. For example some attributes of a process, such as complexity, safety and environmental impact, might put potential buyers off even if the process seems attractive in strictly commercial terms. The risk of failure score is thus intended to be independent of the performance score and as far as possible divorced from costs. It is dependent to quite a degree on the practical results which have been obtained in the laboratory or pilot plant, and represents those situations where money or price can do little to alter technological and commercial realities. Risk scores are assigned for each of the main attributes except for the power cost and emission factors and both the average risk and the highest individual score are determined. For the purposes of comparison the highest score is considered to be more important than the average score, because one show stopping attribute is much worse than several minor difficulties.

Obviously changes to weighting factors can be made but it is recommended that if done this is in the context of a complete scenario in which all factors are reviewed. Furthermore for consistency it would be better to develop additional scenarios keeping intact those which have already been used for a set of evaluations rather than adjust individual weightings in existing scenarios.

3.5 Results of evaluations – the search for a better process

Over the last three years IEAGHG has kept a watching brief for novel CO_2 capture processes and employed a consultancy to evaluate most of them using the PPAP software. Not all results are reported since some of the information on processes was provided on a confidential basis. In those cases the results proved to be quite helpful to the developers of the processes concerned.

3.6 Presentation of results

For each evaluation a separate Excel file is prepared. It is advisable to prepare a set of notes describing the process, listing references, explaining the reason behind choices for the input and with a copy of any external simulation work which has been done. In order to reach conclusions about new processes is necessary to make comparisons with others and this has to be done externally. The programme contains two simple charts to help visualise the performance of the evaluated process relative to a state of the art non-CO_2 capturing base line plant. It is not yet set up to plot multiple results.

A good way to compare results is to plot them on a chart with two axes similar to the one embedded in the "results" sheet. On the vertical axis is the performance score and on the horizontal axis the "likelihood of success". Fig 1 is an example of this type of chart as produced by the programme. The chart in the program plots a second point on the chart which shows the same "risk" but excludes all factors except cost of electricity from the performance score. This "score" shows in effect how the process would be viewed in the context of a today's cost competitive electricity market.

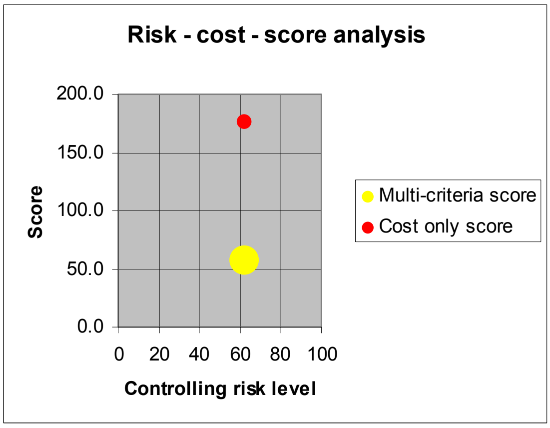


Figure 2 Performance and risk plot

The chart falls naturally into four quadrants as illustrated in figure 2.

High performance with low risk,	- an ideal combination but to date no processes fall into this category
Low performance with low risk,	- typical of the current leading capture options
High performance with high risk	- the region in which to expect promising novel processes to emerge.
High Risk Low performance	- processes which are unlikely to be worth developing

Today's processes tend to occupy the low risk, low performance quadrant. Above this quadrant lies an area of low risk and better performance and any CO_2 capturing power generation process which plotted here would be a front runner for development. However it is unlikely that low risk processes with much better performance will be found. To the side of this "preferred" area is one where performance is good but risk is high. This is the most likely area where a viable new process will be found. There is likely to be a trade off between risk and performance. Investments in development of processes falling in this area will have to have a strong element of "venture". Finally there is a quadrant of low performance and high risk. Processes which fall in this area should be regarded as not worth further development.

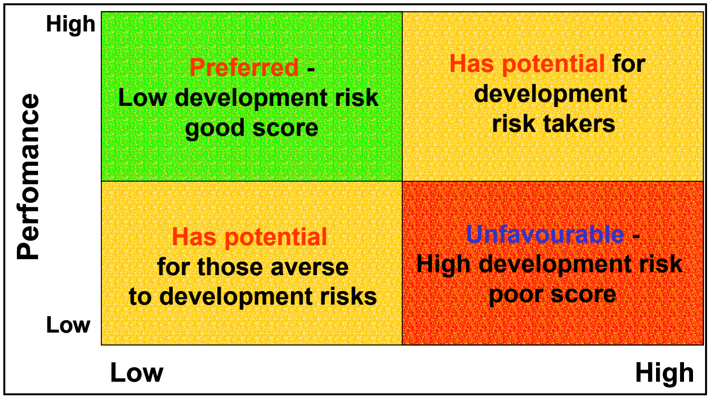


Figure 3. Risk performance matrix

As a refinement of the two dimensional plot a "bubble" plot can be used with the size of the bubble representing the average risk level. This gives an additional comparison particularly between closely competing processes indicating the extent of the critical development problems which may have to be overcome. It should be remembered that the likely cost of overcoming them is already factored into the performance score by the multi criteria analysis.

The other small chart included in the output is a stacked bar chart which shows how the main elements of the performance score of the process compares with those of a base case. This is on the "comparison" sheet. Data for the base case has to be entered in order for this chart to be created. This comparison is done on the basis of an "effective" cost of electricity. The effect of multi-criteria scores is translated into an effective extra electricity price. Lower fuel consumption and reduced CO_2 emissions are also "translated" into effective electricity price changes. This can give a good appreciation of how emission credits are being offset by development costs and extra fuel consumption. A second bar shows the overall difference, positive or negative.

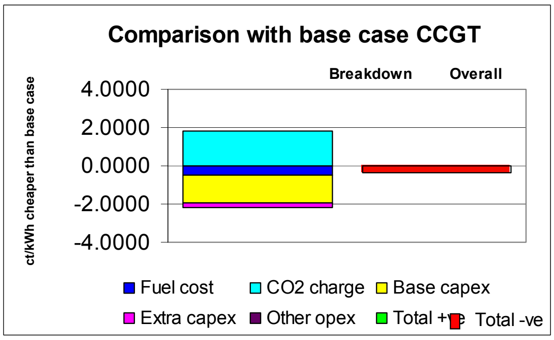


Figure 4 Comparison of performance

TABLE 1 SUMMARY OF RESULTS FROM PPAP EVALUATIONS

Process	Fuel	Cost ¢/kWh	Performance score (1pt equiv to .05¢/kWh)	Highest risk factor (0-100)	Average Risk level (0-100)	Fuel use kW/kW	Efficiency % based on LHV	CO2 emissions gm/kWh
CCGT no capture	Gas	2.9	216.2	11	5	1.73	57.9	365
APO/PCDC	Gas	4.0	199.9	11	5	1.98	50.5	62
Chemical looping (CuO)	Gas	3.8	187.6	100	40	2.19	45.6	0
Pulverised fuel no capture (PF)	Coal	3.8	186.4	5	2	2.22	45	728
Chemical looping (BaO)	Gas	3.7	181.3	100	48	2.26	44.3	0
Clean energy Systems (CES) (with 1200C max TIT)	Gas	4.8	170.1	20	11	2.20	45.4	0
PCDC with circulating Dolomite CO2 acceptor	Gas	5.2	165.2	100	21	2.10	47.7	70
SOFC hybrid	Gas	7.4	128.1	63	20	1.55	64.6	3
PF + Amine scrubbing	Coal	7.3	125.5	10	3	2.88	34.7	94
Israeli-Russian Cryogenic process.	Coal	8.4	56.9	63	16	3.97	25.2	389

3.7 Use of results

The results of an evaluation are based upon the available information and state of development at the time. Some scores will change as development proceeds. The underlying reasons which build up a score on either axis can be determined easily by examining the answers to the various questions and hence give direction for improvement. The results are particularly useful when comparing competing processes enabling an understanding of how the different attributes are affecting their chances. With suggestions for so many potential processes it is becoming increasingly important to identify the future winners as the need for serious action on climate change increases. This type of analysis should be valuable for funding institutions and proponents of specific technologies alike in understanding where best to direct development. It is possible to perform a "what if" exercise to determine how the multi criteria analysis results would change as progress is made in the development.

3.8 Specific results

The following processes have been evaluated to date. They fall into several classes.

Firstly there are base line processes. Examples for calibration were based on information reported in previous IEAGHG studies. Coal and gas fired processes fare differently in the analysis mainly because coal generates more CO_2 and is evaluated with a lower unit fuel price. Thus care should be taken when comparing a gas fired process with a coal fired one. For both base fuels a "with capture" and a "without capture" case was evaluated. For gas fired power plant a conventional Combined Cycle Gas Turbine system (CCGT) was evaluated as the "without capture " base-line. An air blown partial oxidation pre-combustion decarbonisation process (APO/PCDC) making a hydrogen/nitrogen mixture which is fed to a CCGT was used for the "with capture" alternative. For coal fired plant a conventional supercritical pulverised fuel steam boiler plant was evaluated as the "no capture" base case with addition of flue gas amine scrubbing for the "with capture" case.

Seven novel CO_2 capturing processes have been evaluated and the results from five of these are discussed below. They are:

Coal fired process with cryogenic expansion system for CO_2 recovery. (Proposed by Israeli-Russian research centre)

Gas fired oxycombustion using the "Clean Energy Systems" (CES) water recycling process

Gas fired fluid bed chemical looping system using Barium Oxide. Also evaluated with copper oxide. (NB Manganese and Iron oxides based processes were also investigated but no evaluation performed as these seemed less viable)

Gas fired Pre-combustion decarbonisation in the presence of a regenerable CaO/MgO CO_2 receptor

Gas fired pressurised Solid Oxide Fuel Cell hybrid (part based on a Rolls Royce concept)

The evaluations were all performed by a small specialised consultancy “Gasconsult”. The individual reports on each evaluation and the PPAP spreadsheets are contained in the appendices.

The results of the PPAP evaluations lead to some interesting conclusions about what the important features of a leading capture process might be. Efficiency and hence also specific fuel consumption are important. These are generally obtained by processes which achieve high top temperatures in the power generation working fluids. Achieving high temperature by supplementary firing of fuel which is not decarbonised appears to be a good strategy since the improvements in performance score due to efficiency tend to outweigh the losses due to higher CO2 emissions. Process which are simple also do well in the evaluation.

The forgoing insights lead to preliminary examination of a novel hybrid process which are described below.

3.8.1 Oxy-combustion heating of steam (hybrid process)

The concept of this process is to use oxy-combustion of natural gas to raise the temperature of steam from a power plant by direct firing to the maximum level which modern gas turbine technology can tolerate, i.e to around 1500C. The CO_2 steam mixture would then be expanded and after condensation of the steam CO_2 can be recovered. This is the essence of the power generation cycle of the CES process. This hybrid process might be applied to any steam turbine based process whether it be driven by coal, nuclear or renewable energy. This combination would become valuable if the gains in efficiency for the host process outweigh the parasitic power losses of the oxy-combustion element as illustrated in the diagrams below

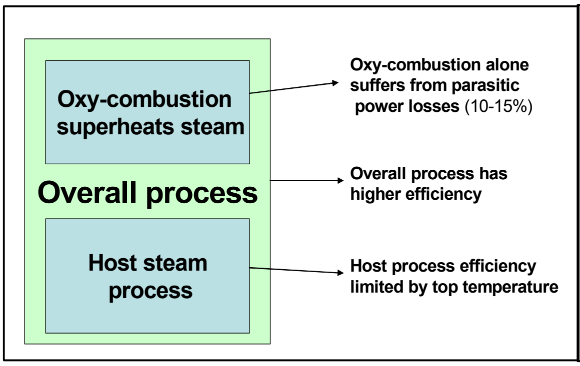


Fig 5 Hybrid process combination

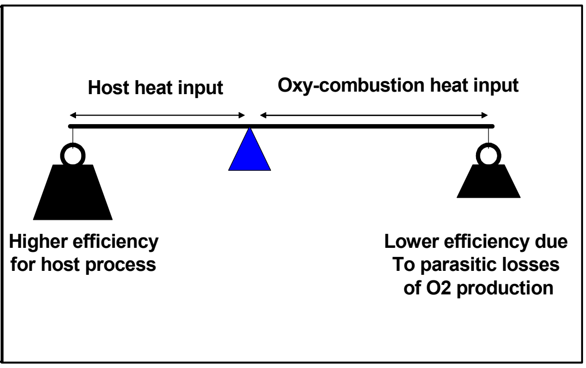


Fig 6 Advantages and disadvantages

A short report on the findings of this investigation is to be found in APP X. The main findings were:-

The amount of heat which has to be supplied by oxy-combustion to raise steam from the range 400-600C up to 1500 C is considerable and represents up to 70% of the total process heat input. Thus up to 70% or so of the thermal input is derived by oxy-combustion and thus is subject to the energy penalty associated with oxygen production. This restricts the advantage which the process could offer to a mere 30% of the total, the rest would have only the performance of a gas fired oxy-combustion process. The amount of thermal energy which would have to be supplied by oxy-combustion in this hybrid scheme depends mainly on the temperature to which the steam is raised by the host and the target top temperature for the oxy-combustion. This is illustrated in the figure below.

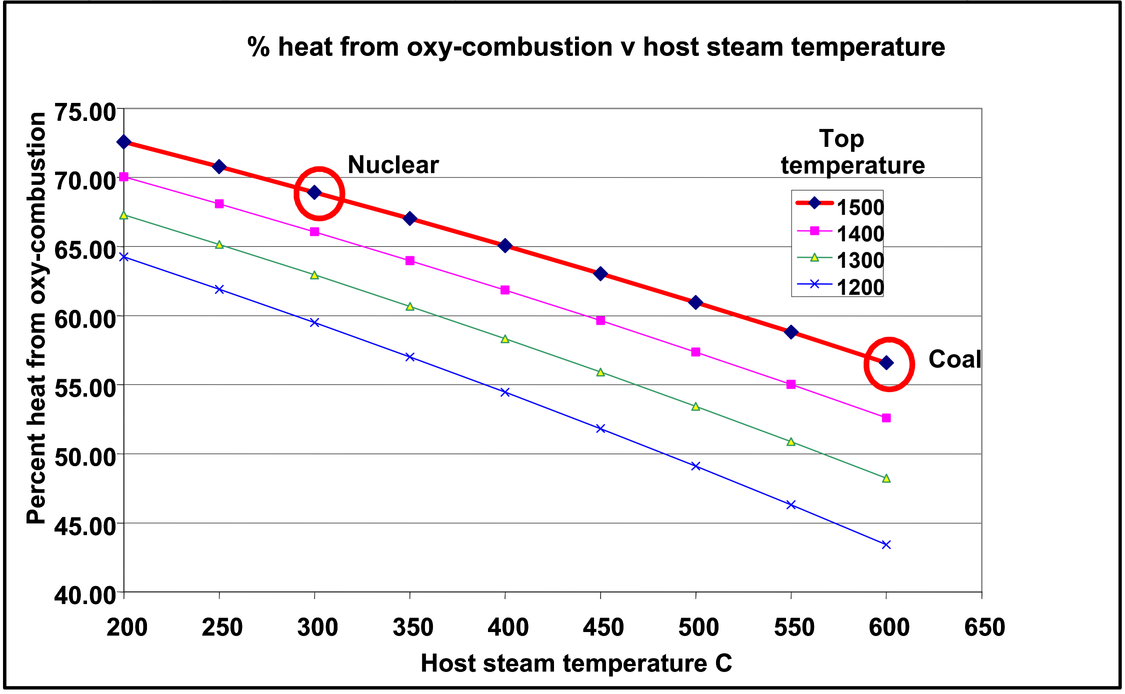


Fig 7 Split of energy inputs between host and oxy-combustion in hybrid process

In principle a power generation cycle with 1500ºC top temperature should approach 60% efficiency. However the efficiency of the basic cycle used in the CES process with these inlet conditions falls short of this in simulations by about 5%. This is sufficient to negate much of the advantage which the overall process might otherwise have had. The reason for the lower efficiency stems in part from the presence of the CO_2 which alters the condensing curve of the working fluid so that no condensation occurs in the final stages of the expansion turbine. None of the latent heat of condensation of the steam can be converted to power and is all rejected to the low temperature cooling utility. This effect is compounded by the much higher outlet temperature of the last stage of the turbine, due to the much higher inlet temperature as compared to that in a conventional steam cycle.

The following table shows the efficiency results for a combination of a host process generating steam at 124 bar with an efficiency of electrical generation of 37.1 %. Two options were examined, one with the configuration proposed by CES with two stages of oxy-combustion and a back pressure on the final turbine of 55mb. The other with one stage of oxy-combustion and a back pressure on the process of 1.04bar. Heat from the final cooling of the turbine exhaust is recovered into the process.

Configuration	Host efficiency %	Overall efficiency	Effective efficiency of oxy-combustion element	Percent of power from oxy-combustion
Two stage with 55mb back pressure	37.1	47.9	50.6	16.7
One stage with 1.04 bar back pressure	37.1	45.5	50.0	29.6

An additional observation is that not only is the latent heat rejected in the CES type cycle but also a large amount of superheat has to be removed under vacuum conditions. Although this heat can be usefully recovered, the cooler in the exit of the turbine is expected to very large and expensive. This is because the low pressure results in very low heat transfer coefficients in the de-superheating region. The simulation with raised backpressure overcomes this drawback to some extent without apparently detracting from overall performance. There may be possibilities to improve the cycle either by using much higher inlet pressures which takes the turbine design into uncharted territory or to revert to a combined cycle system in which the outlet pressure of the topping cycle is kept at several bars so that the latent heat of steam can be recovered at a useful temperature. A conventional all steam bottoming cycle would then be added. However these options have not been explored.

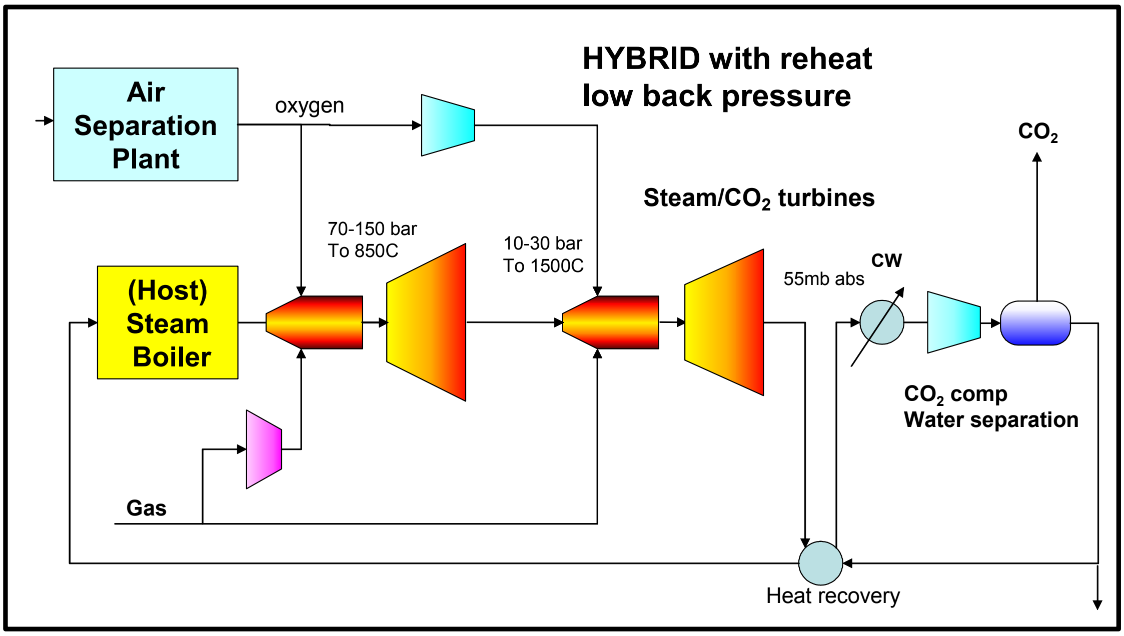


Fig 8 Hybrid oxy-combustion process with low back pressure and single reheat

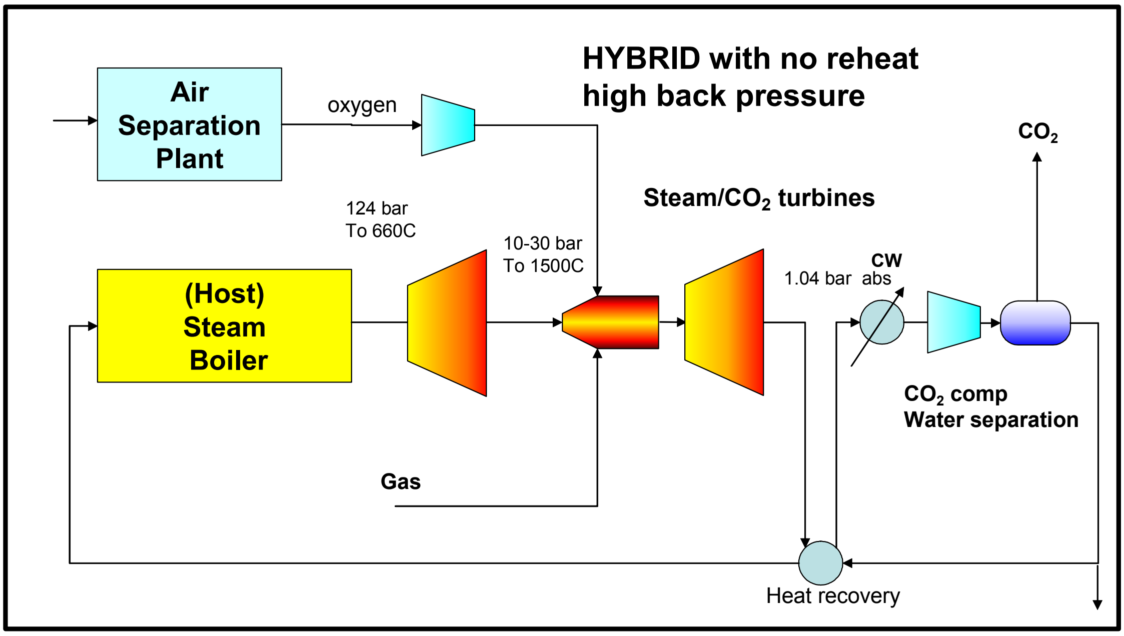


Fig 9 Hybrid oxy-combustion process with no reheat and high back pressure

In conclusion the hybrid process described indicates the ability to achieve power generation from natural gas with an effective efficiency around 50% which is similar to the performance of post-combustion capture.

However the hybrid can be viewed from another perspective which is as an addition to a base CES type process in which steam from an add-on process is mixed into the gas from the CES oxy-fired generators. This additional steam could be raised to full temperature by running the generators at a higher temperature and allowing the two streams to mix. This would enable the heat from the add-on process to be converted to electricity at the same efficiency as the basic CES cycle **without** the parasitic losses for oxygen production or CO_2 compression. This potentially boosts the efficiency of use of the steam up to around 55% which is the efficiency of the basic CES cycle without subtraction of the parasitic losses for oxygen production and CO_2 compression.

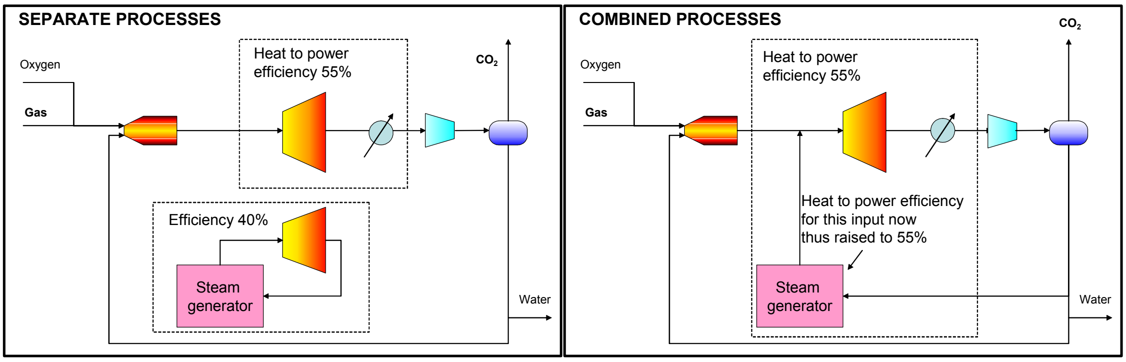


Figure 10 Boosting performance of low efficiency steam cycle by integration with oxy-combustion cycle

3.9 Comparison of specific results.

The main results of the evaluations are summarised in table 1. The results are also plotted on the performance risk chart as described earlier see figure 4. In addition figure 5 illustrates the performance rankings using the multi-criteria analysis as compared to the ranking based on electricity costs alone. For the processes analysed the multi-criteria results tended to widen the range of performance scores but did not significantly change the actual rank order with exception of the gas fired PCDC process which improved its ranking.

Specific conclusions about the processes are as follows. The base cases with capture both lose in performance compared to the no capture alternatives. This indicates that for the scenario incorporated into PPAP, which values CO_2 emission reduction at $50/ton and fuel efficiency with a 3$/Gj premium, there is not a compelling case for capture especially for coal fired units. The main reasons for this are the higher capital costs but also the extra fuel penalty since both capture processes result in considerable increases in specific fuel consumption.

Of the new processes the cryogenic process proposed by the Israeli-Russian research centre shows up with very poor performance which alone is enough to question any further development. This coupled with a quite high development risk score places this process in the “unfavourable” quadrant.
The chemical looping processes using either Barium or Copper oxides had a reasonable but not outstanding performance score but were evaluated as having very high development risk. The risks are intrinsic to this type of process which involves circulation of massive amounts of solid materials at high temperature. Some way of significantly improving the performance would be needed to make this process a serious contender. Net efficiencies were only 44.3%(Barium oxide)/45.6% (Copper oxide) with little prospect of changing the process to raise them.

By contrast the CES process evaluates with much lower risks and has a performance which brings the version using 1200ºC turbine inlet temperatures just inside the “high performance low risk” quadrant. The efficiency was only 45.4% but this could be improved significantly if turbine inlet temperatures can be raised from the assumption of 1200ºC to the same level as those attained in the current generation of gas turbines. However the efficiency loss due to the parasitic power required to produce the oxygen required and to recompress CO_2 amount to about 14%. This is offset by very high turbine efficiency (61.5%) achieved because a condensing system with quite low vacuum pressure is employed. Moving to higher inlet temperatures should allow this process to challenge the efficiency of the CCGT with pre combustion decarbonisation.

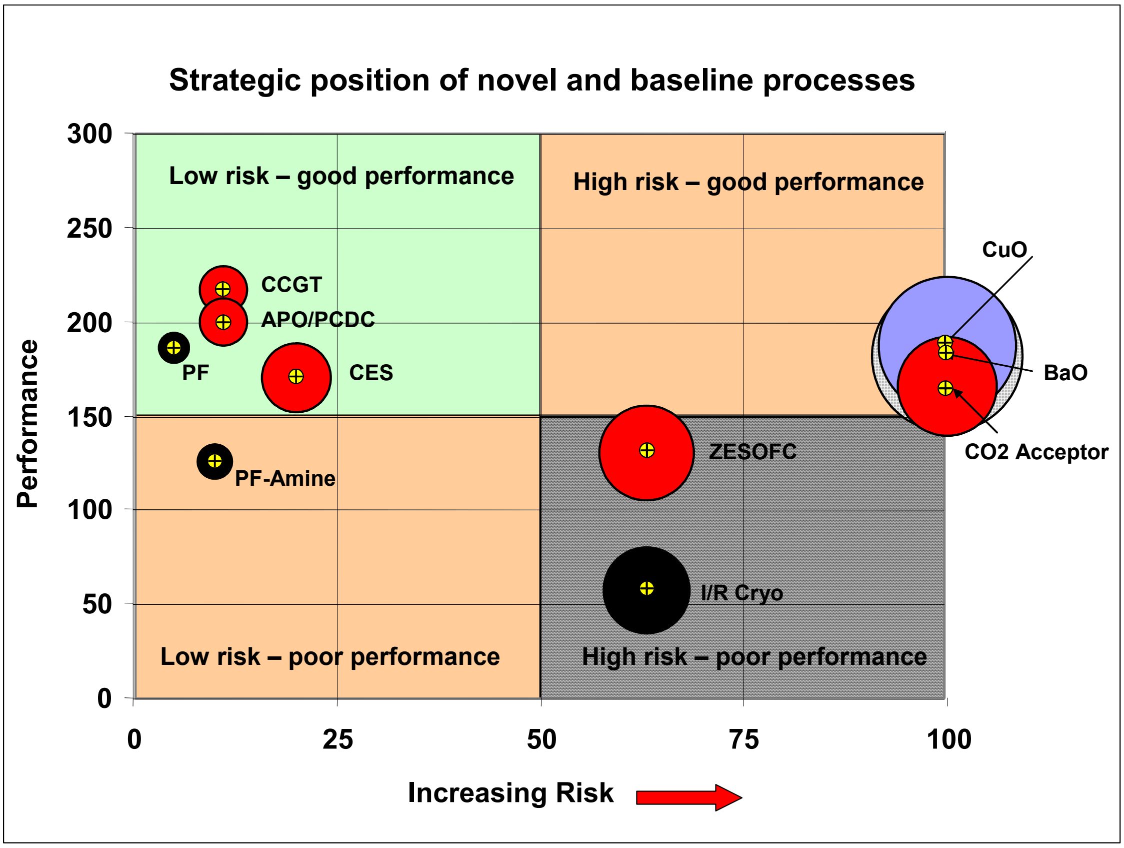
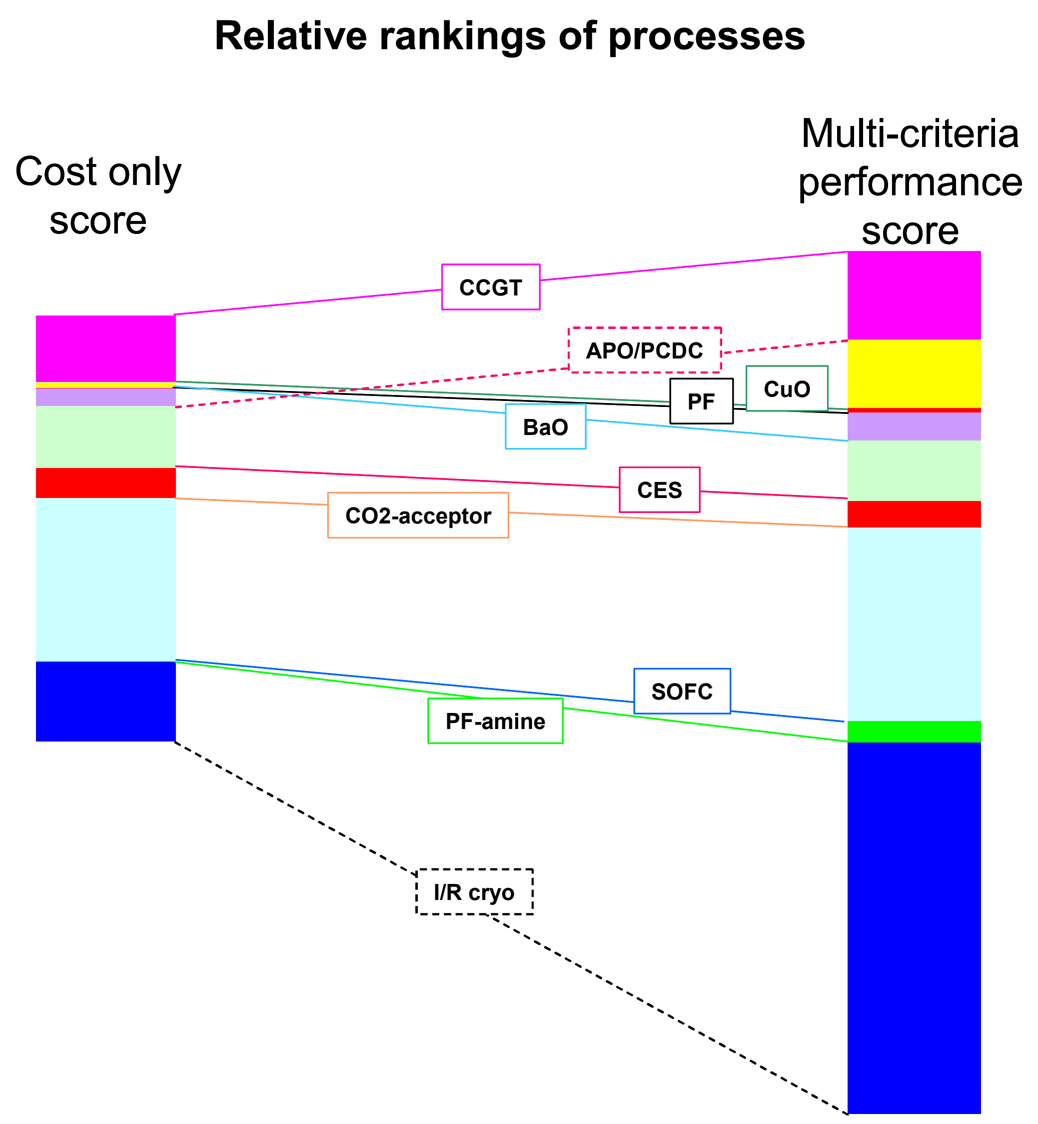


Figure 5 Strategic position of novel and baseline processes

The CO_2 capturing solid oxide fuel cell process evaluated as having a fairly high risk and only moderate performance, it was just below the top of the poor performance high risk quadrant. The poor performance score is due mainly to rather high estimated costs for the equipment which more than offset the high efficiency of 64.8% which was calculated for this process. A significant breakthrough in fuel cell costs would be required to make this process a serious contender.

In the CO_2 acceptor process gas is reformed in the presence of dolomite (CaO/MgO). This shifts the reaction so that no separate shift conversion is needed. As a result the reformed gas does not have to be cooled down for the shift conversion and can be fed at high pressure and temperature directly to a gas turbine. This greatly reduces thermodynamic losses. The regeneration of the circulating Dolomite was also set to occur at high temperature to maximise the efficiency of power generation from the heat removed from the streams exiting this system



Performance scores on cost only basis and with multi-criteria factors included. Note that the multi-criteria analysis increases differentiation between processes. However for the scenario weightings used the preference order does not change significantly. The main change is the ranking of APO/PCDC which mainly reflects the proven nature of this process.

Figure 6 Relative ranking of processes

Regeneration was also modelled at high pressure thus reducing the power required for compression of captured CO_2. The overall efficiency of the process at 47.7% was encouraging but still a few points less than that calculated for air blown partial oxidation pre-combustion decarbonisation process (50.5%). This process was also evaluated as having high development risk because of the massive high temperature solids re-circulation system which this process has in common with the BaO/CuO chemical looping systems.

4 PPAP input and output sheets and GasConsult evaluation reports

All the PPAP outputs and gas consult reports are collected in Appendices to this report. The GasConsult reports include basic commentary on each evaluation as well as flow sheets and material and heat balances from Hysis simulations where used. Also included are comments about the usability of PPAP which have been used to upgrade the programme. Original studies were done on a version with different weighting factors and without evaluation of development risk. The processes which were evaluated on the earlier version were rerun later on the newer version.

4.1 Using PPAP

PPAP comes complete with a help section which explains how to use it and there is thus no separate manual. In addition many of the cells have explanatory notes attached which are intended to clarify the information. This CD also contains a copy of the latest version of PPAP which is thus available for installation and use.

APPENDIX A
Questions and standard answers for multi criteria analysis

The primary answer text gives the multiple choices which are used to determine the performance score. The qualifying answer texts shown in boxes are used in ***conjunction*** with the primary answer texts to generate the risk scores. As such these qualifying answers **DO NOT** affect the performance score. The actual weighting factors can be inspected in the program in the lower part of the "analysis" worksheet. Score contributions are accessed through lookup tables in this part of the worksheet.

Raw material availability;

Primary text

Globally Common
Locally Common
Moderately Common +
Scarce
Very Scarce

Qualifying text

with unlimited availability
with some limits to availability
with severe limits to availability
with totally inadequate availability

\+ for the scale of this application

Process conditions:

Temperature & Pressure texts

<1200K
1200K-1600K
1600K-2000K +
>2000K
Cyrogenic

Atmospheric
<10bar
10-60bar
60-150bar
>150bar

\+

Qualifying text

but no significant technical barriers
needs tech breakthrough with known parallels
needs tech breakthrough without parallels, theory/principles accepted
uses unproven effects not yet accepted by scientific community

Novelty of materials

Selection text

Carbon Steel
Stainless Steel
Existing Special Alloy +
New Special Alloy
Exotic Ceramic

Qualifying text

known material in known environment
or known material but in new environment
or newly discovered material proven in similar duty
or newly discovered material proven in different duty
or new material yet to be developed
or totally new material yet to be discovered

Process novelty

Primary text

First qualifier

Second qualifier

industrial applications in operation
initial industrial application
and extensive pilotscale demonstration
but limited pilot scale demonstration
and extensive benchscale testing
but limited benchscale testing
credited scientific proof of concept

Fully Proven
Minor Modifications
Major Modifications +
Major New Ideas

highly
successful
promising
problematical
unsuccessful
no

+

Safety risk:

Primary text

Qualifying text

Benign
Small Risk
Risk
Major In Plant Risk
Major Ex Plant Risk

extensively demonstrated and publicly accepted
or demonstrated but concerns emerging in public domain
or NOT demonstrated, high degree of public concern existing or likely

Environmental impact:

Primary text

Qualifying text

Useful byproducts
Benign Waste
Mildly Harmful Waste
Moderately Harmful Waste
Extremely Harmful Waste

extensively demonstrated and publicly accepted
or demonstrated but concerns emerging in public domain
or NOT demonstrated, high degree of public concern existing or likely

IEA GREENHOUSE GAS R&D PROGRAMME

PPAP EVALUATION OF EARLIER STUDIES ON POWER GENERATION WITH CO_2 CAPTURE:

- **PF COAL + AMINE WASH (IEAGHG/SR3, 1993)**
- **PRECOMBUSTION DECARBONISATION OF NATURAL GAS (IEA/CON/97/22, 1998)**

IEA CONTRACT NO. IEA/CON/02/75
GASCONSULT LTD CONTRACT NO. 012 - 003

AUGUST 2002

CONTENTS

EXECUTIVE SUMMARY

With a view to establishing two ‘benchmarks’ against which innovative power generation schemes with CO_2 capture can be assessed, IEA has commissioned Gasconsult Ltd to use IEA’s in-house PPAP software to re-assess two earlier studies on power generation with capture of CO_2. These two studies are:-

IEAGHG/SR3 Appendix A (1993):- CO_2 capture by MEA wash from flue gases of conventional pulverised coal fired plant.

IEA/CON/22 Case G (1998):- Combined cycle plant with precombustion decarbonisation of the natural gas fuel by catalytic partial oxidation.

Gasconsult has only been asked to apply PPAP to these two studies, with the subsidiary task of using PPAP to assess the efficiency and performance of a steam cycle. Gasconsult has not been required to calculate or otherwise investigate the potential for redesign or upgrading of these two systems.

The main conclusions to be drawn from the present work are:

1. When used in conjunction with a calculated or representative steam cycle thermal efficiency, PPAP has given values for specific investment cost that are close to those generated in the two original studies.
2. PPAP typically gives steam cycle efficiency that is rather higher than the true efficiency for the selected cycle conditions. This appears to originate in part from minor errors in calculation formulae.
3. It might now be appropriate to consider whether a more modern version of the PF + amine route could be used as a benchmark. Improvements in the PCDC system may also now be possible aimed at lower capex and improved operability – specifically elimination of the problematic feed/effluent exchanger downstream of the ATR reactor, substitution of medium pressure steam for high pressure steam generation and superheating.

1. INTRODUCTION

In order to assess and put in context future results from PPAP, the IEA Greenhouse Gas R&D Programme has commissioned Gasconsult to produce two PPAP case assessments of generating plant with CO_2 capture as a type of 'benchmark'. These two cases are:-

> **CASE A**
> The early 1990's design sub-critical coal PF fired plant with flue gas desulphurisation and MEA CO_2 removal as described in 'The Capture of Carbon Dioxide from Fossil Fuel Fired Power Stations' (IEAGHG/SR1, 1993).
>
> **CASE B**
> The gas-fired combined cycle plant with precombustion decarbonisation (PCDC) by catalytic partial oxidation as described in IEA/CON/22 Case G (1998).

Gasconsult's current work includes the subsidiary task of using PPAP to assess the steam cycle efficiency (particularly of the steam cycle in Case A).

Gasconsult has specifically not been required at this moment to calculate or otherwise investigate the potential for redesign or upgrading of the two systems.

2. DESIGN BASIS

The current work has been carried out on the basis of the standard IEA assessment conditions. These include an electric power output of nominally 500MWe at the generator terminals after deduction of internal electrical consumption.

3. CASE A: PF COAL + AMINE WASH

3.1. Steam Cycle Conditions

The steam cycle conditions assumed in the PPAP assessment are near to those given in Appendix A of 'Greenhouse Gas Releases from Fossil Fuel Power Stations' (IEAGHG/SR1, 1993). These conditions include superheater exit at 190bar/568.5^{0}C and a single reheat to 565^{0}C.

3.2. SO_2 Removal

To reduce as much as reasonable irreversible degradation of the MEA solution by SO_x, the original study IEAGHG/SR3 provided for almost complete removal of SO_2 (to 1ppm concentration) at the inlet to the CO_2 absorber. As limestone-based FGD cannot achieve so low an SO_2 concentration, the study proposed use of the 'Cansolv' liquid wash process. The Cansolv process may well be, and probably is, a satisfactory means of SO_2 removal for this duty, but it should be noted that the extent of practical experience with Cansolv is much less than with limestone-based FGD. It is understood that no full-scale unit has ever been built. Moreover a technical solution which required the substitution of a Cansolv unit for existing limestone sorption equipment would add significantly to the cost of retrofitting CO_2 capture to existing coal-fired plant.

3.3. CO_2 Removal

The specific heat requirement for regeneration and reclamation of the MEA solvent is not given in IEAGHG/SR3, but it is likely to be >60 kWh(th)/kmol CO_2 removed. The rather large drop in overall generating efficiency due to CO_2 capture (from 40% to 28% approximately reported in IEAGHG/SR3) is mostly due to this LP steam demand. Substitution of more recently developed solvents might perhaps approximately halve the specific solvent regeneration heat requirement. If this is substantiated, the penalty in generating efficiency due to CO_2 capture would also be approximately halved.

3.4. Generating Efficiency

PPAP gives an Estimated Steam Cycle Efficiency for the cycle shown in IEAGHG/SR1 Appendix A of about 46%. However Appendix A (p 87) when modified to be consistent with PPAP scope suggests 42%. These efficiencies include boiler feed pumps and condensate pumps within the steam cycle (please refer to Sect 6). They exclude power requirements for solids handling, fans, turbine mechanical loses, generator and transformer losses, cooling water pumps, FGD plus CO_2 removal (if installed). The latter are either considered in PPAP as auxiliaries or are external and subtracted afterwards from the power made (please see summary on Gas Cycle page).

The steam cycle described in Appendix A of IEAGHG/SR1 was also simulated on HYSYS using ASME steam data. This returns about 43.8% excluding boiler losses – which would come down to 40% overall if these were included to put on the basis in the above paragraph. It does seem therefore that the efficiency calculated for this particular case by PPAP may be too high. Based on enthalpies in PPAP a much lower efficiency is calculated. Therefore the efficiency calculation based on calculating the area of the thermodynamic cycle on the TS diagram is suspect.

When an agreed view of the most representative state of the art efficiency is available, it may be possible to insert this value into PPAP and develop new scores.

3.5. PPAP Capital Cost

This is shown in Table 1 (Sect 7). The costs shown in IEAGHG/SR3 Appendix A are on a 1991 basis whereas PPAP costs are from around 1999. On a comparable basis there is reasonably close agreement, though the Appendix A total is slightly (5%) higher. However, this figure over represents the probable agreement as a significant proportion of the items have been simply copied from the Appendix A column to PPAP or vice-versa.

3.6. PPAP Criteria & Scores

Criteria:-

Raw Material: Locally Common	90
Process Conditions: Atm<1200 K	100
Materials: Stainless Steel	95
Process: Minor Modifications	95
Safety: Small Risk	80
Environmental: Mildly Harmful Waste	50

Scores:-

Heat In		1546.5MWth
Estm.	Net Electricity Output	500.0MWe
	Net Efficiency LHV	32.3%
	CO_2 output	14.1kg/s
	CO_2 output	0.101kg/kWh
Estimated Capital Cost		1240.6Mill $
Estimated Op Cost		7.2c/kWh

Multi-Criteria Assessment:-

Decision Factor Scores	
Acceptance	68.0
Applicability	66.9
Confidence	91.3
Estimated Cost	60.1

3.7. Comments

Due in part to the considerations described above relating to removal of SO_2 and CO_2 and in part to the improvements in steam cycle conditions and steam turbine efficiencies since 1993, it may now be appropriate to consider whether a more modern version of the PF + amine route could be used as a benchmark.

4. CASE B: PRECOMBUSTION DECARBONISATION OF NATURAL GAS

4.1. Steam Cycle Conditions

As IEA/CON/22 does not provide very much information on the steam cycle, the efficiency of the steam cycle has been calculated by PPAP. As noted under Case A above, this is likely to give a steam cycle efficiency rather higher than the true efficiency for the cycle conditions selected. As, however, in this Case B scheme the steam cycle only contributes about a third of the total power output, the efficiency overestimate due to PPAP is only likely to be only around 1 %.

4.2. PPAP Capital Cost

The capital cost predicted by PPAP is $458 million. This corresponds to about $386 million when Owners Costs and Contingency are not included. The latter compares well with that predicted in IEA/CON/22 (a range of $347 to 459 million depending on the assumed cost of the base combined cycle).

4.3. PPAP Criteria & Scores

Criteria:-

Raw Material: Locally Common	90
Process Conditions: 10-60 bar, 1200 -1600K	80
Materials: Existing Special Alloys	90
Process: Minor Modifications	95
Safety: Small Risk	80
Environmental: Benign Waste	80

Scores:-

Heat In		986.0MWth
Estm	Net Electricity Output	467.8MWe
	Net Efficiency	47.4%
	CO_2 output	8.6kg/s
	CO_2 output	0.066kg/kWh
Estimated Capital Cost		458.2Mill$
Estimated Op Cost		3.3c/kWh

Multi-Criteria Assessment

Decision Factor Scores

Acceptance	80.0
Applicability	73.0
Confidence	77.5
Estimated Cost	78.3

4.4. Comments

Since the completion of IEA/CON/22 in 1998, Gasonsult has suggested improvements aimed mainly at reducing the complexity of the installation, removing potentially problematic components and reducing investment cost.

5. CONCLUSIONS

PPAP Scores
These have been developed. Further effort is required to assess the precise significance of these figures.

Investment Cost:
PPAP has given investment costs that are close to those previously generated by IEA for both the Cases examined.

Steam Cycle Efficiency:
PPAP typically gives steam cycle efficiency that is rather higher than the representative efficiency for the cycle conditions selected in this study. This appears to be due to errors in the calculation routine.

PF + Amine:
It might now be appropriate to consider whether a more modern version of the PF + amine route could be used as a benchmark

PCDC:
Since the completion of IEA/CON/22 in 1998, improvements in PCDC have been suggested aimed mainly at reducing the complexity of the installation, removing potentially problematic components and reducing investment cost. Improvements in the PCDC system may also now be possible.

6. GENERAL COMMENTS ON PPAP ASSESSMENTS

The steam cycle efficiency definition used by PPAP appears be defined as the ratio of power out to fuel LCV in, all auxiliaries being subtracted later from the gross power made. However, it is not entirely clear how the boiler feed pump power is included in PPAP. It does not appear in the summary with other auxiliaries, which are all brought together and are summarised on the Gas Cycle page. This supporting efficiency calculation is actually on the Steam Cycle page, but is in a hidden area. It is suspected that the boiler feed pump power is not specifically included here, as, if the boiler feed pump pressure is changed to an absurdly high value (say 1000 bar), the cycle efficiency is unchanged in spite of the extra power consumed by the feed pumps. It would be useful to raise this query with the originators of PPAP. The same comment must apply to the condensate pumps though these are not so important.

Also it is not clear how CO_2 removal by amine is included in PPAP. The Acid Gas Removal entry on the Costing page appears to be tied to H_2S removal. CO_2 separation is included in the Plant Components page, but does not appear explicitly on the Costing page. It has been assumed that this is intended to be included as a user defined item.

7. TABLES AND FIGURES

Table 1 Capital Cost Comparison – Case A

Description	Scaling parameter	Size per unit	No of units	Cost multiplier	PPAP 1276.3 MW in Predicted cost M$ (1999)	APPENDIX A 1254.4 MW in Predicted cost M$ (1991)	APP A COMMENTS	**
Solids handling	kg/s	61.9	1	1	15.63	26.40		
Coal pulverise+dry (gasif)								
Oxygen production	kg/s feed	0.0	0	1	0.00			
Gasifier (Shell, inc hopper, cool/filt/scrub)	kg/s O2	0.0	0	1	0.00			
Acid gas removal (scrubbing)	MW fuel feed LHV	0.0	0	1	0.00			
CFBC	kmol/s feed gas	0.0	1	1	0.00			
CO2 compressor (motor driven)	MW fuel feed LHV	0.0	0	1	0.00			
Gas turbine, complete	MWe	54.5	1	1	55.28	43.64	AS PPAP	
Gas turbine, compressor only	MWe	0.0	0	1	0.00			
Gas turbine, turbine only	MW consumed							
Gas turbine, generator only	MW							
HRSG	MWe							
Steam turbine+pipes+cooling system	MWth transferred	590.8	1	1	150.57	117.80	GG Releases App A p 90	
PF coal boiler	MWe	1546.5	1	1	210.30	123.50	GG Releases App A p 90	
FGD (limestone gypsum)	MW fuel feed LHV							
Gasifier fuel gas cooler (fire tube)	kmol/s feed	0.0	1	1	0.00			
Gasifier fuel gas cooler (water tube)	MW transferred	0.0	0	1	0.00			
Candle filter (400C)	MW transferred	0.0	0	1	0.00			
PFBC combustor	kmol/s feed	0.0	0	1	0.00			
Gas/gas exchanger, 20bar, 30C delta T	MW fuel feed	0.0	0	1	0.00			
Acid gas removal (SO2 & CO2)	MW transferred	0.0	0	1	383.58	302.80	C Cap App A A12 p166	
Other	User Defined	0.0	0					
Other	User Defined	0.0	0		0.00	24.40	ESP	
Other	User Defined	0.0	0		0.00	7.30	WTP	
Other	User Defined					10.70	C&I	
Other	User Defined							
Other	User Defined							
Other	User Defined							
	User Defined							
Electrical distribution	MWe gross	500.0	1	1	11.48	19.60		
Sub-Total					826.84	676.14		
Balance of plant	% of above	10			82.68	72.20	MISC	
SUBTOTAL					909.53	748.34		
Engineering, indirects, owners cost	% of above	24			218.29	179.60	AS PPAP	
SUBTOTAL					1127.81	927.94	AS PPAP	
Project contingency	% of above	10			112.78	92.79	AS PPAP	
TOTAL (1991)						**1020.74**		
TOTAL (1999)					**1240.59**	**1293.04**		
Cost escalation assumed 91/99		1.267						**

PPAP EVALUATIONS
GCL Contract No 014-002

Evaluation of CES Technology

We now have pleasure in submitting for your comments the draft Report of our PPAP Evaluation of the CES (Clean Energy Systems, Inc) Zero Emissions power technology.

1. INTRODUCTION

Our evaluation of the CES technology is based on the three files, describing the system, which you e-mailed to us on 24 April 2003:

CES thermodynamic_analysis1.pdf
CES_Cost_Eff1.pdf
CES.ppt

The meeting with Dr. Keith Pronske on 15th July 2003 also provided valuable background information.

While the CES technology can in principle be used (via upstream gasification) with a wide range of primary fuels, this present evaluation is based only on natural gas fuel.

2. BASIS OF DESIGN

The Basis of Design for the evaluation is IEA Technical and Financial Assessment Criteria Rev B 1999, with these exceptions:

2.1 Natural gas cost is $3 /GJ.

2.2 Carbon capture is 100% of the carbon content of the incoming natural gas. It is likely that some improvement in thermal efficiency may be obtained by reducing carbon capture to the standard 85%, perhaps through driving the ASU compressors by a conventional combined cycle. This idea was, however, not pursued, as being contrary to the "zero emission" concept of the technology. Moreover it would add to an already rather complex arrangement of turbo-machinery.

3. TECHNOLOGY DISCUSSION

3.1 Basic Concept

The core of the CES is high-pressure stoichiometric combustion of a fuel (in this case natural gas) with oxygen and quench water, thereby forming a CO_2/steam mixture containing around % CO_2 and % steam. This mixture is then expanded to sub atmospheric pressure, in a series of turbine stages, with intermediate reheat by combustion of more natural gas with oxygen according to variant. The steam content of the turbine exhaust is condensed against cooling water. The CO_2 is compressed, liquefied and exported for disposal**.**

3.2 Variant Studied

CES has provided flowsheets for several variants, with progressively increasing expansion temperatures to reflect future advances in turbine materials and technology. By agreement with IEA and CES, Gasconsult (GCL) has concentrated on a variant with 816 C inlet temperature to the HP turbine and 1200 C inlet to the MP turbine. This variant is intended for application in the medium term, perhaps by 2010.

3.3 Simulation of Heat and Material Balance

The heat and material balance for the selected case was simulated on HYSYS using the information on the CES flow diagram (please see flow diagram PFD2.jpg and Worksheet MATBAL2.xls attached). After allowance for the power required to produce oxygen and deliver it at high pressure, the resulting overall gas-to-power efficiency for this “Medium Term” scheme worked out at 46.9%, which is close to the efficiency predicted by CES.

3.4 Plant Design Aspects

It is assumed that the CES combustion/quench reactor, based on rocket engine technology, has been satisfactorily demonstrated to achieve the stoichiometric combustion required on a small scale. There will be questions over scale-up and reactor life, and the developers may be confident on those counts, taking into consideration the possibility of multiple reactor assemblies, and the small size of the reactor facilitating rapid repair/replacement.

Considering the plant as a whole, there are several aspects that may place the technology at a disadvantage relative to competing alternatives, at least in the near term:

- Difficulty in providing turbine cooling fluids, particularly for the HP turbine. There is no cooling steam available. Recycled CO_2 may be a possibility

- While the HP turbine can be foreseen as an extension of steam turbine practice, and the MP turbine could be based on the expansion section of a gas turbine, the LP turbine will also require a considerable development effort. This is due to its proposed operation with high vacuum and exhaust temperature of 330^0C. This temperature is 250-300^0C higher than the exhaust temperature of a normal condensing steam turbine.

- The quench water heater located down stream of the LP turbine also has demanding duty. High heat load, vacuum on the shell side, stainless steel or titanium on both shell and tube sides due to CO_2 corrosion/erosion.

- The main steam condenser also has an unusual duty, relative to a normal steam condenser. High non-condensable fraction (>20% CO_2), with all-stainless steel or titanium construction unavoidable due to the wet CO_2.

- Another less desirable feature is the rather large number of more or less complex rotating machine duties. Natural gas compression, oxygen compression (although an ASU with oxygen pump can eliminate oxygen compressors as such), complex and developmental turbine assembly, and multi-stage stainless steel wet CO_2 compression with overall compression ratio (110/0.05) = 2200.

- Any defect or trip in the process will disable the whole power production unit. In this, CES is less attractive than, say, CO_2 capture by flue gas scrubbing or PCDC, with which power production can be maintained in event of shut-down of the carbon capture equipment.

4. MAIN PPAP INPUTS

Plant Components:-
Gas Turbines x 1
Gasifier x 1
ASU 86.42 kg/s delivered at 72 bar (mean of HP/LP O_2)
CO2 compression/pumping to 110 bar

Fuel Specification:-
NG 100% CV 46920, C fraction 0.739
Mass & Energy: Fuel 23.00 kg/s
% to Gasification: 100% - all recovered to Gas Cycle

Gas Cycle details (from the HYSYS simulation):-
CO_2 and O_2 Compression power 155.2 MW (It is assumed this includes the power required for the ASU air compressor)
GT Power 663 MW
Overall efficiency after losses 46.87 %
Overall power output 505.7 MW

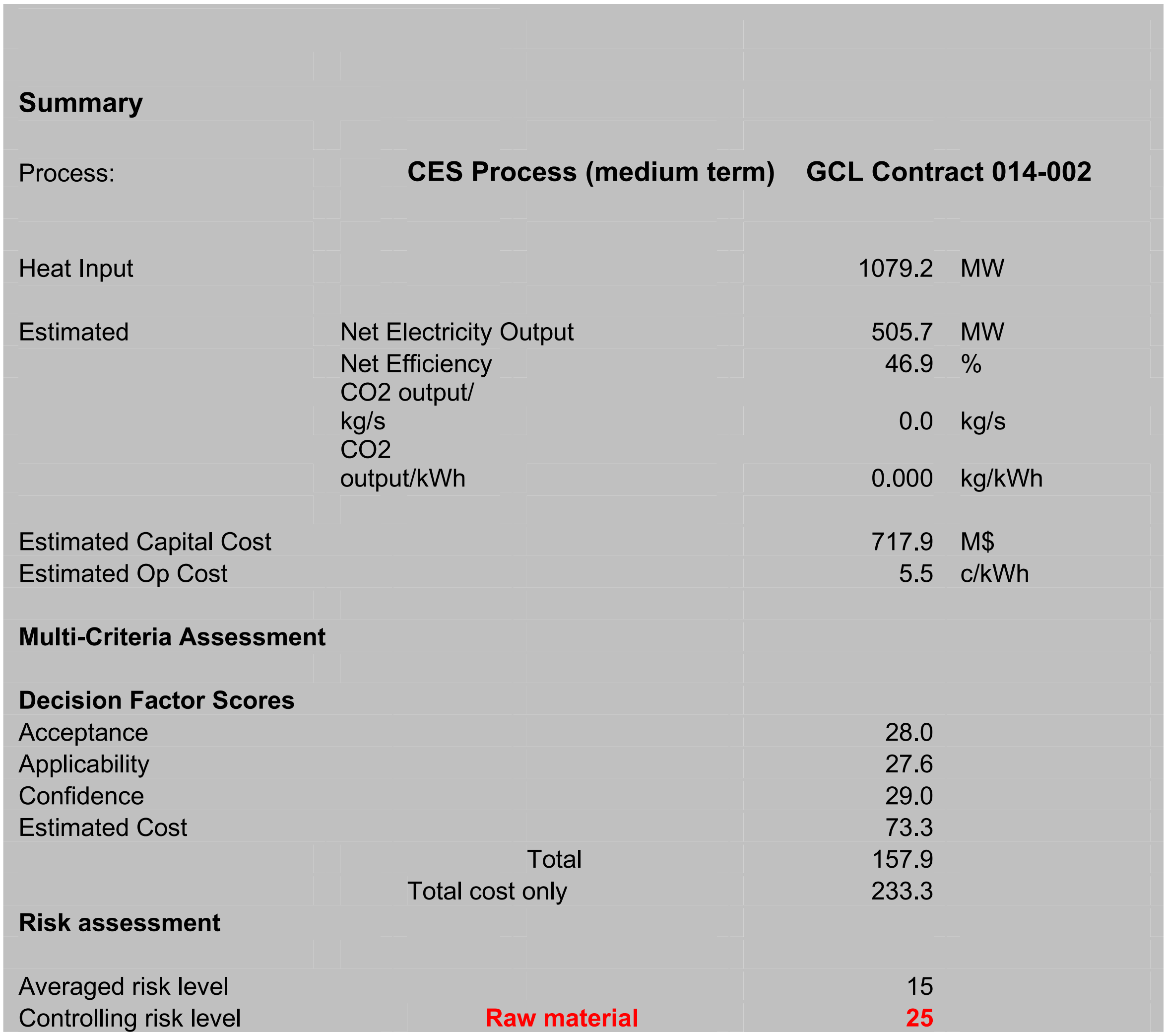
Costing:-
The values predicted by PPAP for the major components were compared with the CES data and it was thought that there was overall order of magnitude agreement. The only correction that was felt necessary was to the Gasifier where PPAP correlated conventional large units whereas the small CES devices based on rocket technology must be much less costly. A correction factor of 0.5 was inserted.
Total investment cost $ 718 million.

Operating Cost:-
Natural Gas $3/GJ
Power cost is ~5.5 c/kWh.

Multi-Criteria Analysis:-

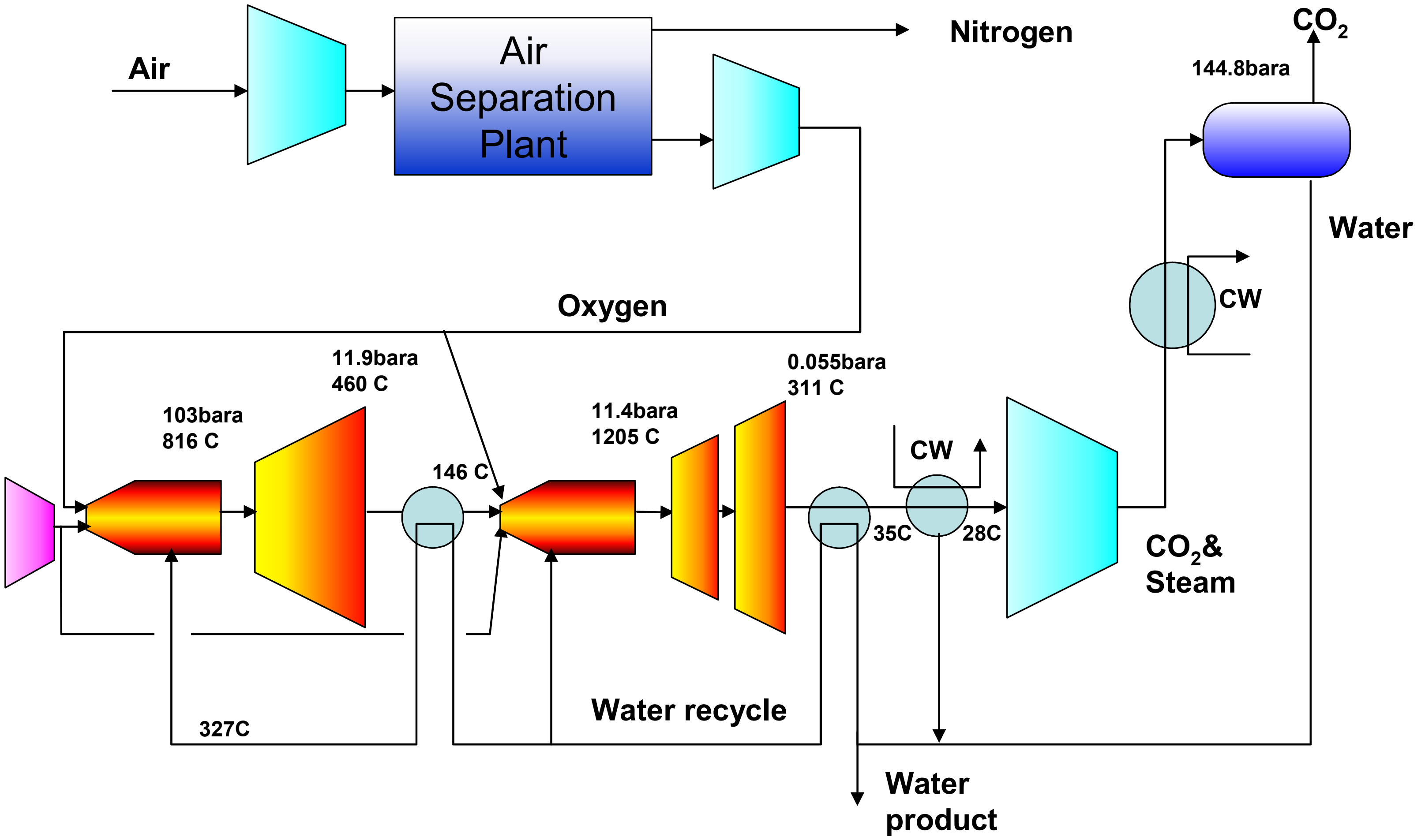
Parameter: Raw Material Availability
Value: Locally Common with some limits to availability
Parameter: Process Conditions
Value: T 1200-1600 degK, 60-150 bar but no significant technical barriers
Parameter: Novelty of Materials
Value: Existing Special Alloys known material but in new environment
Parameter: Plant Complexity
Value: 5 Major Units, no reycle
Parameter: Novelty of Process
Value: Major Modifications with promising and extensive pilot scale demonstration (this is looking into the future a few years and is not today’s situation)
Parameter: Safety Risk
Value: Risk – extensively demonstrated and publicly accepted
Parameter: Environmental Impact
Value: Begnign Waste – extensively demonstrated and publicly accepted

5. RESULTS

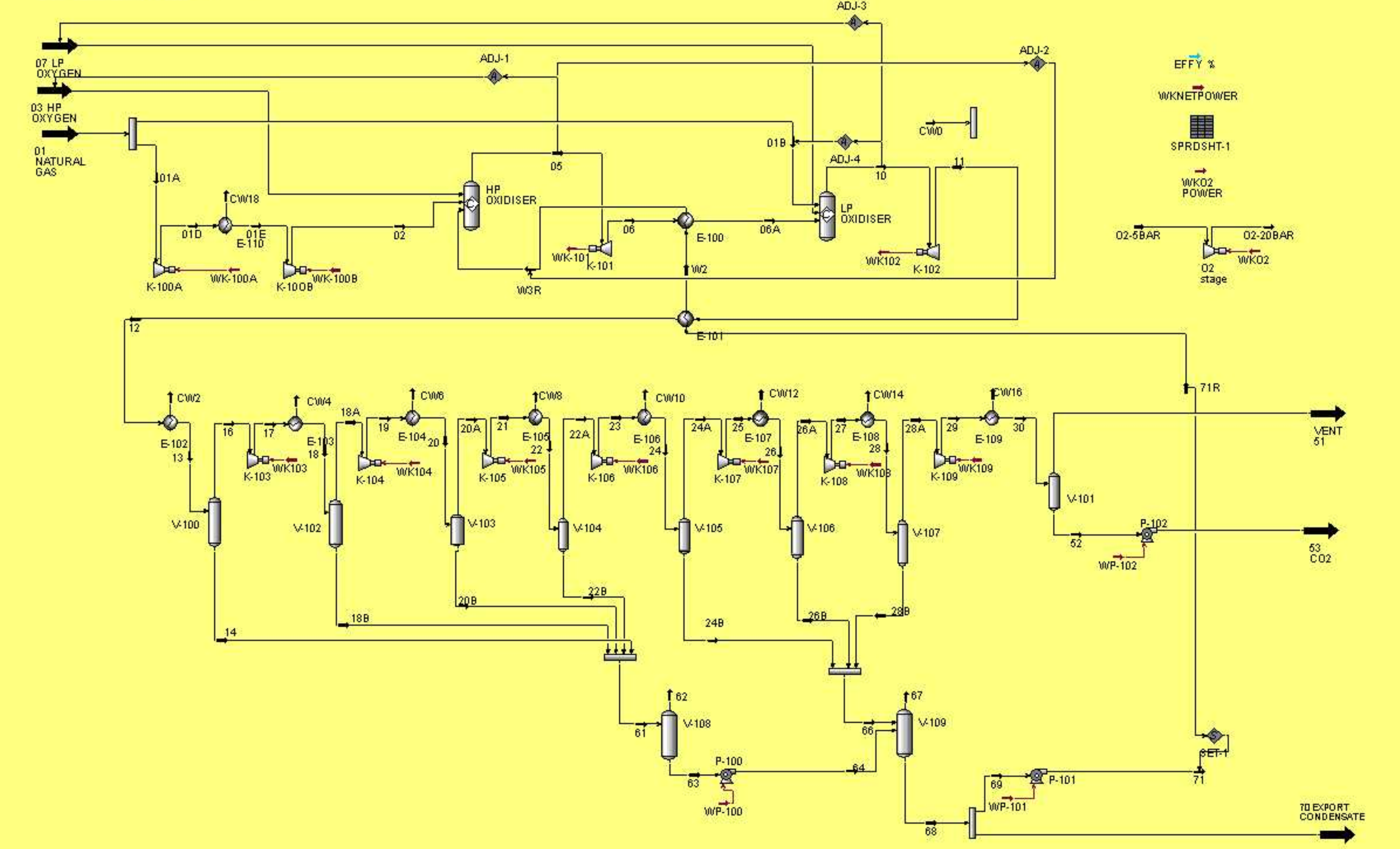


Summary			
Process:	**CES Process (medium term)**	**GCL Contract 014-002**	
Heat Input		1079.2	MW
Estimated	Net Electricity Output	505.7	MW
	Net Efficiency	46.9	%
	CO2 output/ kg/s	0.0	kg/s
	CO2 output/kWh	0.000	kg/kWh
Estimated Capital Cost		717.9	M$
Estimated Op Cost		5.5	c/kWh
Multi-Criteria Assessment			
Decision Factor Scores			
Acceptance		28.0	
Applicability		27.6	
Confidence		29.0	
Estimated Cost		73.3	
	Total	157.9	
	Total cost only	233.3	
Risk assessment			
Averaged risk level		15	
Controlling risk level	**Raw material**	**25**	

CES Process


Air
Air Separation Plant
Nitrogen
CO2
144.8bara
Water
CW
Oxygen
11.9bara
460 C
0.055bara
311 C
103bara
816 C
11.4bara
1205 C
146 C
CW
35C
28C
CO2& Steam
Water recycle
327C
Water product

CES PROCESS MEDIUM TERM
GCL contract 014-002



Workbook: Case (Main) CES PROCESS

Streams

Name	**01 NATURAL GAS**	**01A**	**01B**	**01D**	**01E**
Vapour Fraction	1	1	1	1	1
Temperature (C)	20	20	20	82.72	27
Pressure (bar)	28.6	28.6	28.6	60	58.8
Molar Flow (kgmole/h)	4267.9	2020	2247.9	2020	2020
Mass Flow (kg/h)	82794.9	39187.2	43607.7	39187.2	39187.2
Heat Flow (kW)	-99305.3	-47001.6	-52303.7	-45706.1	-47228.2
Comp Molar Flow (CO2) (kgmole/h)	76.8	36.4	40.5	36.4	36.4
Comp Molar Flow (Nitrogen) (kgmole/h)	17.1	8.1	9	8.1	8.1
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	3580.7	1694.8	1886	1694.8	1694.8
Comp Molar Flow (Ethane) (kgmole/h)	392.6	185.8	206.8	185.8	185.8
Comp Molar Flow (Propane) (kgmole/h)	140.8	66.7	74.2	66.7	66.7
Comp Molar Flow (n-Butane) (kgmole/h)	59.8	28.3	31.5	28.3	28.3

Name	**2**	**03 HP OXYGEN**	**5**	**05A**	**6**
Vapour Fraction	1	1	1	0	1
Temperature (C)	91.68	20	819	819	438.3
Pressure (bar)	124	124	124	124	11.9
Molar Flow (kgmole/h)	2020	4641.4	40625.7	0	40625.7
Mass Flow (kg/h)	39187.2	148340.7	795751.4	0	795751.4
Heat Flow (kW)	-45969.9	-1397.6	-2.49E+06	0	-2.66E+06
Comp Molar Flow (CO2) (kgmole/h)	36.4	0	2415.9	0	2415.9
Comp Molar Flow (Nitrogen) (kgmole/h)	8.1	46.4	54.5	0	54.5
Comp Molar Flow (Oxygen) (kgmole/h)	0	4595	37.9	0	37.9
Comp Molar Flow (H2O) (kgmole/h)	0	0	38117.4	0	38117.4
Comp Molar Flow (Methane) (kgmole/h)	1694.8	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	185.8	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	66.7	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	28.3	0	0	0	0

Name	**06A**	**07 LP OXYGEN**	**10**	**10A**	**11**
Vapour Fraction	1	1	1	0	1
Temperature (C)	220	20	1201	1201	309
Pressure (bar)	11.4	20	10.9	10.9	5.50E-02
Molar Flow (kgmole/h)	40625.7	5088.3	48187	0	48187
Mass Flow (kg/h)	795751.4	162826.1	1.00E+06	0	1.00E+06
Heat Flow (kW)	-2.75E+06	-428	-2.81E+06	0	-3.31E+06
Comp Molar Flow (CO2) (kgmole/h)	2415.9	0	5104.4	0	5104.4
Comp Molar Flow (Nitrogen) (kgmole/h)	54.5	0	63.5	0	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	37.9	5088.3	55	0	55
Comp Molar Flow (H2O) (kgmole/h)	38117.4	0	42964.1	0	42964.1
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**12**	**13**	**14**	**16**	**17**
Vapour Fraction	0.9918	0.4901	0	1	1
Temperature (C)	31.11	27	27	27	129.4
Pressure (bar)	5.00E-02	4.50E-02	4.50E-02	4.50E-02	0.12
Molar Flow (kgmole/h)	48187	48187	24572.1	23614.9	23614.9
Mass Flow (kg/h)	1.00E+06	1.00E+06	442671.9	559511.4	559511.4
Heat Flow (kW)	-3.44E+06	-3.74E+06	-1.95E+06	-1.79E+06	-1.77E+06
Comp Molar Flow (CO2) (kgmole/h)	5104.4	5104.4	0.1	5104.3	5104.3
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	63.5	0	63.5	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	55	55	0	55	55
Comp Molar Flow (H2O) (kgmole/h)	42964.1	42964.1	24572	18392.1	18392.1
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**18**	**18A**	**18B**	**19**	**20**
Vapour Fraction	0.3125	1	0	1	0.7677
Temperature (C)	27	27	27	152.7	27
Pressure (bar)	0.12	0.12	0.12	0.45	0.45
Molar Flow (kgmole/h)	23614.9	7380.1	16234.8	7380.1	7380.1
Mass Flow (kg/h)	559511.4	267024	292487.4	267024	267024
Heat Flow (kW)	-1.99E+06	-702905.4	-1.29E+06	-693058.6	-723839.2
Comp Molar Flow (CO2) (kgmole/h)	5104.3	5103.6	0.6	5103.6	5103.6
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	63.5	0	63.5	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	55	55	0	55	55
Comp Molar Flow (H2O) (kgmole/h)	18392.1	2157.9	16234.2	2157.9	2157.9
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**20A**	**20B**	**21**	**22**	**22A**
Vapour Fraction	1	0	1	0.9697	1
Temperature (C)	27	27	141.2	40	40
Pressure (bar)	0.45	0.45	1.5	1.5	1.5
Molar Flow (kgmole/h)	5665.9	1714.2	5665.9	5665.9	5494.1
Mass Flow (kg/h)	236134	30890	236134	236134	233038.6
Heat Flow (kW)	-587932	-135907.2	-580869.6	-589280	-575712
Comp Molar Flow (CO2) (kgmole/h)	5103.3	0.3	5103.3	5103.3	5103.2
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	0	63.5	63.5	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	55	0	55	55	55
Comp Molar Flow (H2O) (kgmole/h)	444	1713.9	444	444	272.4
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**22B**	**23**	**24**	**24A**	**24B**
Vapour Fraction	0	1	0.9654	1	0
Temperature (C)	40	177.6	40	40	40
Pressure (bar)	1.5	6	5	5	5
Molar Flow (kgmole/h)	171.7	5494.1	5494.1	5304.2	189.9
Mass Flow (kg/h)	3095.4	233038.6	233038.6	229609	3429.5
Heat Flow (kW)	-13568	-567329.7	-578191.7	-563177.2	-15014.5
Comp Molar Flow (CO2) (kgmole/h)	0.1	5103.2	5103.2	5102.9	0.3
Comp Molar Flow (Nitrogen) (kgmole/h)	0	63.5	63.5	63.5	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	55	55	55	0
Comp Molar Flow (H2O) (kgmole/h)	171.6	272.4	272.4	82.8	189.6
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**25**	**26**	**26A**	**26B**	**27**
Vapour Fraction	1	0.9868	1	0	1
Temperature (C)	177.5	27	27	27	128.1
Pressure (bar)	20	18.5	18.5	18.5	55
Molar Flow (kgmole/h)	5304.2	5304.2	5234.3	69.9	5234.3
Mass Flow (kg/h)	229609	229609	228334.7	1274.3	228334.7
Heat Flow (kW)	-555201.1	-565674.3	-560111.6	-5562.8	-554938
Comp Molar Flow (CO2) (kgmole/h)	5102.9	5102.9	5102.4	0.6	5102.4
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	63.5	63.5	0	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	55	55	55	0	55
Comp Molar Flow (H2O) (kgmole/h)	82.8	82.8	13.4	69.4	13.4
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**28**	**28A**	**28B**	**29**	**30**
Vapour Fraction	0.9993	1	0	1	0
Temperature (C)	27	27	27	62.19	27
Pressure (bar)	53	53	53	80	75
Molar Flow (kgmole/h)	5234.3	5230.8	3.5	5230.8	5230.8
Mass Flow (kg/h)	228334.7	228270.2	64.5	228270.2	228270.2
Heat Flow (kW)	-563242.7	-562964.4	-278.3	-561555.6	-572263.7
Comp Molar Flow (CO2) (kgmole/h)	5102.4	5102.3	0.1	5102.3	5102.3
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	63.5	0	63.5	63.5
Comp Molar Flow (Oxygen) (kgmole/h)	55	55	0	55	55
Comp Molar Flow (H2O) (kgmole/h)	13.4	10	3.4	10	10
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**52**	**53 CO2**	**61**	**62**	**63**
Vapour Fraction	0	1	0.0001	1	0
Temperature (C)	27	38.56	27.01	27.01	27.01
Pressure (bar)	75	115	4.50E-02	4.50E-02	4.50E-02
Molar Flow (kgmole/h)	5230.8	5230.8	42692.8	4.2	42688.6
Mass Flow (kg/h)	228270.2	228270.2	769144.7	100.6	769044.2
Heat Flow (kW)	-572263.7	-571652.7	-3.38E+06	-323.5	-3.38E+06
Comp Molar Flow (CO2) (kgmole/h)	5102.3	5102.3	1.1	0.9	0.2
Comp Molar Flow (Nitrogen) (kgmole/h)	63.5	63.5	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	55	55	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	10	10	42691.7	3.3	42688.4
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**64**	**66**	**67**	**68**	**69**
Vapour Fraction	0	0.0017	1	0	0
Temperature (C)	27.16	36.14	27.22	27.22	27.22
Pressure (bar)	5	5	5	5	5
Molar Flow (kgmole/h)	42688.6	263.3	0	42951.9	33762
Mass Flow (kg/h)	769044.2	4768.3	0	773812.5	608248.4
Heat Flow (kW)	-3.38E+06	-20855.5	0	-3.40E+06	-2.68E+06
Comp Molar Flow (CO2) (kgmole/h)	0.2	0.9	0	1.1	0.9
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	42688.4	262.4	0	42950.8	33761.1
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**XPORT CONDENS**	**71**	**71R**	**CW0**	**CW1**
Vapour Fraction	0	0	0	0	0
Temperature (C)	27.22	31.18	27	17	17
Pressure (bar)	5	130	130	5	5
Molar Flow (kgmole/h)	9189.9	33762	33762	2.87E+06	1.42E+06
Mass Flow (kg/h)	165564.1	608248.4	608225.3	5.16E+07	2.56E+07
Heat Flow (kW)	-728516.3	-2.67E+06	-2.68E+06	-2.28E+08	-1.13E+08
Comp Molar Flow (CO2) (kgmole/h)	0.2	0.9	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	9189.7	33761.1	33762	2.87E+06	1.42E+06
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**CW2**	**CW3**	**CW4**	**CW5**	**CW6**
Vapour Fraction	0	0	0	0	0
Temperature (C)	27	17	27	17	27
Pressure (bar)	4	5	4	5	4
Molar Flow (kgmole/h)	1.42E+06	1.06E+06	1.06E+06	147060.9	147060.9
Mass Flow (kg/h)	2.56E+07	1.91E+07	1.91E+07	2.65E+06	2.65E+06
Heat Flow (kW)	-1.12E+08	-8.42E+07	-8.40E+07	-1.17E+07	-1.17E+07
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	1.42E+06	1.06E+06	1.06E+06	147060.9	147060.9
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**CW7**	**CW8**	**CW9**	**CW10**	**CW11**
Vapour Fraction	0	0	0	0	0
Temperature (C)	17	27	17	27	17
Pressure (bar)	5	4	5	4.92	5
Molar Flow (kgmole/h)	40182.2	40182.2	51895.5	51895.5	50038.3
Mass Flow (kg/h)	723886.7	723886.7	934903.3	934903.3	901445.6
Heat Flow (kW)	-3.19E+06	-3.19E+06	-4.12E+06	-4.11E+06	-3.98E+06
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	40182.2	40182.2	51895.5	51895.5	50038.3
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**CW12**	**CW13**	**CW14**	**CW15**	**CW16**
Vapour Fraction	0	0	0	0	0
Temperature (C)	27	17	27	17	27
Pressure (bar)	4	5	4	5	4
Molar Flow (kgmole/h)	50038.3	39677.5	39677.5	51160	51160
Mass Flow (kg/h)	901445.6	714794.9	714794.9	921652.8	921652.8
Heat Flow (kW)	-3.97E+06	-3.15E+06	-3.15E+06	-4.07E+06	-4.06E+06
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	50038.3	39677.5	39677.5	51160	51160
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0

Name	**CW17**	**CW18**	**EFFY %**	**O2-20BAR**	**O2-5BAR**
Vapour Fraction	0	0		1	1
Temperature (C)	17	27	46.87	192.9	20
Pressure (bar)	5	4		20	5
Molar Flow (kgmole/h)	7272.2	7272.2		31.3	31.3
Mass Flow (kg/h)	131010.3	131010.3		1000	1000
Heat Flow (kW)	-578043.6	-576521.5		43.2	-1.6
Comp Molar Flow (CO2) (kgmole/h)	0	0		0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0		0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0		31.3	31.3
Comp Molar Flow (H2O) (kgmole/h)	7272.2	7272.2		0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0		0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0		0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0		0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0		0	0

Name	VENT 51	W2	W3R	WK102	WK103
Vapour Fraction	1	0	0		
Temperature (C)	27	215.9	326		
Pressure (bar)	75	127	124		
Molar Flow (kgmole/h)	0	33762	33762		
Mass Flow (kg/h)	0	608225.3	608225.3		
Heat Flow (kW)	0	-2.54E+06	-2.44E+06	498711.3	23632.9
Comp Molar Flow (CO2) (kgmole/h)	0	0	0		
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0		
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0		
Comp Molar Flow (H2O) (kgmole/h)	0	33762	33762		
Comp Molar Flow (Methane) (kgmole/h)	0	0	0		
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0		
Comp Molar Flow (Propane) (kgmole/h)	0	0	0		
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0		

Name	WK104	WK105	WK106	WK107	WK108		
Vapour Fraction							
Temperature (C)							
Pressure (bar)							
Molar Flow (kgmole/h)							
Mass Flow (kg/h)							
Heat Flow (kW)	9846.8	7062.4	8382.3	7976.1	5173.6	63482.9	CO2comp
Comp Molar Flow (CO2) (kgmole/h)						154626.5	CO2 + O2 comp
Comp Molar Flow (Nitrogen) (kgmole/h)							
Comp Molar Flow (Oxygen) (kgmole/h)							
Comp Molar Flow (H2O) (kgmole/h)							
Comp Molar Flow (Methane) (kgmole/h)							
Comp Molar Flow (Ethane) (kgmole/h)							
Comp Molar Flow (Propane) (kgmole/h)							
Comp Molar Flow (n-Butane) (kgmole/h)							

Name	**WK109**	**WK-101**	**WK-100A**	**WK-100B**	**WKNETPOWER**
Vapour Fraction					
Temperature (C)					
Pressure (bar)					
Molar Flow (kgmole/h)					
Mass Flow (kg/h)					
Heat Flow (kW)	1408.8	167677.2	1295.5	1258.3	505657.2
Comp Molar Flow (CO2) (kgmole/h)					
Comp Molar Flow (Nitrogen) (kgmole/h)					
Comp Molar Flow (Oxygen) (kgmole/h)					
Comp Molar Flow (H2O) (kgmole/h)					
Comp Molar Flow (Methane) (kgmole/h)					
Comp Molar Flow (Ethane) (kgmole/h)					
Comp Molar Flow (Propane) (kgmole/h)					
Comp Molar Flow (n-Butane) (kgmole/h)					

Name	**WKO2**	**WKO2 POWER**	**WP-100**	**WP-101**	**WP-102**
Vapour Fraction					
Temperature (C)					
Pressure (bar)					
Molar Flow (kgmole/h)					
Mass Flow (kg/h)					
Heat Flow (kW)	44.8	91143.6	140.3	2799.7	611
Comp Molar Flow (CO2) (kgmole/h)					
Comp Molar Flow (Nitrogen) (kgmole/h)					
Comp Molar Flow (Oxygen) (kgmole/h)					
Comp Molar Flow (H2O) (kgmole/h)					
Comp Molar Flow (Methane) (kgmole/h)					
Comp Molar Flow (Ethane) (kgmole/h)					
Comp Molar Flow (Propane) (kgmole/h)					
Comp Molar Flow (n-Butane) (kgmole/h)					

PPAP EVALUATIONS
GCL Contract No 014-004
Evaluation of Solid Oxide Fuel Cell Technology
Revised 02/12/2004 using PPAP v3.02

We now have pleasure in submitting for your comments the Report on our PPAP Evaluation of the Solid Oxide Fuel Cell technology.

1 INTRODUCTION

Our evaluation of the SOFC technology is based on the following files, describing the system:

E-mailed by IEA on 20 February 2004:
Attachment "Design of CO_2 Capturing Solid Oxide Fuel Cell"

E-mail of 19 and 24 February 2004
Re costs of SOFC fuel cells

E-mail of 19 and 24 February 2004
Re pressure drop of Rolls-Royce fuel cells

The process scheme defined by IEA in the above-mentioned attachment is essentially an adaptation of the published Roll-Royce Solid Oxide Fuel Cell (SOFC) technology, modified to achieve essentially complete capture of the incoming carbon.

2 BASIS OF DESIGN

The Basis of Design for the evaluation is IEA Technical and Financial Assessment Criteria Rev B 1999, except as noted below:

2.1 Natural Gas Cost

The cost of natural gas is taken as $3/GJ (LHV)

2.2 Carbon Capture

The SOFC process scheme outlined by IEA in the document "Design of CO2 Capturing Solid Oxide Fuel Cell" gives almost 100% capture of the carbon content of the incoming natural gas, together with a gas-to-power efficiency evaluated by us at 67%. Accordingly this evaluation has been based on 99-100% carbon capture. It would have been possible for this PPAP evaluation to have been based on 85% carbon capture, (the target capture for most earlier PPAP studies), by firing 15% of the incoming natural gas on the oxygen-rich cathode exhaust gas from SOFC stacks. However such after firing was seen as unattractive, due to (1) the low pressure ratio - and consequent low efficiency - of the gas turbine part of the process scheme and (2) the need (avoided in the current evaluation) for a steam cycle.

2.3 SOFC Design Basis

The main parameters laid down by IEA for operation of the SOFC stack are as follows:

pressure (anode and cathode sides)	bar abs	7
cathode side pressure drop	%	2
anode recycle/feed ratio	mol/mol	2:1
cathode recycle/feed ratio	mol/mol	1:1
cathode side inlet temperature	degC	760
stack outlet temperature (anode and cathode sides)	^{0}C	900
post combustor outlet temperature	^{0}C	1000
theoretical combustion air (lambda)	mol/mol	2.0
theoretical combustion O_2 to stack	%	80
theoretical combustion O_2 to post combustor	%	20

3 DESIGN DISCUSSION

3.1 Rolls-Royce and IEA SOFC Concepts

According to our understanding, the two significant features of the Rolls-Royce SOFC concept are:

- Operation of the SOFC cell stack (anode and cathode sides) at around 7 bar abs, this medium pressure reducing the size and cost of the stack without too much loss of electrochemical performance.
- Final preheating of the anode and cathode feed streams by ejector recycle.

As modified by IEA to achieve carbon capture, the exit streams from the anode and cathode fed separately to a membrane post combustor, in which sufficient oxygen diffuses from the cathode side to stoichiometrically combust the H_2, CO and CH_4 content of the anode exit stream. The post-combusted anode stream thus consists only of CO_2 and steam, apart from any nitrogen contained in the incoming natural gas.

3.2 HYSYS Simulation

A heat and material balance was simulated on HYSYS. This is shown on attached SOFC1.jpg and MATBAL1.xls.

Some minor changes have been introduced to the parameters laid down by IEA as the technical basis for SOFC operation (see 2.3 above):

- On the anode side, it was deemed by us inadvisable - for fear of cracking C_4+ components - to heat bulk flows of natural gas in conventional heat exchangers to a temperature higher than 450^{0}C. The preferred inlet temperature to the cathode side being 760^{0}C (see 2.3 above), the inlet temperature to the anode side has been fixed at 720^{0}C, with the aim of reducing thermal stresses resulting from the two sides of the cell having significantly different inlet temperatures. In order to achieve that temperature of. 720^{0}C at the anode inlet, the anode recycle:feed ratio has been increased to 3:1.

- On the cathode side, the feed air is heated to 580^{0}C upstream of the cathode side inlet by indirect heat exchange, first with the gas turbine exhaust and secondly with the post combustor “anode” product. In order to achieve the specified cathode side inlet temperature of 760^0C, the recycle:feed ratio has been decreased increased to 0.6:1.

To achieve a reasonably close fit of three parameters, the percentage of theoretical oxygen going to the stack has been increased from the specified 80% to 85 %, and the stack outlet temperature has been reduced to 870^0C from the specified 900^0C. These alterations result in the post-combustor outlet at 1020^0C – without them, it would be over 1050^0C, which is probable too much for the available material of construction of the post combustor.

- The ejectors have been modelled as a compressor in the recycle stream driven by an expander in the feed stream. Both compressors and ejectors have been assigned efficiencies of 50%, the net ejector efficiency therefore being approximately $0.5^2 = 0.25$.

3.3 No Steam Cycle

With intercooling of the air compressor, and by suitable heat recovery from the expander and post-combustor “anode” streams, the gas turbine exhaust is cooled to 163^0C, and the post combustor “anode” stream to 490^0C. Accordingly no steam cycle is provided, thereby reducing the complexity and cost of the plant. Perhaps by further study the rejection of heat from the anode stream (to cooling water, in this evaluation) can be reduced.

3.4 Desulphurisation

For the present evaluation, it is assumed that the incoming natural gas will be desulphurised with active carbon. In a large plant, it will however be more economical, following steam reforming practice, to use CoMo catalyst to hydrogenate organic sulphur to H_2S and then to absorb the total H_2S present with zinc oxide. However this would require the availability at plant start-up of an external source of hydrogen, to ensure around 2% mol H_2 at the inlet to the CoMox hydrogenator. This question should be investigated further, with knowledge of the tolerance of the SOFC to sulphur in the feed gas - can some sulphur slip from the desulphurisers be tolerated at start-up?

3.5 Equipment Design

The plant equipment outside the stack assembly (considered for this purpose to comprise the SOFC stack itself, the post-combustor and the recycle ejectors), employs existing technology.
The air compressor could be an industrial air compressor.
The expander, with an inlet conditions 6 bar/1000^0C, will have probably to be specially developed, although not requiring any new basic technology. Perhaps the LP expansion turbine of an existing gas turbine could be adapted.

3.6 Plant Capacity

Subject to IEA’s requirements, the scheme has been evaluated on the basis of 50MWe modules - ten modules therefore making up the total 500MWe specified. Since in any event the SOFC part, which accounts for most of the investment cost, will be made up from numerous individual stacks, there will not be much economy of scale in formulating a single-line 500MWe installation. The 50MWe module could provide power for a population of around 100,000 and may eventually provide local district heating. With very low emissions, low elevation, low noise, it would be suitable for unmanned operation in urban areas. The CO_2 production (circa 15 tonnes/h) could be railed daily to remote sequestration sites.

3.7 Manifolding

Assuming that the final air heater E-113 (air heated by 1000^0C CO_2 + steam) is associated with each SOFC stack, the manifolding serving all the stacks (air supply, CO_2 + steam collection, GT expander feed) will be in conventional materials. In event of mechanical failure of a few SOFC stacks (anode and cathode sides coming into communication), it may be feasible to isolate the air and CO_2 + steam connections to those stacks, allowing the failed stacks to "float" on the GT expander inlet pressure until repairs can be effected.

3.8 Generating Efficiency

Our evaluation indicates a generation efficiency of approximately 67%, allowing for 7% (?)average loss in stack electronics and the turbine generator.

3.9 Capital cost

Where possible (e.g. for gas turbines) capital cost figures have been generated by PPAP – but a factor has been included to compensate for the low size and pressure ratio of the machines required, which must increase the cost per unit of power produced.

The low size arises from the need to generate 500e MW from 10 x 50 MWe units; however the does not have much effect on the cost of the fuel cell stacks as these are essentially already subdivided. The cost of these items is included in the User Defined category on the PPAP Costing Sheet as in the table below.

COST ESTIMATE for 50 MWe nominal output

ITEM	BASIS	ERECTED COST (USD MILLIONS)
SOFC Stacks	IEA E-mail 24/03/04: 42.29MWe at USD500/kWe x installation factor 2.0	42.3
Post Combustor	IEA E-mail 24/03/04: 42.29MWe at USD100/kWe x installation factor 2.0	8.5
Power Electronics	IEA E-mail 24/03/04: 42.29MWe at USD100/kWe x installation factor 2.0	8.5
Misc. Compressors and Expanders	4000kW @ USD500/kW x installation factor 2.0	4.0
Air Comp/Expander	Included in PPAP GT	0.0
Electric Generator	9292kW @ USD200/kW x installation factor 2.0	3.7
Desulphurisers	287 kmol/h NG guess	2
Heat Exchangers D-112/3/4	22.87 Gcal/h @ USD 50,000/Gcal.h x installation factor 3.0	3.5
Manifolds		7

TOTAL USER-DEFINED ITEMS		**79.5**

The total capital cost for 10 streams generating a nominal 500 MWe, including owner's costs, indirect costs and contingency etc. is US$ 1326 million. This very high cost largely arises from the cost of the SOFC stacks themselves (almost 7 times that was included in a previous evaluation for equivalent membrane reactor heat exchangers. It remains to be seen whether ether of these estimates are realistic.

4 MAIN PPAP INPUTS

Plant Components
GT
Other major plant item
CO_2 compression/pumping to 110 bar
Fuel Cell

Fuel Specification

Natural gas	100% CV 46920, C fraction 0.739
Mass & energy	fuel 15.47 kg/s
CO_2 recovered	99%
Fraction to fuel cell	65% % - 90% recovered to power

PPAP Lite Details

CO2 compression power	8.1	MW
O2 compression power	0	MW
HRSG on GT	0	MW
GT power	92.92	MW
ST power	0	MW
Percent of heat available to Steam cycle	0	%
Overall electrical efficiency after losses	64.6	%
Efficiency GT Cycle	35	%
Efficiency ST cycle	0	%
Overall power output	469	MW
Power from direct generation	423.97	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	725.85	MW

Capital Cost
Gas turbine complete generated by PPAP
Other items as above 3.9

Operating Cost
Natural gas $3/GJ
Power cost is 7.4 c/kWh.
Interest rate, plant life span, load factor and O&M on the software as supplied by IEA are not as previously used, and will have to be reviewed.

Multi-Criteria Analysis

Parameter: Raw Material Availability
Value: Locally Common with unlimited availability

Parameter: Process Conditions
Value: T 1200-1600^0K, <10bar – needs tech breakthrough with known parallels

Parameter: Novelty of Materials
Value: Exotic ceramics – newly discovered material proven in similar duties

Parameter: Plant Complexity
Value: 11 Major Units, no recycle (as generated by PPAP – this may need review)

Parameter: Novelty of Process
Value: Major new ideas with promising industrial units in operation

Parameter: Safety Risk
Value: Small Risk – extensively demonstrated and publicly accepted

Parameter: Environmental Impact
Value: Benign Waste – extensively demonstrated and publicly accepted

5 RESULTS

The full summary output from PPAP is as follows:

Heat Input		725.9	MW
Estimated	Net Electricity Output	469.0	MW
	Net Efficiency	64.6	%
	CO2 output/ kg/s	0.4	kg/s
	CO2 output/kWh	0.003	kg/kWh
Estimated Capital Cost		1338.1	M$
Estimated Op Cost		7.4	c/kWh
Multi-Criteria Assessment			
Decision Factor Scores			
Acceptance		32.0	
Applicability		40.1	
Confidence		21.0	
Estimated Cost		35.0	
	Total	128.1	
	Total cost only	195.1	
Risk assessment			

Averaged risk level		20
Controlling risk level	**Materials**	**63**

Design of CO2 capturing solid oxide fuel cell

The basic principle is to use a so called “4” pole cell in which anode and cathode gas are fully segregated throughout the device.

Designs may be able to achieve this degree of separate manifolding which is an unusual design feature since in typical cells the waste anode and cathode gas are allowed to combine in order to complete oxidation of the fuel. The design most nearly achieving this has been the Siemens Westinghouse tubular design which uses a tubes closed at one end which project through a number of ceramic board tube sheets. Air is supplied via small ceramic tubes, one each, leading air to the closed end from whence it flows back through the annular space around the injection tube. This forms an internal heat exchanger (a bit like a double pipe) which allows air to be introduced well below the operating temperature (about 600C is typical) without causing thermal shock. Fuel is on the outside of the main tubes and can be segregated from the exhaust air by having additional tube sheets. There are two tube sheets in the traditional design leaving a space which can be used to provide an anode gas recycle. Normally the net anode gas leaks through the second tube sheet to mix with spent cathode gas. If this last tube sheet is sealed than the anode gas can be fully segregated from the cathode gas. This seal at 1000C is a huge technological challenge even at atmospheric pressure. When operating in hybrid mode (i.e pressurized) the sealing clearances become even more onerous. The ceramic boards are porous and do not provide a full seal. Some form of barrier layer, e.g. a metal foil would have to be introduced. Also the tubes slide in the tube sheet in the conventional design providing a further leak path which is difficult to seal. A fixed final tube sheet and another solution for accommodating tube expansion is an alternative solution. Siemens has also experimented with flattened tubes to increase active area and the sealing of non-circular penetrations could present an additional challenge.

Rolls Royce has developed a similar layout to the above based on oblong section tubes (prisms) closed at one end. Fuel flows inside these tubes rather than outside as in the Siemens design. The tubes are sealed into a flat base plate at one end and are thus free to expand longitudinally. The base plates have to be sealed together to keep the fuel from the cathode gas which flows around the outside of the tubes. The tubes are made from cheap porous ceramic material and the fuel cell layers are screen printed on to this support making for a very cheap production process. The RR design does not provide an intrinsic air pre heat so a higher inlet temperature is probably needed to avoid thermal shock, typically 800-950C judging by their article. RR has a clever design to achieve high air inlet temperatures without an expensive recuperator. They compress the air adiabatically to 350 C and then recycle cathode gas which is further heated by burning the anode gas in it. This of course mixes all of the concentrated anode exit gas into the cathode gas which is no good for capture!

There are also some slightly odd things about the temperatures shown on the RR diagram. Firstly there is no temperature rise over the cell which is impossible as the energy which does not get converted to power all ends up as heat so the product stream must be hotter than the inlet stream. The internal reforming heat exchange does not prevent this net temperature rise!. Rough calculations show that the RR design is somewhat more efficient than the design with recuperators even when say a 1 bar pressure drop is taken for driving the ejector which induces the recycle. The recycle could either be from downstream of the cell but before the afterburner or presuming all the air goes through the afterburner could be taken from the exit of the afterburner which is hotter. This seems to indicate that with a recycle ratio of 1 the net stoichiometric flow should be about 2-3 times. Recycling from downstream of the afterburner seems to be more efficient. The 350 C adiabatic compression temperature from the air compressor is quite high suggesting a rather inefficient compressor in the RR design. This may be the reality of the very small machines they are considering at this stage in development.

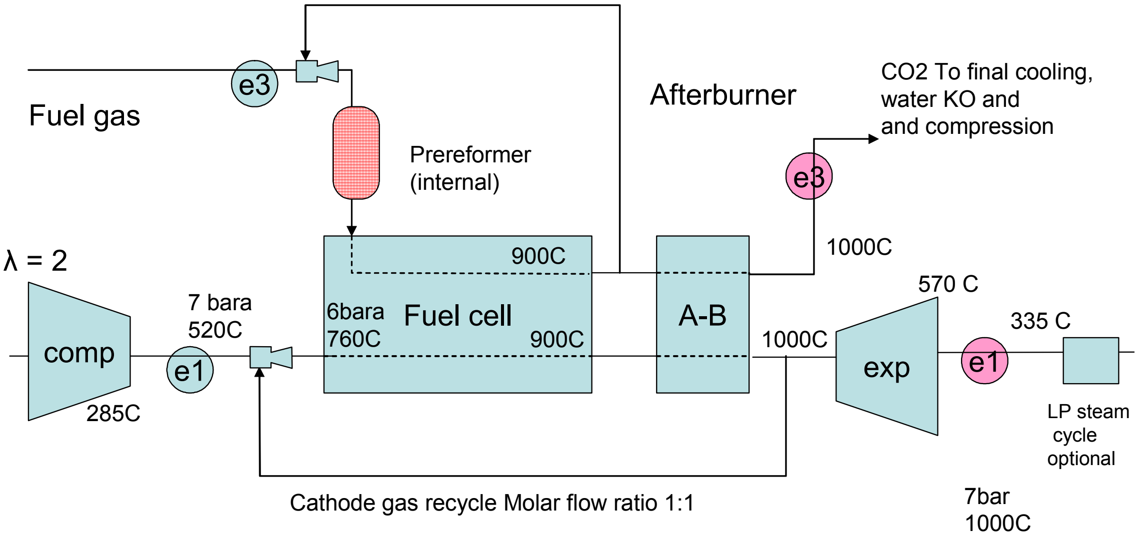
The final design is simply to use a conventional flat plate design. This does require high air inlet temperatures as the flat plates are very susceptible to thermal shock. Conventional wisdom says that no more than 100C temperature rise is acceptable across this type of cell. Also the flat plate designs have not as yet aspired to MW capacities because it is difficult to make big stacks. In principle the sealing problem is much less since the edges of the plates have to be sealed anyway. The manifolds on the inlet side have to be sealed and the same construction can me used for the outlet side. Main problem with this design is that the basic sealing between plates is still problematical.

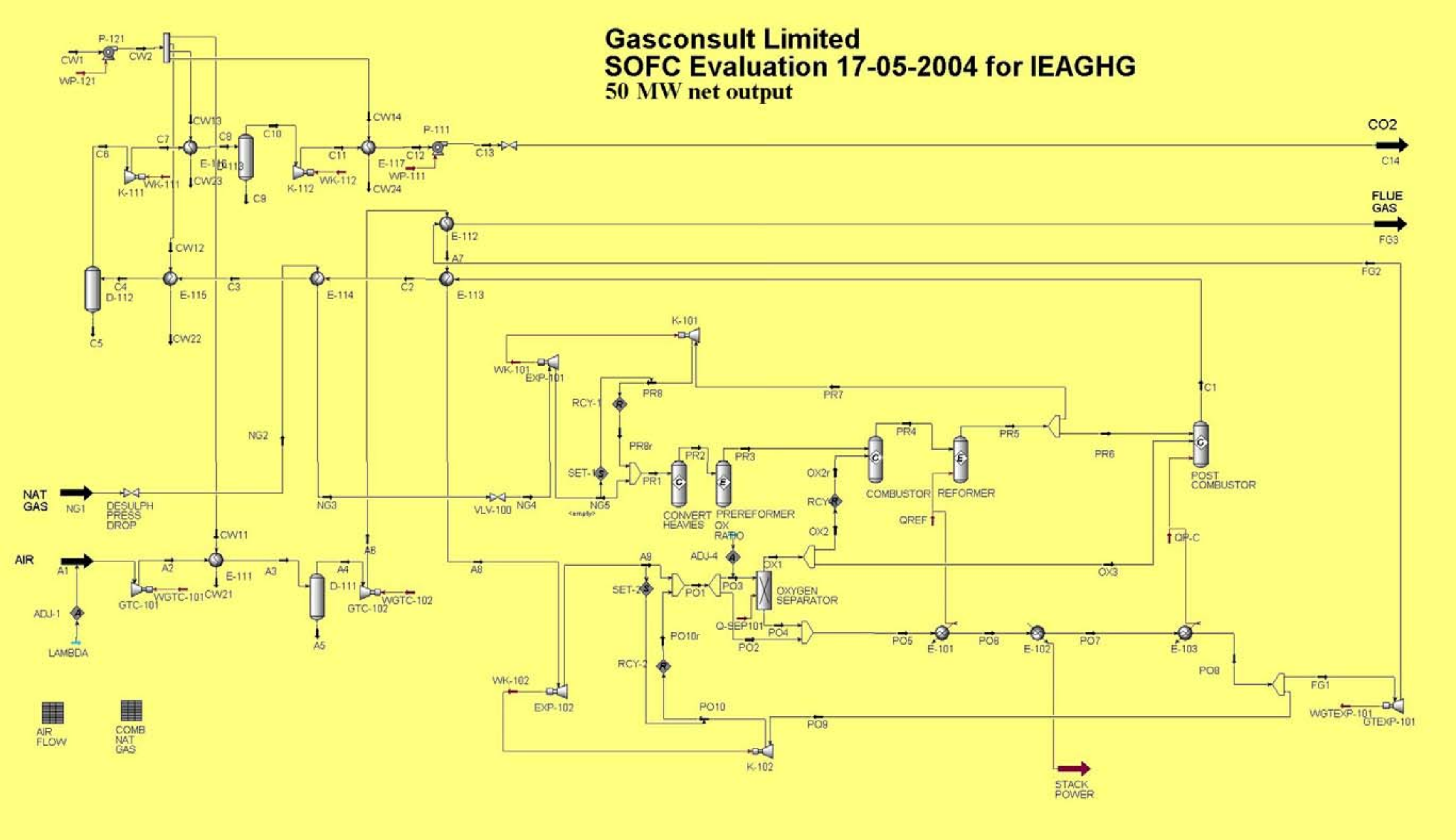
There is a flat plate design in which the gases are introduced at the centre of a disc and flow radially outwards. (Sulzer Hexis). The manifolding for the inlet gases is all at the centre, there is basically a large hole down the centre of the discs. However the gases are released at the periphery of the discs and freely mix. It is not practical to manifold the periphery. If this is not necessary you can see that this arrangement is very attractive.

My proposal is to try simulating first a RR based system using their cathode gas ejector recycle but without the combustor. The recycle should be taken from the outlet of the afterburning device. A net stoichiometric air ratio of about 2 with a recycle of the same molar amount. You need to assume that say 80% of the fuel is consumed in the main stack, electrical voltage is 700mv giving a DC efficiency for the fuel consumed in the stack of 67.3%. A target stack exit temperature of 900C completes the boundary conditions. This temperature will rise to about 980C at the outlet of the afterburning device. This afterburning device has all of the air flow through it and transports oxygen to the fuel until it is precisely combusted. You should assume precise stoichiometric combustion in this device i.e zero fuel in the final stack gas but no excess oxygen transported. This should lead to a system with a stack air inlet temperature of about 740C. O2 content in the afterburner outlet would be about 11% and in the stack inlet about 15.8% giving plenty of partial pressure for operation of the cell. Use suitable efficiencies for the compressor and expander, suggest 85% is a conservative estimate for larger systems.

DC to AC conversion losses have to be included, suggest 95% efficiency is a top limit for big systems but maybe 90% is more realistic. With 95% I predicted an efficiency of about 59% overall but this is a very rough estimate!

CO2 separating SOFC power cycle for PPAP evaluation





Gasconsult Limited
SOFC Evaluation 17-05-2004 for IEAGHG
50 MW net output

Workbook: Case (Main) SOFC HYSIS SIMULATION

Material Streams

Name	**A1**	**A2**	**A3**	**A4**	**A5**
Vapour Fraction	1	1	1	1	0
Pressure (bar)	1.013	4	3.8	3.8	3.8
Temperature (C)	25	198.3	25	25	25
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1.8	1.8	1.8	1.8	0
Comp Molar Flow (Nitrogen) (kgmole/h)	4809.1	4809.1	4809.1	4809.1	0
Comp Molar Flow (Oxygen) (kgmole/h)	1289.9	1289.9	1289.9	1289.9	0
Comp Molar Flow (Argon) (kgmole/h)	57.9	57.9	57.9	57.9	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	41.3	41.3	41.3	41.3	0
Molar Flow (kgmole/h)	6200	6200	6200	6200	0
Mass Flow (kg/h)	179131	179131	179131	179131	0
Molecular Weight	28.89	28.89	28.89	28.89	18.02
Heat Flow (kW)	-2979.4	5775.4	-3020.4	-3020.4	0
Mass Lower Heating Value (kcal/kg)					

Name	A6	A7	A8	A9	C1
Vapour Fraction	1	1	1	1	1
Pressure (bar)	8.25	8.05	7.65	6.8	6.8
Temperature (C)	113.6	500	580	567.7	1000
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1.8	1.8	1.8	1.8	343.3
Comp Molar Flow (Nitrogen) (kgmole/h)	4809.1	4809.1	4809.1	4809.1	1.1
Comp Molar Flow (Oxygen) (kgmole/h)	1289.9	1289.9	1289.9	1289.9	0.1
Comp Molar Flow (Argon) (kgmole/h)	57.9	57.9	57.9	57.9	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	41.3	41.3	41.3	41.3	618.8
Molar Flow (kgmole/h)	6200	6200	6200	6200	963.3
Mass Flow (kg/h)	179131	179131	179131	179131	26290.3
Molecular Weight	28.89	28.89	28.89	28.89	27.29
Heat Flow (kW)	1422.3	21730.6	26134.1	25452.6	-67878.5
Mass Lower Heating Value (kcal/kg)					

Name	C2	C3	C4	C5	C6
Vapour Fraction	1	1	0.3575	0	1
Pressure (bar)	6.8	6.8	6.6	6.6	6.6
Temperature (C)	649.3	489.5	25	25	25
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	343.3	343.3	343.3	1.9	341.3
Comp Molar Flow (Nitrogen) (kgmole/h)	1.1	1.1	1.1	0	1.1
Comp Molar Flow (Oxygen) (kgmole/h)	0.1	0.1	0.1	0	0.1
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	618.8	618.8	618.8	617	1.8
Molar Flow (kgmole/h)	963.3	963.3	963.3	618.9	344.4
Mass Flow (kg/h)	26290.3	26290.3	26290.3	11199.1	15091.2
Molecular Weight	27.29	27.29	27.29	18.1	43.82
Heat Flow (kW)	-72282.1	-74159.1	-86608.6	-49123.6	-37485
Mass Lower Heating Value (kcal/kg)					

Name	C7	C8	C9	C10	C11
Vapour Fraction	1	0.9969	0	1	1
Pressure (bar)	21	20.7	20.7	20.7	65.91
Temperature (C)	135.5	25	25	25	138.1
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	341.3	341.3	0	341.3	341.3
Comp Molar Flow (Nitrogen) (kgmole/h)	1.1	1.1	0	1.1	1.1
Comp Molar Flow (Oxygen) (kgmole/h)	0.1	0.1	0	0.1	0.1
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	1.8	1.8	1.1	0.7	0.7
Molar Flow (kgmole/h)	344.4	344.4	1.1	343.3	343.3
Mass Flow (kg/h)	15091.2	15091.2	19.7	15071.5	15071.5
Molecular Weight	43.82	43.82	18.26	43.9	43.9
Heat Flow (kW)	-37085.9	-37560.7	-86	-37474.8	-37110.2
Mass Lower Heating Value (kcal/kg)					

Name	C12	C13	C14	CW1	CW2
Vapour Fraction	0	0	0	0	0
Pressure (bar)	65.41	120	110	1.5	4
Temperature (C)	25	38.63	36.8	20	20.02
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	341.3	341.3	341.3	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	1.1	1.1	1.1	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0.1	0.1	0.1	0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	0.7	0.7	0.7	106620.2	106620.2
Molar Flow (kgmole/h)	343.3	343.3	343.3	106620.2	106620.2
Mass Flow (kg/h)	15071.5	15071.5	15071.5	1.92E+06	1.92E+06
Molecular Weight	43.9	43.9	43.9	18.02	18.02
Heat Flow (kW)	-38304.7	-38262.2	-38262.2	-8.46E+06	-8.46E+06
Mass Lower Heating Value (kcal/kg)					

Name	CW11	CW12	CW13	CW14	CW21
Vapour Fraction	0	0	0	0	0
Pressure (bar)	4	4	4	4	3
Temperature (C)	20.02	20.02	20.02	20.02	30
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	40928.2	57924.3	2209.5	5558.3	40928.2
Molar Flow (kgmole/h)	40928.2	57924.3	2209.5	5558.3	40928.2
Mass Flow (kg/h)	737324.8	1.04E+06	39804.8	100133.2	737324.8
Molecular Weight	18.02	18.02	18.02	18.02	18.02
Heat Flow (kW)	-3.25E+06	-4.60E+06	-175404.5	-441248.9	-3.24E+06
Mass Lower Heating Value (kcal/kg)					

Name	**CW22**	**CW23**	**CW24**	**FG1**	**FG2**
Vapour Fraction	0	0	0	1	1
Pressure (bar)	3	3	3	6.6	1
Temperature (C)	30	30	30	1048	612.4
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	1.8	1.8
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	4809.1	4809.1
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	642.3	642.3
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	57.9	57.9
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	57924.3	2209.5	5558.3	41.3	41.3
Molar Flow (kgmole/h)	57924.3	2209.5	5558.3	5552.4	5552.4
Mass Flow (kg/h)	1.04E+06	39804.8	100133.2	158408.1	158408.1
Molecular Weight	18.02	18.02	18.02	28.53	28.53
Heat Flow (kW)	-4.59E+06	-174929.7	-440054.3	47044.1	24554
Mass Lower Heating Value (kcal/kg)					

Name	**FG3**	**LAMBDA**	**NG1**	**NG2**	**NG3**
Vapour Fraction	1	1.9922	1	1	1
Pressure (bar)	1		28	26.5	26.1
Temperature (C)	184.9		20	19.09	450
Comp Molar Flow (Hydrogen) (kgmole/h)	0		0	0	0
Comp Molar Flow (CO) (kgmole/h)	0		0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1.8		5.2	5.2	5.2
Comp Molar Flow (Nitrogen) (kgmole/h)	4809.1		1.1	1.1	1.1
Comp Molar Flow (Oxygen) (kgmole/h)	642.3		0	0	0
Comp Molar Flow (Argon) (kgmole/h)	57.9		0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0		240.8	240.8	240.8
Comp Molar Flow (Ethane) (kgmole/h)	0		26.4	26.4	26.4
Comp Molar Flow (Propane) (kgmole/h)	0		9.5	9.5	9.5
Comp Molar Flow (i-Butane) (kgmole/h)	0		4	4	4
Comp Molar Flow (n-Butane) (kgmole/h)	0		0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0		0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0		0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0		0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0		0	0	0
Comp Molar Flow (H2O) (kgmole/h)	41.3		0	0	0
Molar Flow (kgmole/h)	5552.4		287	287	287
Mass Flow (kg/h)	158408.1		5567.7	5567.7	5567.7
Molecular Weight	28.53		19.4	19.4	19.4
Heat Flow (kW)	4245.7		-6692.6	-6692.6	-4815.6
Mass Lower Heating Value (kcal/kg)					

Name	**NG4**	**NG5**	**NG1 CV**	**OX1**	**OX2**
Vapour Fraction	1	1	1	1	1
Pressure (bar)	12.25	7	28	6.8	6.8
Temperature (C)	449.3	424.7	20	763	763
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	5.2	5.2	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	1.1	1.1	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	647.6	534.3
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	240.8	240.8	240.8	0	0
Comp Molar Flow (Ethane) (kgmole/h)	26.4	26.4	26.4	0	0
Comp Molar Flow (Propane) (kgmole/h)	9.5	9.5	9.5	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	4	4	4	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	287	287	280.7	647.6	534.3
Mass Flow (kg/h)	5567.7	5567.7	5308.2	20723	17096.5
Molecular Weight	19.4	19.4	18.91	32	32
Heat Flow (kW)	-4815.6	-4945.2	-6125.8	4313.3	3558.5
Mass Lower Heating Value (kcal/kg)			1.18E+04		

Name	**OX3**	**OX RATIO**	**OX2r**	**PO1**	**PO2**
Vapour Fraction	1	1.0002	1	1	1
Pressure (bar)	6.8		6.8	6.8	6.8
Temperature (C)	763		763	759.1	759.1
Comp Molar Flow (Hydrogen) (kgmole/h)	0		0	0	0
Comp Molar Flow (CO) (kgmole/h)	0		0	0	0
Comp Molar Flow (CO2) (kgmole/h)	0		0	3.1	1.9
Comp Molar Flow (Nitrogen) (kgmole/h)	0		0	8031.1	5007.7
Comp Molar Flow (Oxygen) (kgmole/h)	113.3		534.3	1720.2	1072.6
Comp Molar Flow (Argon) (kgmole/h)	0		0	96.6	60.3
Comp Molar Flow (Methane) (kgmole/h)	0		0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0		0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0		0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0		0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0		0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0		0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0		0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0		0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0		0	0	0
Comp Molar Flow (H2O) (kgmole/h)	0		0	68.9	43
Molar Flow (kgmole/h)	113.3		534.3	9920	6185.5
Mass Flow (kg/h)	3626.5		17097.1	285261.3	177871.3
Molecular Weight	32		32	28.76	28.76
Heat Flow (kW)	754.8		3558.6	57652.8	35948.7
Mass Lower Heating Value (kcal/kg)					

Name	**PO3**	**PO4**	**PO5**	**PO6**	**PO7**
Vapour Fraction	1	1	1	1	1
Pressure (bar)	6.8	6.8	6.8	6.6	6.6
Temperature (C)	759.1	763	760.4	1357	880
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1.2	1.2	3.1	3.1	3.1
Comp Molar Flow (Nitrogen) (kgmole/h)	3023.4	3023.4	8031.1	8031.1	8031.1
Comp Molar Flow (Oxygen) (kgmole/h)	647.6	0	1072.6	1072.6	1072.6
Comp Molar Flow (Argon) (kgmole/h)	36.4	36.4	96.6	96.6	96.6
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	25.9	25.9	68.9	68.9	68.9
Molar Flow (kgmole/h)	3734.5	3086.9	9272.4	9272.4	9272.4
Mass Flow (kg/h)	107390.1	86667.1	264538.4	264538.4	264538.4
Molecular Weight	28.76	28.08	28.53	28.53	28.53
Heat Flow (kW)	21704.1	17526.1	53474.8	106068.9	63780.3
Mass Lower Heating Value (kcal/kg)					

Name	PO8	PO9	PO10	PO10r	PR1
Vapour Fraction	1	1	1	1	1
Pressure (bar)	6.6	6.6	6.8	6.8	7
Temperature (C)	1048	1048	1067	1067	721.3
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	121.8
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	80.5
Comp Molar Flow (CO2) (kgmole/h)	3.1	1.2	1.2	1.2	231.5
Comp Molar Flow (Nitrogen) (kgmole/h)	8031.1	3222	3222	3222	2.2
Comp Molar Flow (Oxygen) (kgmole/h)	1072.6	430.3	430.3	430.3	0
Comp Molar Flow (Argon) (kgmole/h)	96.6	38.8	38.8	38.8	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	240.8
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	26.4
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	9.5
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	4
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	68.9	27.6	27.6	27.6	431.3
Molar Flow (kgmole/h)	9272.4	3720	3720	3720	1148
Mass Flow (kg/h)	264538.4	106130.2	106130.2	106130.3	25828.6
Molecular Weight	28.53	28.53	28.53	28.53	22.5
Heat Flow (kW)	78562.7	31518.6	32200.1	32200.2	-52956.6
Mass Lower Heating Value (kcal/kg)					

Name	**PR2**	**PR3**	**PR4**	**PR5**	**PR6**
Vapour Fraction	1	1	1	1	1
Pressure (bar)	7	7	6.8	6.8	6.8
Temperature (C)	717.1	604.8	2517	880	880
Comp Molar Flow (Hydrogen) (kgmole/h)	121.8	275.5	0	258	136.2
Comp Molar Flow (CO) (kgmole/h)	99.6	92.4	0	170.5	90
Comp Molar Flow (CO2) (kgmole/h)	231.5	275.3	542.9	479.5	253.2
Comp Molar Flow (Nitrogen) (kgmole/h)	2.2	2.2	2.2	2.2	1.1
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	319	282.4	107.2	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	412.2	331.7	957.6	913.8	482.5
Molar Flow (kgmole/h)	1186.3	1259.5	1609.8	1824.1	963.1
Mass Flow (kg/h)	25828.6	25828.6	42924.8	42924.9	22664
Molecular Weight	21.77	20.51	26.66	23.53	23.53
Heat Flow (kW)	-52956.4	-52956.4	-49397.8	-101991.9	-53850.9
Mass Lower Heating Value (kcal/kg)					

Name	**PR7**	**PR8**	**PR8r**
Vapour Fraction	1	1	1
Pressure (bar)	6.8	7	7
Temperature (C)	880	892.4	892.4
Comp Molar Flow (Hydrogen) (kgmole/h)	121.8	121.8	121.8
Comp Molar Flow (CO) (kgmole/h)	80.5	80.5	80.5
Comp Molar Flow (CO2) (kgmole/h)	226.3	226.3	226.3
Comp Molar Flow (Nitrogen) (kgmole/h)	1	1	1
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0
Comp Molar Flow (Methane) (kgmole/h)	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0
Comp Molar Flow (i-Butane) (kgmole/h)	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0
Comp Molar Flow (i-Pentane) (kgmole/h)	0	0	0
Comp Molar Flow (n-Pentane) (kgmole/h)	0	0	0
Comp Molar Flow (n-Hexane) (kgmole/h)	0	0	0
Comp Molar Flow (Ammonia) (kgmole/h)	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	431.3	431.3	431.3
Molar Flow (kgmole/h)	861	861	861
Mass Flow (kg/h)	20260.9	20260.9	20260.9
Molecular Weight	23.53	23.53	23.53
Heat Flow (kW)	-48140.9	-48011.4	-48011.4
Mass Lower Heating Value (kcal/kg)			
Compositions			

Name	PREREFORMER-Liqui	REFORMER-Liquid	COMBUSTOR-Liquid	ST COMBUSTOR-Liq	NVERT HEAVIES-Liq
Comp Mole Frac (Hydrogen)	0.2187	0.1415	0	0	0.1027
Comp Mole Frac (CO)	0.0734	0.0935	0	0	0.084
Comp Mole Frac (CO2)	0.2186	0.2629	0.3372	0.3563	0.1952
Comp Mole Frac (Nitrogen)	0.0017	0.0012	0.0014	0.0012	0.0018
Comp Mole Frac (Oxygen)	0	0	0	0.0001	0
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0.2242	0	0.0666	0	0.2689
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.2634	0.501	0.5948	0.6423	0.3475

Name	**NG1**	**NG3**	**NG5**	**PR8r**	**PR1**
Comp Mole Frac (Hydrogen)	0	0	0	0.1415	0.1061
Comp Mole Frac (CO)	0	0	0	0.0935	0.0701
Comp Mole Frac (CO2)	0.018	0.018	0.018	0.2629	0.2017
Comp Mole Frac (Nitrogen)	0.004	0.004	0.004	0.0012	0.0019
Comp Mole Frac (Oxygen)	0	0	0	0	0
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0.839	0.839	0.839	0	0.2098
Comp Mole Frac (Ethane)	0.092	0.092	0.092	0	0.023
Comp Mole Frac (Propane)	0.033	0.033	0.033	0	0.0082
Comp Mole Frac (i-Butane)	0.014	0.014	0.014	0	0.0035
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0	0	0	0.501	0.3757

Name	**PR3**	**A1**	**A2**	**PO10r**	**A9**
Comp Mole Frac (Hydrogen)	0.2187	0	0	0	0
Comp Mole Frac (CO)	0.0734	0	0	0	0
Comp Mole Frac (CO2)	0.2186	0.0003	0.0003	0.0003	0.0003
Comp Mole Frac (Nitrogen)	0.0017	0.7757	0.7757	0.8661	0.7757
Comp Mole Frac (Oxygen)	0	0.208	0.208	0.1157	0.208
Comp Mole Frac (Argon)	0	0.0093	0.0093	0.0104	0.0093
Comp Mole Frac (Methane)	0.2242	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.2634	0.0067	0.0067	0.0074	0.0067

Name	**PO1**	**PO4**	**PR4**	**PR5**	**PO6**
Comp Mole Frac (Hydrogen)	0	0	0	0.1415	0
Comp Mole Frac (CO)	0	0	0	0.0935	0
Comp Mole Frac (CO2)	0.0003	0.0004	0.3373	0.2629	0.0003
Comp Mole Frac (Nitrogen)	0.8096	0.9794	0.0014	0.0012	0.8661
Comp Mole Frac (Oxygen)	0.1734	0	0	0	0.1157
Comp Mole Frac (Argon)	0.0097	0.0118	0	0	0.0104
Comp Mole Frac (Methane)	0	0	0.0666	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0069	0.0084	0.5948	0.501	0.0074

Name	**PO7**	**PR8**	**PR6**	**PO10**	**OX2r**
Comp Mole Frac (Hydrogen)	0	0.1415	0.1415	0	0
Comp Mole Frac (CO)	0	0.0935	0.0935	0	0
Comp Mole Frac (CO2)	0.0003	0.2629	0.2629	0.0003	0
Comp Mole Frac (Nitrogen)	0.8661	0.0012	0.0012	0.8661	0
Comp Mole Frac (Oxygen)	0.1157	0	0	0.1157	1
Comp Mole Frac (Argon)	0.0104	0	0	0.0104	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0074	0.501	0.501	0.0074	0

Name	**C1**	**PO8**	**FG1**	**PR7**	**NG4**
Comp Mole Frac (Hydrogen)	0	0	0	0.1415	0
Comp Mole Frac (CO)	0	0	0	0.0935	0
Comp Mole Frac (CO2)	0.3563	0.0003	0.0003	0.2629	0.018
Comp Mole Frac (Nitrogen)	0.0012	0.8661	0.8661	0.0012	0.004
Comp Mole Frac (Oxygen)	0.0001	0.1157	0.1157	0	0
Comp Mole Frac (Argon)	0	0.0104	0.0104	0	0
Comp Mole Frac (Methane)	0	0	0	0	0.839
Comp Mole Frac (Ethane)	0	0	0	0	0.092
Comp Mole Frac (Propane)	0	0	0	0	0.033
Comp Mole Frac (i-Butane)	0	0	0	0	0.014
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.6423	0.0074	0.0074	0.501	0

Name	**PO9**	**FG2**	**PR2**	**OX RATIO**	**PO3**
Comp Mole Frac (Hydrogen)	0	0	0.1027		0
Comp Mole Frac (CO)	0	0	0.084		0
Comp Mole Frac (CO2)	0.0003	0.0003	0.1952		0.0003
Comp Mole Frac (Nitrogen)	0.8661	0.8661	0.0018		0.8096
Comp Mole Frac (Oxygen)	0.1157	0.1157	0		0.1734
Comp Mole Frac (Argon)	0.0104	0.0104	0		0.0097
Comp Mole Frac (Methane)	0	0	0.2689		0
Comp Mole Frac (Ethane)	0	0	0		0
Comp Mole Frac (Propane)	0	0	0		0
Comp Mole Frac (i-Butane)	0	0	0		0
Comp Mole Frac (n-Butane)	0	0	0		0
Comp Mole Frac (i-Pentane)	0	0	0		0
Comp Mole Frac (n-Pentane)	0	0	0		0
Comp Mole Frac (n-Hexane)	0	0	0		0
Comp Mole Frac (Ammonia)	0	0	0		0
Comp Mole Frac (H2O)	0.0074	0.0074	0.3475		0.0069

Name	PO2	OX1	PO5	OX2	OX3
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.0003	0	0.0003	0	0
Comp Mole Frac (Nitrogen)	0.8096	0	0.8661	0	0
Comp Mole Frac (Oxygen)	0.1734	1	0.1157	1	1
Comp Mole Frac (Argon)	0.0097	0	0.0104	0	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0069	0	0.0074	0	0

Name	A3	A4	A5	A6	A8
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.0003	0.0003	0	0.0003	0.0003
Comp Mole Frac (Nitrogen)	0.7757	0.7757	0	0.7757	0.7757
Comp Mole Frac (Oxygen)	0.208	0.208	0	0.208	0.208
Comp Mole Frac (Argon)	0.0093	0.0093	0	0.0093	0.0093
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0067	0.0067	0.9999	0.0067	0.0067

Name	**NG2**	**FG3**	**A7**	**C2**	**C3**
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.018	0.0003	0.0003	0.3563	0.3563
Comp Mole Frac (Nitrogen)	0.004	0.8661	0.7757	0.0012	0.0012
Comp Mole Frac (Oxygen)	0	0.1157	0.208	0.0001	0.0001
Comp Mole Frac (Argon)	0	0.0104	0.0093	0	0
Comp Mole Frac (Methane)	0.839	0	0	0	0
Comp Mole Frac (Ethane)	0.092	0	0	0	0
Comp Mole Frac (Propane)	0.033	0	0	0	0
Comp Mole Frac (i-Butane)	0.014	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0	0.0074	0.0067	0.6423	0.6423

Name	**C4**	**C6**	**C5**	**C7**	**C8**
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.3563	0.991	0.0031	0.991	0.991
Comp Mole Frac (Nitrogen)	0.0012	0.0033	0	0.0033	0.0033
Comp Mole Frac (Oxygen)	0.0001	0.0004	0	0.0004	0.0004
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.6423	0.0052	0.9969	0.0052	0.0052

Name	**C10**	**C9**	**C11**	**C12**	**C13**
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.9941	0.0094	0.9941	0.9941	0.9941
Comp Mole Frac (Nitrogen)	0.0033	0	0.0033	0.0033	0.0033
Comp Mole Frac (Oxygen)	0.0004	0	0.0004	0.0004	0.0004
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0021	0.9906	0.0021	0.0021	0.0021

Name	**C14**	**CW11**	**CW21**	**CW12**	**CW22**
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0.9941	0	0	0	0
Comp Mole Frac (Nitrogen)	0.0033	0	0	0	0
Comp Mole Frac (Oxygen)	0.0004	0	0	0	0
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	0.0021	1	1	1	1

Name	**CW13**	**CW23**	**CW14**	**CW24**	**CW1**
Comp Mole Frac (Hydrogen)	0	0	0	0	0
Comp Mole Frac (CO)	0	0	0	0	0
Comp Mole Frac (CO2)	0	0	0	0	0
Comp Mole Frac (Nitrogen)	0	0	0	0	0
Comp Mole Frac (Oxygen)	0	0	0	0	0
Comp Mole Frac (Argon)	0	0	0	0	0
Comp Mole Frac (Methane)	0	0	0	0	0
Comp Mole Frac (Ethane)	0	0	0	0	0
Comp Mole Frac (Propane)	0	0	0	0	0
Comp Mole Frac (i-Butane)	0	0	0	0	0
Comp Mole Frac (n-Butane)	0	0	0	0	0
Comp Mole Frac (i-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Pentane)	0	0	0	0	0
Comp Mole Frac (n-Hexane)	0	0	0	0	0
Comp Mole Frac (Ammonia)	0	0	0	0	0
Comp Mole Frac (H2O)	1	1	1	1	1

Name	**CW2**	**LAMBDA**	**NG1 CV**
Comp Mole Frac (Hydrogen)	0		0
Comp Mole Frac (CO)	0		0
Comp Mole Frac (CO2)	0		0
Comp Mole Frac (Nitrogen)	0		0
Comp Mole Frac (Oxygen)	0		0
Comp Mole Frac (Argon)	0		0
Comp Mole Frac (Methane)	0		0.8579
Comp Mole Frac (Ethane)	0		0.0941
Comp Mole Frac (Propane)	0		0.0337
Comp Mole Frac (i-Butane)	0		0.0143
Comp Mole Frac (n-Butane)	0		0
Comp Mole Frac (i-Pentane)	0		0
Comp Mole Frac (n-Pentane)	0		0
Comp Mole Frac (n-Hexane)	0		0
Comp Mole Frac (Ammonia)	0		0
Comp Mole Frac (H2O)	1		0
Energy Streams			

Name	**WK-101**	**WK-102**	**Q-SEP101**	**QREF**	**STACK POWER**
Heat Flow (kW)	129.5	681.5	135.3	52594.1	42288.6

Name	**QP-C**	**WGTC-101**	**WGTEXP-101**	**WGTC-102**	**WK-111**
Heat Flow (kW)	14782.4	8754.8	22490.1	4442.7	399.1

Name	**WK-112**	**WP-111**	**WP-121**
Heat Flow (kW)	364.6	42.5	175.9

PPAP EVALUATIONS
GCL Contract No 014-011

Evaluation of CO_2 Acceptor Technology

Gasconsult Ltd (GCL) now has pleasure in submitting for IEA's comments this Report of our PPAP Evaluation of a process for power production from natural gas with CO_2 capture, based on simultaneous steam reforming and CO shift over a nickel catalyst and CO_2 sorption by limestone or dolomite. This work was authorised by IEA in e-mail of 18 June 2004.

1. INTRODUCTION

The process and the recommended operation conditions were advised to GCL in IEA's e-mails 30 April (with attachment) and 11 June 2004.

2. BASIS OF DESIGN

The Basis of Design for the evaluation is IEA Technical and Financial Assessment Criteria Rev B 1999, with these exceptions:

2.1 Natural gas cost is $3 /GJ.

2.2 Calculated carbon capture for the reaction conditions chosen is 83.3%, slightly lower than the target 85% set by IEA. It is probable that 85% capture can be achieved, but such fine-tuning would, on our view, best be left until after the prospective stage of pilot-scale testing and demonstration discussed below.

3. TECHNOLOGY DISCUSSION

3.1 Basic Concept

The basic process feature consists of admitting a natural gas plus steam into a fluidised bed containing both a nickel-based steam reforming catalyst and free calcium oxide. The hydrocarbon and steam are converted over the nickel catalyst into hydrogen and carbon oxides by the steam reforming and CO shift reactions, while the lime removes the CO_2 produced. The favourable effect of the continuous removal of CO_2 permits the reforming/shift reactions to be operated at a much lower temperature (around 600^0-700^0C) than in a normal steam reforming plant, that temperature being sufficiently low for the lime to capture most of the CO_2 produced. The gas leaving the reforming reactor, consisting mainly of hydrogen and unreacted steam with some residual methane and carbon oxides, is used directly as fuel for a gas turbine.

The spent limestone (partly converted to $CaCO_3$) flows to a regeneration reactor, in which it is heated to around 1000^0C by combustion of an auxiliary stream of natural gas with oxygen, thus releasing the CO_2 absorbed in the reforming reactor. The regenerated CaO then returns to the reforming reactor.

The outlet gas from this second reactor, consisting of CO_2 plus steam, can be cooled to ambient temperature to condense its water content and then sent, at close to the feed natural gas pressure, for liquefaction and sequestration. Alternatively it can be expanded in a power recovery turbine to a lower pressure, prior to cooling and removal of condensed steam, in which case the CO_2 is sent for sequestration at that lower pressure and accordingly requires more compression energy in the liquefaction stage.

If successfully implemented, and in comparison with a normal steam reforming process, the new scheme would:

- avoid the investment and energy loss resulting from cooling the fuel gas before, and reheating after, CO_2 removal
- produce the captured CO_2 at elevated pressure, thereby saving net liquefaction energy.

3.2 Process Parameters

Our simulations have been based on the following assumptions:

- Reforming pressure of 25 bar, assumed to be sufficient pressure to provide fuel directly to a modified gas turbine with 20:1 pressure ratio
- Natural gas preheated initially to 380^0C, as needed for desulphurisation by CoMo/ZnO.
- No allowance has been made at this stage for recycle of the small amount of hydrogen from the reformer outlet that is necessary to provide the required concentration (about 2% H_2) upstream of the desulphurisers. As the required flow is only about 100kmol/h, the effect of this omission on efficiency and investment will be negligible.
- 4 mols of reforming steam per mol of carbon (in hydrocarbon) in natural gas.
- Reformer mixed feed inlet temperature 625^0C.
- The base sorbent was assumed to be 50% mol $CaCO_3$ + 50% mol% MgO.
- Sorbent feed to reformer (mol%): CaO 27.5, $CaCO_3$ 22.5, MgO 50.
- 50% of CaO entering reformer converted to $CaCO_3$.
- Reformer equilibrium approaches (^{0}C): CH_4/stm 10, shift 0, CO_2 capture 0.
- Nominal fluidising/transport CO_2 recycle to regenerator of 1810kmol/h.
- Subcritical steam cycle HP turbine inlet 150 bar/540^0C, reheat to 540^0C.
- Supercritical steam cycle HP turbine inlet 250 bar/600^0C, reheat to 540^0C.
- Optional CO_2/steam expansion turbine inlet 25 bar/1070^0C, outlet 3 bar.

3.3 Simulation of Heat and Material Balance

The heat and material balance for the selected case was simulated on HYSYS (please see flow diagram CaOCaCO3.jpg and Worksheet CaOCaCO3.xls attached). After allowance for the power required to produce oxygen and deliver it at high pressure, the resulting overall gas-to-power efficiencies are:

	% LHV
- Subcritical steam cycle	48.3
- Subcritical steam cycle with CO_2/steam expander	47.1
- Supercritical steam cycle	49.2

In view of the very small differences and rather small HP turbine capacity (50MW approx shaft power), we have based PPAP evaluation on the subcritical steam cycle (without CO_2/steam expander).

3.4 Plant Design Aspects

Considering the plant as a whole, there are aspects of the new scheme that will require further experimental work to determine if it offers a realistic alternative to steam reforming technologies, particularly:

- Verification of reaction equilibrium approaches in the reformer
- Nickel catalyst replacement rate. There is only some prospect of keeping this within acceptable limits if a dense, attrition-resistant catalyst is available, or can be developed, that will largely remain in the reformer reactor. Fluid bed steam reformers are understood to have been piloted by Exxon and GTI Chicago.
- Confirmation of gas filter performance, particularly for the regenerator outlet gas stream. Conceivably this could be overcome by locating the primary cyclones directly at the regenerator outlet (Stream C2 on the simulation) and the secondary cyclones and filters at Stream C3, where the gas temperature have been reduced to under 600^0C.

Another factor, relating to plant design rather to the basic process, is the possibility of integrating the gas turbine with the oxygen plant. In the present simulation, the molar exhaust flow of the gas turbine is 111% of the compressor flow, whereas in an equivalent gas turbine fired with natural gas the exhaust flow is about 104% of the compressor flow. This opens up the possibility, with the new process, of extracting some air from the discharge if the GT air compressor, to restore the relative flows of a methane-fired gas turbine. The extracted air can then be diverted to the oxygen plant, thereby reducing the normal investment there in air compressors. Development of this option is, however, beyond the scope of this evaluation.

4. MAIN PPAP INPUTS

Plant Components

GT
ST
PFBC
ASU
CO_2 compression/pumping to 110 bar

Fuel Specification

Natural gas	100% CV 48912 kJ/kg, C fraction 0.74
Mass & energy	fuel 21.57 kg/s
CO_2 recovered	83.3%

PPAP Lite Details

CO_2 compression power	5.1	MW
O_2 compression power	13.6	MW
HRSG on GT	400	MW
GT power	398	MW
ST power	166	MW
Percent of heat available to Steam cycle	25	%
Overall electrical efficiency after losses	47.7	%
Efficiency GT Cycle	35	%
Efficiency ST cycle	35	%
Overall power output	503	MW
Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1055.03	MW

Capital Cost
Oxygen Plant generated by PPAP
Gas turbine complete by PPAP with 30% cost enhancement
HRSTG by PPAP
Steam system & turbine etc by PPAP
Reformer & regenerator by PPAP using PFBC with 50% cost enhancement
$US 40 million total included for gas filters and catalyst handling
Total bottom line capital cost $ 737 million

Operating Cost
Natural gas $3/GJ
Power cost is 5.2 c/kWh.
Interest rate, plant life span, load factor and O&M as on the software v 3.0.2, supplied by IEA.
No special allowance has been made in the PPAP input for the cost of catalyst consumed. This could be quite considerable.

Multi-Criteria Analysis
Parameter: Raw Material Availability
Value: Locally Common with unlimited availability

Parameter: Process Conditions
Value: T 1200-1600^{0}K, 10-60bar – but no significant technical barriers

Parameter: Novelty of Materials
Value: Existing special alloys – known material in known environment

Parameter: Plant Complexity
Value: 6 Major Units, no recycle (as generated by PPAP – this may need review)

Parameter: Novelty of Process
Value: Major Modifications with problematical credited scientific proof of concept. The warning “very high risk of failure” is produced by PPAP

Parameter: Safety Risk
Value: Small Risk – extensively demonstrated and publicly accepted

Parameter: Environmental Impact
Value: Benign Waste – extensively demonstrated and publicly accepted

5. RESULTS

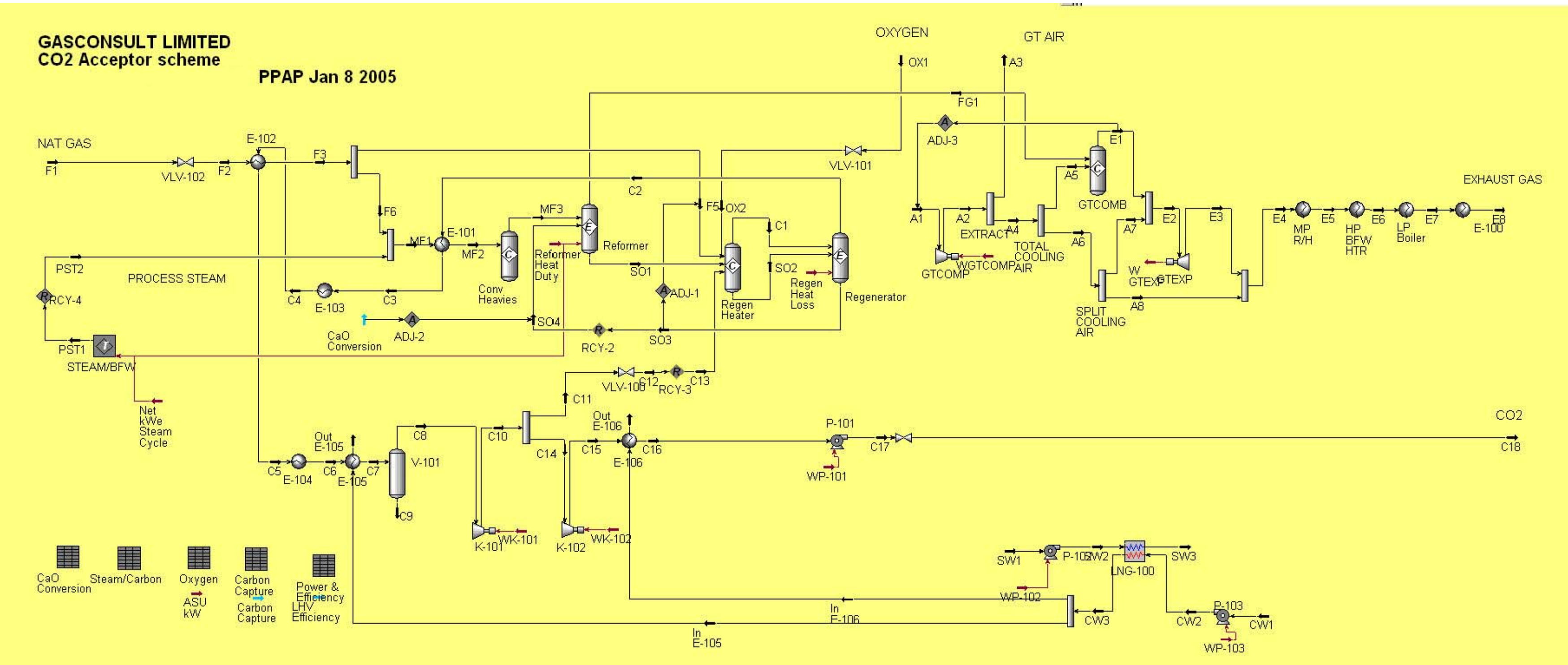
The full summary output from PPAP is as follows:

Heat Input		1055.0	MW
Estimated	Net Electricity Output	503.0	MW
	Net Efficiency	47.7	%
	CO_2 output/ kg/s	9.8	kg/s
	CO_2 output/kWh	0.070	kg/kWh
Estimated Capital Cost		737.1	M$
Estimated Op Cost		5.2	c/kWh
Multi-Criteria Assessment			
Decision Factor Scores			
Acceptance		32.0	
Applicability		28.4	
Confidence		30.0	
Estimated Cost		74.8	
	Total	165.2	
	Total cost only	238.9	
Risk assessment			
Averaged risk level		21	
Controlling risk level	**Process novelty**	**100**	

6. CONCLUSIONS

The combined steam reforming and CO_2 chemisorption technology evaluated in this PPAP study could show promise of evolving into a technically feasible solution for electric power generation from natural gas with CO2 capture.

Additional experimental and pilot plant work is, however, necessary for the purpose of determining a satisfactory method of ensuring that nickel losses in the spent dolomite do not exceed economically and environmentally acceptable levels. It might be concluded that the economics of this process are not so encouraging relative to much simpler processes, to justify this.



GASCONSULT LIMITED
CO2 Acceptor scheme

PPAP Jan 8 2005

CaOCaCO3 Workbook: Case (Main)
Streams

Name	**A1**	**A2**	**A3**	**A4**	**A5**
Vapour Fraction	1	1	1	1	1
Temperature (C)	9	461.2	461.2	461.2	461.2
Pressure (bar)	1	20	20	20	20
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	280.6	280.6	0	280.6	238.5
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	73051.7	73051.7	0	73051.7	62093.9
Comp Molar Flow (Oxygen) (kgmole/h)	19593.3	19593.3	0	19593.3	16654.3
Comp Molar Flow (Argon) (kgmole/h)	879.1	879.1	0	879.1	747.3
Comp Molar Flow (H2O) (kgmole/h)	637.9	637.9	0	637.9	542.2
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	94442.5	94442.5	0	94442.5	80276.2
Molecular Weight	28.93	28.93	28.93	28.93	28.93
Mass Flow (kg/h)	2.73E+06	2.73E+06	0	2.73E+06	2.32E+06
Heat Flow (kW)	-85871.5	271128	0	271128	230458.8

Name	**A6**	**A7**	**A8**	**ASU kW**	**C1**
Vapour Fraction	1	1	1		1
Temperature (C)	461.2	461.2	461.2		1303
Pressure (bar)	20	20	20		25
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0		1.1
Comp Molar Flow (CO) (kgmole/h)	0	0	0		0
Comp Molar Flow (CO2) (kgmole/h)	42.1	29.5	12.6		3403.1
Comp Molar Flow (Methane) (kgmole/h)	0	0	0		0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0		0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0		0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0		0
Comp Molar Flow (Nitrogen) (kgmole/h)	10957.8	7670.4	3287.3		7.9
Comp Molar Flow (Oxygen) (kgmole/h)	2939	2057.3	881.7		0
Comp Molar Flow (Argon) (kgmole/h)	131.9	92.3	39.6		44.6
Comp Molar Flow (H2O) (kgmole/h)	95.7	67	28.7		2960.8
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0		0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0		0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0		0
Molar Flow (kgmole/h)	14166.4	9916.5	4249.9		6417.5
Molecular Weight	28.93	28.93	28.93		31.96
Mass Flow (kg/h)	409851.1	286895.8	122955.3		205114.7
Heat Flow (kW)	40669.2	28468.4	12200.8	39985	-466891.9

Name	C2	C3	C4	C5	C6
Vapour Fraction	1	1	1	1	0.9001
Temperature (C)	1069	556.6	425	233.8	155
Pressure (bar)	25	24.7	24.4	23.9	23.4
Comp Molar Flow (Hydrogen) (kgmole/h)	1.1	1.1	1.1	1.1	1.1
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	5921.3	5921.3	5921.3	5921.3	5921.3
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	7.9	7.9	7.9	7.9	7.9
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	44.6	44.6	44.6	44.6	44.6
Comp Molar Flow (H2O) (kgmole/h)	2960.8	2960.8	2960.8	2960.8	2960.8
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	8935.7	8935.7	8935.7	8935.7	8935.7
Molecular Weight	35.36	35.36	35.36	35.36	35.36
Mass Flow (kg/h)	315938.9	315938.9	315938.9	315938.9	315938.9
Heat Flow (kW)	-726917.8	-791023.4	-806176.4	-827162.1	-844810.3

Name	C7	C8	C9	C10	C11
Vapour Fraction	0.6673	1	0	1	1
Temperature (C)	30	30	30	52.42	52.42
Pressure (bar)	23.1	23.1	23.1	30	30
Comp Molar Flow (Hydrogen) (kgmole/h)	1.1	1.1	0	1.1	0.3
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	5921.3	5893.9	27.4	5893.9	1789
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	7.9	7.9	0	7.9	2.4
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	44.6	44.6	0	44.6	13.5
Comp Molar Flow (H2O) (kgmole/h)	2960.8	15.7	2945.1	15.7	4.8
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	8935.7	5963.1	2972.5	5963.1	1810
Molecular Weight	35.36	43.88	18.25	43.88	43.88
Mass Flow (kg/h)	315938.9	261676.3	54262.6	261676.3	79427
Heat Flow (kW)	-883554	-647184.1	-236369.9	-645932.7	-196060.9

Name	C12	C13	C14	C15	C16
Vapour Fraction	1	1	1	1	0
Temperature (C)	50.64	50.64	52.42	141.9	27
Pressure (bar)	28	28	30	75	74.7
Comp Molar Flow (Hydrogen) (kgmole/h)	0.3	1.1	0.7	0.7	0.7
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1789	1788.5	4104.9	4104.9	4104.9
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	2.4	2.4	5.5	5.5	5.5
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	13.5	13.3	31	31	31
Comp Molar Flow (H2O) (kgmole/h)	4.8	4.8	10.9	10.9	10.9
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	1810	1810	4153.1	4153.1	4153.1
Molecular Weight	43.88	43.87	43.88	43.88	43.88
Mass Flow (kg/h)	79427	79397.4	182249.3	182249.3	182249.3
Heat Flow (kW)	-196060.9	-196006.1	-449871.7	-446286.7	-461646.4

Name	C17	C18	CaO Conversion	Carbon Capture	CW1
Vapour Fraction	0	0	0.5	0.8351	0
Temperature (C)	36.56	35.1			27
Pressure (bar)	120	110			1
Comp Molar Flow (Hydrogen) (kgmole/h)	0.7	0.7			0
Comp Molar Flow (CO) (kgmole/h)	0	0			0
Comp Molar Flow (CO2) (kgmole/h)	4104.9	4104.9			0
Comp Molar Flow (Methane) (kgmole/h)	0	0			0
Comp Molar Flow (Ethane) (kgmole/h)	0	0			0
Comp Molar Flow (Propane) (kgmole/h)	0	0			0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0			0
Comp Molar Flow (Nitrogen) (kgmole/h)	5.5	5.5			0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0			0
Comp Molar Flow (Argon) (kgmole/h)	31	31			0
Comp Molar Flow (H2O) (kgmole/h)	10.9	10.9			258491.3
Comp Molar Flow (CaO*) (kgmole/h)	0	0			0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0			0
Comp Molar Flow (MgO*) (kgmole/h)	0	0			0
Molar Flow (kgmole/h)	4153.1	4153.1			258491.3
Molecular Weight	43.88	43.88			18.02
Mass Flow (kg/h)	182249.3	182249.3			4.66E+06
Heat Flow (kW)	-461203.4	-461203.4			-2.05E+07

Name	**CW2**	**CW3**	**E1**	**E2**	**E3**
Vapour Fraction	0	0	1	1	1
Temperature (C)	27.09	17	1401	1317	581.7
Pressure (bar)	4	3.5	20	20	1.013
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	0	0	1028.8	1058.3	1058.3
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	62105.2	69775.7	69775.7
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	10331.5	12388.8	12388.8
Comp Molar Flow (Argon) (kgmole/h)	0	0	747.3	839.6	839.6
Comp Molar Flow (H2O) (kgmole/h)	258491.3	258491.3	19789.9	19856.9	19856.9
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	258491.3	258491.3	94002.8	103919.3	103919.3
Molecular Weight	18.02	18.02	26.62	26.84	26.84
Mass Flow (kg/h)	4.66E+06	4.66E+06	2.50E+06	2.79E+06	2.79E+06
Heat Flow (kW)	-2.05E+07	-2.05E+07	-213923.1	-185454.7	-940661.2

Name	**E4**	**E5**	**E6**	**E7**	**E8**
Vapour Fraction	1	1	1	1	1
Temperature (C)	577.2	532.1	210	170	115.1
Pressure (bar)	1.013	1.013	1.013	1.013	1.013
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)	1070.9	1070.9	1070.9	1070.9	1070.9
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	73063	73063	73063	73063	73063
Comp Molar Flow (Oxygen) (kgmole/h)	13270.5	13270.5	13270.5	13270.5	13270.5
Comp Molar Flow (Argon) (kgmole/h)	879.1	879.1	879.1	879.1	879.1
Comp Molar Flow (H2O) (kgmole/h)	19885.6	19885.6	19885.6	19885.6	19885.6
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	108169.2	108169.2	108169.2	108169.2	108169.2
Molecular Weight	26.92	26.92	26.92	26.92	26.92
Mass Flow (kg/h)	2.91E+06	2.91E+06	2.91E+06	2.91E+06	2.91E+06
Heat Flow (kW)	-928460.5	-973653.4	-1.28E+06	-1.32E+06	-1.37E+06

Name	**F1**	**F2**	**F3**	**F5**	**F6**
Vapour Fraction	1	1	1	1	1
Temperature (C)	30.98	30	380	380	380
Pressure (bar)	28	26	25.5	25.5	25.5
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CO) (kgmole/h)	0.1	0.1	0.1	0	0.1
Comp Molar Flow (CO2) (kgmole/h)	0.1	0.1	0.1	0	0.1
Comp Molar Flow (Methane) (kgmole/h)	3505.5	3505.5	3505.5	1151.4	2354.1
Comp Molar Flow (Ethane) (kgmole/h)	382.7	382.7	382.7	125.7	257
Comp Molar Flow (Propane) (kgmole/h)	137.3	137.3	137.3	45.1	92.2
Comp Molar Flow (n-Butane) (kgmole/h)	58.2	58.2	58.2	19.1	39.1
Comp Molar Flow (Nitrogen) (kgmole/h)	16.9	16.9	16.9	5.5	11.3
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)	0.3	0.3	0.3	0.1	0.2
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	0
Molar Flow (kgmole/h)	4101	4101	4101	1347	2754
Molecular Weight	18.94	18.94	18.94	18.94	18.94
Mass Flow (kg/h)	77668.4	77668.4	77668.4	25511.2	52157.2
Heat Flow (kW)	-88364.5	-88364.5	-67378.8	-22131.5	-45247.4

Name	**FG1**	**In E-105**	**In E-106**	**LHV Efficiency**	**MF1**
Vapour Fraction	1	0	0	0.4831	1
Temperature (C)	700	17	17		310.3
Pressure (bar)	25	3.5	3.5		25.5
Comp Molar Flow (Hydrogen) (kgmole/h)	9752.9	0	0		0
Comp Molar Flow (CO) (kgmole/h)	33.2	0	0		0.1
Comp Molar Flow (CO2) (kgmole/h)	42.3	0	0		0.1
Comp Molar Flow (Methane) (kgmole/h)	714.9	0	0		2354.1
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0		257
Comp Molar Flow (Propane) (kgmole/h)	0	0	0		92.2
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0		39.1
Comp Molar Flow (Nitrogen) (kgmole/h)	11.3	0	0		11.3
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0		0
Comp Molar Flow (Argon) (kgmole/h)	0	0	0		0
Comp Molar Flow (H2O) (kgmole/h)	8065.1	185107	73384.4		13204.4
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0		0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0		0
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0		0
Molar Flow (kgmole/h)	18619.7	185107	73384.4		15958.2
Molecular Weight	9.642	18.02	18.02		18.17
Mass Flow (kg/h)	179532.1	3.33E+06	1.32E+06		290031.4
Heat Flow (kW)	-444383.7	-1.47E+07	-5.83E+06		-901477.2

Name	MF2	MF3	et kWe Steam Cycl	Out E-105	Out E-106
Vapour Fraction	1	1		0	0
Temperature (C)	625	621.3		27	27
Pressure (bar)	25.2	25.2		2.5	2.5
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0		0	0
Comp Molar Flow (CO) (kgmole/h)	0.1	186.3		0	0
Comp Molar Flow (CO2) (kgmole/h)	0.1	0.1		0	0
Comp Molar Flow (Methane) (kgmole/h)	2354.1	3114.8		0	0
Comp Molar Flow (Ethane) (kgmole/h)	257	0		0	0
Comp Molar Flow (Propane) (kgmole/h)	92.2	0		0	0
Comp Molar Flow (n-Butane) (kgmole/h)	39.1	0		0	0
Comp Molar Flow (Nitrogen) (kgmole/h)	11.3	11.3		0	0
Comp Molar Flow (Oxygen) (kgmole/h)	0	0		0	0
Comp Molar Flow (Argon) (kgmole/h)	0	0		0	0
Comp Molar Flow (H2O) (kgmole/h)	13204.4	13018.1		185107	73384.4
Comp Molar Flow (CaO*) (kgmole/h)	0	0		0	0
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0		0	0
Comp Molar Flow (MgO*) (kgmole/h)	0	0		0	0
Molar Flow (kgmole/h)	15958.2	16330.6		185107	73384.4
Molecular Weight	18.17	17.76		18.02	18.02
Mass Flow (kg/h)	290031.4	290031.5		3.33E+06	1.32E+06
Heat Flow (kW)	-838628.5	-838628.5	165689.3	-1.47E+07	-5.82E+06

Name	OX1	OX2	PST1	PST2	Reformer Heat Duty
Vapour Fraction	1	1	1	1	
Temperature (C)	20	19.49	300.4	300.4	
Pressure (bar)	27	25	30	30	
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0	0	
Comp Molar Flow (CO) (kgmole/h)	0	0	0	0	
Comp Molar Flow (CO2) (kgmole/h)	0	0	0	0	
Comp Molar Flow (Methane) (kgmole/h)	0	0	0	0	
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0	0	
Comp Molar Flow (Propane) (kgmole/h)	0	0	0	0	
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0	0	
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0	0	
Comp Molar Flow (Oxygen) (kgmole/h)	3092.6	3092.6	0	0	
Comp Molar Flow (Argon) (kgmole/h)	31.2	31.2	0	0	
Comp Molar Flow (H2O) (kgmole/h)	0	0	13204.2	13204.2	
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0	0	
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0	0	
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0	0	
Molar Flow (kgmole/h)	3123.8	3123.8	13204.2	13204.2	
Molecular Weight	32.08	32.08	18.02	18.02	
Mass Flow (kg/h)	100210.7	100210.7	237874.2	237874.2	
Heat Flow (kW)	-309.8	-309.8	-856229.4	-856229.8	109608.6

Name	**Regen Heat Loss**	**SO1**	**SO2**	**SO3**	**SO4**
Vapour Fraction		0	0	0	0
Temperature (C)		700	1303	1069	1069
Pressure (bar)		25	25	25	25
Comp Molar Flow (Hydrogen) (kgmole/h)		0	0	0	0
Comp Molar Flow (CO) (kgmole/h)		0	0	0	0
Comp Molar Flow (CO2) (kgmole/h)		0	0	0	0
Comp Molar Flow (Methane) (kgmole/h)		0	0	0	0
Comp Molar Flow (Ethane) (kgmole/h)		0	0	0	0
Comp Molar Flow (Propane) (kgmole/h)		0	0	0	0
Comp Molar Flow (n-Butane) (kgmole/h)		0	0	0	0
Comp Molar Flow (Nitrogen) (kgmole/h)		0	0	0	0
Comp Molar Flow (Oxygen) (kgmole/h)		0	0	0	0
Comp Molar Flow (Argon) (kgmole/h)		0	0	0	0
Comp Molar Flow (H2O) (kgmole/h)		0	0	0	0
Comp Molar Flow (CaO*) (kgmole/h)		2510.8	2510.8	5029	5021.6
Comp Molar Flow (CaCO3*) (kgmole/h)		6619.6	6619.6	4101.4	4108.8
Comp Molar Flow (MgO*) (kgmole/h)		9130.2	9130.2	9130.2	9130.2
Molar Flow (kgmole/h)		18260.6	18260.6	18260.6	18260.6
Molecular Weight		64.14	64.14	58.07	58.09
Mass Flow (kg/h)		1.17E+06	1.17E+06	1.06E+06	1.06E+06
Heat Flow (kW)	3486.7	-3.95E+06	-3.70E+06	-3.44E+06	-3.44E+06

Name	**SW1**	**SW2**	**SW3**	**W GTEXP**	**WGTCOMP**
Vapour Fraction	0	0	0		
Temperature (C)	7	7.058	16		
Pressure (bar)	1	3	2.5		
Comp Molar Flow (Hydrogen) (kgmole/h)	0	0	0		
Comp Molar Flow (CO) (kgmole/h)	0	0	0		
Comp Molar Flow (CO2) (kgmole/h)	0	0	0		
Comp Molar Flow (Methane) (kgmole/h)	0	0	0		
Comp Molar Flow (Ethane) (kgmole/h)	0	0	0		
Comp Molar Flow (Propane) (kgmole/h)	0	0	0		
Comp Molar Flow (n-Butane) (kgmole/h)	0	0	0		
Comp Molar Flow (Nitrogen) (kgmole/h)	0	0	0		
Comp Molar Flow (Oxygen) (kgmole/h)	0	0	0		
Comp Molar Flow (Argon) (kgmole/h)	0	0	0		
Comp Molar Flow (H2O) (kgmole/h)	291000.7	291000.7	291000.7		
Comp Molar Flow (CaO*) (kgmole/h)	0	0	0		
Comp Molar Flow (CaCO3*) (kgmole/h)	0	0	0		
Comp Molar Flow (MgO*) (kgmole/h)	0	0	0		
Molar Flow (kgmole/h)	291000.7	291000.7	291000.7		
Molecular Weight	18.02	18.02	18.02		
Mass Flow (kg/h)	5.24E+06	5.24E+06	5.24E+06		
Heat Flow (kW)	-2.32E+07	-2.32E+07	-2.31E+07	755206.6	356999.5

Name	WK-101	WK-102	WP-101	WP-102	WP-103
Vapour Fraction					
Temperature (C)					
Pressure (bar)					
Comp Molar Flow (Hydrogen) (kgmole/h)					
Comp Molar Flow (CO) (kgmole/h)					
Comp Molar Flow (CO2) (kgmole/h)					
Comp Molar Flow (Methane) (kgmole/h)					
Comp Molar Flow (Ethane) (kgmole/h)					
Comp Molar Flow (Propane) (kgmole/h)					
Comp Molar Flow (n-Butane) (kgmole/h)					
Comp Molar Flow (Nitrogen) (kgmole/h)					
Comp Molar Flow (Oxygen) (kgmole/h)					
Comp Molar Flow (Argon) (kgmole/h)					
Comp Molar Flow (H2O) (kgmole/h)					
Comp Molar Flow (CaO*) (kgmole/h)					
Comp Molar Flow (CaCO3*) (kgmole/h)					
Comp Molar Flow (MgO*) (kgmole/h)					
Molar Flow (kgmole/h)					
Molecular Weight					
Mass Flow (kg/h)					
Heat Flow (kW)	1251.5	3585.1	443	356.7	482.3

IEA GREENHOUSE GAS R&D PROGRAMME

EVALUATION OF BARIUM OXIDE–BASED POWER GENERATION CONCEPT WITH CO_2 CAPTURE

GASCONSULT LTD CONTRACT NO. 012-001

MARCH 2002

CONTENTS

EXECUTIVE SUMMARY

In 1999 IEA carried out a preliminary evaluation of a proposed process for power generation from natural gas with capture of CO_2 described by Jody et al. This process employs absorption of oxygen from air by oxidation of barium oxide BaO to barium peroxide BaO_2, followed by decomposition of the resulting BaO_2 at higher temperatures with release of free oxygen. The released oxygen is reacted with natural gas (or in principle with other carbonaceous fuels) to form CO_2 and steam, from which substantially pure CO_2 can be recovered for sequestration. High-grade heat evolved in both the oxygen absorption and decomposition/combustion stages is recovered for use in power generation.

IEA has commissioned Gasconsult Ltd to make a further assessment of this BaO/BaO_2 cycle. It has been concluded that the BaO/BaO_2 process has some merit in that almost 100% carbon capture is apparently achievable using an adaptation of existing AFBC technology. Overall thermal efficiency at around 45% is comparable with other natural gas fired CO_2 capture power generation options. However there are serious and unresolved concerns over the toxicity, availability and cost of the barium oxide make-up, and over the cost and practicalities of disposing of or recycling the fines. Moreover the very high barium oxide recirculation rate between the oxidiser and the decomposer/combustor (circa 1 tonne/s for 500 MWe) should be noted.

It is possible that alternative chemical oxygen carrier systems may be worth investigating.

1. INTRODUCTION

In 1999 IEA carried out a preliminary evaluation of a proposed process for power generation from natural gas with capture of CO_2 described by Jody et al[1]. This process employs absorption of oxygen from air by oxidation of barium oxide BaO to barium peroxide BaO_2, followed by decomposition of the resulting BaO_2 at higher temperatures with release of free oxygen. The released oxygen is reacted with natural gas (or in principle with other carbonaceous fuels) to form CO_2 and steam, from which substantially pure CO_2 can be recovered for sequestration. High-grade heat evolved in both the oxygen absorption and decomposition/combustion stages is recovered for use in power generation.

In response to continuing interest in this concept, IEA has commissioned Gasconsult Ltd to make a further assessment of this BaO/BaO_2 cycle. This assessment has been performed in two stages. In the first stage, several variants of the process were simulated using HYSYS, in combination with additional thermodynamic data for the BaO/ BaO_2 system obtained from Kubachewski & Alcock and from the Handbook of Chemistry and Physics. The resulting simulation has enabled consistent calculation of the reaction heats and equilibria in the reaction system, together with the steam cycle. In the second stage, the resulting process scheme was evaluated using IEA's techno-economic evaluation PPAP software.

In order to produce, as far as possible, an independent assessment, only limited reference has been made to IEA's earlier evaluation of this process.

[1] Integrating O_2 Production with Power Systems to Capture CO_2: Jody B.J., Daniels E.J., Wolsky A.M, Energy Conv & Management Vol. 38 Suppl. pp S135-S140, 1997.

2. DESIGN BASIS

The work has been carried out on the basis of the standard IEA assessment conditions, except that it has been assumed that natural gas is pure methane, as for the previous assessment.

3. SCREENING OF PROCESS OPTIONS

At the outset of this new study, consideration was given to a number of possible process variants within the principle of circulating barium oxides between an oxidiser and a combustor. These were:

Option A	A combined cycle type of operation, in which the BaO_2 decomposer/methane combustor would essentially take the place of the combustor of a gas turbine (GT) and operate at elevated pressure (20–30 bar). The BaO oxidiser would operate at atmospheric pressure. The GT compressor would operate on recycled CO_2. The GT expander would be followed by heat recovery steam generation, supplying steam turbines. The HRSG outlet gas would be cooled and water of combustion separated. Some of the resulting CO_2 stream would be bled from the cycle and compressed for disposal, while the balance would be recycled to the suction of the GT compressor.
Option B	As Option A, but the oxidiser would also operate at the same pressure (20–30 bar) as the decomposer/combustor. The depleted air (nitrogen) would be heated and expanded, thus forming a second GT cycle.
Option C	Low (essentially atmospheric) pressure operation for both oxidiser and decomposer/combustor, with a steam cycle providing all the power output.

One clear disadvantage of the basic process is the great amount of solid material BaO/BaO_2 that must be recycled round the system – approximately 3400 tonnes/h, or almost one tonne per second at the scale studied (500MWe net power production). This high solids recirculation arises because 0.5 kmol of O_2 (16 kg) requires 1 kmol of BaO (153kg) for transport, a weight ratio of about 10. In contrast, the combustion of 16 kg of oxygen by carbon requires only 6 kg of solid material, a weight ratio of about 0.375. Thus, on a simple oxygen basis, the mass solids transport required for the process studied is a factor of 30 over combustion of coal. This is somewhat compensated for by the higher s.g. of BaO/BaO_2 (ca 5). To transmit this amount of material over a substantial pressure difference, e.g. via lock hoppers, would be very expensive even if possible.

For this reason Option A was eliminated, and attention was then given to Option B. Examination of the chemical equilibria shows that enhanced pressure is not required to carry out the oxidation reaction. Enhanced pressure also makes the combustion step somewhat more problematic, as it is necessary to maintain the oxygen partial pressure in this step below a fixed value. Therefore when the total pressure in the decomposer/combustor is raised, the oxygen concentration must be reduced in order to limit the oxygen partial pressure. Achieving this may under some circumstances require a significant recycle of product CO_2 to the decomposer/combustor. Moreover, the operation of the absorber at elevated pressure in this option requires provision of a form of gas turbine to compress the oxidising air to 20-30 bar and to expand the oxygen-depleted air leaving the absorber to atmospheric pressure. In order for this secondary GT to generate net power, it would be necessary to raise the temperature of the depleted air leaving the absorber. If this were done by direct combustion of natural gas, the resulting CO_2 would be discharged to the atmosphere, while the temperature achievable with indirect heating would be limited and hence little power made

Option C was therefore selected. The oxidiser and decomposer both operate at near-atmospheric pressure, and both reactors are assumed to be of fluidised-bed type, employing AFBC-type technology.

It should be note that this is a different arrangement from IEA's previous assessment of this process, which incorporated a version of Option A with low-pressure absorber and high-pressure decomposer/combustor.

4. DESCRIPTION OF SELECTED PROCESS

Please refer to the attached schematic Process Flow Diagram and Material Balance in Section 9.

Air supplied by the Air Blower enters the fluid-bed BaO Oxidiser, which operates at near-atmospheric pressure and 500^0C. The oxidation of BaO to BaO_2 effectively removes almost all the oxygen from the incoming air. The reaction is exothermic, and the reaction heat is used to generate HP steam. The Oxidiser off-gas (essentially nitrogen) leaves the reactor at 500^0C. After passing through a Cyclone, gas Filter and Boiler Feedwater Heater, the gas is scrubbed with water to remove traces of barium oxides before it is discharged to atmosphere. The solid material recovered in the cyclone is returned to the Oxidiser, but the fines from the filter and Wet Scrubber system are rejected.

The solids leaving the Oxidiser, which are assumed to contain 95mol% BaO_2, pass to the Decomposer/ Combustor. This is also a fluidised reactor and operates at near atmospheric pressure and 800^0C. This reactor is supplied with a fluidising gas consisting of the natural gas supply to the plant plus some recycled CO_2 sweep gas. At the operating temperature of 800^0C, the incoming BaO_2 is decomposed into BaO, which is recycled to the Oxidiser, and oxygen, which reacts with methane to form CO_2 and steam. The regeneration of BaO from BaO_2 is itself endothermic, but the combustion of the methane in the evolved oxygen results in a strongly exothermic overall reaction. As with the Oxidiser, the heat evolved is used to generate HP steam.

It may be feasible to burn the natural gas without any sweep gas, but the flow rate of natural gas alone, which is very much less than the reactor exit gas flow, would probably be insufficient to fluidise the bed. Since the design of the combustor is unknown, an arbitrary provision has been made for a CO_2 sweep gas flow.

The gas leaving the Decomposer/Combustor consists of a mixture of CO_2, water vapour and a trace oxygen. It would be impractical simultaneously to avoid both residual methane and residual oxygen. Residual oxygen is on balance preferred, due to a desire to avoid formation of carbon in the Decomposer/Combustor.

After removal of solids a Cyclone and gas Filter system, the outlet gas is cooled successively in an HP steam generator/BFW heater and a final gas cooler. The cold gas after removal of condensed water of combustion consists of almost pure CO_2. After some gas has been is separated for recycle to the Decomposer/Combustor as described above, the balance of the CO_2 is compressed to about 60 bar, at which pressure it is condensed. The liquid CO_2 is then pumped to storage at 110 bar.

Heat removed from the Oxidiser and from the Decomposer/Combustor and its exit gas together are also used to generate and reheat HP steam. The steam balance has been calculated as a typical supercritical system with primary conditions 255 bar/600degC and reheat to 58 bar/610degC

The corresponding process flows are also shown in Section 9.

5. COMMENTS ON SELECTED PROCESS

The process achieves a clear objective in that the only outputs are power, almost pure nitrogen and almost pure CO_2. The oxidation/decomposition cycle can also be well integrated with supercritical pressure steam power generation. The calculated thermal efficiency (LHV) is 45.5%. It is anticipated that the efficiency would be ~2 % less using the sub-critical conditions of the previous IEA study.

At some locations the very pure nitrogen may have some value as well as the CO_2, for example to enhance oil recovery.

A consequence of the high solids circulation mentioned above is that there will probably be considerable attrition of the circulating solids. A further potential cause of particle size reduction is degradation at a molecular level, due to the stresses induced by addition and removal of an oxygen atom as the material circulates between the oxidiser and the decomposer/combustor. Whilst these factors will not affect the chemistry of the process, they will aggravate the difficult of efficient separation of solids, disposal of fines and prevention of significant process losses. For instance, even if 99.95 % cyclone collection efficiency is obtained downstream of both the oxidiser and the decomposer/combustor, a make-up of BaO of 3.4 tonnes/h would still be required. The use of hot gas filters in the proposed flowsheet, plus final wet scrubbing on the waste nitrogen stream from the oxidiser, should substantially eliminate barium oxide losses to the environment, but the above-mentioned BaO flowrate in the cyclone discharge indicates the probable scale of fines disposal.

Another possible difficulty is that the circulating solid may become contaminated with carbon, resulting from thermal cracking of natural gas, particularly heavier components of some natural gases, in the decomposer/combustor. If any carbon formed is not burned off in the oxidiser, there could be a gradual accumulation of fine carbon in the system. It is not clear, however, whether this would necessarily inhibit chemical reaction.

As it is likely that a substantial continuous make-up of BaO will be needed, the availability and cost of BaO are important considerations. It might be possible to develop a method for reconstituting BaO dust into larger particles that could be used as make-up.

It would be necessary to assess whether any atmospheric losses of barium compounds at all would be acceptable (barium compounds are generally considered hazardous - see below) or whether any potential losses would have to be captured in a liquid or solid form. We addressed this point in Safety Risk and Environmental in the PPAP assessment Section 6. If further study discloses that the toxicity of barium oxides is a serious obstacle to further development, other chemical systems such as sodium nitrate/nitrite, or nickel or other metal oxide systems, could be considered in the future.

6. PPAP INPUTS AND RESULTS

The IEA Power Plant Assessment Program (PPAP), written in MS Excel, is designed to be a powerful yet easy to use program for producing a quick relative assessment of power generation processes. The program aims to lead the engineer assessing the process through a series of screens that gather information about the power generation process. The required information ranges from the technical process specification, through costing, to risk assessment. The more data that is available to the engineer, the more accurate the final assessment will be. However, if the information is not sufficiently detailed it is possible to make simplifying assumptions. Although the program is designed to be easy to use, it should be noted that considerable experience in power plant design and analysis is still required for its use.

The sections below record the main inputs to the various screens in PPAP

Plant Components

Gas Turbines x 0
Combustors 2 x FBC
Supercritical steam cycle
HRSG x1
Other major plant items x 1
CO_2 compression/pumping to 110 bar
Solids handling assumed included in FBC's

Fuel Specification

NG 100%
Mass & Energy: Fuel 21.88 kg/s
% to combustion or steam: 100

Steam Cycle

Efficiency 50 %. This value has been chosen so that the net power closely corresponds to the results of our simulation with a supercritical steam cycle.

Costing

Because the program does not appear in this case to input any data automatically for the FBC option, some assumptions have been made as follows. On the basis that one CFBC to fit the total capacity predicts an erected cost of $245 million, and two (each sized for 100%) PFBC's gives $268 million, two atmospheric FBC's are assumed to be approximately 50% of this ($130 million) included under Other Equipment (User Defined). It is reasonable to put in two 100% units here, as the fuel and oxygen are not split into two parallel streams but in a sense are processed twice in series. The solids handing auto-entry is tied to coal feed and is therefore zero.

Other items :
- two candle filter units: cost multiplier 2 (as higher temperature)
- cyclones: assumed included in FBC's.

Total investment cost $522 million.

The program predicts 503 MWe net power c.f. the 501 MW from HYSYS simulation.

Operating Cost

Using the standard IEA assumptions (except that pure methane has been used for NG - a very minor difference), power cost is ~3.75 c/kWh.

Multi-Criteria Analysis

PPAP uses the following criteria: 0 is most unfavourable, 100 is most favourable.

Raw Material: Rating 60 (Moderately Available)

We have not found any quoted price for supply of BaO, for example in Chemical Marketing Reporter. Kirk Othmer says that it is not being currently manufactured in the US, and need is met from imports. We have made enquires with a supplier and await a response. As it is manufactured by thermal decomposition of barium carbonate, this might possibly be performed within the power plant, with some savings in cost.

The hydrated form $Ba(OH)_2$ is widely used; in lubricating oils and greases, plastics stabilisers, as a papermaking additive, as an ingredient in sealants, vulcanisation accelerators, pigment dispersant, in PF foams, and as a protectant for limestone fine art objects.

Process Conditions Rating: 100 <1200degK, atmospheric pressure

On the basis that the steam cycle part is well known, it is not considered under this heading.

Material Rating: 100 Carbon steel

With refractory lining, as AFBC boiler construction.

Recycles: Only one major recycle (BaO_x), the CO_2 recycle being considered minor.

Novelty Rating: 60 Major Modifications

Safety Risk Rating: 30 Major In-Plant Risk

BaO/BaO_2 is toxic. Kirk Othmer does mention that soluble barium compounds are poisonous and the hydroxide is certainly soluble, and quotes a lethal dose between 1 and 15 g. The hydroxide is nevertheless used in a great range of consumer products mentioned above. There may be a great difference in toxicity between the hydrated material, which is not easily inhaled, and the anhydrous material as a fine dust. Kirk Othmer also refers to fire hazard, presumably due to spontaneous oxidation of BaO.

US/Canada EPA Data/Scorecard states “not a recognised or suspect carcinogen”, but gives “ Data Gap” for both non-cancer inhalation risk and Ambient Air Quality Standard.

JT Baker Material Safety Data Sheet says: Health Rating 3 - Severe (Life), and gives following Airborne Exposure Limits for Soluble Barium Compounds: OSHA Permissible Exposure Limit (PEL): 0.5mg (Ba)/m^3, ACGIH Threshold Limit Value (TLV) 0.5 mg (Ba)/m^3 A4 - not classifiable as a human carcinogen. It says not considered a fire hazard (which seems to contradict Kirk Othmer).

In the process considered here, the equipment containing the material is at atmospheric pressure. It could even be run under induced draught, so risk of escape would be low always provided process control was such as to eliminate any possibility of explosive combustion. On this basis we have chosen Major In-Plant Risk, rather than Major Ex-Plant Risk.

Environmental Impact Rating: 50 Mildly Harmful Waste

On the basis that the barium compounds could be almost totally collected, e.g. finally by wet scrubbing, there should be no atmospheric emissions. This rating assumes that discharge of all liquid barium-containing waste will be minimised. This would imply a facility to re-crystallise $Ba(OH)_2$ and recover BaO from the wet scrubber and other gas/liquid separators. This re-crystallisation has not been allowed for in the flowsheet at this stage of the study. We therefore suggest Mildly Harmful Waste.

PPAP Results

Power cost (based on 503 MWe) is 3.75 c/kWh

Decision Factor Scores

	BaO Process	Typical proven technology for comparison
Acceptance	**38.0**	**Paul, please could you see if you have the scores that we can use, e.g. for gas-fired combined cycle with post combustion scrubbing**
Applicability	**54.4**	**I don't have figs I think either on disk**
Confidence	**77.5**	**or in the book. Would you like to advise please?**
Estimated Cost	**71.2**	

7. CONCLUSIONS

The BaO/BaO_2 process has some merit in that almost 100% carbon capture is apparently achievable using an adaptation of existing AFBC technology. Overall thermal efficiency at around 45% is comparable with other natural gas fired CO_2 capture power generation options. However there are serious and unresolved concerns over the toxicity, availability and cost of the barium oxide make-up, and over the cost and practicalities of disposing of or recycling the fines. Moreover the very high barium oxide recirculation rate between the oxidiser and the decomposer/combustor (circa 1 tonne/s) should be noted.

The low acceptance score arises in part from the toxicity issue which, though serious, may not be worse than for many other chemical processes commonly in use. However, it is clearly more serious than for a normal power plant. This risk would have to be assessed in relation to the proposed power plant location.

Alternative chemical systems could be assessed, such as sodium nitrate/nitrite, or nickel or other metal oxide systems. Sodium nitrate/nitrite is superficially attractive due to probably lower cost, greater availability, lower density and safety, relative to BaO. Its high solubility in water would also facilitate recycle of fines by recrystallisation. However the performance of sodium nitrate/nitrite in its basic function as an oxygen carrier would have to be evaluated from first principles.

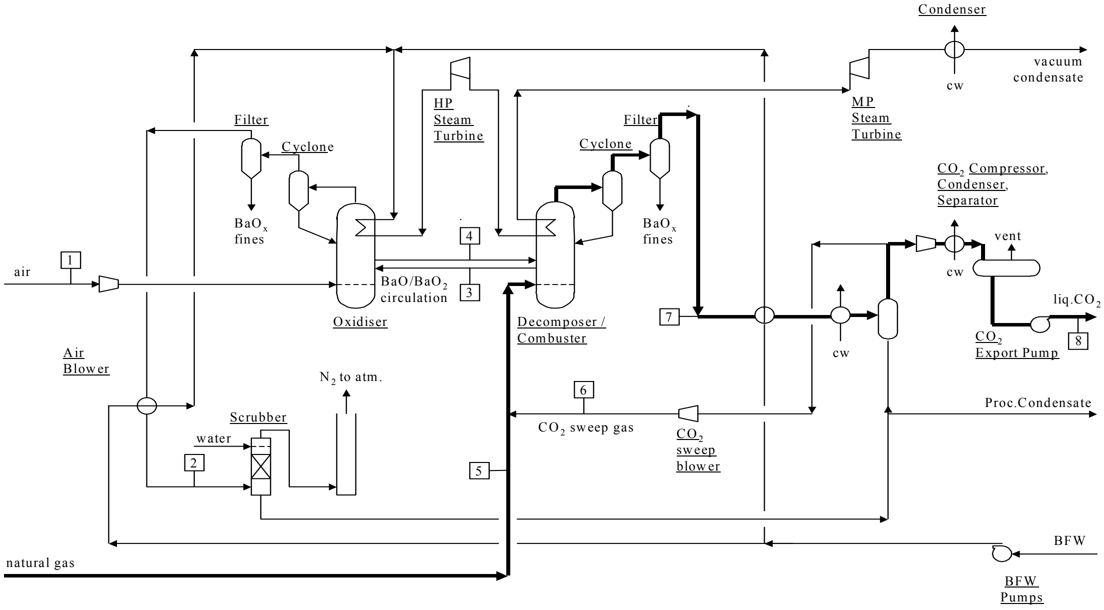
8. COMMENTS ON PPAP SOFTWARE

The following features were noted in the version of the PPAP software used and installed by us.

Costing Sheet: the program does not appear in this case to input any data automatically for the FBC option (it does for the PFBC, CFBC and PF cases).

Costing Sheet/Plant Components Sheet: as the number of units of a given type for a given total capacity is varied, the size per unit alters accordingly on the “Plant Components” sheet but does not appear to vary at all on the “Costing” sheet. As the type of steam cycle is changed on the “Plant Components” sheet, the capital cost of the steam cycle appears to stay constant on the “Costing” sheet. This, of course, may be intentional.

9. HEAT AND MATERIAL BALANCES



Streams	1	2	3	4	5	6	7	8
Name	AIR IN	N2 TO ATM	BaO TO OXDR	BaO2 TO COMB	NG TO COMB	CO2 SWEEP	COMB EXIT G	CO2 DISCH
Temp (C)	20	70	800	500	30	53.57	800	30.54
Pr (bar abs)	1	1.114	1.2	1.2	1.2	1.5	1.101	110
kmol/h								
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	1754.8	6693.3	4933.3
CH4	0.0	0.0	0.0	0.0	4938.5	0.0	0.0	0.0
N2 +Ar	37651.4	37651.4	0.0	0.0	0.0	0.0	0.0	0.0
O2	10008.6	18.1	0.0	0.0	0.0	0.0	0.0	0.0
H2O	0.0	0.0	0.0	0.0	0.0	55.2	9933.1	10.2
BaO	0.0	12.9	21053.8	1059.9	0.0	0.0	0.0	0.0
BaO2	0.0	253.1	1108.1	20836.0	0.0	0.0	0.0	0.0
Total	**47660.0**	**37935.4**	**22161.9**	**21896.0**	**4938.5**	**1810.0**	**16626.4**	**4943.5**
kg/h	1.38E+06	1.10E+06	3.42E+06	3.69E+06	79228.2	78222.3	473515.8	217296.4
Mol Wt	28.85	29.00	154.10	168.60	16.04	43.22	28.48	43.96

IEA GREENHOUSE GAS R&D PROGRAMME

PPAP EVALUATION OF CRYOGENIC CO_2 SEPARATION FROM BOILER FLUE GASES (SCHEME PROPOSED BY JOINT ISRAELI-RUSSIAN LABORATORY FOR ENERGY RESEARCH)

IEA CONTRACT NO. IEA/CON/02/75
GASCONSULT CONTRACT NO. 012 - 002

NOVEMBER 2002

EXECUTIVE SUMMARY

IEA has commissioned Gasconsult Ltd (GCL) to make a evaluation of a cryogenic process, proposed by the Joint Israeli-Russian Laboratory for Energy Research, for capture of CO_2 from the flue gases of a power station boiler. This evaluation uses the IEA in-house PPAP software.

The key features this process, as outlined in a 1997 paper by Dr G Saksonov of the Laboratory, are as follows:

- Compressing the flue gas
- Cooling the gas to the near the temperature at which solid CO_2 is formed
- Expanding the cold gas to atmospheric pressure in a turbine
- Separating the solid CO_2 formed in the turbine
- Recovering the separated CO_2 in a form suitable for permanent disposal.

GCL's current evaluation is based on the flue gas composition and temperature given for a PF-fired generating station with Flue Gas Desulphurisation (FGD) taken from IEAGHG/SR1.

The main conclusions drawn from the present work are as follows:

1. With compression of flue gas to 3 bar, as proposed by the Laboratory, GCL has calculated CO_2 capture in the region of only 20-25%. The present evaluation is based on 15 bar expander inlet, giving a predicted CO_2 capture of 70% to 80%.

2. Mechanical separation of condensed water from the compressed flue gas, as proposed by the Laboratory, will not avoid frosting, and consequent blockage, in the cryogenic gas cooler. A silica gel dryer is therefore recommended, to remove residual water vapour before the gas enters the cryogenic zone.

3. The effect of SO_2 in the flue gas has not been fully investigated. Preliminary work suggests, however, that SO_2 could be preferentially removed or co-captured with the solid CO_2. If this is substantiated, it might be possible to eliminate conventional FGD.

4. Although relatively small expanders currently condense directly over 30% of inlet hydrocarbon vapours streams, an expander condensing around 10 mol% of its feed stream in the form of solid CO_2 has probably not yet been demonstrated. When the high output required (around 30MW in a large plant) is considered, this would be a major new development.

5. Another key aspect of the Laboratory's process is the separation and liquefaction of the very large flow of solid CO_2 formed (up to 600 t/h @500MWe coal-based). GCL suggests a thermally efficient method of subliming the dry ice and liquefying the resulting vapour at low pressure and temperature. This also would require intensive development**.**

6. The economic performance of the process emerging from PPAP appears somewhat worse than for mainstream flue gas CO_2 capture proposals. Considerable development work would be needed, particularly on the expander and the handling/processing of the solid CO_2. The possibility of co-capture of SO_2 could, however, be a positive feature.

CONTENTS

1. INTRODUCTION

IEA has commissioned Gasconsult Ltd to evaluate a cryogenic process, proposed by the Joint Israeli-Russian Laboratory for Energy Research, for capture of CO_2 from the flue gases of a power station boiler. This evaluation has been made using IEA in-house PPAP software.

The basic elements of this cryogenic process, as outlined in a 1997 paper by Dr G Saksonov of the Laboratory, are as follows:

- Compressing the flue gases to around 3 bar (all pressures in this report are absolute)
- Using the adiabatic heat of compression to heat boiler feed water in the upstream steam cycle
- Cooling the compressed gas and separating the condensed water
- Cooling the compressed gas further to around the temperature at which solid CO_2 is formed
- Expanding the cold gas to near atmospheric pressure in a turbine
- Separating the solid CO_2 formed in the expansion turbine
- Reheating the CO_2 depleted gas and discharging it to the atmosphere
- Recovering the separated CO_2 in a form suitable for permanent disposal.

It has been assumed that the facility will comprise a single conventional limestone-based FGD unit, removing 90% of the SOx content of the boiler flue gas, followed by cryogenic CO_2 capture. Due to capacity limitations of compressors and gas dryers, however, the cryogenic part would be divided into two parallel 50% capacity lines.

As agreed with IEA, the overall carbon capture (percentage capture of inlet CO_2) has been set at 70%, requiring the flue gases to be compressed to give an expander inlet pressure of 15 bar.

The products from the facility are liquid CO_2 at 110 bar and ambient temperature, and a CO_2 depleted dry flue gas discharged to the boiler stack at 92^0C, equal to the flue gas inlet temperature.

Acid condensate from the cryogenic process is recycled to the upstream FGD unit.

2. DESIGN BASIS

The current work has been carried out on the basis of the standard IEA assessment conditions, except that the target for CO_2 capture has been reduced as above. The incoming flue gas composition and temperature, defined in the table below, have been taken from IEAGHG/SR1 for a PF-fired generating station:

Composition	mol%	H_2O	10.9
		O_2	4.5
		CO_2	12.6
		Ar	0.9
		N_2	71.2
		total	100.1
	mg/Nm^3	SO_x	190
		NO_x	650
Pressure		bar	1.016
Temperature		^{0}C	92

3. DESIGN DISCUSSION

3.1 Expander Calculation

A key aspect of the proposed process is the expander, in which CO_2 is captured from the boiler flue gas in the form of solid "dry ice".

The formation of solid CO_2 and the mechanical power generated in the expander have been calculated by a procedure which combines HYSYS simulation with information from an Internet source on the vapour pressure, temperature, entropy and enthalpy data for saturated CO_2 vapour and solid CO_2. This physical property data was curve-fitted on a spreadsheet.

The method of calculation was as follows:

(1) A first estimate was made of the expander outlet temperature.

(2) The % solidification of the inlet CO_2 content was varied until the sum of the component entropies at the inlet and outlet of the expander were equal.

(3) This gave an exit CO_2 partial pressure in the expander outlet gas stream, which was compared with the true vapour pressure of solid CO_2 at the temperature estimated in (1) above.

(4) The temperature estimate in (1) was then varied until agreement on CO_2 partial pressure was obtained, thus providing a prediction of the performance of a 100% efficient expander.

(5) The above procedure could have been repeated with isentropic efficiencies less than 100%, to represent the performance of real expanders. Since no industrial experience has however been identified with solidifying expanders, it has been agreed with IEA that this initial evaluation of the process should be based on isentropic expansion (100% expander efficiency), thus giving the most optimistic process assessment.

3.2 Expander Inlet Pressure

The calculation procedure described above, applied with 3 bar expander inlet pressure as foreseen in the Laboratory's paper, resulted in only 25% solidification (capture) of CO_2. This appears far too low for a practical application. The expander inlet pressure was therefore raised to 15 bar, giving a 70% to 80% CO_2 capture prediction by above procedure.

3.3 Expander Availability and Development

The availability of an expander capable of condensing up to 10 mol % of its feed stream as solid CO_2 is a critical factor affecting process feasibility. Existing designs of expander used by the natural gas, oil and petrochemical industries achieve over 30% liquefaction of their inlet hydrocarbon streams. These expanders, however, are relatively small in inlet flow volume and power output. Moreover reliable operation with condensation of a solid phase has probably not yet been demonstrated.

3.4 Two Parallel Process Lines

Due to capacity limitations of available compressors and gas drying equipment, (see below), this cost assessment has been based on two parallel 50% lines downstream of FGD.

3.5 Compressor/Expander Groups

Each 50% compressor/expander group comprises an axial flow low-pressure flue gas compressor, a radial flow high-pressure flue gas compressor, a cryogenic flue gas expander and a make-up electric motor. The order-of-magnitude powers for each group are:

Compressors	100 MW
Expander	30 MW
Motor	70 MW

The choice of electric motor drives is convenient for the purposes of this evaluation, as it minimises reconfiguring of the main steam cycle. In practice, however, steam turbines would be a feasible and perhaps preferable make-up drivers.

3.6 Flue Gas Drying

The Laboratory's paper showed removal of condensed water vapour from the compressed flue gas, but no gas drying. As a result their scheme would most probably suffer ice fouling in the downstream exchangers. Accordingly the present evaluation includes gas drying by thermally regenerated silica gel. The investment cost is based on the cost of the dryers used in large air separation plants.

Two drying lines are envisaged, each approximately equivalent in mass flow to the dryers for a 6000 tonnes/day ASU. In some areas it may be necessary to upgrade the materials of construction of the dryers to take account of the higher acidity of any condensate formed, relative to operation on air.

For the present assessment the dryers are located downstream of the high-pressure flue gas compressors. An alternative location downstream of the low-pressure flue gas compressors may be investigated at a later stage.

3.7 Gas/Gas Heat Exchangers

The two heat exchangers provided for cooling the compressed flue gas with cold residue gas are based on the plate-fin type of exchanger used in air separation plants. The cryogenic exchanger E-107 would be constructed of aluminium, and the smaller, warmer exchanger E-104 of stainless steel.

3.8 Separation of Solid CO_2

The solid CO_2 formed in the expanders (up to 600 t/h for a 500MWe coal-based station) is separated by cyclones. These cyclones have not been sized, but multiple units will probably be required.

3.9 Recovery of Liquid CO_2

Application of the Laboratory's process requires the development of a means of handling the very large flow of solid CO_2 as above and recovering it as liquid.

The present assessment is based on a fluidised bed sublimer, operating together with the cyclones at around 1.05 bar. The solid CO_2 is conveyed pneumatically from the cyclones to the fluidised bed sublimer, using a small stream of compressed CO_2 as the motive fluid. In the sublimer, a stream of CO_2 vapour fluidises the solid CO_2. The heat required to sublime the solid CO_2 is provided by condensation of liquid CO_2 in tubing immersed in the fluidised region. The CO_2 vapour is then compressed, but only to around 5 bar, at which it is condensed to liquid at $-55^{o}C$. The liquid CO_2 formed is then pumped to 120 bar, reheated to ambient temperature and exported at 100 bar.

This concept potentially provides a means of handling the large throughput of low-density solid CO_2 and converting it into high-pressure liquid, without having to move the solid from one pressure region to another by means of lock-hoppers, and without significant waste of latent heat of condensation. Mechanical compression of the solid into blocks as practised by the commercial dry ice industry appears impractical due to the high throughput, and there would still be the problem of how to convert the blocks into liquid CO_2.

3.10 Removal of SO_x

For the present assessment, it has been assumed that 90% of the SO_2 in the incoming flue gas will be removed in a conventional limestone-based FGD unit, and that the remaining 10% will report to the residue gas discharged to the stack. This FGD unit is shown as a single block on the enclosed Schematic Flowsheet, although it may comprise more than one line, depending on the technology used. Acidic condensate from the two 50% cryogenic lines is recycled to the FGD unit.

The appeal of the Laboratory's process could be increased substantially if it could be shown that the sufficient SO_x (mainly SO_2) could be co-solidified from the flue gas with the captured CO_2 and exported with it from the plant as single liquid stream.

In order to obtain an indication of the potential for co-capture of SO_2, the FGD-treated flue gas containing 190 mg/Nm^3 of SO_2 from IEAGHG/SR1 was notionally dried and compressed to 50 bar. HYSYS gave $-44^{o}C$ for the liquid dew-point of this stream and $-61^{o}C$ for the onset of CO_2 solidification. The simulation showed that cooling this gas to $-60^{o}C$ liquefies 2.5% of the incoming CO_2 plus 47% of the SO_2 (and incidentally 86% of the NO_2).

Then, to simulate a flue gas from an approx. 2.5% sulphur coal without FGD, the SO_2 content was increased to 3800 mg/Nm^3. Under the same conditions as above, 5% of the incoming CO_2 was liquefied plus 63% of the SO_2 (and 92% of the NO_2).

Extrapolation of this data to the process described in this report (CO_2 solidification with an expander inlet 15 bar) would, if substantiated, suggest that cryogenic capture of 60-70% of the CO_2 from the non-FGD-treated flue gas could co-capture over 90% of its SO_2 content. This could opens up the prospect of eliminating conventional limestone-based FGD, with environmentally beneficial relief from limestone supply and gypsum disposal. This could be an unexpected credit for the cryogenic CO_2 capture process, relative for example to MEA scrubbing, but it would require general acceptance of the presence of up to 5 wt % SO_2 in the dry liquid CO_2 sent for permanent disposal.

4. PROCESS DESCRIPTION

Please refer to the Schematic Flowsheet attached at the end of this report.

The incoming flue gas from the PF-fired generating plant flows first to a conventional limestone-based FGD unit, which is assumed to remove 90% of its SO_x content.

The outlet gas (Stream 1) at 92^0C is divided into two equal streams, each flowing to one of two 50% capacity cryogenic CO_2 separation units. One of these streams (Stream 2) flows first to direct-contact Flue Gas Inlet Cooler T-101, in which it is cooled to 30^0C by a circulating stream of treated water. T-101 also serves to wash solid material from the incoming gas, and this is blown down from the circulating water and recycled to the FGD unit. Condensate Circulating Pumps P-101A/B pump the circulating water through plate-type Condensate Cooler E-109.

The cooled and washed flue gas is next compressed to 6 bar in axial flow LP Flue Gas Compressor C-101, emerging at around 235^0C. The compressed gas is cooled first in LP Steam Cycle Exchanger E-101 to 125^0C, notionally transferring heat to the BFW system of the upstream generating unit. The gas is then further cooled to 34^0C in Flue Gas Intercooler E-102, and condensed water is removed in LP Condensate Separator D-101.

The cooled gas is next compressed to 17 bar in radial flow HP Flue Gas Compressor C-102, emerging at around 155^0C. The compressed gas is cooled first in LP Steam Cycle Exchanger E-103 to 125^0C, notionally transferring heat to the BFW system of the upstream generating unit. The gas is then further cooled to 52^0C in Residue Gas Reheater E-104, to 34^0C in Flue Gas Aftercooler E-105, and then to 15^0C in Flue Gas Chiller E-106. Condensed water is removed in HP Condensate Separator D-102.

The chilled water used to cool the gas in E-106 is produced by Chilled Water Package X-102 (not shown on the Schematic Flowsheet). The chilled compressed gas next flows to Flue Gas Dryer Package X-101, in which its dew point is lowered to -80^0C by adsorptive drying with silica gel. The dry chilled gas is cooled in Cryogenic Interchanger E-107 to the temperature (-78^0C) at which solid CO_2 starts to appear (Stream 3). It then enters Expander EXP-101 at 15 bar, leaving at 1.05 bar/-110^0C with 70% of its CO_2 content in solid form (Stream 4). The expander outlet stream flows directly to Expander Outlet Cyclone(s) D-103, in which the gas and solid phases are separated.

The CO_2 depleted residue gas (Stream 5) leaving D-103 is reheated to 5^0C in E-107, and then to 92^0C in E-104 (Stream 6). It is then joined by the residue gas from the second 50% line and is discharged to the stack (Stream 7). The solid CO_2 gravitates from the base of D-103 through Rotary Valve(s) X-103, and is pneumatically conveyed by a small flow of CO_2 into CO_2 Sublimer D-104.

D-104 consists of a vertical vessel in which the incoming solid CO_2 is fluidised by a further stream of CO_2, with a tubular Sublimer Exchanger E-108 suspended in the fluid bed. E-108 transfers heat to the fluid bed, subliming the solid CO_2 directly into saturated CO_2 vapour at -77^0C. Some CO_2 is recycled as fluidising gas to the base of D-104 by CO_2 Circulator C-104. CO2 Compressor C-103 compresses the net output of CO2 to around 5 bar. The compressor outlet stream then flows to the tube side of E-108, where it condenses at -55^0C.

The condensed liquid flows to CO_2 Accumulator D-105. From there it is pumped by CO_2 Export Pumps P-102A/B at 120 bar through E-107, in which it is heated to ambient temperature (Stream 9). This stream is then joined by CO_2 from the second 50% line and is exported at 110 bar (Stream 10).

The acidic condensate from D-101, D-102 and X-101 joins the purge from T-101 and is then recycled with acidic condensate from the second 50% line to the FGD unit.

5. PPAP CRITERIA AND SCORES

Criteria:-

Raw Material: Locally Common	90
Process Conditions: 10-60 bar <1200 K	90
Materials: Stainless Steel	95
Process: Major New Ideas	20
Safety: Small Risk	80
Environmental: Mildly Harmful Waste	50

Scores:-

Heat In		1982.3MWth
Estm.	Net Electricity Output	500.0MWe
	Net Efficiency LHV	25.2%
	CO_2 output	54.1kg/s
	CO_2 output	0.389kg/kWh
Estimated Capital Cost		1382.0Mill $
Estimated Op Cost		8.3c/kWh

Multi-Criteria Assessment:-

Decision Factor Scores	
Acceptance	68.0
Applicability	64.1
Confidence	70.0
Estimated Cost	30.9

6. CONCLUSIONS

6.1 Percentage CO_2 Capture

Calculations indicate that the CO_2 capture feasible with compression of the flue gas to 3 bar, as proposed by the Laboratory, would only be in the region of 20-25%. After discussion with IEA, this present evaluation has been based on compression of the flue gas to give 15 bar at the expander inlet. This will result in a predicted CO_2 capture of about 70% to 80%, based on a 100% efficient expander.

6.2 Water Vapour Removal

The separation of condensed water from the compressed flue gas as proposed by the Laboratory is insufficient to avoid formation of water ice in the downstream cryogenic heat exchanger and resultant blocking. It is therefore necessary to provide a dryer stage (for example silica gel) to remove residual water vapour before the flue gas enters the cryogenic exchanger.

6.3 SO_x Removal

Allowance must be made in due course for the presence of SO_x (mainly SO_2) in the incoming flue gas. The present study assumes bulk removal of SO_x upstream in a limestone-based FGD unit, with recycle of acidic condensate to FGD. The effect of the residual SO_2 on the adsorptive dryer will also require future evaluation, as will the likely distribution of SO_2 between the solid CO_2 formed in the expander and the residual gas.

Preliminary simulations suggest that cryogenic capture of 60-70% of the CO_2 from the non-FGD-treated flue gas could co-capture over 90% of its SO_2 content. If substantiated, this could open up the prospect of eliminating conventional FGD altogether, with environmentally beneficial relief from limestone supply and gypsum disposal. This could be an unexpected credit for the cryogenic CO_2 capture process, relative for example to MEA scrubbing, but it would require general acceptance of the presence of up to 5 wt% SO_2 in the exported dry liquid CO_2. Reliable prediction of the extent of co-capture of SO_2 in the solidified CO_2 would require more study and, probably, experimental verification.

6.4 Availability of Expander

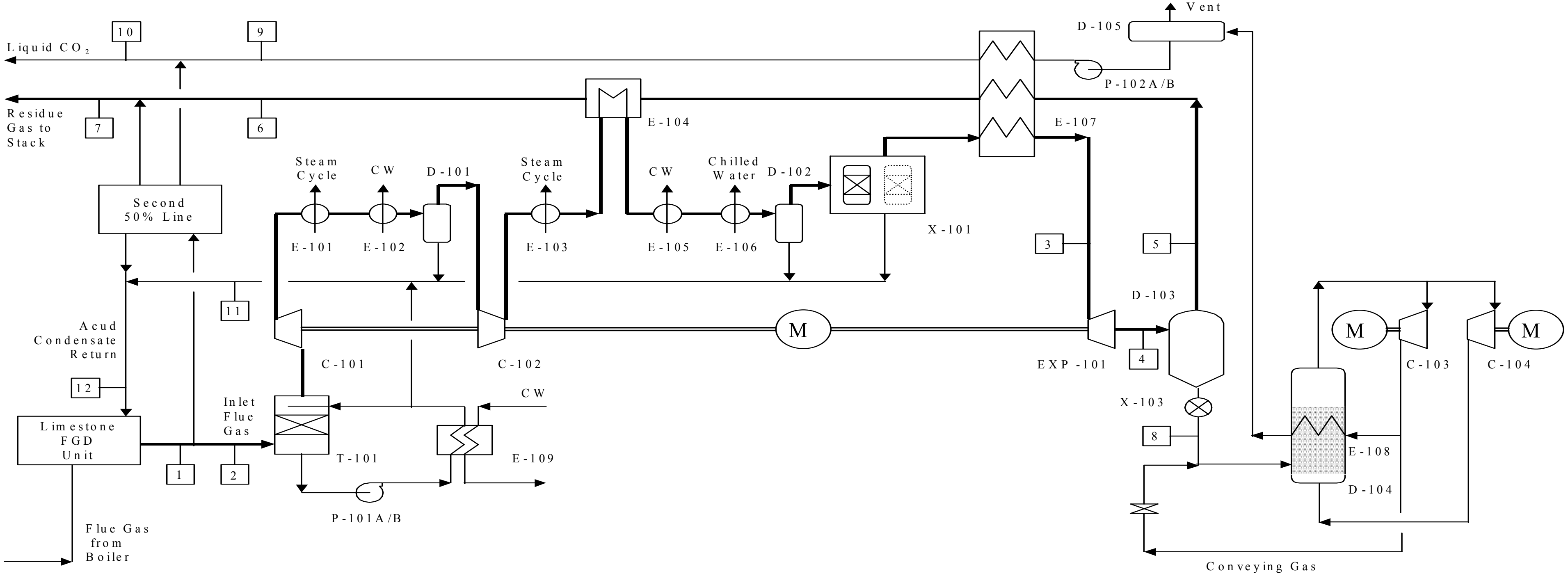
The availability of a circa 30MWe expander capable of condensing around 10 mol% of its feed stream in the form of solid CO_2 is a critical to the feasibility of the Laboratory's process. Existing designs of expander used by the natural gas, oil and petrochemical industries achieve over 30% liquefaction of the hydrocarbon streams. These expanders, however, are relatively small in inlet flow volume and power output. Moreover reliable operation with a condensation of a solid phase has probably not yet been demonstrated.

6.5 Solid CO_2 Handling

Another key aspect of the Laboratory's process, requiring intensive development, is the means of handling the very large flow of solid CO_2 (up to 600 t/h @500MWe coal-based). The solid CO_2 produced in the expander has to be separated from the residual gas and then converted into the export stream of liquid CO_2 at 110 bar and ambient temperature as required in IEA's standard design basis. Mechanical compression of the solid into blocks as practised by the commercial dry ice industry appears impractical due to the high throughput, and there would be the problem of converting the blocks into liquid CO_2. GCL suggests a thermally efficient sequence of separating the solid CO_2 from the expander outlet in cyclone(s), pneumatically conveying it to a fluidised bed sublimer, and compressing/condensing the CO_2 vapour produced at low pressure and temperature.

6.6 Comparison with Alternatives

The economic performance of the process emerging from PPAP appears somewhat worse than for mainstream flue gas CO_2 capture proposals. Moreover, it is clear that a considerable amount of development work is needed, particularly on the expander and the handling/processing of the solid CO_2. However, the possibility of co-capture of SO_2 could be a positive feature.


Vent
D-105
10
9
Liquid CO_2
P-102A/B
E-104
E-107
Residue
Gas to
Stack
7
6
Steam
Cycle
CW
D-101
Steam
Cycle
CW
Chilled
Water
D-102
Second
50% Line
E-101
E-102
E-103
E-105
E-106
X-101
3
5
D-103
11
Acud
Condensate
Return
M
C-101
C-102
EXP-101
4
M
M
C-103
C-104
12
Inlet
Flue
Gas
CW
X-103
Limestone
FGD
Unit
T-101
E-109
8
E-108
1
2
D-104
P-101A/B
Flue Gas
from
Boiler
Conveying Gas

The PPAP help files. Understanding the worksheets

Associated with the PPAP program is a help file which contains much useful information about how to add data to the worksheets and what the program does with it. A copy of this interactive help file is included separately on this CD and can be opened independently to assist with interpretation of the worksheets which follow.

Power Plant Assessment program

Introductory worksheet pages to PPAP

Intro
Intro2

Power Generation Process Assessment Facility

This is an Excel spreadsheet that takes some basic information about a power generation process and attempts to provide an insight into the viability of the process.

The calculations are performed in a number of stages each represented by a series of interacting worksheets. To start the assessment procedure Click on the Start button.

Written for IEA Greenhouse Gas Project
by CRE Group Ltd, (c) 1997,1999

Version 1.1 by TR Dennish April 2002
Version 2.1 by TR Dennish March 2003,
Incorporating changes requested by M Haines (IEA GHG)
Version 3.0 by T R Dennish August 2003,
With PPAP Lite page as designed by M Haines (IEA GHG)
Incorporating changes requested by M Haines (IEA GHG)

Power Generation Process Assessment Facility

Please enter a name to identify this process: **Base Combined Cycle (rerun)**

The procedure for plant assessment involves four stages of operator input

First: Input of process information

Second: Input of costing information

Third: Multi-Criteria analysis

Fourth: View results summary sheet

OR Import data from a Version 2 or later spreadsheet

Power Plant Assessment program

Worksheets for baseline gas fired Combined Cycle Gas Turbine (CCGT) power plant without CO_2 capture

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☑	Gas Turbine	1	331.0	MWe
☑	Steam Turbine	1	161.0	MWe
☐	Combustor	0	0.0	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☑	HRSG	1	355.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	
	Aux Power Reqd		10000	kJ/Unit size
☐	Other major plant item	0	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Compression	0		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type
☐ Solid
☐ Liquid
☑ Gaseous

Steam Cycle Type
○ Sub Critical
● SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

		Solid	Liquid	Gas
Fuel Mass Fractions		0	0	1
LCV	kJ/kg	25000	42000	46884
Carbon fraction	%mass	0.62	0.86	0.75
Ash Fraction	%mass	0.12	0	0
% in Feed		0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)	1			

Combined LCV	46884	kJ/kg
Combined Carbon fraction	0.75	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	17.61	46884	0.75	13.2075
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	0.0%			
CO2 recovered	0.00	0	0.273	0
CO2 emitted	48.43	0	0.273	13.2075

Gross available energy	46884	kJ/kg fuel
	825627.2	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	0%	0
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatior		
Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

Process Detail Specification

If you have data from an external mass and heat balance program
You can select Use PPAP Lite to enter summary data
from this into PPAP, this bypasses many of the calculations within PPAP
You may still need to set information to account for some losses in the Process Assumptions page too.

Bypass Steam and GT cycle and enter data directly from external process simulation

Or configure the steam and gas cycle details by using the buttons below

Steam Cycle details Steam Cycle Setup not available when using PPAP Lite

Gas Turbine details GT Cycle Setup not available when using PPAP Lite

Process Assumptions

Cycle Analysis

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
Air/Fuel Ratio by Mass for Gas Turbine	40.3	===> Air flow of	40.30	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	2.53	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	0	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	355	MW	Transferred to B7	Sheet CycleAnalysis
GT power	331	MW	Transferred to D65	Sheet CycleAnalysis
ST power	161	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	0	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	57.9	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	41.95	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	46.3	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	478	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	825.63	MW

Losses

GT mech loss	1.66	MW
GT gen loss	4.97	MW
ST mech loss	0.81	MW
ST mech loss	2.42	MW
GT + ST transformer loss	1.97	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**11.81**	**MW**

Auxiliaries NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*	
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	0	MW	0	0		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	0.61	MW	0.61	0		86.46 MW ST rejection
Misc	1.43	MW	1.43	0		0.00 MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**2.04**	**MW**				

TOTAL Losses/Auxiliaries	**13.85**	**MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**			
	Value imported			**I/P to GT**	**kJ/kg**	**MW**	
To steam	355000	kJ/s from	HRSG before losses	43.00	20159.0	355.000	--|
GT loss	7130	kJ/s from	Stack	19.49	9139.1	160.939	|
GT Efficiency				41.95			|
Total				104.44			|

Gas cycle Output						|
Estimated GT Efficiency	0.4195	**Value imported**				|
Gross avail. energy to GT cycle	46884	kJ/kg				|
GT Output	**19667.84**	**kJ/kg**	equiv to	346350.6	kW	|
						V

Steam Cycle Output								
Estimated Steam Cycle Efficiency	0.463	**Value imported**						
Heat Balance						HRSG Heat available	20159	kJ/kg
From Combustion	0	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	19957.41	kJ/kg
From GT HRSG etc after losses	19957.41	kJ/kg	<---|					
From Direct Generation	0	kJ/kg						
Export/Import	0	kJ/kg						
Heat available to steam cycle	19957.41	kJ/kg	equiv to	351450	kW			
ST Output	**9206.17**	**kJ/kg**	equiv to	162120.6	kW			
Total Potential Output	28874.01	kJ/kg	equiv to	508471.3	kW			

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2542.4	1731.8	810.6
Generator Loss	1.50%	7627.1	5195.3	2431.8
Transformer Loss	0.40%	2033.9	1385.4	648.5

Gross Power Output	**28181.03 kJ/kg**	equiv to	496268	kW

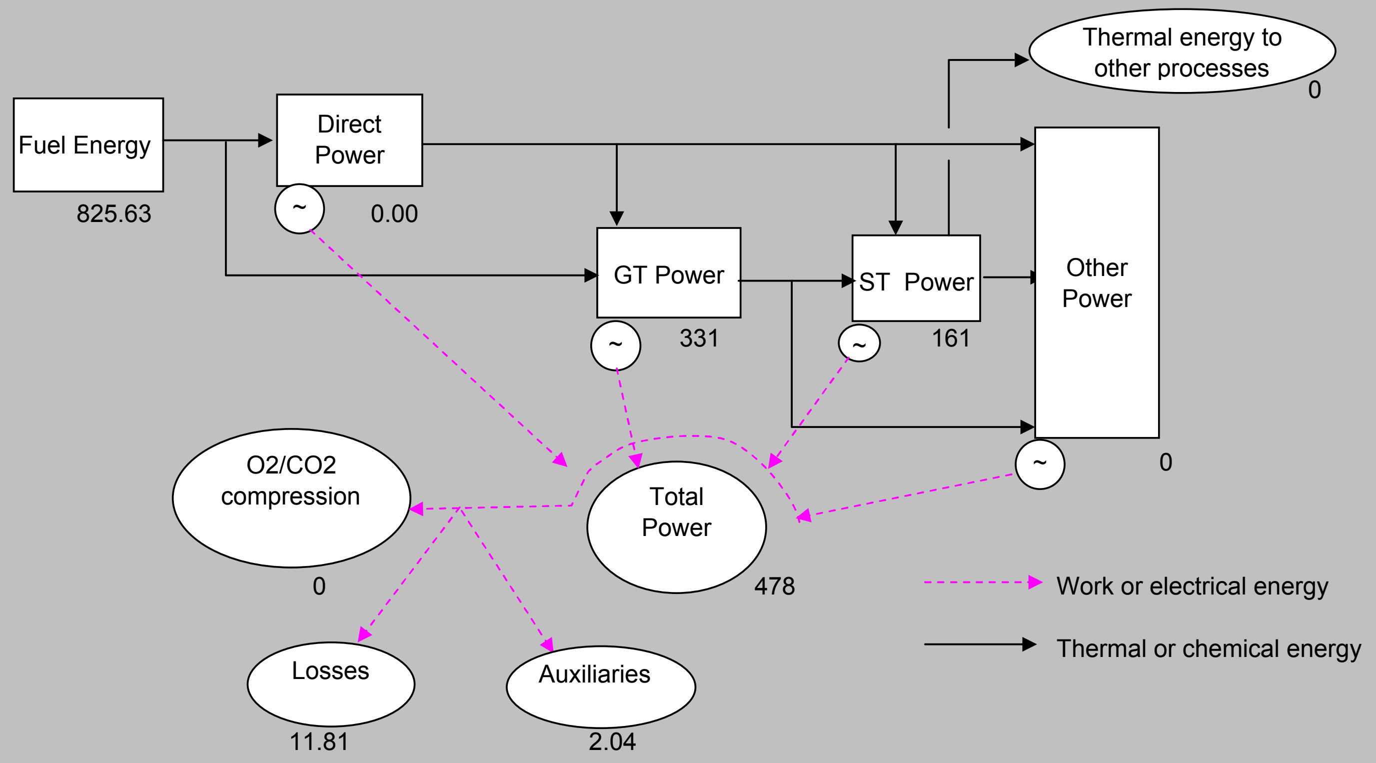
Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg	0	0		
	Sorbent	50	kJ/kg	0	0		
	Ash	50	kJ/kg	0	0		
Fan and compressor mech eff.		93%					
Oxygen Production		950	kJ/kg O2	0	0		
Oxygen Compression				**Value imported**	0		0.7 Is good nur
CO2 Compression				0	0	**Value imported**	O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel	0	0		
FGD		8	kJ/MJ fuel	0	0		
Cooling water system		7	kJ/MJ rejected	1	75.01991		Steam Cycle Condens
Misc		0.30%	of gross		84.54309		
H2S Sepn					0		
CO2 Sepn					0		
Other					0		
Total Auxiliaries					159.563 kJ/kg		

Total Input	46884	kJ/kg					
Total Output (Net)	28021.47	kJ/kg	=>	478000	kW	**Value imported**	
Efficiency	57.9	%	**Value imported**				-14
							2.13164
GT Output (Generator Terminals)	331.00	MW	**Value imported**				-11.8684
ST Output (Generator Terminals)	161.00	MW	**Value imported**				
Direct O/P (Gross)	0	MW					
% heat available to steam cycle	0	%	**Value imported**				

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	0	1	0.00
Gas turbine, complete	MWe	0	331	1	1	56.62
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		355	1	1	28.36
Steam turbine+pipes+cooling system	MWe		161	1	1.1	62.47
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	1	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		478	1	1	11.08
Sub-Total						**158.53**
Balance of plant	% of above		10			15.85
Engineering, indirects, owners cost	% of above		24			41.85
Project contingency	% of above		10			21.62
TOTAL						**237.86**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ
	Liquid	3	$/GJ
	Gaseous	3	$/GJ

Calculated Fuel Cost	3.0000	$/GJ
Fuel cost of electricity	1.8653	c/kWh

Capital Charges

Interest Rate	10%	
Plant Life Span	25	years
Load Factor	0.9	

Interest during construction	36.0582	M$
Annual capital Charge	30.1774	M$/y
Capital Charges	0.8002	c/kWh

O&M Costs

O&M Factor	0.03		Other Materials Cost	20	$/tonne
			Residue Disposal Cost	20	$/tonne
Fixed O&M cost	0.1892	c/kWh			
Variable O&M cost	0.0000	c/kWh			

Estimated Operating Costs	**2.8547**	**c/kWh**

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	Value	Risk assessment & Score%	Score %	Weighting	DECISION FACTOR	Weighted Score
Fuel Consumption kJ/kW	1.727		64	42.9	**APPLICABILITY**	36.3
Raw Material Availability	Locally Common with unlimited availability for scale of this application	No risk 0	90	10		
Process Conditions Temperature Pressure NB Use least well known part of process	1200K-1600K 10-60 bar but no significant technical barriers	No risk 11	80	10	**CONFIDENCE IN WHETHER IT WILL WORK**	35.5
Novelty of Materials which is	Existing Special Alloys known material in known environment	No risk 6	90	10		
Plant Complexity No. of major units No. of major recycles	3 0		85	10		
Novelty of Process with	Fully proven highly successful industrial applications in operation	No risk 0	100	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.365		-2	40	**ESTIMATED COSTS**	112.4
Costs Total Operating c/kWh	2.85		103	100		
Safety Risk Control of these risks	Small Risk extensively demonstrated and publicly accepted	No risk 5	80	20	**ACCEPTANCE**	32.0
Environmental Impact Management of these impacts	Benign Waste extensively demonstrated and publicly accepted	No risk 5	80	20		

Averaged risk level	**5**			
Controlling risk level	**11**	**Process conditions**	**TOTALS**	216.2

Results of Analysis

Summary

Process: **Base Combined Cycle (rerun)**

Heat Input		825.6 MW		
Estimated	Net Electricity Output	478.0 MW	NOTE GT efficiency calculated by program as …	42.0 %
	Net Efficiency	57.9 %	NOTE Steam cycle efficiency calculated as...	46.3 %
	CO2 output/ kg/s	48.4 kg/s	NOTE percentage of input energy to steam cycle ..	0.0 %
	CO2 output/kWh	0.365 kg/kWh		
Estimated Capital Cost		237.9 M$		
Estimated Op Cost		2.9 c/kWh		

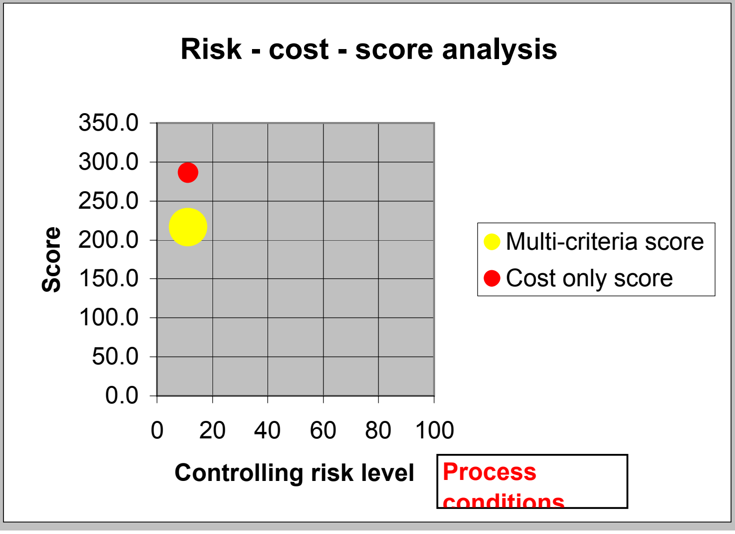
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		32.0
Applicability		36.3
Confidence		35.5
Estimated Cost		112.4
	Total	216.2
	Total cost only	285.9

Risk assessment

Averaged risk level		5
Controlling risk level	**Process conditions**	**11**



Comparison with Base Case CCGT

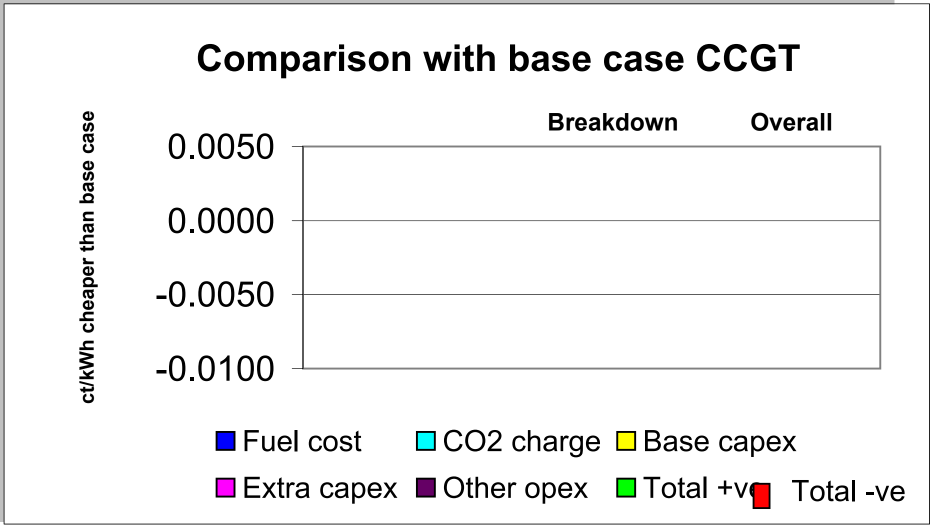
CO2 emission penalty	50	$/ton
CO2 emissions	0.365	kg/kWh
CO2 emission cost	1.824	c/kWh

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates	
Fuel cost	1.865	1.865	0.0000	3.0000	$/GJ
CO2 charge	1.824	1.824	0.0000	50	$/ton
Base capex	0.989	0.989	0.0000		
Extra capex	0.094	0.094	0.0000		
Other opex	0.000	0	0.0000		
				Total	0.0000
TOTAL	4.7724	4.7724	0.0000		
Extra fuel			0.0000		
Extra capex			0.0000		
Total extra			0.0000		
CO2 tax benefit			0.0000		

Factor analysis		Effect on costs of electricity
	Scores	
Raw materials	90	0.0099
Process conditions	80	0.0198
Novelty of materials	90	0.0099
Complexity	85	0.0148
Safety	80	0.0198
Environmental	80	0.0198
TOTAL		**0.0940**

Base Case data

Fuel cost	1.865	c/kWh Based on	3	$/GJ
CO2 Tax	1.824	c/kWh Based on	50	$/tonne
Base Capex+Opex	0.989	c/kWh		
Extra Capex	0.094	c/kWh		
Other Opex	0	c/kWh		



WEIGHTINGS ANALYSIS

CO2 emission calc

Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.6E-05	
Mix kgC/kJ	1.6E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.352	kg/kWh

Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3519	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)

DO NOT EDIT

Project Title		Base Combined Cycle (rerun)
Power Out	MWe	478
Efficiency	%	57.9
CO2 emitted	%	100
CO2 emitted	kg/kWh	0.364726
Fuel in	kg/s	17.61
Fuel in	MW	825.6272
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	0.00
Gas Cycle Efficiency	%	0.42
Steam Cycle Efficiency	%	0.46
Est Capital Cost	M$	237.86
Est Operating Cost	ct/kWh	2.85
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	0
	Cost	0.00
Gas turbine, complete	MWe	331
	Number	1
	Cost	56.62
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	355
	Number	1
	Cost	28.36
Steam turbine+pipes+cooling syste	MWe	177.1

	Number	1
	Cost	62.47
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	478
	Number	1

	Cost	11.08
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		2
Press max		3
Process Conditions Qualifer		1
Construction Materials		3
Construction Materials Qualifier		1
No of Recycles		0
Novelty		1
Novelty Qualifer 1		1
Novelty Qualifer 2		1
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		5
Controlling Risk Level		11
Controlling Risk is		Process conditions
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		80
Process Conditions Extra Cost	ct/kWh	0
Novelty		90
Novelty Extra Cost	ct/kWh	0
Complexity		85
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	1.865285
CO2 Charge	$ct/kWh	1.82363
Base Capex	$ct/kWh	0.989444
Extra Capex	$ct/kWh	0.093997
Other Opex	$ct/kWh	0
Total	$ct/kWh	4.772356
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		46884
Mixture LCV		46884
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	0
O2 compression power	MW	0
HRSG on GT	MW	355
GT power	MW	331
ST power	MW	161
Percent of heat available to Steam	MW	0
Overall electrical efficiency after lo	MW	57.9
Efficiency GT Cycle	MW	41.95
Efficiency ST cycle	MW	46.3
Overall power output	MW	478
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for baseline Pulverized Fuel (PF) coal fired power plant without CO_2 capture

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☐	Gas Turbine	0	0.0	MWe
☑	Steam Turbine	1	526.5	MWe
☑	Combustor	1	43.7	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☐	HRSG	0	0.0	MW
☑	FGD	1		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		10000	kJ/Unit size
☐	Other major plant item	0	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	2	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Compression	0		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☑ Solid

☐ Liquid

☐ Gaseous

Steam Cycle Type

○ Sub Critical

● SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

			Solid	Liquid	Gas
Fuel Mass Fractions			1	0	0
LCV	kJ/kg		25000	42000	50013
Carbon fraction	%mass		0.62	0.86	0.75
Ash Fraction	%mass		0.12	0	0
% in Feed			100.00%	0.00%	0.00%
Fuel Fractions Sum (must = 1)		1			

Combined LCV	25000	kJ/kg
Combined Carbon fraction	0.62	
Combined Ash Fraction	0.12	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	43.7	25000	0.62	27.094
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	0.0%			
CO2 recovered	0.00	0	0.273	0
CO2 emitted	99.34	0	0.273	27.094

Gross available energy	25000	kJ/kg fuel
	1092500	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	100%	25000	
Percent of Input Fuel to gasification system	0%	0	
Heat recovered from gasifier to steam cycle	0%	0	
Heat recovered from gasifier to gas cycle	0%	0	
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0	
Percent of fuel to direct generatio			
Converted to power	0%	0	
Heat recovered from direct generation to steam cycle	0%	0	
Heat recovered from direct generationto gas cycle	0%	0	
Heat from Steam cycle lost to Process or ?	0	kW	
Energy available to GT	1E-07	kJ/kg	<== Calculated from above information

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
	40.3	===> Air flow of	40.30	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	2.53	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	0	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	0	MW	Transferred to D65	Sheet CycleAnalysis
ST power	526.5	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	100	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	44.95	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	0	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	46.3	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	491	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1092.50	MW

Losses

GT mech loss	0.00	MW
GT gen loss	0.00	MW
ST mech loss	2.63	MW
ST mech loss	7.90	MW
GT + ST transformer loss	2.11	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**12.64**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

			PPAP	External	*hidden calc*		
Solids handling:							
Fuel	2.185	MW	2.185	0			
Sorbant	0	MW	0.00	0			
Residue	0	MW	0.00	0			
Oxygen Production	0	MW	0	0			
Combustor fans (PF)	8.74	MW	8.74	0			
FGD	8.74	MW	8.74	0			
Cooling water system	1.98	MW	1.98	0		282.73	MW ST rejection
Misc	1.47	MW	1.47	0		0.00	MW compression losses
H2S Sepn	0	MW	0	0			
CO2 Sepn	0	MW	0	0			
Other	0	MW	0	0			
Subtotal	**23.12**	**MW**					

TOTAL Losses/Auxiliaries	**35.75**	**MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**			
	Value imported			**I/P to GT**	**kJ/kg**	**MW**	
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	---|
GT loss	0	kJ/s from	Stack	0.00	0.0	0.000	|
GT Efficiency				0.00			|
Total				0.00			|

Gas cycle Output						|
Estimated GT Efficiency	0	**Value imported**				|
Gross avail. energy to GT cycle	1E-07	kJ/kg				|
GT Output	**0**	**kJ/kg**	equiv to	0	kW	|

Steam Cycle Output						V		
Estimated Steam Cycle Efficiency	0.463	**Value imported**						
Heat Balance						HRSG Heat available	0	kJ/kg
From Combustion	25000	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	0	kJ/kg
From GT HRSG etc after losses	0	kJ/kg	<---|					
From Direct Generation	0	kJ/kg						
Export/Import	0	kJ/kg						
Heat available to steam cycle	25000	kJ/kg	equiv to	1092500	kW			
ST Output	**11532.27**	**kJ/kg**	equiv to	503960.2	kW			
Total Potential Output	11532.27	kJ/kg	equiv to	503960.2	kW			

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2519.8	0.0	2519.8
Generator Loss	1.50%	7559.4	0.0	7559.4
Transformer Loss	0.40%	2015.8	0.0	2015.8

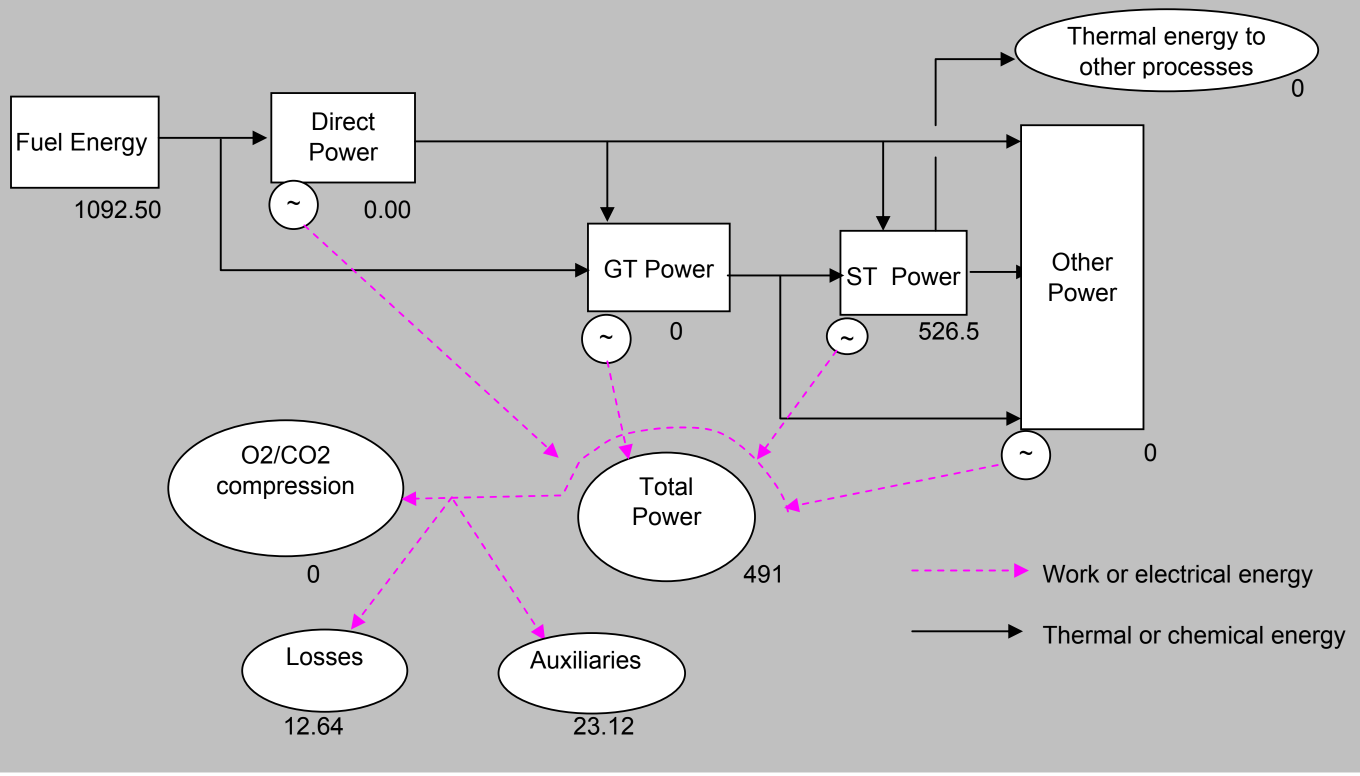
Gross Power Output	**11255.5**	**kJ/kg**	equiv to	491865.1	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg				1	50			
	Sorbent	50	kJ/kg				1	0			
	Ash	50	kJ/kg				1	0			
Fan and compressor mech eff.		93%									
Oxygen Production		950	kJ/kg O2				0	0			
Oxygen Compression						**Value imported**		0		0.7	Is good nur
CO2 Compression							0	0	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel				1	200			
FGD		8	kJ/MJ fuel				1	200			
Cooling water system		7	kJ/MJ rejected				1	93.975			Steam Cycle Condens
Misc		0.30%	of gross					33.76649			
H2S Sepn								0			
CO2 Sepn								0			
Other								0			
Total Auxiliaries								577.7415	kJ/kg		
Total Input		25000	kJ/kg								
Total Output (Net)		10677.75	kJ/kg	=>	491000 kW	**Value imported**					
Efficiency		44.95	%	**Value imported**						-35.5	
										0	
GT Output (Generator Terminals)		0.00	MW	**Value imported**						-35.5	
ST Output (Generator Terminals)		526.50	MW	**Value imported**							
Direct O/P (Gross)		0	MW								
% heat available to steam cycle		100	%	**Value imported**							

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	**Scaling parameter**	**User specified size**	**Size per unit**	**No of units**	**Cost multiplier**	**Predicted cost, M$**
Solids handling	kg/s		43.7	1	1	13.60
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	0	1	0.00
Gas turbine, complete	MWe	0	0	0	1	0.00
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		526.5	1	1.1	151.92
PF coal boiler	MW fuel feed LHV		1092.5	1	1	159.26
FGD (limestone gypsum)	kmol/s feed		10.74729	1	1	42.84
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	0	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	0.477	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		491	1	1	11.32
Sub-Total						**378.93**
Balance of plant	% of above		10			37.89
Engineering, indirects, owners cost	% of above		24			100.04
Project contingency	% of above		10			51.69
TOTAL						**568.55**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ
	Liquid	3	$/GJ
	Gaseous	3	$/GJ

Calculated Fuel Cost	1.5000	$/GJ
Fuel cost of electricity	1.2013	c/kWh

Capital Charges

Interest Rate	10%	
Plant Life Span	25	years
Load Factor	0.85	
Interest during construction	86.1879	M$
Annual capital Charge	72.1313	M$/y
Capital Charges	1.9716	c/kWh

O&M Costs

O&M Factor	0.04		Other Materials Cost	20	$/tonne
			Residue Disposal Cost	20	$/tonne
Fixed O&M cost	0.6216	c/kWh			
Variable O&M cost	0.0000	c/kWh			

Estimated Operating Costs	**3.7946**	**c/kWh**

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user
to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its
overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	2.225		39	42.9		
		No risk			**APPLICABILITY**	26.6
Raw Material Availability	Universally Common	0	100	10		
	with unlimited availability					
	for scale of this application					
Process Conditions		No risk				
Temperature	<1200K	0	100	10		
Pressure	Atmospheric					
NB Use least well known part of process	but no significant technical barriers					
Novelty of Materials		No risk			**CONFIDENCE IN WHETHER IT**	
	Carbon Steel	0	100	10		38.0
which is	known material in known environment				**WILL WORK**	
Plant Complexity						
No. of major units	4		80	10		
No. of major recycles	0					
Novelty of Process	Fully proven	No risk	100	10		
with	highly successful	0				
	industrial applications in operation					
Greenhouse Gas Emissions						
CO2 emission in kg/Kwh	0.728		-14	40	**ESTIMATED COSTS**	
Costs						88.8
Total Operating c/kWh	3.79		84	100		
Safety Risk		No risk				
	Small Risk	5	80	20		
Control of these risks	extensively demonstrated and publicly accepted				**ACCEPTANCE**	32.0
Environmental Impact		No risk				
	Benign Waste	5	80	20		
Management of these impacts	extensively demonstrated and publicly accepted					

Averaged risk level	2		**TOTALS**	185.4
Controlling risk level	5	Safety		

Results of Analysis

Summary

Process: **PF Alone (Base Case)**

Heat Input		1092.5	MW
Estimated	Net Electricity Output	491.0	MW
	Net Efficiency	45.0	%
	CO2 output/ kg/s	99.3	kg/s
	CO2 output/kWh	0.728	kg/kWh
Estimated Capital Cost		568.6	M$
Estimated Op Cost		3.8	c/kWh

NOTE GT efficiency calculated by program as …	0.0	%
NOTE Steam cycle efficiency calculated as...	46.3	%
NOTE percentage of input energy to steam cycle ..	100.0	%

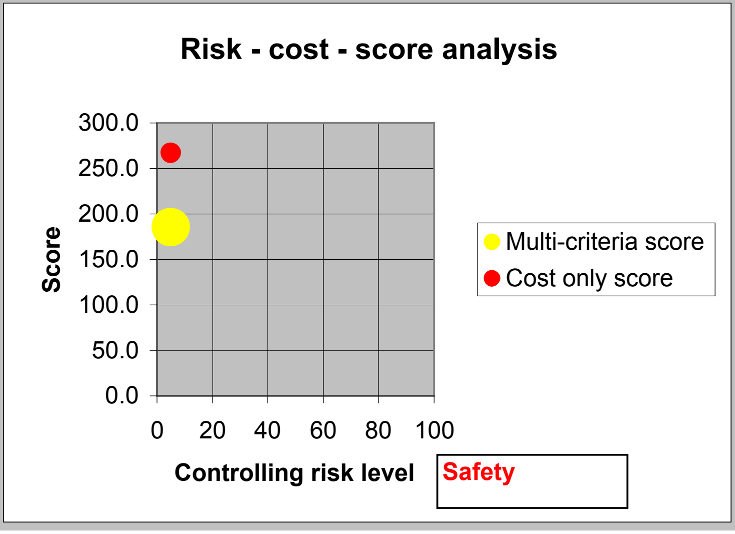
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		32.0
Applicability		26.6
Confidence		38.0
Estimated Cost		88.8
	Total	185.4
	Total cost only	267.1

Risk assessment

Averaged risk level		2
Controlling risk level	**Safety**	**5**



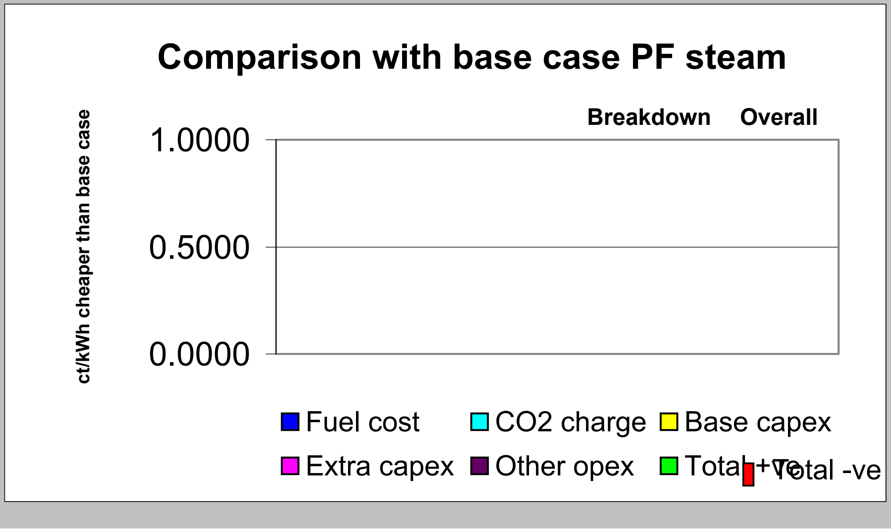
CO2 emission penalty	50	$/ton
CO2 emissions	0.728	kg/kWh
CO2 emission cost	3.642	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	100	0.0000
Process conditions	100	0.0000
Novelty of materials	100	0.0000
Complexity	80	0.0519
Safety	80	0.0519
Environmental	80	0.0519
TOTAL		**0.1556**

Base Case data

Fuel cost	1.201	c/kWh Based on	1.5	$/GJ
CO2 Tax	3.642	c/kWh Based on	50	$/tonne
Base Capex+Opex	2.593	c/kWh		
Extra Capex	0.156	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates		
Fuel cost	1.201	1.201	0.0000	1.5000	$/GJ	
CO2 charge	3.642	3.642	0.0000	50	$/ton	
Base capex	2.593	2.593	0.0000			
Extra capex	0.156	0.156	0.0000			
Other opex	0.000	0	0.0000			
					Total	0.0000
TOTAL	7.5921	7.5921	0.0000			
Extra fuel			0.0000			
Extra capex			0.0000			
Total extra			0.0000			
CO2 tax benefit			0.0000			



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.5E-05	
Mix kgC/kJ	0.0000248	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.330	kg/kWh
Calorific fraction of gas	0	
Calorific fraction of oil	0	
CO2 allowance	0.6177	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT

Project Title		PF Alone (Base Case)
Power Out	MWe	491
Efficiency	%	44.95
CO2 emitted	%	100
CO2 emitted	kg/kWh	0.728393
Fuel in	kg/s	43.7
Fuel in	MW	1092.5
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	0.00
Gas Cycle Efficiency	%	0.00
Steam Cycle Efficiency	%	0.46
Est Capital Cost	M$	568.55
Est Operating Cost	ct/kWh	3.79
Capital Cost Items		
Solids handling	'Size'	43.7
	Number	1
	Cost	13.60
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	0
	Cost	0.00
Gas turbine, complete	MWe	0
	Number	0
	Cost	0.00
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	0
	Cost	0.00
Steam turbine+pipes+cooling syste	MWe	579.15

	Number	1
	Cost	151.92
PF coal boiler	MW fuel feed LHV	1092.5
	Number	1
	Cost	
FGD (limestone gypsum)	kmol/s feed	10.74729
	Number	1
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	491
	Number	1

	Cost	11.32
Multi Criteria		
Feed Material		1
Feed Material Qualifier		1
Temp max		1
Press max		1
Process Conditions Qualifer		1
Construction Materials		1
Construction Materials Qualifier		1
No of Recycles		0
Novelty		1
Novelty Qualifer 1		1
Novelty Qualifer 2		1
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		2
Controlling Risk Level		5
Controlling Risk is		Safety
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		100
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		100
Process Conditions Extra Cost	ct/kWh	0
Novelty		100
Novelty Extra Cost	ct/kWh	0
Complexity		80
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	1.201335
CO2 Charge	$ct/kWh	3.641963
Base Capex	$ct/kWh	2.593238
Extra Capex	$ct/kWh	0.155594
Other Opex	$ct/kWh	0
Total	$ct/kWh	7.592131
Fuel Mix		
Solid	frac	1
Liquid	frac	0
Gas	frac	0
Solid LCV		25000
Liquid LCV		42000
Gas LCV		50013
Mixture LCV		25000
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	0
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	0
ST power	MW	526.5
Percent of heat available to Steam	MW	100
Overall electrical efficiency after lo	MW	44.95
Efficiency GT Cycle	MW	0
Efficiency ST cycle	MW	46.3
Overall power output	MW	491
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for baseline gas fired Air blown Partial Oxidation Pre-Combustion De-Carbonisation (APO.PCDC) power plant with CO_2 capture

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☑	Gas Turbine	1	330.0	MWe
☑	Steam Turbine	1	204.0	MWe
☐	Combustor	0	0.0	kg/s fuel
☑	Gasifier	1	21.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☑	HRSG	1	355.0	MW
☐	FGD	0		
☐	H2S Removal	3	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☑	Other major plant item	1	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Separation	1	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☐ Solid

☐ Liquid

☑ Gaseous

Steam Cycle Type

● Sub Critical

○ SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

		Solid	**Liquid**	**Gas**
Fuel Mass Fractions		0	0	1
LCV	kJ/kg	25000	42000	46884
Carbon fraction	%mass	0.62	0.86	0.74
Ash Fraction	%mass	0.12	0	0
% in Feed		0.00%	0.00%	100.00%

Fuel Fractions Sum (must = 1) 1

Combined LCV	46884	kJ/kg
Combined Carbon fraction	0.74	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	21.03	46884	0.74	15.5622
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	85.0%			
CO2 recovered	48.50	0	0.273	13.22787
CO2 emitted	8.56	0	0.273	2.33433

Gross available energy	46884	kJ/kg fuel
	985970.5	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	0%	0	
Percent of Input Fuel to gasification system	100%	46884	
Heat recovered from gasifier to steam cycle	23%	10783.32	
Heat recovered from gasifier to gas cycle	76%	35631.84	
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0	
Percent of fuel to direct generatior Converted to power	0%	0	
Heat recovered from direct generation to steam cycle	0%	0	
Heat recovered from direct generationto gas cycle	0%	0	
Heat from Steam cycle lost to Process or ?	210000	kW	
Energy available to GT	35631.84	kJ/kg	<== Calculated from above information

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
Air/Fuel Ratio by Mass for Gas Turbine	56.8635	===> Air flow of	56.86	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	3.57	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	20.9	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	355	MW	Transferred to B7	Sheet CycleAnalysis
GT power	330	MW	Transferred to D65	Sheet CycleAnalysis
ST power	204	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	45	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	50.5	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	41.95	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	43.4	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	498	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	985.97	MW

Losses

GT mech loss	1.65	MW
GT gen loss	4.95	MW
ST mech loss	1.02	MW
ST mech loss	3.06	MW
GT + ST transformer loss	2.14	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**12.82**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

			PPAP	External	*hidden calc*
Solids handling:					
Fuel	0	MW	0	0	
Sorbant	0	MW	0.00	0	
Residue	0	MW	0.00	0	
Oxygen Production	0	MW	0	0	
Combustor fans (PF)	0.00	MW	0.00	0	
FGD	0.00	MW	0.00	0	
Cooling water system	0.95	MW	0.95	0	115.46 MW ST rejection
Misc	1.49	MW	1.49	0	20.71 MW compression losses
H2S Sepn	0	MW	0	0	
CO2 Sepn	0	MW	0	0	
Other	0	MW	0	0	
Subtotal	**2.45**	**MW**			
TOTAL Losses/Auxiliaries	**15.26**	**MW**			

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat I/P to GT**	**kJ/kg**	**MW**	
	Value imported						
To steam	355000	kJ/s from	HRSG before losses	47.38	16880.6	355.000	--|
GT loss	9989	kJ/s from	Stack	19.60	6983.1	146.854	|
GT Efficiency				41.95			|
Total				108.92			|

Gas cycle Output						
Estimated GT Efficiency	0.4195	**Value imported**				|
Gross avail. energy to GT cycle	35631.84	kJ/kg				|
GT Output	**14947.56**	**kJ/kg**	equiv to	314347.1	kW	|

Steam Cycle Output						V
Estimated Steam Cycle Efficiency	0.434	**Value imported**				
Heat Balance						
From Combustion	0	kJ/kg				
From Gasification	10783.32	kJ/kg				
From GT HRSG etc after losses	16711.84	kJ/kg	<--|			
From Direct Generation	0	kJ/kg				
Export/Import	9985.735	kJ/kg				
Heat available to steam cycle	17509.43	kJ/kg	equiv to	368223.2	kW	
ST Output	**7569.163**	**kJ/kg**	equiv to	159179.5	kW	

HRSG Heat available	16880.65
HRSG heat loss	1.0%
HRSG to Steam Cycle	16711.84

Total Potential Output	22516.72	kJ/kg	equiv to	473526.6	kW

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2367.6	1571.7	795.9
Generator Loss	1.50%	7102.9	4715.2	2387.7
Transformer Loss	0.40%	1894.1	1257.4	636.7

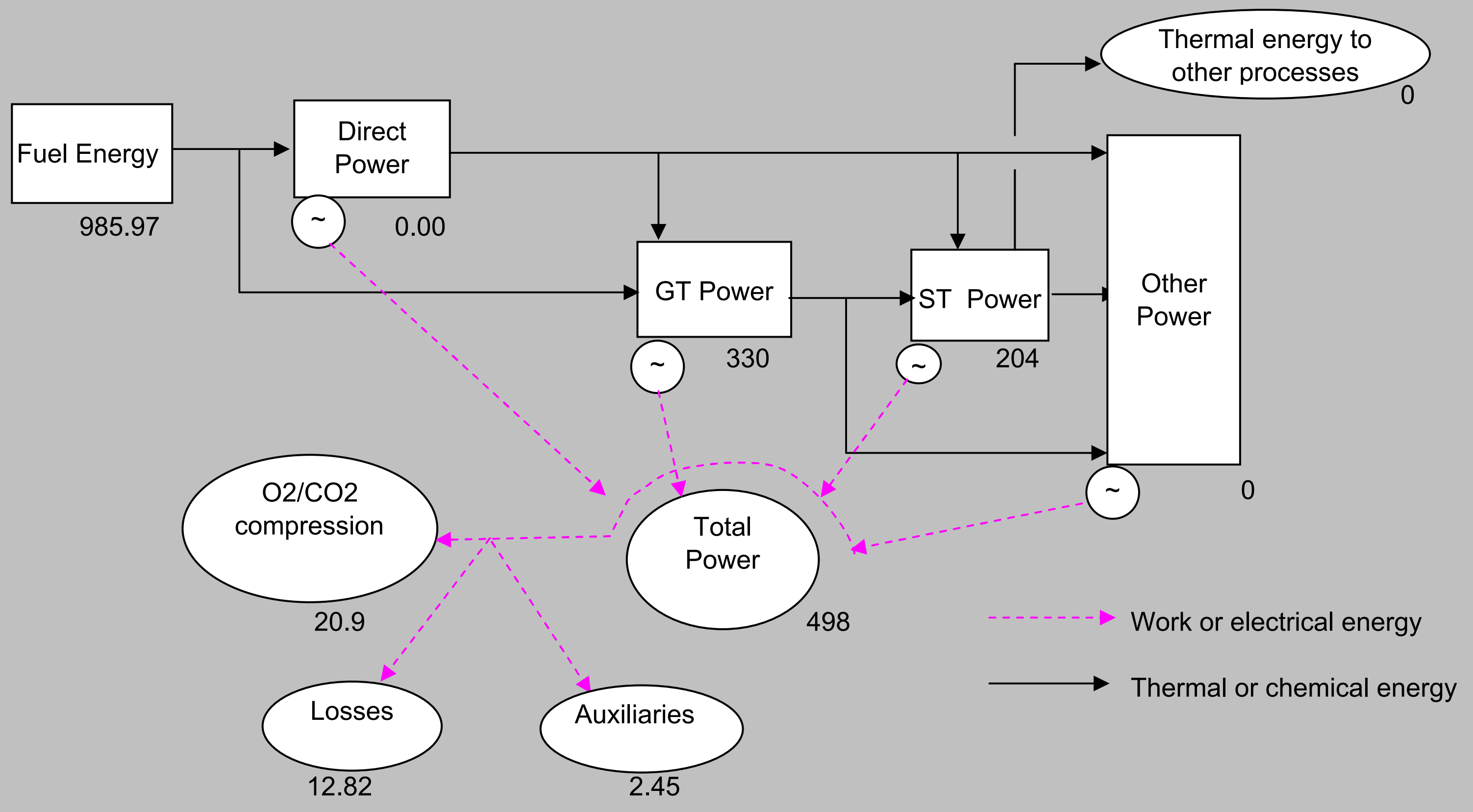
Gross Power Output	**21976.32**	**kJ/kg**	equiv to	462162	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg				0	0		
	Sorbent	50	kJ/kg				0	0		
	Ash	50	kJ/kg				0	0		
Fan and compressor mech eff.		93%								
Oxygen Production		950	kJ/kg O2				0	0		
Oxygen Compression							Value imported	993.8184		0.7
CO2 Compression							1	0	Value imported	
Combustor fans (PF)		8	kJ/MJ fuel				0	0		
FGD		8	kJ/MJ fuel				0	0		
Cooling water system		7	kJ/MJ rejected				1	70.93068		Steam Cycl
Misc		0.30%	of gross					65.92896		
H2S Sepn								0		
CO2 Sepn								0		
Other								0		
Total Auxiliaries								1130.678	kJ/kg	
Total Input		46884	kJ/kg							
Total Output (Net)		20845.64	kJ/kg	=>	498000	kW	Value imported			
Efficiency		50.5	%	Value imported						-36
										2.6928
GT Output (Generator Terminals)		330.00	MW	Value imported						-33.3072
ST Output (Generator Terminals)		204.00	MW	Value imported						
Direct O/P (Gross)		0	MW							
% heat available to steam cycle		45	%	Value imported						

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		985.9705	1	1	123.92
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	1	1	0.00
Gas turbine, complete	MWe	0	330	1	1	56.49
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		355	1	1	28.36
Steam turbine+pipes+cooling system	MWe		204	1	1	67.83
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	1	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		15	1		0.00
Other	User Defined		0	1		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		498	1	1	11.45
Sub-Total						**288.05**
Balance of plant	% of above		10			28.81
Engineering, indirects, owners cost	% of above		24			76.05
Project contingency	% of above		10			39.29
TOTAL						**432.19**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ
	Liquid	3	$/GJ
	Gaseous	3	$/GJ

Calculated Fuel Cost	3.0000	$/GJ
Fuel cost of electricity	2.1386	c/kWh

Capital Charges

Interest Rate	10%	
Plant Life Span	30	years
Load Factor	0.8	

Interest during construction	65.5168	M$
Annual capital Charge	52.7965	M$/y

Capital Charges	1.5118	c/kWh

O&M Costs

O&M Factor	0.03		Other Materials Cost	20	$/tonne
			Residue Disposal Cost	20	$/tonne
Fixed O&M cost	0.3713	c/kWh			
Variable O&M cost	0.0000	c/kWh			

Estimated Operating Costs	**4.0216**	**c/kWh**

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	Value	Risk assessment & Score%	Score %	Weighting	DECISION FACTOR	Weighted Score
Fuel Consumption kJ/kW	1.980		51	42.9	**APPLICABILITY**	30.9
Raw Material Availability	Locally Common with unlimited availability for scale of this application	No risk 0	90	10		
Process Conditions Temperature Pressure NB Use least well known part of process	1200K-1600K 10-60 bar but no significant technical barriers	No risk 11	80	10		
Novelty of Materials which is	Existing Special Alloys known material in known environment	No risk 6	90	10	**CONFIDENCE IN WHETHER IT WILL WORK**	34.0
Plant Complexity No. of major units No. of major recycles	5 0		75	10		
Novelty of Process with	Minor modifications highly successful industrial applications in operation	No risk 0	95	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.062		35	40	**ESTIMATED COSTS**	103.0
Costs Total Operating c/kWh	4.02		80	100		
Safety Risk Control of these risks	Small Risk extensively demonstrated and publicly accepted	No risk 5	80	20	**ACCEPTANCE**	32.0
Environmental Impact Management of these impacts	Benign Waste extensively demonstrated and publicly accepted	No risk 5	80	20		

Averaged risk level	**5**			
Controlling risk level	**11**	**Process conditions**	**TOTALS**	199.9

Results of Analysis

Summary

Process: **FW APO PCDC rerun GCL Contract No 013-003**

Heat Input		986.0	MW		
Estimated	Net Electricity Output	498.0	MW	NOTE GT efficiency calculated by program as …	42.0 %
	Net Efficiency	50.5	%	NOTE Steam cycle efficiency calculated as...	43.4 %
	CO2 output/ kg/s	8.6	kg/s	NOTE percentage of input energy to steam cycle ..	45.0 %
	CO2 output/kWh	0.062	kg/kWh		
Estimated Capital Cost		432.2	M$		
Estimated Op Cost		4.0	c/kWh		

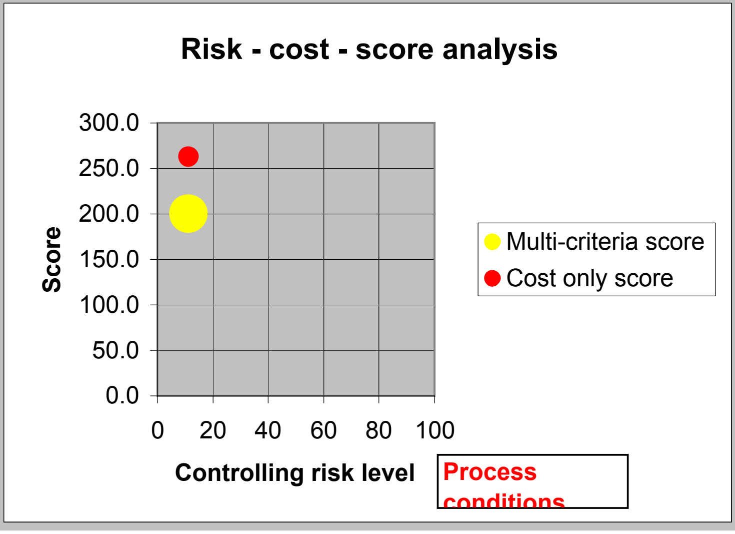
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		32.0
Applicability		30.9
Confidence		34.0
Estimated Cost		103.0
	Total	199.9
	Total cost only	262.5

Risk assessment

Averaged risk level		5
Controlling risk level	**Process conditions**	**11**



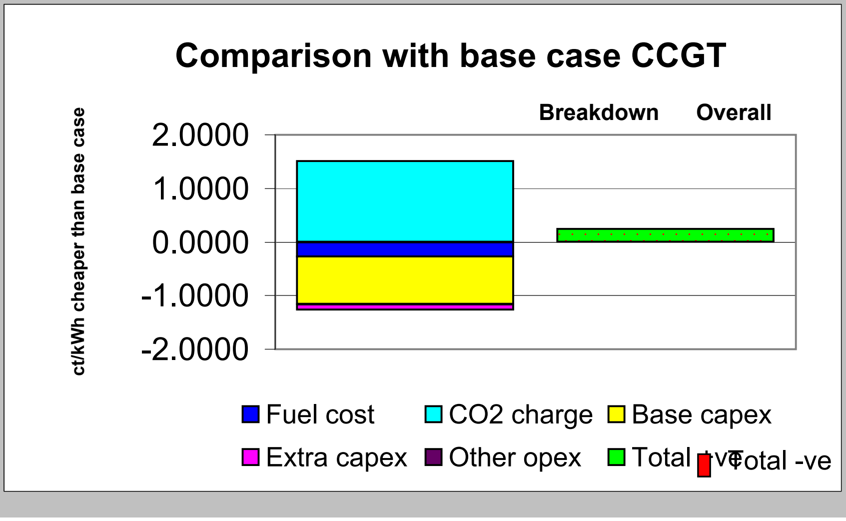
CO2 emission penalty	50	$/ton
CO2 emissions	0.062	kg/kWh
CO2 emission cost	0.309	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0188
Process conditions	80	0.0377
Novelty of materials	90	0.0188
Complexity	75	0.0471
Safety	80	0.0377
Environmental	80	0.0377
TOTAL		**0.1977**

Base Case data

Fuel cost	1.865	c/kWh Based on	3	$/GJ
CO2 Tax	1.824	c/kWh Based on	50	$/tonne
Base Capex+Opex	0.989	c/kWh		
Extra Capex	0.094	c/kWh		
Other Opex	0	c/kWh		

Fuel cost	2.139	1.865	-0.2733	3.0000 $/GJ	
CO2 charge	0.309	1.824	1.5143	50 $/ton	
Base capex	1.883	0.989	-0.8936		
Extra capex	0.198	0.094	-0.1037		
Other opex	0.000	0	0.0000		
				Total	0.2436
TOTAL	4.5287	4.7724	0.2436		
Extra fuel			0.2733		
Extra capex			0.9973		
Total extra			1.2706		
CO2 tax benefit			1.5143		



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.578E-05	
Mix kgC/kJ	1.578E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.347	kg/kWh
Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3472	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)

DO NOT EDIT

Project Title		FW APO PCDC rerun GCL Contra
Power Out	MWe	498
Efficiency	%	50.5
CO2 emitted	%	15
CO2 emitted	kg/kWh	0.061874
Fuel in	kg/s	21.03
Fuel in	MW	985.9705
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	48.50
Gas Cycle Efficiency	%	0.42
Steam Cycle Efficiency	%	0.43
Est Capital Cost	M$	432.19
Est Operating Cost	ct/kWh	4.02
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	985.9705
	Number	1
	Cost	123.92
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	1
	Cost	0.00
Gas turbine, complete	MWe	330
	Number	1
	Cost	56.49
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	355
	Number	1
	Cost	28.36
Steam turbine+pipes+cooling syste	MWe	204

	Number	1
	Cost	67.83
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	1
	Cost	0.00
Other	User Defined	0
	Number	1
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	498
	Number	1

	Cost	11.45
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		2
Press max		3
Process Conditions Qualifer		1
Construction Materials		3
Construction Materials Qualifier		1
No of Recycles		0
Novelty		2
Novelty Qualifer 1		1
Novelty Qualifer 2		1
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		5
Controlling Risk Level		11
Controlling Risk is		Process conditions
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		80
Process Conditions Extra Cost	ct/kWh	0
Novelty		90
Novelty Extra Cost	ct/kWh	0
Complexity		75
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.138614
CO2 Charge	$ct/kWh	0.309369
Base Capex	$ct/kWh	1.883023
Extra Capex	$ct/kWh	0.197717
Other Opex	$ct/kWh	0
Total	$ct/kWh	4.528723
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		46884
Mixture LCV		46884
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	20.9
O2 compression power	MW	0
HRSG on GT	MW	355
GT power	MW	330
ST power	MW	204
Percent of heat available to Steam	MW	45
Overall electrical efficiency after lo	MW	50.5
Efficiency GT Cycle	MW	41.95
Efficiency ST cycle	MW	43.4
Overall power output	MW	498
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for Baseline Pulverized Fuel (PF) coal fired power plant with CO_2 capture using Amine scrubbing of flue gas

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☐	Gas Turbine	0	0.0	MWe
☑	Steam Turbine	1	580.9	MWe
☑	Combustor	1	55.0	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☐	HRSG	0	0.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		10000	kJ/Unit size
☑	Other major plant item	1	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Separation	1	1	
	Aux Power Reqd		18500	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☑ Solid

☐ Liquid

☐ Gaseous

Steam Cycle Type

○ Sub Critical

● SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

			Solid	Liquid	Gas
Fuel Mass Fractions			1	0	0
LCV	kJ/kg		25000	42000	50013
Carbon fraction	%mass		0.62	0.86	0.75
Ash Fraction	%mass		0.12	0	0
% in Feed			100.00%	0.00%	0.00%
Fuel Fractions Sum (must = 1)		1			

Combined LCV	25000	kJ/kg
Combined Carbon fraction	0.62	
Combined Ash Fraction	0.12	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	55	25000	0.62	34.1
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	90.0%			
CO2 recovered	112.53	0	0.273	30.69
CO2 emitted	12.50	0	0.273	3.41

Gross available energy	25000	kJ/kg fuel
	1375000	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	100%	25000	
Percent of Input Fuel to gasification system	0%	0	
Heat recovered from gasifier to steam cycle	0%	0	
Heat recovered from gasifier to gas cycle	0%	0	
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0	
Percent of fuel to direct generatior			
Converted to power	0%	0	
Heat recovered from direct generation to steam cycle	0%	0	
Heat recovered from direct generationto gas cycle	0%	0	
Heat from Steam cycle lost to Process or ?	296000	kW	
Energy available to GT	1E-07	kJ/kg	<== Calculated from above information

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
	40.3	===> Air flow of	40.30	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	2.53	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	54.4	MW	Added into cell J45	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J44	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	0	MW	Transferred to D65	Sheet CycleAnalysis
ST power	580.9	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	100	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	34.7	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	0	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	46.3	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	477	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1375.00	MW

Losses

GT mech loss	0.00	MW
GT gen loss	0.00	MW
ST mech loss	2.90	MW
ST mech loss	8.71	MW
GT + ST transformer loss	2.32	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**13.94**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*	
Fuel	2.75	MW	2.75	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	0	MW	0	0		
Combustor fans (PF)	11.00	MW	11.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	2.21	MW	2.21	0		311.94 MW ST rejection
Misc	1.43	MW	1.43	0		3.81 MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	18.5	MW	18.5	0		
Other	0	MW	0	0		
Subtotal	**35.89**	**MW**				
TOTAL Losses/Auxiliaries	**49.83**	**MW**				

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat I/P to GT**	**kJ/kg**	**MW**	
	Value imported						
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	---
GT loss	0	kJ/s from	Stack	0.00	0.0	0.000	
GT Efficiency				0.00			
Total				0.00			

Gas cycle Output					
Estimated GT Efficiency	0	**Value imported**			
Gross avail. energy to GT cycle	1E-07	kJ/kg			
GT Output	**0**	**kJ/kg**	equiv to	0	kW

V

Steam Cycle Output								
Estimated Steam Cycle Efficiency	0.463	**Value imported**						
Heat Balance						HRSG Heat available	0	kJ/kg
From Combustion	25000	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	0	kJ/kg
From GT HRSG etc after losses	0	kJ/kg	<--					
From Direct Generation	0	kJ/kg						
Export/Import	5381.818	kJ/kg						
Heat available to steam cycle	19618.18	kJ/kg	equiv to	1079000	kW			
ST Output	**9049.687**	**kJ/kg**	equiv to	497732.8	kW			
Total Potential Output	9049.687	kJ/kg	equiv to	497732.8	kW			

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2488.7	0.0	2488.7
Generator Loss	1.50%	7466.0	0.0	7466.0
Transformer Loss	0.40%	1990.9	0.0	1990.9

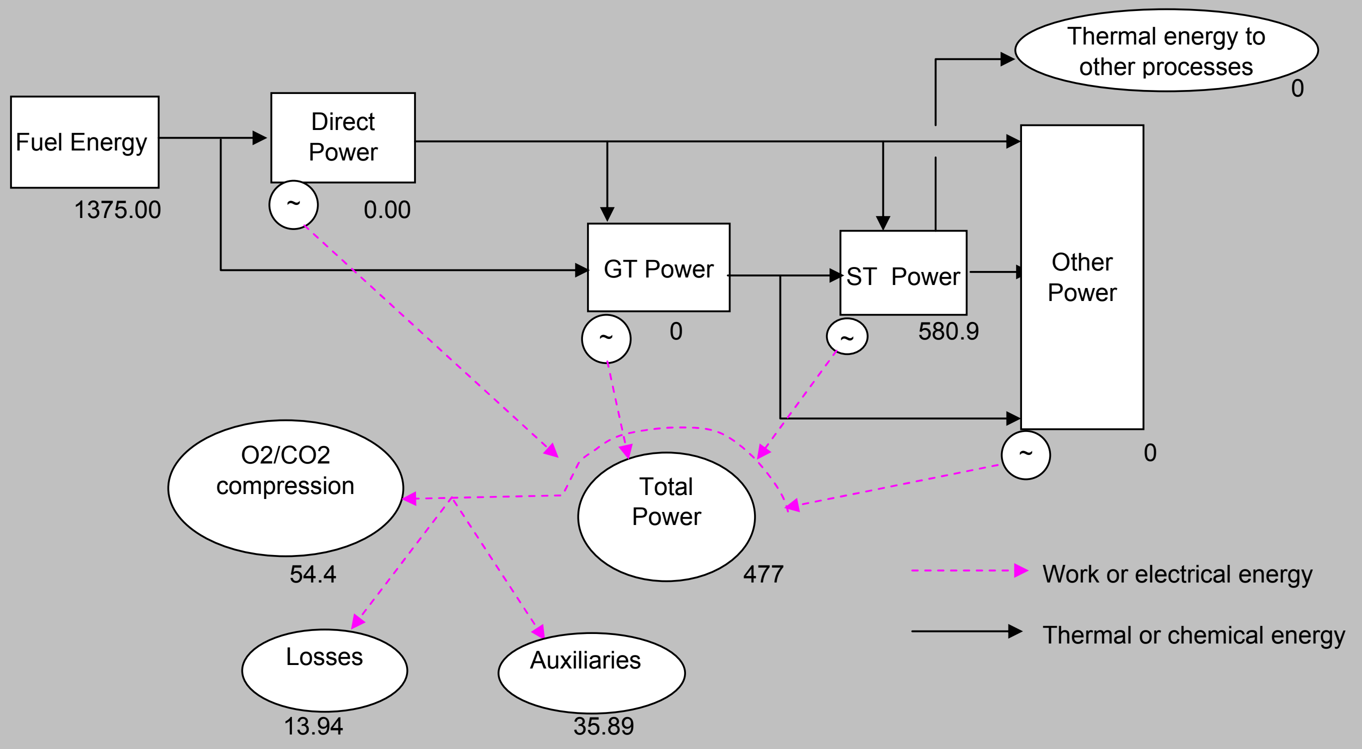
Gross Power Output	**8832.494**	**kJ/kg**	equiv to	485787.2	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg				1	50			
	Sorbent	50	kJ/kg				0	0			
	Ash	50	kJ/kg				1	0			
Fan and compressor mech eff.		93%									
Oxygen Production		950	kJ/kg O2				0	0			
Oxygen Compression						**Value imported**		0		0.7	Is good nur
CO2 Compression							1	989.0909	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel				1	200			
FGD		8	kJ/MJ fuel				0	0			
Cooling water system		7	kJ/MJ rejected				1	75.39475	Steam Cycle Condens		
Misc		0.30%	of gross					26.49748			
H2S Sepn								0			
CO2 Sepn								336.3636			
Other								0			
Total Auxiliaries								1677.347	kJ/kg		
Total Input		25000	kJ/kg								
Total Output (Net)		7155.147	kJ/kg	=>	477000 kW	**Value imported**					
Efficiency		34.7	%	**Value imported**						-103.9	
										0	
GT Output (Generator Terminals)		0.00	MW	**Value imported**						-103.9	
ST Output (Generator Terminals)		580.90	MW	**Value imported**							
Direct O/P (Gross)		0	MW								
% heat available to steam cycle		100	%	**Value imported**							

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		55	1	1	14.91
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		54.4	1	1	55.22
Gas turbine, complete	MWe	0	0	0	1	0.00
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		580.9	1	1.1	163.55
PF coal boiler	MW fuel feed LHV		1375	1	1	191.43
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	0	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	0.477	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Acid Gas removal	CC App A A12p166 (adj)		0	1		383.58
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		477	1	1	11.06
Sub-Total						**819.75**
Balance of plant	% of above		10			81.97
Engineering, indirects, owners cost	% of above		24			216.41
Project contingency	% of above		10			111.81
TOTAL						**1229.95**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ			
	Liquid	3	$/GJ			
	Gaseous	3	$/GJ			
Calculated Fuel Cost		1.5000	$/GJ			
Fuel cost of electricity		1.5562	c/kWh			
Capital Charges						
Interest Rate		10%				
Plant Life Span		25	years			
Load Factor		0.85				
Interest during construction		186.4503	M$			
Annual capital Charge		156.0418	M$/y			
Capital Charges		4.3904	c/kWh			
O&M Costs						
O&M Factor		0.04		Other Materials Cost	20	$/tonne
				Residue Disposal Cost	20	$/tonne
Fixed O&M cost		1.3842	c/kWh			
Variable O&M cost		0.0000	c/kWh			
Estimated Operating Costs		**7.3308**	**c/kWh**			

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	2.882	No risk	6	42.9	**APPLICABILITY**	12.5
Raw Material Availability	Universally Common ▼ with unlimited availability ▼ for scale of this application	0	100	10		
Process Conditions Temperature Pressure NB Use least well known part of process	<1200K ▼ Atmospheric ▼ but no significant technical barriers ▼	No risk 0	100	10		
Novelty of Materials which is	Carbon Steel ▼ known material in known environment ▼	No risk 0	100	10	**CONFIDENCE IN WHETHER IT WILL WORK**	38.0
Plant Complexity No. of major units No. of major recycles	4 0		80	10		
Novelty of Process with	Fully proven ▼ highly successful ▼ industrial applications in operation ▼	No risk 0	100	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.094		64	40	**ESTIMATED COSTS**	48.9
Costs Total Operating c/kWh	7.33		13	100		
Safety Risk Control of these risks	Small Risk ▼ extensively demonstrated and publicly accepted ▼	No risk 5	80	20	**ACCEPTANCE**	26.0
Environmental Impact Management of these impacts	Mildly harmful waste ▼ extensively demonstrated and publicly accepted ▼	No risk 10	50	20		

Averaged risk level	**3**		**TOTALS**	125.5
Controlling risk level	**10**	**Environment**		

Results of Analysis

Summary

Process: **PF+ FGD + Amine (rerun)**

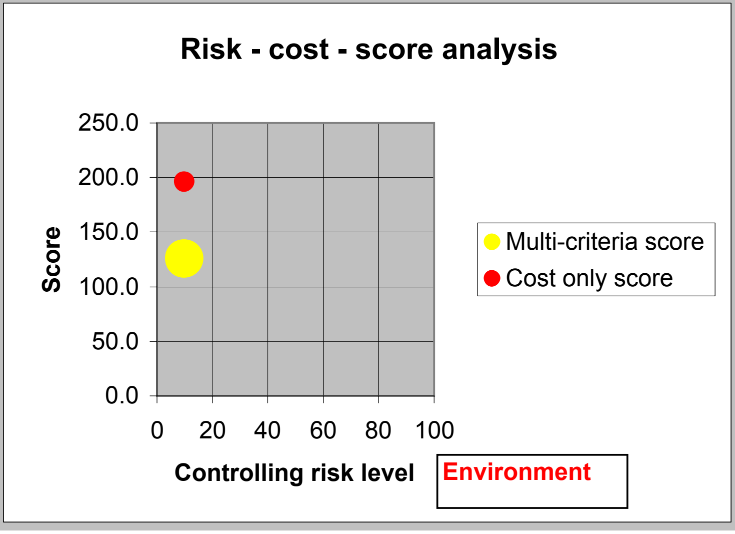
Heat Input		1375.0	MW		
Estimated	Net Electricity Output	477.0	MW	NOTE GT efficiency calculated by program as …	0.0 %
	Net Efficiency	34.7	%	NOTE Steam cycle efficiency calculated as...	46.3 %
	CO2 output/ kg/s	12.5	kg/s	NOTE percentage of input energy to steam cycle ..	100.0 %
	CO2 output/kWh	0.094	kg/kWh		
Estimated Capital Cost		1229.9	M$		
Estimated Op Cost		7.3	c/kWh		

Multi-Criteria Assessment

Decision Factor Scores		
Acceptance		26.0
Applicability		12.5
Confidence		38.0
Estimated Cost		48.9
	Total	125.5
	Total cost only	196.3

Risk assessment

Averaged risk level		3
Controlling risk level	**Environment**	**10**



Comparison with Base Case CCGT

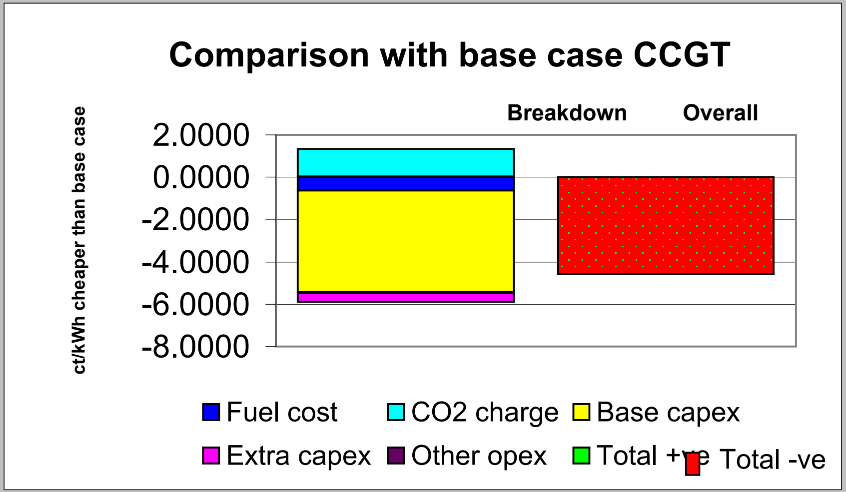
CO2 emission penalty	50	$/ton
CO2 emissions	0.094	kg/kWh
CO2 emission cost	0.472	c/kWh

	This Case	Base Case	Difference	Base rates	
	$ct/kWh	$ct/kWh	$ct/kWh		
Fuel cost	1.556	0.920	-0.6363	1.5000 $/GJ	
CO2 charge	0.472	1.79730928	1.3255	50 $/ton	
Base capex	5.775	0.94102649	-4.8336		
Extra capex	0.520	0.06116672	-0.4585		
Other opex	0.000	0	0.0000		
				Total	-4.6029
TOTAL	8.3223	3.7194	-4.6029		
Extra fuel			0.6363		
Extra capex			5.2921		
Total extra			5.9284		
CO2 tax benefit			1.3255		

Factor analysis	Scores	Effect on costs of electricity
Raw materials	100	0.0000
Process conditions	100	0.0000
Novelty of materials	100	0.0000
Complexity	80	0.1155
Safety	80	0.1155
Environmental	50	0.2887
TOTAL		**0.5197**

Base Case data

Fuel cost	1.839864	c/kWh Based on	3	$/GJ
CO2 Tax	1.797309	c/kWh Based on	50	$/tonne
Base Capex+Opex	0.941026	c/kWh		
Extra Capex	0.061167	c/kWh		
Other Opex	0	c/kWh		



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.5E-05	
Mix kgC/kJ	0.0000248	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.330	kg/kWh
Calorific fraction of gas	0	
Calorific fraction of oil	0	
CO2 allowance	0.6177	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT

Project Title		PF+ FGD + Amine (rerun)
Power Out	MWe	477
Efficiency	%	34.7
CO2 emitted	%	10
CO2 emitted	kg/kWh	0.094365
Fuel in	kg/s	55
Fuel in	MW	1375
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	112.53
Gas Cycle Efficiency	%	0.00
Steam Cycle Efficiency	%	0.46
Est Capital Cost	M$	1229.95
Est Operating Cost	ct/kWh	7.33
Capital Cost Items		
Solids handling	'Size'	55
	Number	1
	Cost	14.91
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	54.4
	Number	1
	Cost	55.22
Gas turbine, complete	MWe	0
	Number	0
	Cost	0.00
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	0
	Cost	0.00
Steam turbine+pipes+cooling syste	MWe	638.99

	Number	1
	Cost	163.55
PF coal boiler	MW fuel feed LHV	1375
	Number	1
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	1
	Cost	383.58
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	477
	Number	1

	Cost	11.06
Multi Criteria		
Feed Material		1
Feed Material Qualifier		1
Temp max		1
Press max		1
Process Conditions Qualifer		1
Construction Materials		1
Construction Materials Qualifier		1
No of Recycles		0
Novelty		1
Novelty Qualifer 1		1
Novelty Qualifer 2		1
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		3
Environmental Impact Qualifier		1
Average Risk Level		3
Controlling Risk Level		10
Controlling Risk is		Environment
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		100
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		100
Process Conditions Extra Cost	ct/kWh	0
Novelty		100
Novelty Extra Cost	ct/kWh	0
Complexity		80
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		50
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	1.556196
CO2 Charge	$ct/kWh	0.471824
Base Capex	$ct/kWh	5.774608
Extra Capex	$ct/kWh	0.519715
Other Opex	$ct/kWh	0
Total	$ct/kWh	8.322343
Fuel Mix		
Solid	frac	1
Liquid	frac	0
Gas	frac	0
Solid LCV		25000
Liquid LCV		42000
Gas LCV		50013
Mixture LCV		25000
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	54.4
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	0
ST power	MW	580.9
Percent of heat available to Steam	MW	100
Overall electrical efficiency after lo	MW	34.7
Efficiency GT Cycle	MW	0
Efficiency ST cycle	MW	46.3
Overall power output	MW	477
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for gas fired CO_2 capturing power plant utilizing oxy-combustion with water recirculation according to the Clean Energy Systems process

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☑	Gas Turbine	1	663.0	MWe
☐	Steam Turbine	0	0.0	MWe
☐	Combustor	0	0.0	kg/s fuel
☑	Gasifier	1	23.0	kg/s fuel
☑	Air Separation Unit	1	86.42	kg/s O2
	O2 compression Press.		72	bar
☐	HRSG	0	0.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☐	Other major plant item	0	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	1	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☐ Solid
☐ Liquid
☑ Gaseous

Steam Cycle Type

● Sub Critical
○ SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

		Solid	Liquid	Gas
Fuel Mass Fractions		0	0	1
LCV	kJ/kg	25000	42000	46920.3
Carbon fraction	%mass	0.62	0.86	0.739
Ash Fraction	%mass	0.12	0	0
% in Feed		0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)	1			

Combined LCV	46920.3	kJ/kg
Combined Carbon fraction	0.739	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	**Flow kg/s**	**LCV kJ/kg**	**kg Carbon /kg**	**Carbon Balance kg/s**
Fuel	23	46920.3	0.739	16.997
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	100.0%			
CO2 recovered	62.32	0	0.273	16.997
CO2 emitted	0.00	0	0.273	0

Gross available energy 46920.3 kJ/kg fuel
1079167 kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	0%	0
Percent of Input Fuel to gasification system	100%	46920.3
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	100%	46920.3
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatio		
Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
Air/Fuel Ratio by Mass for Gas Turbine	3.75	===> Air flow of	3.75	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	0.24	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		921	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	63.5	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	91.1	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	663	MW	Transferred to D65	Sheet CycleAnalysis
ST power	0	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	0	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	45.4	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	61.5	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	0	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	490	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1079.17	MW

Losses

GT mech loss	3.32	MW
GT gen loss	9.95	MW
ST mech loss	0.00	MW
ST mech loss	0.00	MW
GT + ST transformer loss	2.65	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**15.91**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

			PPAP	External	*hidden calc*	
Solids handling:						
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	overidden	MW	79.59282	overidden		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	1.07	MW	1.07	0	0.00	MW ST rejection
Misc	1.47	MW	1.47	0	153.16	MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**2.54**	**MW**				
TOTAL Losses/Auxiliaries	**18.45**	**MW**				

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**			
	Value imported			**I/P to GT**	**kJ/kg**	**MW**	
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	--|
GT loss	820	kJ/s from	Stack	17.04	7995.8	183.903	|
GT Efficiency				61.50			|
Total				78.54			|

Gas cycle Output						
Estimated GT Efficiency	0.615	**Value imported**				|
Gross avail. energy to GT cycle	46920.3	kJ/kg				|
GT Output	**28855.98**	**kJ/kg**	equiv to	663687.6	kW	|

Steam Cycle Output						V		
Estimated Steam Cycle Efficiency	0	**Value imported**						
Heat Balance						HRSG Heat available	0	kJ/kg
From Combustion	0	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	0	kJ/kg
From GT HRSG etc after losses	0	kJ/kg	<--|					
From Direct Generation	0	kJ/kg						
Export/Import	0	kJ/kg						
Heat available to steam cycle	0	kJ/kg	equiv to	0	kW			
ST Output	**0**	**kJ/kg**	equiv to	0	kW			

Total Potential Output	28855.98	kJ/kg	equiv to	663687.6	kW

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	3318.4	3318.4	0.0
Generator Loss	1.50%	9955.3	9955.3	0.0
Transformer Loss	0.40%	2654.8	2654.8	0.0

Gross Power Output	**28163.44**	**kJ/kg**	equiv to	647759.1	kW

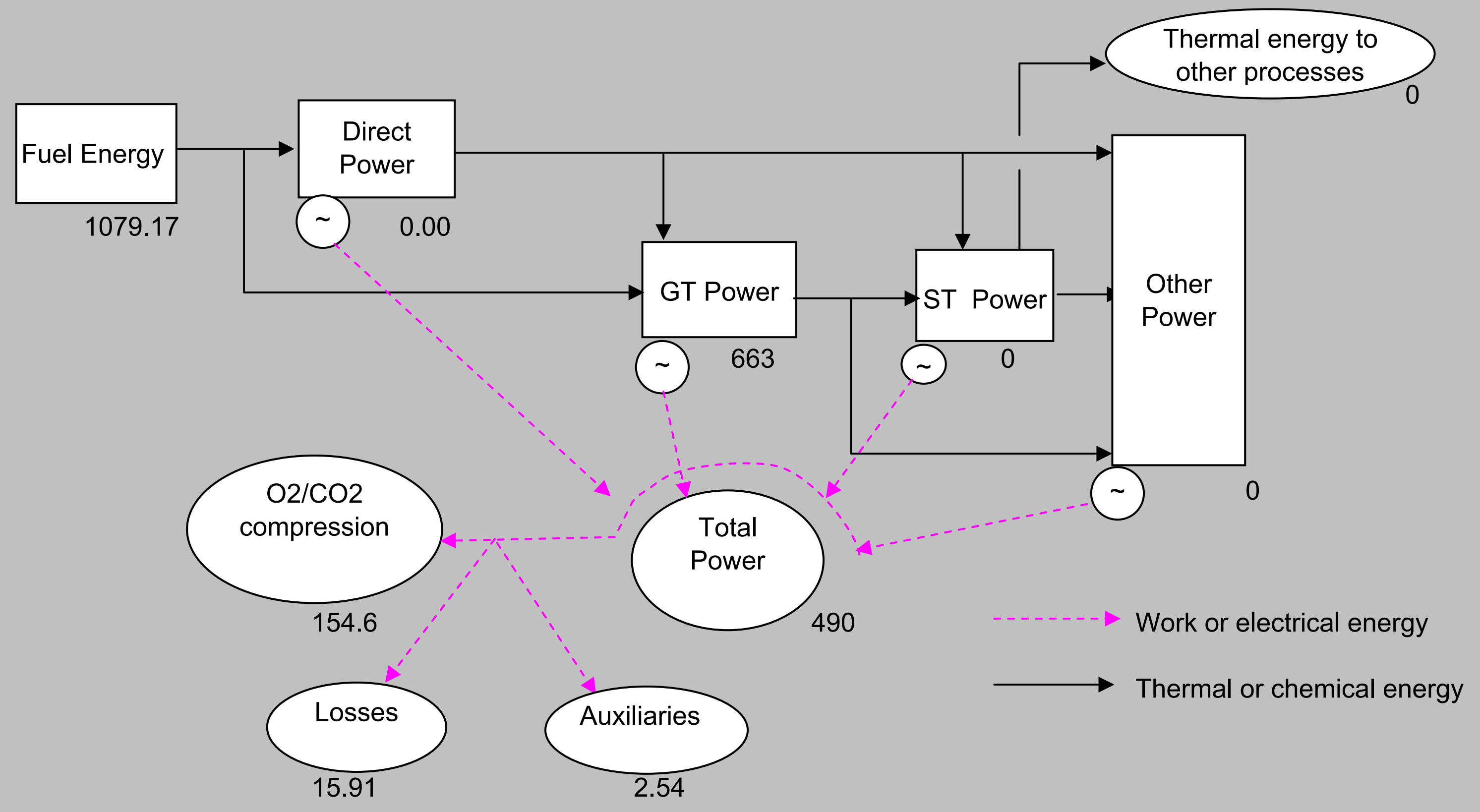
Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg	0	0

Sorbent	50	kJ/kg					0	0			
Ash	50	kJ/kg					0	0			
Fan and compressor mech eff.	93%										
Oxygen Production	921	kJ/kg O2					1	3460.557			
Oxygen Compression						**Value imported**		2760.87		0.7	Is good nur
CO2 Compression							1	3960.87	**Value imported**		O2 & CO2
Combustor fans (PF)	8	kJ/MJ fuel					0	0			
FGD	8	kJ/MJ fuel					0	0			
Cooling water system	7	kJ/MJ rejected					0	2.113333			Steam Cycle Condens
Misc	0.30%	of gross						84.49032			
H2S Sepn								0			
CO2 Sepn								0			
Other								0			
Total Auxiliaries								10268.9	kJ/kg		
Total Input	46920.3	kJ/kg									
Total Output (Net)	17894.54	kJ/kg	=>	490000	kW	**Value imported**					
Efficiency	45.4	%	**Value imported**							-173	
										0	
GT Output (Generator Terminals)	663.00	MW	**Value imported**							-173	
ST Output (Generator Terminals)	0.00	MW	**Value imported**								
Direct O/P (Gross)	0	MW									
% heat available to steam cycle	0	%	**Value imported**								

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	**Scaling parameter**	**User specified size**	**Size per unit**	**No of units**	**Cost multiplier**	**Predicted cost, M$**
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		86.42	1	1	147.40
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		1079.167	1	0.25	33.30
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		91.1	1	1	92.47
Gas turbine, complete	MWe	0	663	1	0.75	71.50
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		0	0	1	0.00
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	0	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		490	1	1	11.30
Sub-Total						**355.97**
Balance of plant	% of above		10			35.60
Engineering, indirects, owners cost	% of above		24			93.98
Project contingency	% of above		10			48.55
TOTAL						**534.10**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ
	Liquid	3	$/GJ
	Gaseous	3	$/GJ

Calculated Fuel Cost	3.0000	$/GJ
Fuel cost of electricity	2.3789	c/kWh

Capital Charges

Interest Rate	10%	
Plant Life Span	25	years
Load Factor	0.85	

Interest during construction	80.9659	M$
Annual capital Charge	67.7610	M$/y

Capital Charges	1.8559	c/kWh

O&M Costs

O&M Factor	0.04		Other Materials Cost	20	$/tonne
			Residue Disposal Cost	20	$/tonne
Fixed O&M cost	0.5852	c/kWh			
Variable O&M cost	0.0000	c/kWh			

Estimated Operating Costs	**4.8199**	**c/kWh**

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	2.203		40	42.9		
		No risk			**APPLICABILITY**	26.1
Raw Material Availability	Locally Common	0	90	10		
	with unlimited availability					
	for scale of this application					
Process Conditions		Low risk				
Temperature	1200K-1600K	20	65	10		
Pressure	60-150 bar					
NB Use least well known part of process	but no significant technical barriers					
Novelty of Materials		No risk			**CONFIDENCE IN WHETHER IT**	
	Existing Special Alloys	13	90	10		29.5
which is	known material but in new environment				**WILL WORK**	
Plant Complexity						
No. of major units	4		80	10		
No. of major recycles	0					
Novelty of Process	Major modifications	No risk	60	10		
with	promising	16				
	and extensive pilotscale demonstration					
Greenhouse Gas Emissions						
CO2 emission in kg/Kwh	0.000		42	40	**ESTIMATED**	
Costs					**COSTS**	86.5
Total Operating c/kWh	4.82		64	100		
Safety Risk		No risk				
	Risk	10	60	20		
Control of these risks	extensively demonstrated and publicly accepted				**ACCEPTANCE**	28.0
Environmental Impact		No risk				
	Benign Waste	5	80	20		
Management of these impacts	extensively demonstrated and publicly accepted					
Averaged risk level		**11**			**TOTALS**	170.1
Controlling risk level		**20**	Process conditions			

Results of Analysis

Summary

Process: **CES Process (medium term)** **GCL Contract 014-002**

Heat Input		1079.2	MW			
Estimated	Net Electricity Output	490.0	MW	NOTE GT efficiency calculated by program as …	61.5	%
	Net Efficiency	45.4	%	NOTE Steam cycle efficiency calculated as...	0.0	%
	CO2 output/ kg/s	0.0	kg/s	NOTE percentage of input energy to steam cycle ..	0.0	%
	CO2 output/kWh	0.000	kg/kWh			
Estimated Capital Cost		534.1	M$			
Estimated Op Cost		4.8	c/kWh			

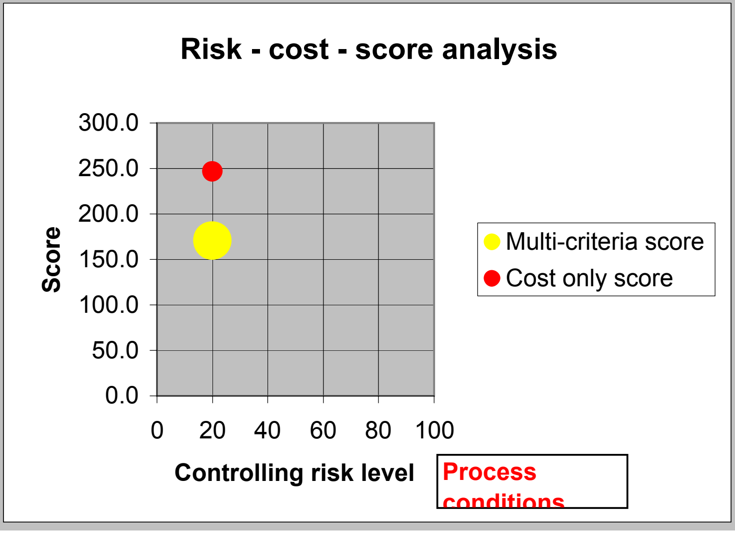
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		28.0
Applicability		26.1
Confidence		29.5
Estimated Cost		86.5
	Total	170.1
	Total cost only	246.5

Risk assessment

Averaged risk level		11
Controlling risk level	**Process conditions**	**20**



Comparison with Base Case CCGT

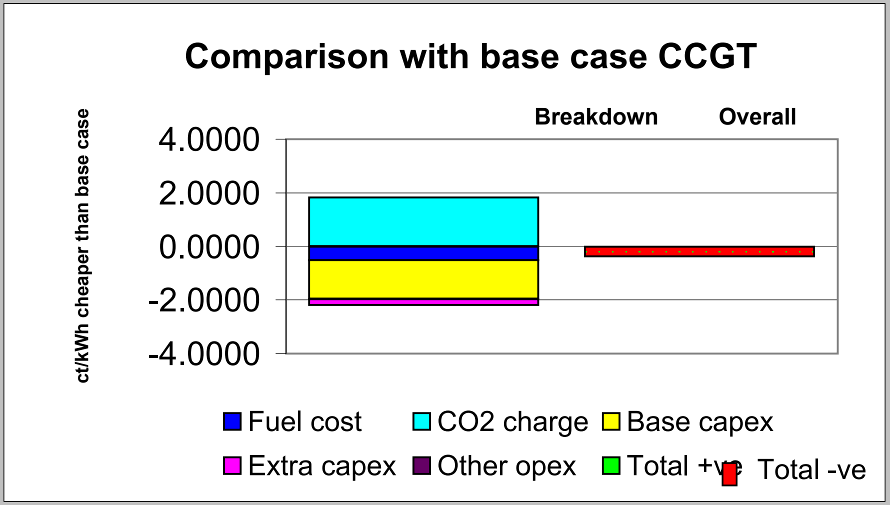
CO2 emission penalty	50	$/ton
CO2 emissions	0.000	kg/kWh
CO2 emission cost	0.000	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0244
Process conditions	65	0.0854
Novelty of materials	90	0.0244
Complexity	80	0.0488
Safety	60	0.0976
Environmental	80	0.0488
TOTAL		**0.3295**

Base Case data

Fuel cost	1.865	c/kWh Based on	3	$/GJ
CO2 Tax	1.824	c/kWh Based on	50	$/tonne
Base Capex+Opex	0.989	c/kWh		
Extra Capex	0.084	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates	
Fuel cost	2.379	1.865	-0.5136	3.0000 $/GJ	
CO2 charge	0.000	1.824	1.8236	50 $/ton	
Base capex	2.441	0.989	-1.4516		
Extra capex	0.330	0.084	-0.2454		
Other opex	0.000	0	0.0000		
				Total	-0.3870
TOTAL	5.1495	4.7625	-0.3870		
Extra fuel			0.5136		
Extra capex			1.6971		
Total extra			2.2107		
CO2 tax benefit			1.8236		



WEIGHTINGS ANALYSIS

CO2 emission calc

Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.575E-05	
Mix kgC/kJ	1.575E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.347	kg/kWh

Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3465	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT

Project Title		CES Process (medium term)	GCL Contract
Power Out	MWe	490	
Efficiency	%	45.4	
CO2 emitted	%	0	
CO2 emitted	kg/kWh	0	
Fuel in	kg/s	23	
Fuel in	MW	1079.167	
Other in	kg/s	0	
Ash (residue) Out	kg/s	0	
CO2 to 'storage'	kg/s	62.32	
Gas Cycle Efficiency	%	0.62	
Steam Cycle Efficiency	%	0.00	
Est Capital Cost	M$	534.10	
Est Operating Cost	ct/kWh	4.82	
Capital Cost Items			
Solids handling	'Size'	0	
	Number	0	
	Cost	0.00	
Coal pulverise+dry (gasif)	kg/s feed	0	
	Number	0	
	Cost	0.00	
Oxygen production	kg/s O2	86.42	
	Number	1	
	Cost	147.40	
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	269.7917	
	Number	1	
	Cost	33.30	
Acid gas removal (scrubbing)	kmol/s feed gas	0	
	Number	0	
	Cost	0.00	
CFBC combustor /stack	MW fuel feed	0	
	Number	0	
	Cost	0.00	
CO2 compressor (motor driven)	MWe	91.1	
	Number	1	
	Cost	92.47	
Gas turbine, complete	MWe	497.25	
	Number	1	
	Cost	71.50	
Gas turbine, compressor only	MW consumed	0	
	Number	0	
	Cost	0	
Gas turbine, turbine only	MW	0	
	Number	0	
	Cost	0	
Gas turbine, generator only	MWe	0	
	Number	0	
	Cost	0	
HRSG	MWth transferred	0	
	Number	0	
	Cost	0.00	
Steam turbine+pipes+cooling syst	MWe	0	

	Number	0
	Cost	0.00
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	490
	Number	1

	Cost	11.30
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		2
Press max		4
Process Conditions Qualifer		1
Construction Materials		3
Construction Materials Qualifier		2
No of Recycles		0
Novelty		3
Novelty Qualifer 1		2
Novelty Qualifer 2		3
Safety Risk		3
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		11
Controlling Risk Level		20
Controlling Risk is		Process conditions
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		65
Process Conditions Extra Cost	ct/kWh	0
Novelty		90
Novelty Extra Cost	ct/kWh	0
Complexity		80
Complexity Extra Cost	ct/kWh	0
Safety		60
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.378855
CO2 Charge	$ct/kWh	0
Base Capex	$ct/kWh	2.441091
Extra Capex	$ct/kWh	0.329547
Other Opex	$ct/kWh	0
Total	$ct/kWh	5.149493
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		46920.3
Mixture LCV		46920.3
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	63.5
O2 compression power	MW	91.1
HRSG on GT	MW	0
GT power	MW	663
ST power	MW	0
Percent of heat available to Steam	MW	0
Overall electrical efficiency after lo	MW	45.4
Efficiency GT Cycle	MW	61.5
Efficiency ST cycle	MW	0
Overall power output	MW	490
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		overidden
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for gas fired CO_2 capturing power plant utilising hybrid solid oxide fuel cell/ gas turbine power plant

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☑	Gas Turbine	10	9.3	MWe
☐	Steam Turbine	0	0.0	MWe
☐	Combustor	0	0.0	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☐	HRSG	0	0.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☑	Other major plant item	10	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☑	Fuel Cell (or Direct Generator)	10		

Fuel Type

☐ Solid

☐ Liquid

☑ Gaseous

Fuel Specifications

User to enter fuel specification figures in blue

			Solid	Liquid	Gas
Fuel Mass Fractions			0	0	1
LCV	kJ/kg		25000	42000	46920
Carbon fraction	%mass		0.62	0.86	0.74
Ash Fraction	%mass		0.12	0	0
% in Feed			0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)		1			

Combined LCV	46920	kJ/kg
Combined Carbon fraction	0.74	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	**Flow kg/s**	**LCV kJ/kg**	**kg Carbon /kg**	**Carbon Balance kg/s**
Fuel	15.47	46920	0.74	11.4478
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	99.0%			
CO2 recovered	41.56	0	0.273	11.33332
CO2 emitted	0.42	0	0.273	0.114478

Gross available energy	46920	kJ/kg fuel
	725852.4	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	0%	0
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	65%	30451.08
Percent of fuel to direct generatior Converted to power	90%	27405.97
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
Air/Fuel Ratio by Mass for Gas Turbine	56.8635	===> Air flow of	56.86	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	3.57	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	7.00%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	8.1	MW	Added into cell J45	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J44	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	92.92	MW	Transferred to D65	Sheet CycleAnalysis
ST power	0	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	0	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	64.62	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	35	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	0	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	469	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	423.97	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	725.85	MW

Losses

GT mech loss	0.46	MW
GT gen loss	1.39	MW
ST mech loss	0.00	MW
ST mech loss	0.00	MW
GT + ST transformer loss	6.50	MW
Transformer loss direct power generated	29.68	MW
Subtotal	**38.04**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*	
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	0	MW	0	0		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	0.00	MW	0.00	0	0.00	MW ST rejection
Misc	1.41	MW	1.41	0	0.57	MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**1.41**	**MW**				

TOTAL Losses/Auxiliaries	**39.45**	**MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**			
	Value imported			**I/P to GT**	**kJ/kg**	**MW**	
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	--|
GT loss	9989	kJ/s from	Stack	19.60	3227.5	49.930	|
GT Efficiency				35.00			|
Total				54.60			|

Gas cycle Output					
Estimated GT Efficiency	0.35	**Value imported**			
Gross avail. energy to GT cycle	16468.92	kJ/kg			
GT Output	**5764.122**	**kJ/kg**	equiv to	89170.97	kW

V

Steam Cycle Output					
Estimated Steam Cycle Efficiency	0	**Value imported**			
Heat Balance					
From Combustion	0	kJ/kg			
From Gasification	0	kJ/kg			
From GT HRSG etc after losses	0	kJ/kg	<--|		
From Direct Generation	0	kJ/kg			
Export/Import	0	kJ/kg			
Heat available to steam cycle	0	kJ/kg	equiv to	0	kW
ST Output	**0**	**kJ/kg**	equiv to	0	kW
Total Potential Output	5764.122	kJ/kg	equiv to	89170.97	kW

HRSG Heat available	0	kJ/kg
HRSG heat loss	1.0%	
HRSG to Steam Cycle	0	kJ/kg

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	445.9	445.9	0.0
Generator Loss	1.50%	1337.6	1337.6	0.0
Transformer Loss	7.00%	6242.0	6242.0	0.0

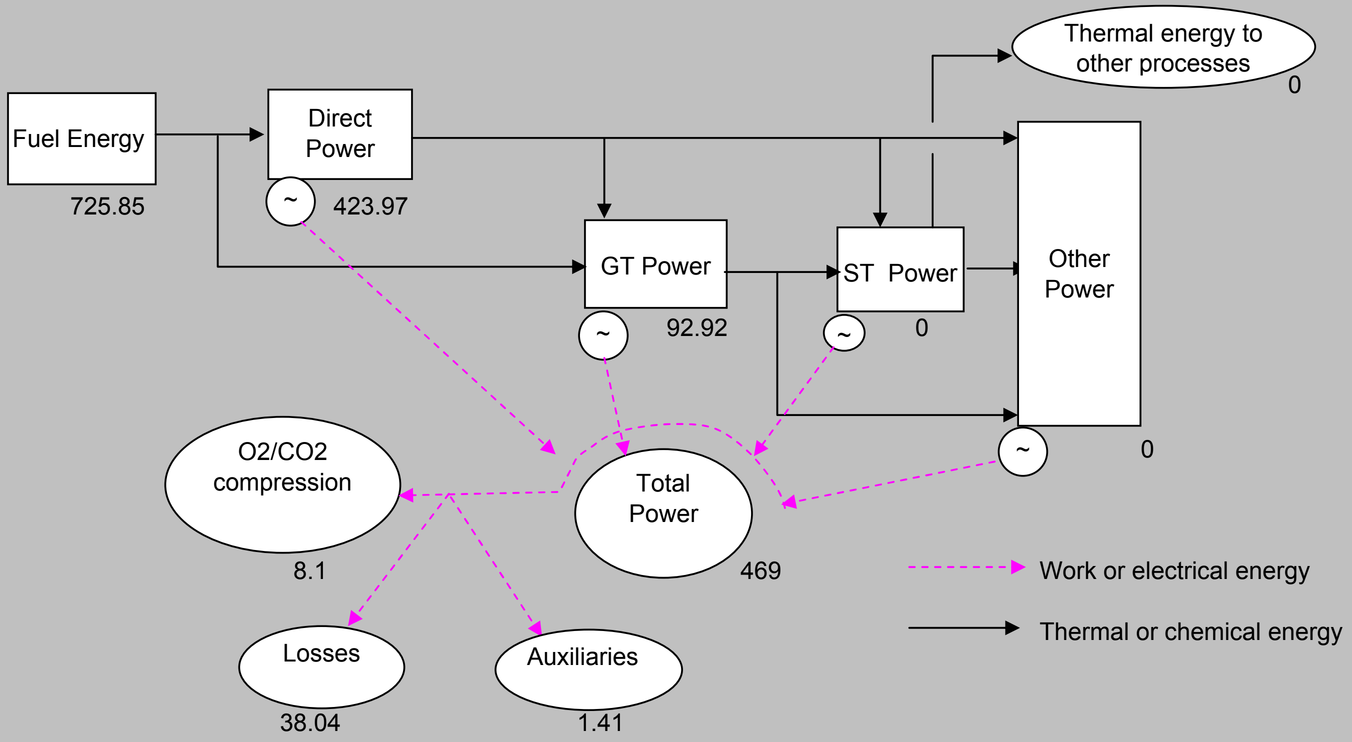
Gross Power Output	**30732.9**	**kJ/kg**	equiv to	475438	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg					0	0			
	Sorbent	50	kJ/kg					0	0			
	Ash	50	kJ/kg					0	0			
Fan and compressor mech eff.		93%										
Oxygen Production		950	kJ/kg O2					0	0			
Oxygen Compression							**Value imported**		0		0.7	Is good nur
CO2 Compression								1	523.5941	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel					0	0			
FGD		8	kJ/MJ fuel					0	0			
Cooling water system		7	kJ/MJ rejected					0	1.815			Steam Cycle Condens
Misc		0.30%	of gross						92.19871			
H2S Sepn									0			
CO2 Sepn									0			
Other									0			
Total Auxiliaries									617.6078	kJ/kg		
Total Input		46920	kJ/kg									
Total Output (Net)		30115.3	kJ/kg	=>	469000	kW	**Value imported**					
Efficiency		64.62	%	**Value imported**							376.08	
											0	
GT Output (Generator Terminals)		92.92	MW	**Value imported**							376.08	
ST Output (Generator Terminals)		0.00	MW	**Value imported**								
Direct O/P (Gross)		394.2925	MW									
% heat available to steam cycle		0	%	**Value imported**								

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		8.1	1	1	8.22
Gas turbine, complete	MWe	0	9.292	10	2	77.66
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		0	0	1	0.00
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	1	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		795.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		469	1	1	10.91
Sub-Total						**891.80**
Balance of plant	% of above		10			89.18
Engineering, indirects, owners cost	% of above		24			235.43
Project contingency	% of above		10			121.64
TOTAL						**1338.05**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ			
	Liquid	3	$/GJ			
	Gaseous	3	$/GJ			
Calculated Fuel Cost		3.0000	$/GJ			
Fuel cost of electricity		1.6713	c/kWh			
Capital Charges						
Interest Rate		9%				
Plant Life Span		30	years			
Load Factor		0.8				
Interest during construction		181.7504	M$			
Annual capital Charge		147.9318	M$/y			
Capital Charges		4.4978	c/kWh			
O&M Costs						
O&M Factor		0.03		Other Materials Cost	20	$/tonne
				Residue Disposal Cost	20	$/tonne
Fixed O&M cost		1.2205	c/kWh			
Variable O&M cost		0.0000	c/kWh			
Estimated Operating Costs		**7.3896**	**c/kWh**			

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	1.548		73	42.9	**APPLICABILITY**	40.2
Raw Material Availability	Locally Common ▼ with unlimited availability ▼ for scale of this application	No risk 0	90	10		
Process Conditions Temperature Pressure NB Use least well known part of process	1200K-1600K ▼ <10bar ▼ needs tech breakthrough with known parallels ▼	Low risk 34	85	10	**CONFIDENCE IN WHETHER IT WILL WORK**	21.0
Novelty of Materials which is	Exotic Ceramic ▼ newly discovered material proven in similar duty ▼	High risk 63	20	10		
Plant Complexity No. of major units No. of major recycles	11 0		45	10		
Novelty of Process with	Major modifications ▼ promising ▼ industrial applications in operation ▼	No risk 13	60	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.003		42	40	**ESTIMATED COSTS**	35.0
Costs Total Operating c/kWh	7.39		12	100		
Safety Risk Control of these risks	Small Risk ▼ extensively demonstrated and publicly accepted ▼	No risk 5	80	20	**ACCEPTANCE**	32.0
Environmental Impact Management of these impacts	Benign Waste ▼ extensively demonstrated and publicly accepted ▼	No risk 5	80	20		

Averaged risk level	**20**			
Controlling risk level	**63**	**Materials**	**TOTALS**	128.1

Results of Analysis

Summary

Process: **SOFC v3.02 rerun based on 17-05-2004 flowsheet (10 streams)**

Heat Input		725.9	MW			
Estimated	Net Electricity Output	469.0	MW	NOTE GT efficiency calculated by program as …	35.0	%
	Net Efficiency	64.6	%	NOTE Steam cycle efficiency calculated as...	0.0	%
	CO2 output/ kg/s	0.4	kg/s	NOTE percentage of input energy to steam cycle ..	0.0	%
	CO2 output/kWh	0.003	kg/kWh			

Estimated Capital Cost	1338.1	M$
Estimated Op Cost	7.4	c/kWh

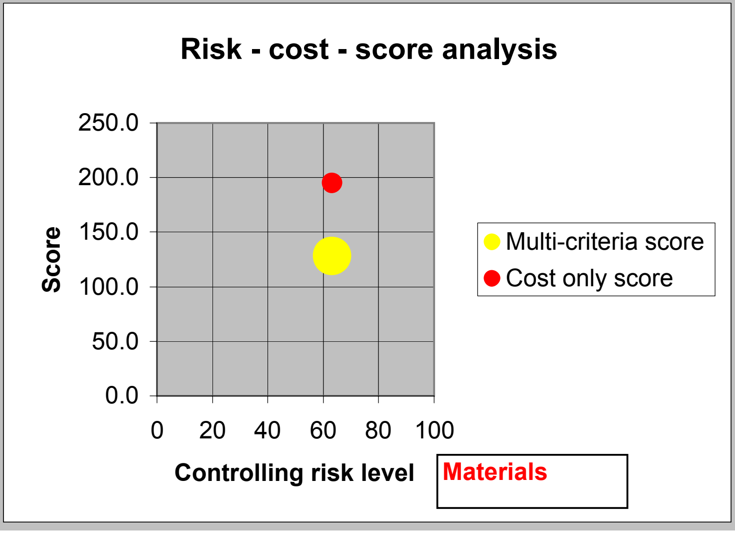
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		32.0
Applicability		40.2
Confidence		21.0
Estimated Cost		35.0
	Total	128.1
	Total cost only	195.1

Risk assessment

Averaged risk level		20
Controlling risk level	**Materials**	**63**



Comparison with Base Case CCGT

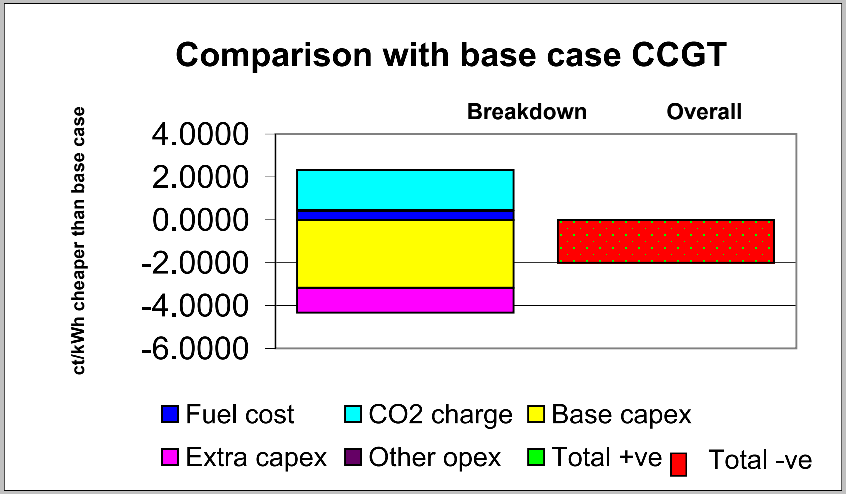
CO2 emission penalty	50	$/ton
CO2 emissions	0.003	kg/kWh
CO2 emission cost	0.016	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0572
Process conditions	85	0.0858
Novelty of materials	20	0.4575
Complexity	45	0.3145
Safety	80	0.1144
Environmental	80	0.1144
TOTAL		**1.1436**

Base Case data

Fuel cost	2.0966	c/kWh Based on	3	$/GJ
CO2 Tax	1.921	c/kWh Based on	50	$/tonne
Base Capex+Opex	2.5125	c/kWh		
Extra Capex	0	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates	
Fuel cost	1.671	2.097	0.4253	3.0000 $/GJ	
CO2 charge	0.016	1.921	1.9049	50 $/ton	
Base capex	5.718	2.5125	-3.2057		
Extra capex	1.144	0	-1.1436		
Other opex	0.000	0	0.0000		
				Total	-2.0192
TOTAL	8.5493	6.5301	-2.0192		
Extra fuel			-0.4253		
Extra capex			4.3494		
Total extra			3.9241		
CO2 tax benefit			1.9049		



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.577E-05	
Mix kgC/kJ	1.577E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.347	kg/kWh
Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3470	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT
Project Title SOFC v3.02 rerun based on 17-05-2004 flowsheet (10 st

Power Out	MWe	469
Efficiency	%	64.62
CO2 emitted	%	1
CO2 emitted	kg/kWh	0.003222
Fuel in	kg/s	15.47
Fuel in	MW	725.8524
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	41.56
Gas Cycle Efficiency	%	0.35
Steam Cycle Efficiency	%	0.00
Est Capital Cost	M$	1338.05
Est Operating Cost	ct/kWh	7.39
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	8.1
	Number	1
	Cost	8.22
Gas turbine, complete	MWe	18.584
	Number	10
	Cost	77.66
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	0
	Cost	0.00
Steam turbine+pipes+cooling syst	MWe	0

	Number	0
	Cost	0.00
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	795.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	469
	Number	1

	Cost	10.91
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		2
Press max		2
Process Conditions Qualifer		2
Construction Materials		5
Construction Materials Qualifier		3
No of Recycles		0
Novelty		3
Novelty Qualifer 1		2
Novelty Qualifer 2		1
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		20
Controlling Risk Level		63
Controlling Risk is		Materials
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		85
Process Conditions Extra Cost	ct/kWh	0
Novelty		20
Novelty Extra Cost	ct/kWh	0
Complexity		45
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	1.671309
CO2 Charge	$ct/kWh	0.01611
Base Capex	$ct/kWh	5.718248
Extra Capex	$ct/kWh	1.14365
Other Opex	$ct/kWh	0
Total	$ct/kWh	8.549316
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		46920
Mixture LCV		46920
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	8.1
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	92.92
ST power	MW	0
Percent of heat available to Steam	MW	0
Overall electrical efficiency after lo	MW	64.62
Efficiency GT Cycle	MW	35
Efficiency ST cycle	MW	0
Overall power output	MW	469
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for gas fired CO_2 capturing power plant utilizing circulating Dolomite CO_2 acceptor in pre-combustion de-carbonisation reforming process.

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☑	Gas Turbine	1	398.0	MWe
☑	Steam Turbine	1	166.0	MWe
☑	Combustor	1	21.4	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☑	Air Separation Unit	1	27.8	kg/s O2
	O2 compression Press.		27	bar
☑	HRSG	1	400.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☐	Other major plant item	0	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type
- ☐ Solid
- ☐ Liquid
- ☑ Gaseous

Combustor Type
- ○ PF
- ○ FBC
- ○ CFBC
- ● PFBC

Steam Cycle Type
- ● Sub Critical
- ○ SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

			Solid	Liquid	Gas
Fuel Mass Fractions			0	0	1
LCV	kJ/kg		25000	42000	48912
Carbon fraction	%mass		0.62	0.86	0.74
Ash Fraction	%mass		0.12	0	0
% in Feed			0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)		1			

Combined LCV	48912	kJ/kg
Combined Carbon fraction	0.74	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	**Flow kg/s**	**LCV kJ/kg**	**kg Carbon /kg**	**Carbon Balance kg/s**
Fuel	21.57	48912	0.74	15.9618
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	83.3%			
CO2 recovered	48.77	0	0.273	13.30097
CO2 emitted	9.76	0	0.273	2.660832

Gross available energy	48912	kJ/kg fuel
	1055032	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	99%	48422.88
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatior Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
Air/Fuel Ratio by Mass for Gas Turbine	56.8635	===> Air flow of	56.86	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	3.57	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	5.1	MW	Added into cell J45	Sheet CycleAnalysis
O2 compression power	13.6	MW	Added into cell J44	Sheet CycleAnalysis
HRSG on GT	400	MW	Transferred to B7	Sheet CycleAnalysis
GT power	398	MW	Transferred to D65	Sheet CycleAnalysis
ST power	166	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	25	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	47.7	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	35	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	35	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	503	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1055.03	MW

Losses

GT mech loss	1.99	MW
GT gen loss	5.97	MW
ST mech loss	0.83	MW
ST mech loss	2.49	MW
GT + ST transformer loss	2.26	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**13.54**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*	
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	26.41	MW	26.41	0		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	0.76	MW	0.76	0	107.90	MW ST rejection
Misc	1.51	MW	1.51	0	1.31	MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**28.68**	**MW**				

TOTAL Losses/Auxiliaries	**42.22**	**MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle

Value imported

				% of heat I/P to GT	**kJ/kg**	**MW**
To steam	400000	kJ/s from	HRSG before losses	3791.35	18544.3	400.000
GT loss	9989	kJ/s from	Stack	19.60	95.9	2.068
GT Efficiency				35.00		
Total				3845.95		

Gas cycle Output

Estimated GT Efficiency	0.35	**Value imported**			
Gross avail. energy to GT cycle	489.12	kJ/kg			
GT Output	**171.192**	**kJ/kg**	equiv to	3692.6114	kW

Steam Cycle Output

Estimated Steam Cycle Efficiency	0.35	**Value imported**			
Heat Balance					
From Combustion	48422.88	kJ/kg			
From Gasification	0	kJ/kg			
From GT HRSG etc after losses	18358.83	kJ/kg			
From Direct Generation	0	kJ/kg			
Export/Import	0	kJ/kg			
Heat available to steam cycle	66781.71	kJ/kg	equiv to	1440481.5	kW
ST Output	**23259.46**	**kJ/kg**	equiv to	501706.45	kW
Total Potential Output	23430.65	kJ/kg	equiv to	505399.06	kW

HRSG Heat available	18544.27	kJ/kg
HRSG heat loss	1.0%	
HRSG to Steam Cycle	18358.83	kJ/kg

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2527.0	18.5	2508.5
Generator Loss	1.50%	7581.0	55.4	7525.6
Transformer Loss	0.40%	2021.6	14.8	2006.8

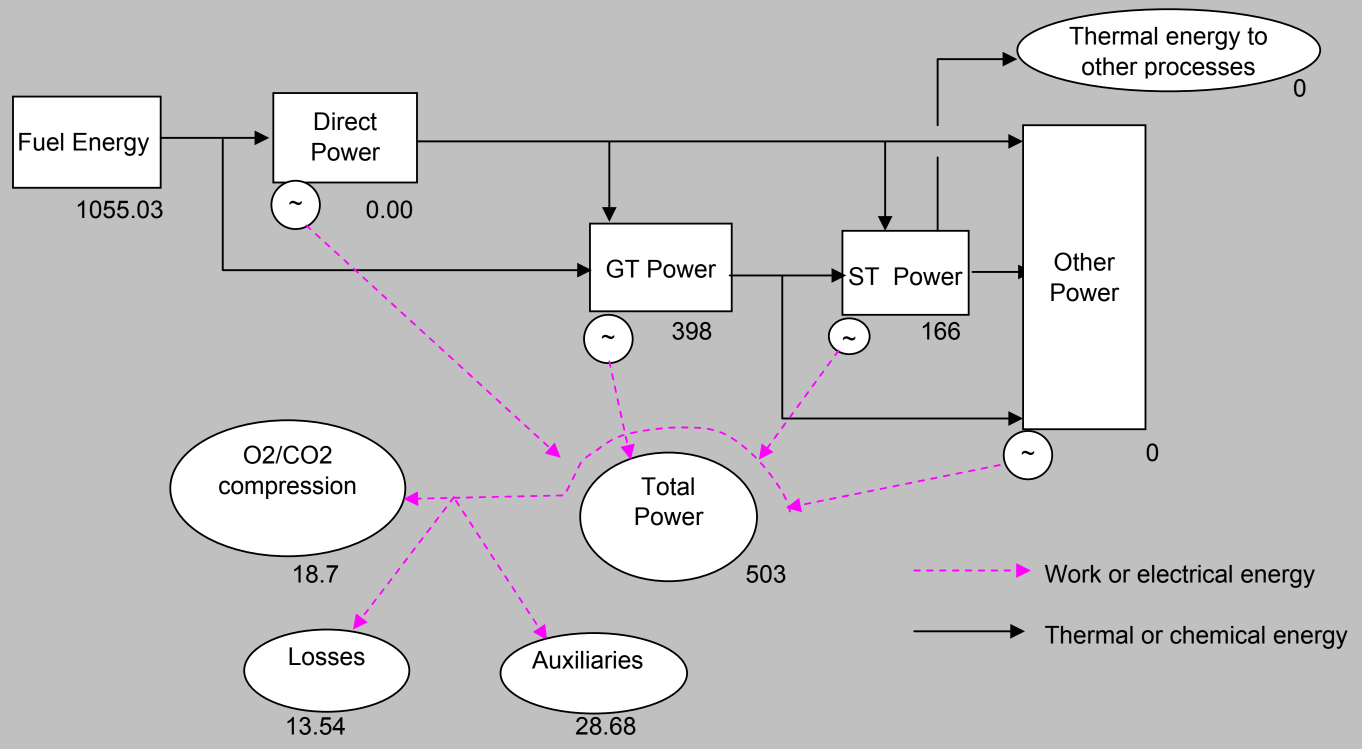
Gross Power Output	**22868.31**	**kJ/kg**	equiv to	493269.48	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg					0	0			
	Sorbent	50	kJ/kg					0	0			
	Ash	50	kJ/kg					0	0			
Fan and compressor mech eff.		93%										
Oxygen Production		950	kJ/kg O2					1	1224.386			
Oxygen Compression							**Value imported**		630.5053		0.7	Is good nur
CO2 Compression								1	236.4395	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel					0	0			
FGD		8	kJ/MJ fuel					0	0			
Cooling water system		7	kJ/MJ rejected					1	305.6645		Steam Cycle Condense	
Misc		0.30%	of gross						68.60494			
H2S Sepn									0			
CO2 Sepn									0			
Other									0			
Total Auxiliaries									2465.6	kJ/kg		
Total Input		48912	kJ/kg									
Total Output (Net)		20402.71	kJ/kg	=>	503000	kW	**Value imported**					
Efficiency		47.7	%	**Value imported**							-61	
											2.64272	
GT Output (Generator Terminals)		398.00	MW	**Value imported**							-58.35728	
ST Output (Generator Terminals)		166.00	MW	**Value imported**								
Direct O/P (Gross)		0	MW									
% heat available to steam cycle		25	%	**Value imported**								

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		27.8	1	1	66.63
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		5.1	1	1	5.18
Gas turbine, complete	MWe	0	398	1	1.3	84.52
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		400	1	1	31.96
Steam turbine+pipes+cooling system	MWe		166	1	1	58.11
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	1	0.00
PFBC combustor	MW fuel feed		1044.482	1	1.5	193.35
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Gas filters	Say		0	0		30.00
Catalyst loading/unloading	Say		0	0		10.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		503	1	1	11.54
Sub-Total						**491.28**
Balance of plant	% of above		10			49.13
Engineering, indirects, owners cost	% of above		24			129.70
Project contingency	% of above		10			67.01
TOTAL						**737.12**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ			
	Liquid	3	$/GJ			
	Gaseous	3	$/GJ			
Calculated Fuel Cost		3.0000	$/GJ			
Fuel cost of electricity		2.2642	c/kWh			
Capital Charges						
Interest Rate		9%				
Plant Life Span		30	years			
Load Factor		0.8				
Interest during construction		100.1251	M$			
Annual capital Charge		81.4947	M$/y			
Capital Charges		2.3103	c/kWh			
O&M Costs						
O&M Factor		0.03		Other Materials Cost	20	$/tonne
				Residue Disposal Cost	20	$/tonne
Fixed O&M cost		0.6269	c/kWh			
Variable O&M cost		0.0000	c/kWh			
Estimated Operating Costs		**5.2014**	**c/kWh**			

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	Value	Risk assessment & Score%	Score %	Weighting	DECISION FACTOR	Weighted Score
Fuel Consumption kJ/kW	2.096	No risk	45	42.9	**APPLICABILITY**	28.4
Raw Material Availability	Locally Common with unlimited availability for scale of this application	0	90	10		
Process Conditions Temperature Pressure NB Use least well known part of process	1200K-1600K 10-60 bar but no significant technical barriers	No risk 11	80	10	**CONFIDENCE IN WHETHER IT WILL WORK**	30.0
Novelty of Materials which is	Existing Special Alloys known material in known environment	No risk 6	90	10		
Plant Complexity No. of major units No. of major recycles	6 0		70	10		
Raw score = 100 **Novelty of Process** with	*Caution - Very high risk of failure* Major modifications problematical credited scientific proof of concept	Unacceptable risk 100	60	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.070		32	40	**ESTIMATED COSTS**	74.8
Costs Total Operating c/kWh	5.2		56	100		
Safety Risk Control of these risks	Small Risk extensively demonstrated and publicly accepted	No risk 5	80	20	**ACCEPTANCE**	32.0
Environmental Impact Management of these impacts	Benign Waste extensively demonstrated and publicly accepted	No risk 5	80	20		

Averaged risk level	**21**		**TOTALS**	165.2
Controlling risk level	**100**	**Process novelty**		

Results of Analysis

Summary

Process: **CaO (+MgO) Acceptor - Subcritical**

Heat Input		1055.0	MW
Estimated	Net Electricity Output	503.0	MW
	Net Efficiency	47.7	%
	CO2 output/ kg/s	9.8	kg/s
	CO2 output/kWh	0.070	kg/kWh
Estimated Capital Cost		737.1	M$
Estimated Op Cost		5.2	c/kWh

NOTE GT efficiency calculated by program as …	35.0	%
NOTE Steam cycle efficiency calculated as...	35.0	%
NOTE percentage of input energy to steam cycle ..	25.0	%

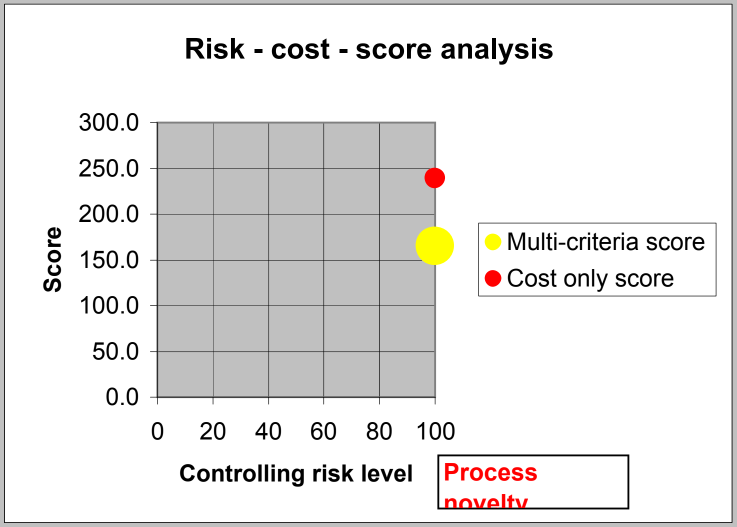
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		32.0
Applicability		28.4
Confidence		30.0
Estimated Cost		74.8
	Total	165.2
	Total cost only	238.9

Risk assessment

Averaged risk level		21
Controlling risk level	**Process novelty**	**100**



Comparison with Base Case CCGT

CO2 emission penalty 50 $/ton

CO2 emissions 0.070 kg/kWh

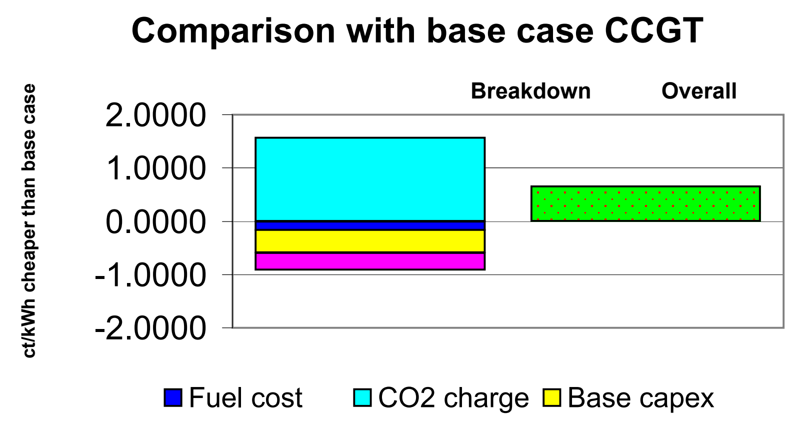
CO2 emission cost 0.349 c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0294
Process conditions	80	0.0587
Novelty of materials	90	0.0294
Complexity	70	0.0881
Safety	80	0.0587
Environmental	80	0.0587
TOTAL		**0.3231**

Base Case data

Fuel cost	2.0966	c/kWh Based on	3	$/GJ
CO2 Tax	1.921	c/kWh Based on	50	$/tonne
Base Capex+Opex	2.5125	c/kWh		
Extra Capex	0	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates	
Fuel cost	2.264	2.097	-0.1676	3.0000	$/GJ
CO2 charge	0.349	1.921	1.5719	50	$/ton
Base capex	2.937	2.5125	-0.4247		
Extra capex	0.323	0	-0.3231		
Other opex	0.000	0	0.0000		
				Total	0.6565
TOTAL	5.8736	6.5301	0.6565		
Extra fuel			0.1676		
Extra capex			0.7478		
Total extra			0.9154		
CO2 tax benefit			1.5719		



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.513E-05	
Mix kgC/kJ	1.513E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.333	kg/kWh
Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3328	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT

Project Title		CaO (+MgO) Acceptor - Subcritical
Power Out	MWe	503
Efficiency	%	47.7
CO2 emitted	%	16.67
CO2 emitted	kg/kWh	0.069827
Fuel in	kg/s	21.57
Fuel in	MW	1055.032
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	48.77
Gas Cycle Efficiency	%	0.35
Steam Cycle Efficiency	%	0.35
Est Capital Cost	M$	737.12
Est Operating Cost	ct/kWh	5.20
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	27.8
	Number	1
	Cost	66.63
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	5.1
	Number	1
	Cost	5.18
Gas turbine, complete	MWe	517.4
	Number	1
	Cost	84.52
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	400
	Number	1
	Cost	31.96
Steam turbine+pipes+cooling syst	MWe	166

	Number	1
	Cost	58.11
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	1566.722
	Number	1
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	30.00
Other	User Defined	0
	Number	0
	Cost	10.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	503
	Number	1

	Cost	11.54
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		2
Press max		3
Process Conditions Qualifer		1
Construction Materials		3
Construction Materials Qualifier		1
No of Recycles		0
Novelty		3
Novelty Qualifer 1		3
Novelty Qualifer 2		7
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		2
Environmental Impact Qualifier		1
Average Risk Level		21
Controlling Risk Level		100
Controlling Risk is		Process novelty
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		80
Process Conditions Extra Cost	ct/kWh	0
Novelty		90
Novelty Extra Cost	ct/kWh	0
Complexity		70
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		80
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.264151
CO2 Charge	$ct/kWh	0.349135
Base Capex	$ct/kWh	2.937212
Extra Capex	$ct/kWh	0.323093
Other Opex	$ct/kWh	0
Total	$ct/kWh	5.873592
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		48912
Mixture LCV		48912
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	5.1
O2 compression power	MW	13.6
HRSG on GT	MW	400
GT power	MW	398
ST power	MW	166
Percent of heat available to Steam	MW	25
Overall electrical efficiency after lo	MW	47.7
Efficiency GT Cycle	MW	35
Efficiency ST cycle	MW	35
Overall power output	MW	503
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for gas fired CO_2 capturing power plant utilizing chemical looping process with recirculating barium oxides

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☐	Gas Turbine	0	0.0	MWe
☑	Steam Turbine	1	519.0	MWe
☑	Combustor	2	10.9	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O_2
	O_2 compression Press.		1.22	bar
☑	HRSG	1	0.0	MW
☐	FGD	0		
☐	H_2S Removal	0	0	ton/day
	Aux Power Reqd		10000	kJ/Unit size
☑	Other major plant item	1	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO_2 Separation	0	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO_2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☐ Solid

☐ Liquid

☑ Gaseous

Steam Cycle Type

○ Sub Critical

● SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

		Solid	Liquid	Gas
Fuel Mass Fractions		0	0	1
LCV	kJ/kg	25000	42000	50013
Carbon fraction	%mass	0.62	0.86	0.75
Ash Fraction	%mass	0.12	0	0
% in Feed		0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)	1			

Combined LCV	50013	kJ/kg
Combined Carbon fraction	0.75	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	**Flow kg/s**	**LCV kJ/kg**	**kg Carbon /kg**	**Carbon Balance kg/s**
Fuel	21.88	50013	0.75	16.41
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	100.0%			
CO2 recovered	60.17	0	0.273	16.41
CO2 emitted	0.00	0	0.273	0

Gross available energy	50013	kJ/kg fuel
	1094284	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	100%	50013
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatior Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
	40.3	===> Air flow of	40.30	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	2.53	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	19	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	0	MW	Transferred to D65	Sheet CycleAnalysis
ST power	519	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	0	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	44.3	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	0	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	46.3	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	484	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1094.28	MW

Losses

GT mech loss	0.00	MW
GT gen loss	0.00	MW
ST mech loss	2.60	MW
ST mech loss	7.79	MW
GT + ST transformer loss	2.08	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**12.46**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*	
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	0	MW	0	0		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	2.08	MW	2.08	0	278.70	MW ST rejection
Misc	1.45	MW	1.45	0	18.82	MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**3.53**	**MW**				

TOTAL Losses/Auxiliaries **15.99** **MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**			
	Value imported			**I/P to GT**	**kJ/kg**	**MW**	
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	--|
GT loss	0	kJ/s from	Stack	0.00	0.0	0.000	|
GT Efficiency				0.00			|
Total				0.00			|

Gas cycle Output						
Estimated GT Efficiency	0	**Value imported**				|
Gross avail. energy to GT cycle	1E-07	kJ/kg				|
GT Output	**0**	**kJ/kg**	equiv to	0	kW	|
						V

Steam Cycle Output								
Estimated Steam Cycle Efficiency	0.463	**Value imported**						
Heat Balance						HRSG Heat available	0	kJ/kg
From Combustion	50013	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	0	kJ/kg
From GT HRSG etc after losses	0	kJ/kg	<--|					
From Direct Generation	0	kJ/kg						
Export/Import	0	kJ/kg						
Heat available to steam cycle	50013	kJ/kg	equiv to	1094284	kW			
ST Output	**23070.54**	**kJ/kg**	equiv to	504783.3	kW			
Total Potential Output	23070.54	kJ/kg	equiv to	504783.3	kW			

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	2523.9	0.0	2523.9
Generator Loss	1.50%	7571.8	0.0	7571.8
Transformer Loss	0.40%	2019.1	0.0	2019.1

Gross Power Output	**22516.84**	**kJ/kg**	equiv to	492668.5	kW

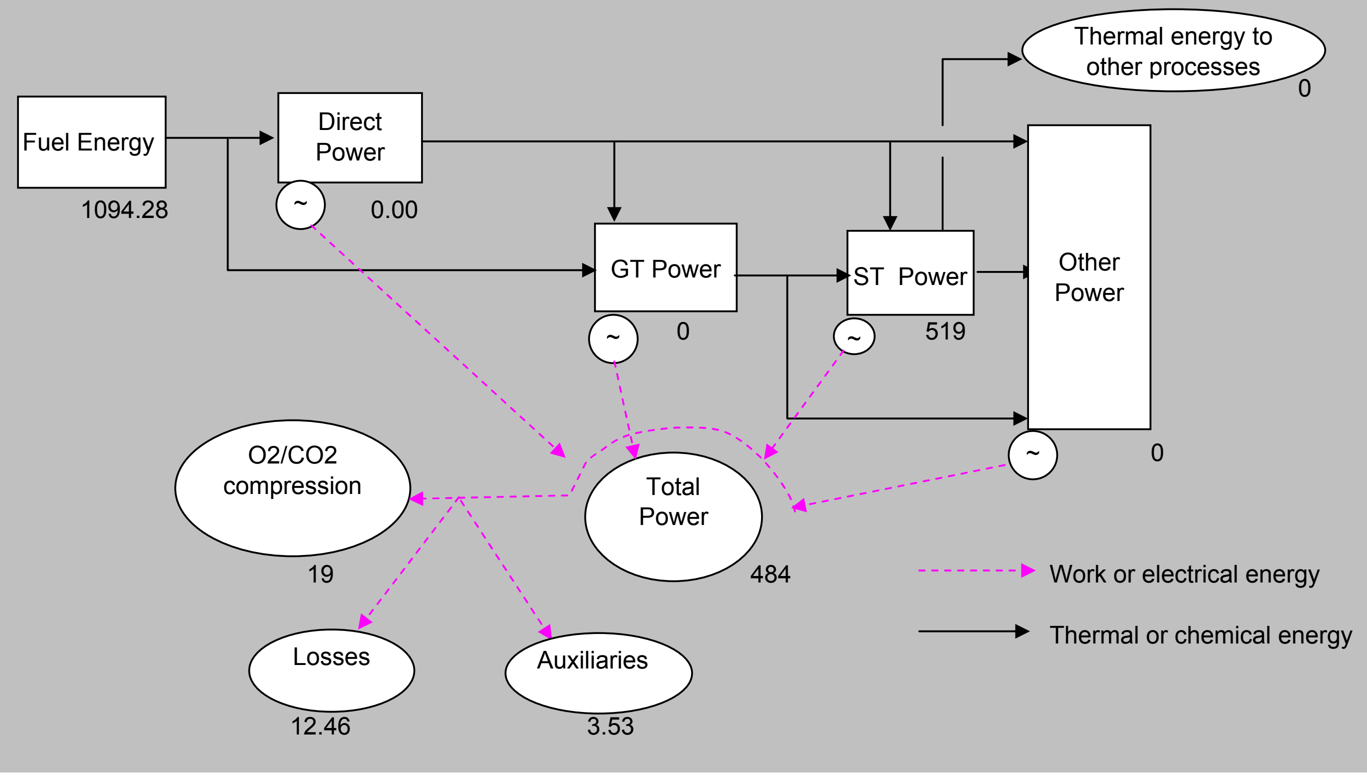
Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg		0	0		
	Sorbent	50	kJ/kg		0	0		
	Ash	50	kJ/kg		0	0		
Fan and compressor mech eff.		93%						
Oxygen Production		950	kJ/kg O2		0	0		
Oxygen Compression				**Value imported**		868.3729		0.7 Is good number for gasifiers kg O2
CO2 Compression					1	0	**Value imported**	O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel		0	0		
FGD		8	kJ/MJ fuel		0	0		

Cooling water system	7	kJ/MJ rejected				1	189.8322		Steam Cycle Condenser + Allow 0.5MJ/kg CC
Misc	0.30%	of gross					67.55053		
H2S Sepn							0		
CO2 Sepn							0		
Other							0		
Total Auxiliaries							1125.756	kJ/kg	
Total Input	50013	kJ/kg							
Total Output (Net)	21391.09	kJ/kg	=>	484000	kW	**Value imported**			
Efficiency	44.3	%	**Value imported**						-35
									0
GT Output (Generator Terminals)	0.00	MW	**Value imported**						-35
ST Output (Generator Terminals)	519.00	MW	**Value imported**						
Direct O/P (Gross)	0	MW							
% heat available to steam cycle	0	%	**Value imported**						

SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW



Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	1	1	0.00
Gas turbine, complete	MWe	0	0	0	1	0.00
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	1	1	0.00
Steam turbine+pipes+cooling system	MWe		519	1	1.1	150.29
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		8	2	2	33.07
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	2	0.477	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		484	1	1	11.19
Sub-Total						**194.55**
Balance of plant	% of above		10			19.45
Engineering, indirects, owners cost	% of above		24			51.36
Project contingency	% of above		10			26.54
TOTAL						**291.90**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ
	Liquid	3	$/GJ
	Gaseous	3	$/GJ

Calculated Fuel Cost	3.0000	$/GJ
Fuel cost of electricity	2.4379	c/kWh

Capital Charges

Interest Rate	10%	
Plant Life Span	25	years
Load Factor	0.9	
Interest during construction	44.2495	M$
Annual capital Charge	37.0328	M$/y
Capital Charges	0.9698	c/kWh

O&M Costs

O&M Factor	0.04		Other Materials Cost	20	$/tonne
			Residue Disposal Cost	20	$/tonne
Fixed O&M cost	0.3058	c/kWh			
Variable O&M cost	0.0000	c/kWh			

Estimated Operating Costs	**3.7135**	**c/kWh**

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	2.257	Low risk	37	42.9	**APPLICABILITY**	24.9
Raw Material Availability	Locally Common with some limits to availability for scale of this application	25	90	10		
Process Conditions		No risk				
Temperature	<1200K	0	100	10		
Pressure	Atmospheric					
NB Use least well known part of process	but no significant technical barriers					
Novelty of Materials	Carbon Steel	No risk 0	100	10	**CONFIDENCE IN WHETHER IT WILL WORK**	32.5
which is	known material in known environment					
Plant Complexity						
No. of major units	7		65	10		
No. of major recycles	0					
Raw score = 125	*Caution - Very high risk of failure*					
Novelty of Process	Major modifications	Unacceptable risk	60	10		
with	no	100				
	industrial applications in operation					
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.000		40	40	**ESTIMATED COSTS**	107.9
Costs Total Operating c/kWh	3.71		86	100		
Safety Risk	Major In Plant Risk	Unacceptable risk 95	30	20	**ACCEPTANCE**	16.0
Control of these risks	NOT demonstrated, high degree of public concern existing or likely					
Environmental Impact	Mildly harmful waste	High risk 70	50	20		
Management of these impacts	NOT demonstrated, high degree of public concern existing or likely					

Averaged risk level	**48**		**TOTALS** 181.3
Controlling risk level	**100**	**Process novelty**	

Results of Analysis

Summary

Process: **BaO/BaO2 (rerun)**

Heat Input		1094.3	MW			
Estimated	Net Electricity Output	484.0	MW	NOTE GT efficiency calculated by program as …	0.0	%
	Net Efficiency	44.3	%	NOTE Steam cycle efficiency calculated as...	46.3	%
	CO2 output/ kg/s	0.0	kg/s	NOTE percentage of input energy to steam cycle ..	0.0	%
	CO2 output/kWh	0.000	kg/kWh			
Estimated Capital Cost		291.9	M$			
Estimated Op Cost		3.7	c/kWh			

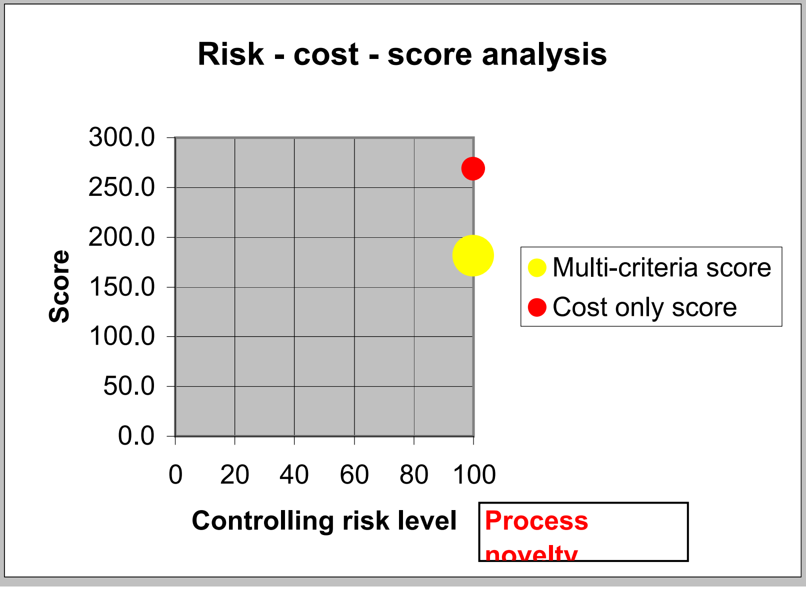
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		16.0
Applicability		24.9
Confidence		32.5
Estimated Cost		107.9
	Total	181.3
	Total cost only	268.7

Risk assessment

Averaged risk level		48
Controlling risk level	**Process novelty**	**100**



Comparison with Base Case CCGT

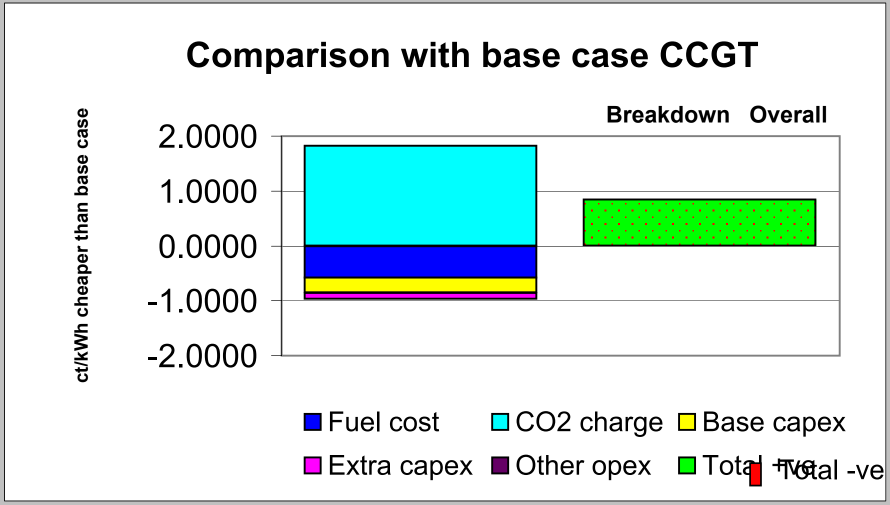
CO2 emission penalty	50	$/ton
CO2 emissions	0.000	kg/kWh
CO2 emission cost	0.000	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0128
Process conditions	100	0.0000
Novelty of materials	100	0.0000
Complexity	65	0.0446
Safety	30	0.0893
Environmental	50	0.0638
TOTAL		**0.2105**

Base Case data

Fuel cost	1.865	c/kWh Based on	3	$/GJ
CO2 Tax	1.824	c/kWh Based on	50	$/tonne
Base Capex+Opex	0.989	c/kWh		
Extra Capex	0.094	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates		
Fuel cost	2.438	1.865	-0.5726	3.0000	$/GJ	
CO2 charge	0.000	1.824	1.8236	50	$/ton	
Base capex	1.276	0.989	-0.2862			
Extra capex	0.210	0.094	-0.1165			
Other opex	0.000	0	0.0000			
				Total		0.8483
TOTAL	3.9240	4.7724	0.8483			
Extra fuel			0.5726			
Extra capex			0.4026			
Total extra			0.9753			
CO2 tax benefit			1.8236			



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.5E-05	
Mix kgC/kJ	1.5E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.330	kg/kWh

Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3299	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)

DO NOT EDIT

Project Title		BaO/BaO2 (rerun)
Power Out	MWe	484
Efficiency	%	44.3
CO2 emitted	%	0
CO2 emitted	kg/kWh	0
Fuel in	kg/s	21.88
Fuel in	MW	1094.284
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	60.17
Gas Cycle Efficiency	%	0.00
Steam Cycle Efficiency	%	0.46
Est Capital Cost	M$	291.90
Est Operating Cost	ct/kWh	3.71
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	1
	Cost	0.00
Gas turbine, complete	MWe	0
	Number	0
	Cost	0.00
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	1
	Cost	0.00
Steam turbine+pipes+cooling syst	MWe	570.9

	Number	1
	Cost	150.29
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	16
	Number	2
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	2
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	484
	Number	1

	Cost	11.19
Multi Criteria		
Feed Material		2
Feed Material Qualifier		2
Temp max		1
Press max		1
Process Conditions Qualifer		1
Construction Materials		1
Construction Materials Qualifier		1
No of Recycles		0
Novelty		3
Novelty Qualifer 1		5
Novelty Qualifer 2		1
Safety Risk		4
Safety Risk Qualifer		3
Environmental Impact		3
Environmental Impact Qualifier		3
Average Risk Level		48
Controlling Risk Level		100
Controlling Risk is		Process novelty
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		100
Process Conditions Extra Cost	ct/kWh	0
Novelty		100
Novelty Extra Cost	ct/kWh	0
Complexity		65
Complexity Extra Cost	ct/kWh	0
Safety		30
Safety Extra Cost	ct/kWh	0
Environmental		50
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.437923
CO2 Charge	$ct/kWh	0
Base Capex	$ct/kWh	1.275608
Extra Capex	$ct/kWh	0.210475
Other Opex	$ct/kWh	0
Total	$ct/kWh	3.924007
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		50013
Mixture LCV		50013
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	19
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	0
ST power	MW	519
Percent of heat available to Steam	MW	0
Overall electrical efficiency after lo	MW	44.3
Efficiency GT Cycle	MW	0
Efficiency ST cycle	MW	46.3
Overall power output	MW	484
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for gas fired CO_2 capturing power plant utilizing chemical looping process with recirculating copper oxide

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☐	Gas Turbine	0	0.0	MWe
☑	Steam Turbine	1	561.0	MWe
☑	Combustor	2	11.1	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☐	HRSG	0	0.0	MW
☐	FGD	0		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☑	Other major plant item	1	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Separation	0	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Compression	1		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☐ Solid
☐ Liquid
☑ Gaseous

Combustor Type

○ PF
● FBC
○ CFBC
○ PFBC

Steam Cycle Type

○ Sub Critical
● SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

			Solid	Liquid	Gas
Fuel Mass Fractions			0	0	1
LCV	kJ/kg		25000	42000	50046
Carbon fraction	%mass		0.62	0.86	0.75
Ash Fraction	%mass		0.12	0	0
% in Feed			0.00%	0.00%	100.00%
Fuel Fractions Sum (must = 1)		1			

Combined LCV	50046	kJ/kg
Combined Carbon fraction	0.75	
Combined Ash Fraction	0	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	22.11	50046	0.75	16.5825
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	100.0%			
CO2 recovered	60.80	0	0.273	16.5825
CO2 emitted	0.00	0	0.273	0

Gross available energy 50046 kJ/kg fuel
1106517 kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	100%	50046
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatio Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
	56.8635	===> Air flow of	56.86	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	3.57	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	36.5	MW	Added into cell J44	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J45	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	0	MW	Transferred to D65	Sheet CycleAnalysis
ST power	561	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	0	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	45.73	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle	0	%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	0	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	506	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1106.52	MW

Losses

GT mech loss	0.00	MW
GT gen loss	0.00	MW
ST mech loss	2.81	MW
ST mech loss	8.42	MW
GT + ST transformer loss	2.24	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**13.46**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

			PPAP	External	*hidden calc*	
Solids handling:						
Fuel	0	MW	0	0		
Sorbant	0	MW	0.00	0		
Residue	0	MW	0.00	0		
Oxygen Production	0	MW	0	0		
Combustor fans (PF)	0.00	MW	0.00	0		
FGD	0.00	MW	0.00	0		
Cooling water system	3.94	MW	3.94	0	561.00	MW ST rejection
Misc	1.52	MW	1.52	0	2.56	MW compression losses
H2S Sepn	0	MW	0	0		
CO2 Sepn	0	MW	0	0		
Other	0	MW	0	0		
Subtotal	**5.46**	**MW**				

TOTAL Losses/Auxiliaries	**18.93**	**MW**

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat I/P to GT**	**kJ/kg**	**MW**	
	Value imported						
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000	---|
GT loss	0	kJ/s from	Stack	0.00	0.0	0.000	|
GT Efficiency				0.00			|
Total				0.00			|

Gas cycle Output						
Estimated GT Efficiency	0	**Value imported**				|
Gross avail. energy to GT cycle	1E-07	kJ/kg				|
GT Output	**0**	**kJ/kg**	equiv to	0	kW	|

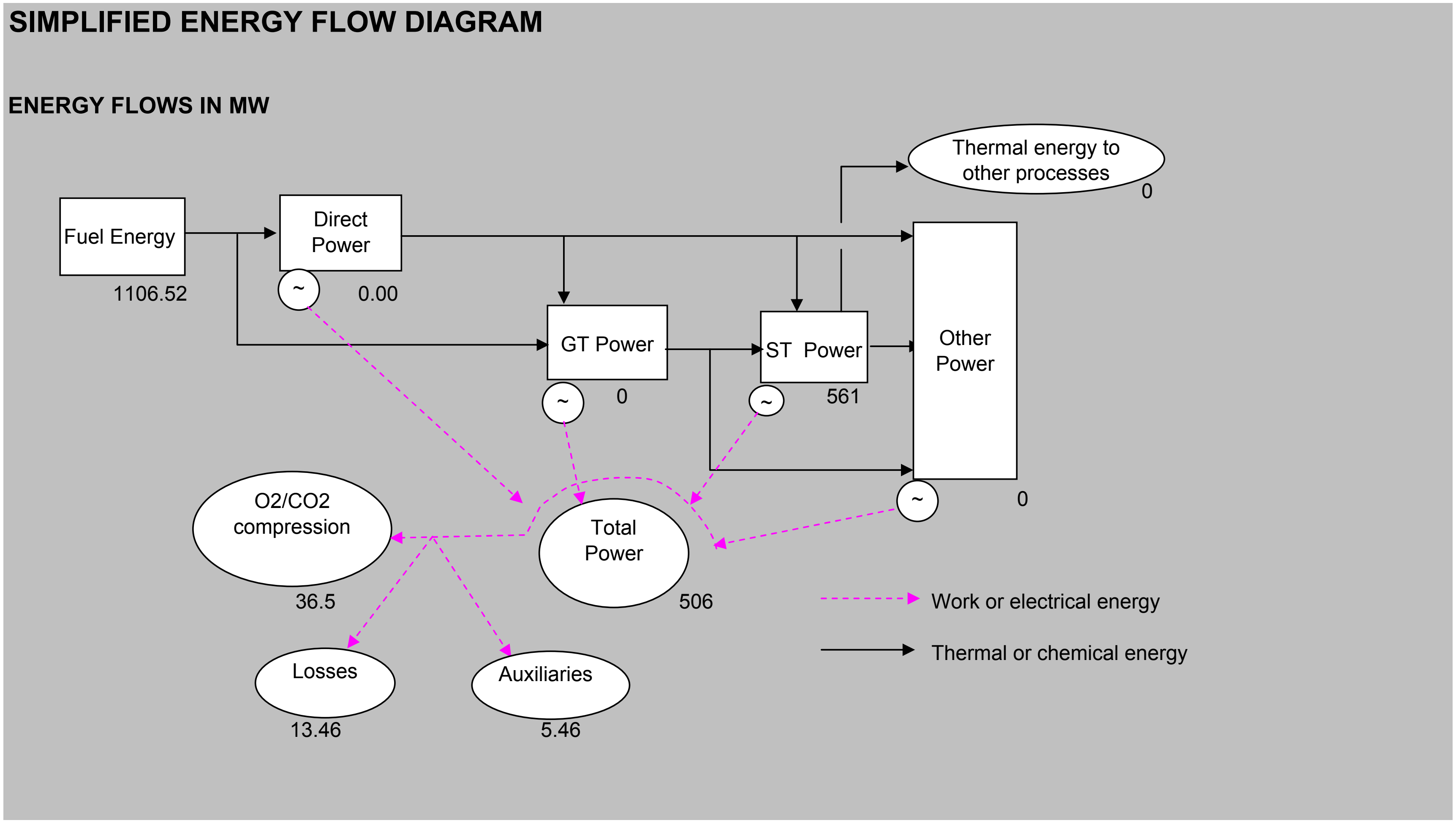
Steam Cycle Output							V	
Estimated Steam Cycle Efficiency	0	**Value imported**						
Heat Balance						HRSG Heat available	0	kJ/kg
From Combustion	50046	kJ/kg				HRSG heat loss	1.0%	
From Gasification	0	kJ/kg				HRSG to Steam Cycle	0	kJ/kg
From GT HRSG etc after losses	0	kJ/kg	<---|					
From Direct Generation	0	kJ/kg						
Export/Import	0	kJ/kg						
Heat available to steam cycle	50046	kJ/kg	equiv to	1106517	kW			
ST Output	**-85.53907**	**kJ/kg**	equiv to	-1891.269	kW			
Total Potential Output	-85.53907	kJ/kg	equiv to	-1891.269	kW			

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	-9.5	0.0	-9.5
Generator Loss	1.50%	-28.4	0.0	-28.4
Transformer Loss	0.40%	-7.6	0.0	-7.6

Gross Power Output	**-83.48613**	**kJ/kg**	equiv to	-1845.878	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg					0	0			
	Sorbent	50	kJ/kg					0	0			
	Ash	50	kJ/kg					0	0			
Fan and compressor mech eff.		93%										
Oxygen Production		950	kJ/kg O2					0	0			
Oxygen Compression							**Value imported**		1650.837		0.7	Is good nur
CO2 Compression								1	0	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel					0	0			
FGD		8	kJ/MJ fuel					0	0			
Cooling water system		7	kJ/MJ rejected					1	352.1553	Steam Cycle Condens		
Misc		0.30%	of gross						-0.250458			
H2S Sepn									0			
CO2 Sepn									0			
Other									0			
Total Auxiliaries									2002.742	kJ/kg		
Total Input		50046	kJ/kg									
Total Output (Net)		-2086.228	kJ/kg	=>	506000	kW	**Value imported**					
Efficiency		45.73	%	**Value imported**							-55	
											0	
GT Output (Generator Terminals)		0.00	MW	**Value imported**							-55	
ST Output (Generator Terminals)		561.00	MW	**Value imported**								
Direct O/P (Gross)		0	MW									
% heat available to steam cycle		0	%	**Value imported**								



SIMPLIFIED ENERGY FLOW DIAGRAM

ENERGY FLOWS IN MW

Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		0	0	1	0.00
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	1	1	0.00
Gas turbine, complete	MWe	0	0	0	1	0.00
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		561	1	1.1	159.33
PF coal boiler	MW fuel feed LHV		0	0	1	0.00
FGD (limestone gypsum)	kmol/s feed		0	0	1	0.00
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		8	2	2	33.07
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	2	0.477	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
CO2 compressor (motor driven)	User Defined		23	1		20.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Electrical distribution	MWe gross		506	1	1	11.59
Sub-Total						**223.98**
Balance of plant	% of above		10			22.40
Engineering, indirects, owners cost	% of above		24			59.13
Project contingency	% of above		10			30.55
TOTAL						**336.07**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ			
	Liquid	3	$/GJ			
	Gaseous	3	$/GJ			
Calculated Fuel Cost		3.0000	$/GJ			
Fuel cost of electricity		2.3617	c/kWh			
Capital Charges						
Interest Rate		10%				
Plant Life Span		25	years			
Load Factor		0.9				
Interest during construction		50.9451	M$			
Annual capital Charge		42.6363	M$/y			
Capital Charges		1.0680	c/kWh			
O&M Costs						
O&M Factor		0.04		Other Materials Cost	20	$/tonne
				Residue Disposal Cost	20	$/tonne
Fixed O&M cost		0.3367	c/kWh			
Variable O&M cost		0.0000	c/kWh			
Estimated Operating Costs		**3.7665**	**c/kWh**			

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user
to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its
overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	**Value**	**Risk assessment & Score%**	**Score %**	**Weighting**	**DECISION FACTOR**	**Weighted Score**
Fuel Consumption kJ/kW	2.187		41	42.9		
		Low risk			**APPLICABILITY**	26.4
Raw Material Availability	Locally Common	25	90	10		
	with some limits to availability					
	for scale of this application					
Process Conditions		No risk				
Temperature	<1200K	3	95	10		
Pressure	<10bar					
NB Use least well known part of process	but no significant technical barriers					
Novelty of Materials		No risk			**CONFIDENCE IN WHETHER IT**	
	Carbon Steel	0	100	10		32.5
which is	known material in known environment				**WILL WORK**	
Plant Complexity						
No. of major units	6		70	10		
No. of major recycles	0					
Raw score = 125	*Caution - Very high risk of failure*					
Novelty of Process	Major modifications	Unacceptable risk	60	10		
with	no	100				
	industrial applications in operation					
Greenhouse Gas Emissions						
CO2 emission in kg/Kwh	0.000		40	40	**ESTIMATED COSTS**	106.7
Costs						
Total Operating c/kWh	3.77		85	100		
Safety Risk		Medium risk				
	Risk	40	60	20		
Control of these risks	demonstrated but concerns emerging in public domain				**ACCEPTANCE**	22.0
Environmental Impact		High risk				
	Mildly harmful waste	70	50	20		
Management of these impacts	NOT demonstrated, high degree of public concern existing or likely					

Averaged risk level	**40**		
Controlling risk level	**100**	**Process novelty**	
		TOTALS	187.6

Results of Analysis

Summary

Process: **Cu - CuO scheme preliminary based on Hysys fs 2A**

Heat Input		1106.5	MW			
Estimated	Net Electricity Output	506.0	MW	NOTE GT efficiency calculated by program as …	0.0	%
	Net Efficiency	45.7	%	NOTE Steam cycle efficiency calculated as...	0.0	%
	CO2 output/ kg/s	0.0	kg/s	NOTE percentage of input energy to steam cycle ..	0.0	%
	CO2 output/kWh	0.000	kg/kWh			
Estimated Capital Cost		336.1	M$			
Estimated Op Cost		3.8	c/kWh			

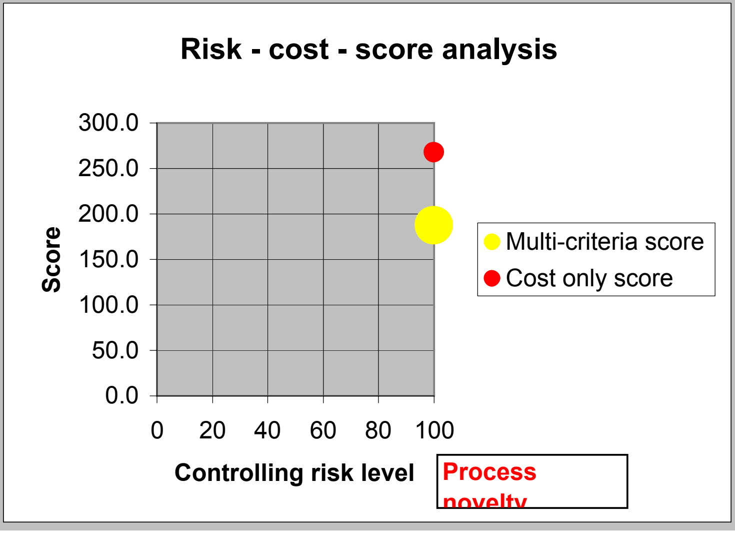
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		22.0
Applicability		26.4
Confidence		32.5
Estimated Cost		106.7
	Total	187.6
	Total cost only	267.5

Risk assessment

Averaged risk level		40
Controlling risk level	**Process novelty**	**100**



Comparison with Base Case CCGT

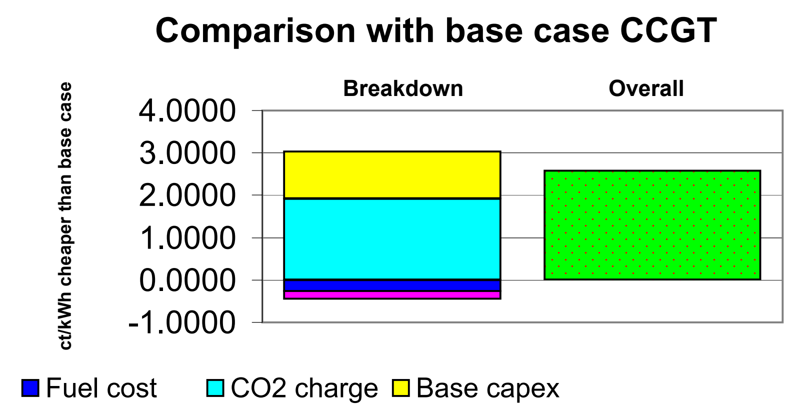
CO2 emission penalty	50	$/ton
CO2 emissions	0.000	kg/kWh
CO2 emission cost	0.000	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0140
Process conditions	95	0.0070
Novelty of materials	100	0.0000
Complexity	70	0.0421
Safety	60	0.0562
Environmental	50	0.0702
TOTAL		**0.1896**

Base Case data

Fuel cost	2.0966	c/kWh Based on	3	$/GJ
CO2 Tax	1.921	c/kWh Based on	50	$/tonne
Base Capex+Opex	2.5125	c/kWh		
Extra Capex	0	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates	
Fuel cost	2.362	2.097	-0.2651	3.0000 $/GJ	
CO2 charge	0.000	1.921	1.9210	50 $/ton	
Base capex	1.405	2.5125	1.1077		
Extra capex	0.190	0	-0.1896		
Other opex	0.000	0	0.0000		
				Total	2.5740
TOTAL	3.9561	6.5301	2.5740		
Extra fuel			0.2651		
Extra capex			-0.9181		
Total extra			-0.6530		
CO2 tax benefit			1.9210		



WEIGHTINGS ANALYSIS

CO2 emission calc		
Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.499E-05	
Mix kgC/kJ	1.499E-05	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.330	kg/kWh
Calorific fraction of gas	1	
Calorific fraction of oil	0	
CO2 allowance	0.3297	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)
DO NOT EDIT

Project Title		Cu - CuO scheme preliminary based on Hysys fs 2A
Power Out	MWe	506
Efficiency	%	45.73
CO2 emitted	%	0
CO2 emitted	kg/kWh	0
Fuel in	kg/s	22.11
Fuel in	MW	1106.517
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	60.80
Gas Cycle Efficiency	%	0.00
Steam Cycle Efficiency	%	0.00
Est Capital Cost	M$	336.07
Est Operating Cost	ct/kWh	3.77
Capital Cost Items		
Solids handling	'Size'	0
	Number	0
	Cost	0.00
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	1
	Cost	0.00
Gas turbine, complete	MWe	0
	Number	0
	Cost	0.00
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	0
	Cost	0.00
Steam turbine+pipes+cooling syste	MWe	617.1

	Number	1
	Cost	159.33
PF coal boiler	MW fuel feed LHV	0
	Number	0
	Cost	
FGD (limestone gypsum)	kmol/s feed	0
	Number	0
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	16
	Number	2
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	2
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	1
	Cost	20.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Electrical distribution	MWe gross	506
	Number	1

	Cost	11.59
Multi Criteria		
Feed Material		2
Feed Material Qualifier		2
Temp max		1
Press max		2
Process Conditions Qualifer		1
Construction Materials		1
Construction Materials Qualifier		1
No of Recycles		0
Novelty		3
Novelty Qualifer 1		5
Novelty Qualifer 2		1
Safety Risk		3
Safety Risk Qualifer		2
Environmental Impact		3
Environmental Impact Qualifier		3
Average Risk Level		40
Controlling Risk Level		100
Controlling Risk is		Process novelty
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		95
Process Conditions Extra Cost	ct/kWh	0
Novelty		100
Novelty Extra Cost	ct/kWh	0
Complexity		70
Complexity Extra Cost	ct/kWh	0
Safety		60
Safety Extra Cost	ct/kWh	0
Environmental		50
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.361688
CO2 Charge	$ct/kWh	0
Base Capex	$ct/kWh	1.404772
Extra Capex	$ct/kWh	0.189644
Other Opex	$ct/kWh	0
Total	$ct/kWh	3.956104
Fuel Mix		
Solid	frac	0
Liquid	frac	0
Gas	frac	1
Solid LCV		25000
Liquid LCV		42000
Gas LCV		50046
Mixture LCV		50046
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	36.5
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	0
ST power	MW	561
Percent of heat available to Steam	MW	0
Overall electrical efficiency after lo	MW	45.73
Efficiency GT Cycle	MW	0
Efficiency ST cycle	MW	0
Overall power output	MW	506
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		0
Other		0

Power Plant Assessment program

Worksheets for coal fired power plant with CO_2 capture using cryogenic flue gas CO_2 capture process as proposed by Israeli-Russian Research Institute

Plant Components

Choose the major plant components which are the closest match to the design you are assessing:

		Number of Units	Nominal Size	Units
☐	Gas Turbine	0	0.0	MWe
☑	Steam Turbine	1	812.4	MWe
☑	Combustor	1	79.3	kg/s fuel
☐	Gasifier	0	0.0	kg/s fuel
☐	Air Separation Unit	0	0	kg/s O2
	O2 compression Press.		1.22	bar
☐	HRSG	0	0.0	MW
☑	FGD	1		
☐	H2S Removal	0	0	ton/day
	Aux Power Reqd		0	kJ/Unit size
☑	Other major plant item	1	0	
	Aux Power Reqd		0	kJ/Unit size
☑	CO2 Separation	1	0	
	Aux Power Reqd		0	kJ/Unit size
☐	CO2 Compression	0		
	To Pressure		110	bar
☐	Fuel Cell (or Direct Generator)	0		

Fuel Type

☑ Solid
☐ Liquid
☐ Gaseous

Combustor Type

● PF
○ FBC
○ CFBC
○ PFBC

Steam Cycle Type

● Sub Critical
○ SuperCritical

Fuel Specifications

User to enter fuel specification figures in blue

		Solid	Liquid	Gas
Fuel Mass Fractions		1	0	0
LCV	kJ/kg	25000	42000	50013
Carbon fraction	%mass	0.62	0.86	0.75
Ash Fraction	%mass	0.12	0	0
% in Feed		100.00%	0.00%	0.00%

Fuel Fractions Sum (must = 1) 1

Combined LCV	25000	kJ/kg
Combined Carbon fraction	0.62	
Combined Ash Fraction	0.12	

Mass & Energy Balance

This datasheet requires some details on the feed and outlet streams of the process:
Please enter data for figures shown in blue

Basis :	Flow kg/s	LCV kJ/kg	kg Carbon /kg	Carbon Balance kg/s
Fuel	79.293	25000	0.62	49.16166
Other Materials	0	0	0	0
Residue	0	0	0	0
% CO2 recovered =	70.0%			
CO2 recovered	126.18	0	0.273	34.41316
CO2 emitted	54.08	0	0.273	14.7485

Gross available energy	25000	kJ/kg fuel
	1982325	kJ Total

Fuel/Energy Distribution

Percent of Input Fuel direct to combustion or steam cycle	100%	25000
Percent of Input Fuel to gasification system	0%	0
Heat recovered from gasifier to steam cycle	0%	0
Heat recovered from gasifier to gas cycle	0%	0
Percent of Input Fuel direct to Fuel Cell/MHD etc	0%	0
Percent of fuel to direct generatior Converted to power	0%	0
Heat recovered from direct generation to steam cycle	0%	0
Heat recovered from direct generationto gas cycle	0%	0
Heat from Steam cycle lost to Process or ?	0	kW

ASSUMPTIONS - Process

Gas Cycle

Actual Fuel flow rate to Gas Turbine	1	kg/s		
	56.8635	===> Air flow of	56.86	kg/s
Air Bleed for Blade Cooling	6.27%	===> Cooling flow of	3.57	kg/s
HRSG heat loss	1.0%			

Steam Cycle

BFW Efficiency	70%	
Misc & Unaccounted Losses	0%	% off efficiency

Misc

Turbine Mechanical Loss	0.50%	
Generator Loss	1.50%	
Transformer Loss	0.40%	
Fan and compressor mech eff.	93.00%	
Misc power consumption	0.30%	of gross

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg
	Sorbent	50	kJ/kg
	Ash	50	kJ/kg
Oxygen Production		950	kJ/kg O2
Combustor fans (PF)		8	kJ/MJ fuel
FGD		8	kJ/MJ fuel
Cooling water system		7	kJ/MJ rejected

PPAP Lite

Use for direct data entry from other heat and mass balance packages

Overide internal calculations ☑ Tick box to activate input of values on this sheet.

(ie Use PPAP Lite)

CO2 compression power	25	MW	Added into cell J45	Sheet CycleAnalysis
O2 compression power	0	MW	Added into cell J44	Sheet CycleAnalysis
HRSG on GT	0	MW	Transferred to B7	Sheet CycleAnalysis
GT power	0	MW	Transferred to D65	Sheet CycleAnalysis
ST power	812.4	MW	Transferred to D66	Sheet CycleAnalysis
Percent of heat available to Steam cycle	100	%	Transferred to D69	Sheet CycleAnalysis
Overall electrical efficiency after losses	25.22	%	Transferred to D62	Sheet CycleAnalysis
Efficiency GT Cycle		%	Transferred to D13	Sheet CycleAnalysis
Efficiency ST cycle	40	%	Transferred to D18	Sheet CycleAnalysis
Overall power output	500	MW	Transferred to G61	Sheet CycleAnalysis

Power from direct generation	0.00	MW
Other power from GT/ST waste heat	0	MW
Energy content of fuel	1982.33	MW

Losses

GT mech loss	0.00	MW
GT gen loss	0.00	MW
ST mech loss	4.06	MW
ST mech loss	12.19	MW
GT + ST transformer loss	3.25	MW
Transformer loss direct power generated	0.00	MW
Subtotal	**19.50**	**MW**

Auxiliaries

NB external entries of <>0 overide PPAP calculated values

Solids handling:			PPAP	External	*hidden calc*
Fuel	3.96465	MW	3.96465	0	
Sorbant	0	MW	0.00	0	
Residue	0	MW	0.00	0	
Oxygen Production	0	MW	0	0	
Combustor fans (PF)	15.86	MW	15.86	0	
FGD	15.86	MW	15.86	0	
Cooling water system	3.42	MW	3.42	0	487.44 MW ST rejection
Misc	1.50	MW	1.50	0	1.75 MW compression losses
H2S Sepn	0	MW	0	0	
CO2 Sepn	227	MW	0	227	
Other	0	MW	0	0	
Subtotal	**267.61**	**MW**			
TOTAL Losses/Auxiliaries	**287.10**	**MW**			

Cycle Analysis

PPAP Lite mode - Values highlighted in yellow have been imported, see PPAPLITE Sheet

The per kg figures below refer to the TOTAL fuel feed to the system (not just to the GT)

Heat Recovery/Losses in GT Cycle				**% of heat**		
	Value imported			**I/P to GT**	**kJ/kg**	**MW**
To steam	0	kJ/s from	HRSG before losses	0.00	0.0	0.000
GT loss	0	kJ/s from	Stack	0.00	0.0	0.000
GT Efficiency				0.00		
Total				0.00		

Gas cycle Output					
Estimated GT Efficiency	0	**Value imported**			
Gross avail. energy to GT cycle	1E-07	kJ/kg			
GT Output	**0**	**kJ/kg**	equiv to	0	kW

Steam Cycle Output					
Estimated Steam Cycle Efficiency	0.4	**Value imported**			
Heat Balance					
From Combustion	25000	kJ/kg			
From Gasification	0	kJ/kg			
From GT HRSG etc after losses	0	kJ/kg			
From Direct Generation	0	kJ/kg			
Export/Import	0	kJ/kg			
Heat available to steam cycle	25000	kJ/kg	equiv to	1982325	kW
ST Output	**9957.27**	**kJ/kg**	equiv to	789541.8	kW
Total Potential Output	9957.27	kJ/kg	equiv to	789541.8	kW

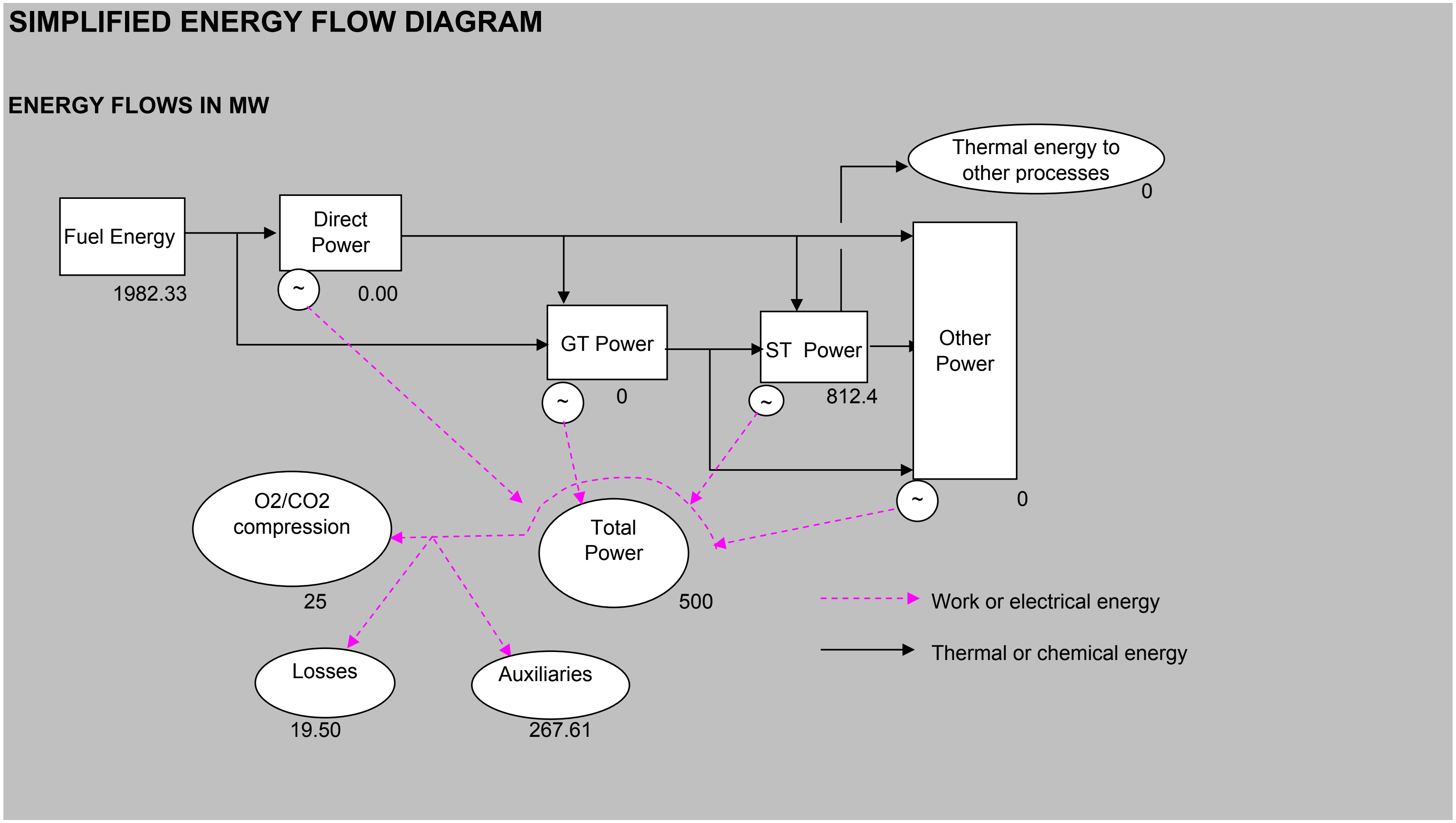
HRSG Heat available	0	kJ/kg
HRSG heat loss	1.0%	
HRSG to Steam Cycle	0	kJ/kg

Process Losses		Total	GT	ST
Turbine Mech Loss	0.50%	3947.7	0.0	3947.7
Generator Loss	1.50%	11843.1	0.0	11843.1
Transformer Loss	0.40%	3158.2	0.0	3158.2

Gross Power Output	**9718.295**	**kJ/kg**	equiv to	770592.8	kW

Auxiliary Power Requirements

Solids handling	Fuel	50	kJ/kg				1	50			
	Sorbent	50	kJ/kg				1	0			
	Ash	50	kJ/kg				1	0			
Fan and compressor mech eff.		93%									
Oxygen Production		950	kJ/kg O2				0	0			
Oxygen Compression						**Value imported**		0		0.7	Is good nur
CO2 Compression							0	315.2863	**Value imported**		O2 & CO2
Combustor fans (PF)		8	kJ/MJ fuel				1	200			
FGD		8	kJ/MJ fuel				1	200			
Cooling water system		7	kJ/MJ rejected				1	105		Steam Cycle Condens	
Misc		0.30%	of gross					29.15489			
H2S Sepn								0			
CO2 Sepn								0			
Other								0			
Total Auxiliaries								899.4412	kJ/kg		
Total Input		25000	kJ/kg								
Total Output (Net)		8818.854	kJ/kg	=>	500000	kW	**Value imported**				
Efficiency		25.22	%	**Value imported**						-312.4	
										0	
GT Output (Generator Terminals)		0.00	MW	**Value imported**						-312.4	
ST Output (Generator Terminals)		812.40	MW	**Value imported**							
Direct O/P (Gross)		0	MW								
% heat available to steam cycle		100	%	**Value imported**							


SIMPLIFIED ENERGY FLOW DIAGRAM
ENERGY FLOWS IN MW
Thermal energy to other processes
0
Fuel Energy
1982.33
Direct Power
~
0.00
GT Power
~
0
ST Power
~
812.4
Other Power
~
0
O2/CO2 compression
25
Total Power
500
Work or electrical energy
Thermal or chemical energy
Losses
19.50
Auxiliaries
267.61

Process Cost Estimation

Description	Scaling parameter	User specified size	Size per unit	No of units	Cost multiplier	Predicted cost, M$
Solids handling	kg/s		79.293	1	1	17.26
Coal pulverise+dry (gasif)	kg/s feed		0	0	1	0.00
Oxygen production	kg/s O2		0	0	1	0.00
Gasifier (Shell, inc hopper, cool/filt/scrub)	MW fuel feed LHV		0	0	1	0.00
Acid gas removal (scrubbing)	kmol/s feed gas		0	0	1	0.00
CFBC	MW fuel feed LHV		0	0	1	0.00
CO2 compressor (motor driven)	MWe		0	0	1	0.00
Gas turbine, complete	MWe	0	0	0	1	0.00
Gas turbine, compressor only	MW consumed					
Gas turbine, turbine only	MW					
Gas turbine, generator only	MWe					
HRSG	MWth transferred		0	0	1	0.00
Steam turbine+pipes+cooling system	MWe		812.4	1	1	191.21
PF coal boiler	MW fuel feed LHV		1982.325	1	1	256.51
FGD (limestone gypsum)	kmol/s feed		19.50079	1	1	68.99
Gasifier fuel gas cooler (fire tube)	MW transferred		0	0	1	0.00
Gasifier fuel gas cooler (water tube)	MW transferred		0	0	1	0.00
Candle filter (400C)	kmol/s feed		0	0	1	0.00
PFBC combustor	MW fuel feed		0	0	1	0.00
FBC	MW fuel feed LHV		0	0	1	0.00
CO2 regeneration	Kg/s CO2 captured		0	0	1	0.00
Gas absorption for CO2 capture	Kg/s total gas flow		0	0	1	0.00
Gas reforming	Kg/s potential CO2		0	0	1	0.00
Gas shift reaction	Kg/s CO2 in outlet		0	0	1	0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Other	User Defined		0	0		0.00
Equipment estimate	Equipment estimate		0	0		379.06
Electrical distribution	MWe gross		500	1	1	11.48
Sub-Total						**924.52**
Balance of plant	% of above		10			92.45
Engineering, indirects, owners cost	% of above		24			244.07
Project contingency	% of above		10			126.10
TOTAL						**1387.14**

Operating Cost Specification

Fuel Cost	Solid	1.5	$/GJ			
	Liquid	3	$/GJ			
	Gaseous	3	$/GJ			
Calculated Fuel Cost		1.5000	$/GJ			
Fuel cost of electricity		2.1412	c/kWh			
Capital Charges						
Interest Rate		10%				
Plant Life Span		25	years			
Load Factor		0.85				
Interest during construction		210.2799	M$			
Annual capital Charge		175.9850	M$/y			
Capital Charges		4.7237	c/kWh			
O&M Costs						
O&M Factor		0.04		Other Materials Cost	20	$/tonne
				Residue Disposal Cost	20	$/tonne
Fixed O&M cost		1.4893	c/kWh			
Variable O&M cost		0.0000	c/kWh			
Estimated Operating Costs		**8.3542**	**c/kWh**			

Multi-Criteria Analysis

This page of the assessment proceedure bring together data from the first two steps and allows the user to applied 'weightings' to the results to provide a ranking for the proposed power plant indicating its overall suitability as a 'green' power generation process.
To edit the percentages allocated to different attributes scroll down the page

Multi-Criteria Analysis	Value	Risk assessment & Score%	Score %	Weighting	DECISION FACTOR	Weighted Score
Fuel Consumption kJ/kW	3.965		-48	42.9	**APPLICABILITY**	-11.7
Raw Material Availability	Locally Common ▼ with unlimited availability ▼ for scale of this application	No risk 0	90	10		
Process Conditions Temperature Pressure NB Use least well known part of process	<1200K ▼ 10-60 bar ▼ but no significant technical barriers ▼	No risk 6	90	10	**CONFIDENCE IN WHETHER IT WILL WORK**	32.5
Novelty of Materials which is	Stainless Steel ▼ known material but in new environment ▼	No risk 10	95	10		
Plant Complexity No. of major units No. of major recycles	4 0		80	10		
Novelty of Process with	Major modifications ▼ promising ▼ credited scientific proof of concept ▼	High risk 63	60	10		
Greenhouse Gas Emissions CO2 emission in kg/Kwh	0.389		28	40	**ESTIMATED COSTS**	10.1
Costs Total Operating c/kWh	8.35		-7	100		
Safety Risk Control of these risks	Small Risk ▼ extensively demonstrated and publicly accepted ▼	No risk 5	80	20	**ACCEPTANCE**	26.0
Environmental Impact Management of these impacts	Mildly harmful waste ▼ extensively demonstrated and publicly accepted ▼	No risk 10	50	20		

Averaged risk level	**16**			
Controlling risk level	**63**	**Process novelty**	**TOTALS**	56.9

Results of Analysis

Summary

Process: **Russian Israeli research centre cryogenic process**

Heat Input		1982.3	MW		
Estimated	Net Electricity Output	500.0	MW	NOTE GT efficiency calculated by program as …	0.0 %
	Net Efficiency	25.2	%	NOTE Steam cycle efficiency calculated as...	40.0 %
	CO2 output/ kg/s	54.1	kg/s	NOTE percentage of input energy to steam cycle ..	100.0 %
	CO2 output/kWh	0.389	kg/kWh		
Estimated Capital Cost		1387.1	M$		
Estimated Op Cost		8.4	c/kWh		

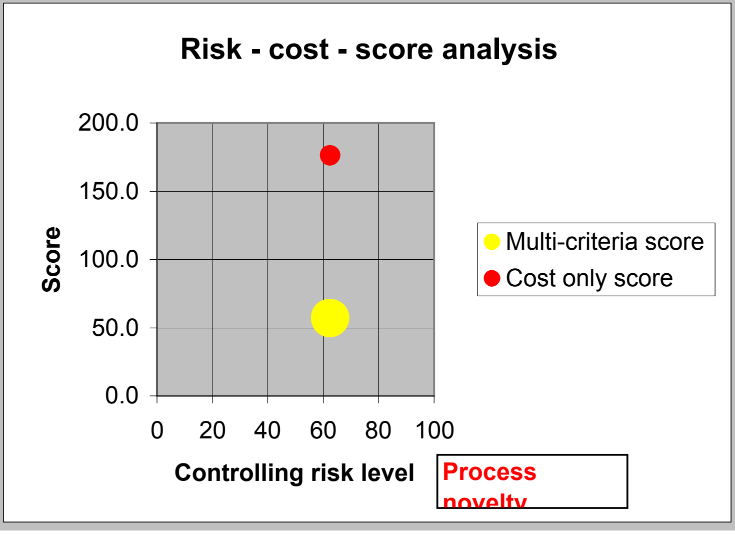
Multi-Criteria Assessment

Decision Factor Scores

Acceptance		26.0
Applicability		-11.7
Confidence		32.5
Estimated Cost		10.1
	Total	56.9
	Total cost only	175.9

Risk assessment

Averaged risk level		16
Controlling risk level	**Process novelty**	**63**



Comparison with Base Case CCGT

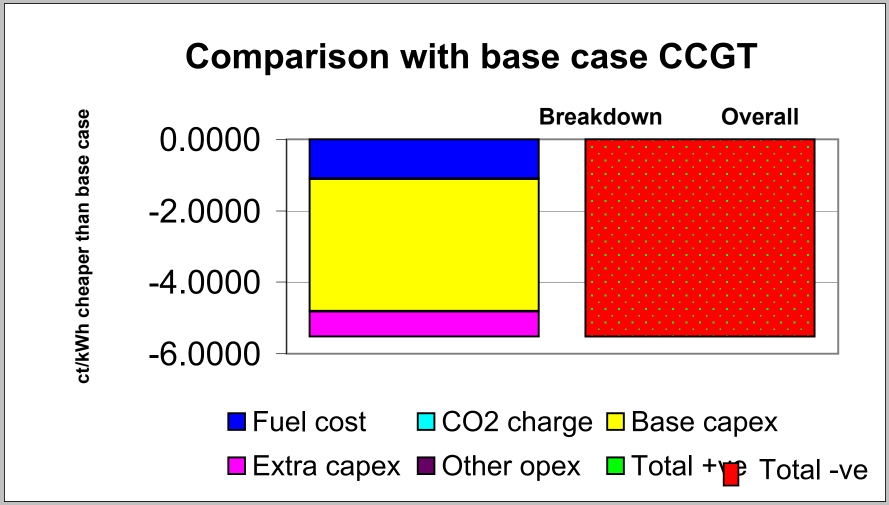
CO2 emission penalty	50	$/ton
CO2 emissions	0.389	kg/kWh
CO2 emission cost	1.947	c/kWh

Factor analysis	Scores	Effect on costs of electricity
Raw materials	90	0.0621
Process conditions	90	0.0621
Novelty of materials	95	0.0311
Complexity	80	0.1243
Safety	80	0.1243
Environmental	50	0.3107
TOTAL		**0.7145**

Base Case data

Fuel cost	2.0966	c/kWh Based on	3	$/GJ
CO2 Tax	1.921	c/kWh Based on	50	$/tonne
Base Capex+Opex	2.5125	c/kWh		
Extra Capex	0	c/kWh		
Other Opex	0	c/kWh		

	This Case $ct/kWh	Base Case $ct/kWh	Difference $ct/kWh	Base rates		
Fuel cost	2.141	1.048	-1.0929	1.5000	$/GJ	
CO2 charge	1.947	1.921	-0.0258	50	$/ton	
Base capex	6.213	2.5125	-3.7006			
Extra capex	0.715	0	-0.7145			
Other opex	0.000	0	0.0000			
					Total	-5.5337
TOTAL	11.0155	5.4818	-5.5337			
Extra fuel			1.0929			
Extra capex			4.4151			
Total extra			5.5079			
CO2 tax benefit			-0.0258			



WEIGHTINGS ANALYSIS

CO2 emission calc

Coal kgC/kJ	0.0000248	
Oil kgC/kJ	2.048E-05	
Gas kgC/kJ	1.5E-05	
Mix kgC/kJ	0.0000248	
Standard coal efficiency	0.53	
Standard oil efficiency	0.6	
Standard gas efficiency	0.6	
Standard coal emission	0.618	kg/kWh
Standard oil emission	0.450	kg/kWh
Standard gas emission	0.330	kg/kWh
Calorific fraction of gas	0	
Calorific fraction of oil	0	
CO2 allowance	0.6177	kg/kWh

Data for comparison with other processes (Used in IEA_PPC.xlt)

DO NOT EDIT

Project Title		Russian Israeli research centre cryogenic process
Power Out	MWe	500
Efficiency	%	25.22
CO2 emitted	%	30
CO2 emitted	kg/kWh	0.38936
Fuel in	kg/s	79.293
Fuel in	MW	1982.325
Other in	kg/s	0
Ash (residue) Out	kg/s	0
CO2 to 'storage'	kg/s	126.18
Gas Cycle Efficiency	%	0.00
Steam Cycle Efficiency	%	0.40
Est Capital Cost	M$	1387.14
Est Operating Cost	ct/kWh	8.35
Capital Cost Items		
Solids handling	'Size'	79.293
	Number	1
	Cost	17.26
Coal pulverise+dry (gasif)	kg/s feed	0
	Number	0
	Cost	0.00
Oxygen production	kg/s O2	0
	Number	0
	Cost	0.00
Gasifier (Shell, inc hopper, cool/filt	MW fuel feed LHV	0
	Number	0
	Cost	0.00
Acid gas removal (scrubbing)	kmol/s feed gas	0
	Number	0
	Cost	0.00
CFBC combustor /stack	MW fuel feed	0
	Number	0
	Cost	0.00
CO2 compressor (motor driven)	MWe	0
	Number	0
	Cost	0.00
Gas turbine, complete	MWe	0
	Number	0
	Cost	0.00
Gas turbine, compressor only	MW consumed	0
	Number	0
	Cost	0
Gas turbine, turbine only	MW	0
	Number	0
	Cost	0
Gas turbine, generator only	MWe	0
	Number	0
	Cost	0
HRSG	MWth transferred	0
	Number	0
	Cost	0.00
Steam turbine+pipes+cooling syste	MWe	812.4

	Number	1
	Cost	191.21
PF coal boiler	MW fuel feed LHV	1982.325
	Number	1
	Cost	
FGD (limestone gypsum)	kmol/s feed	19.50079
	Number	1
	Cost	
Gasifier fuel gas cooler (fire tube)	MW transferred	0
	Number	0
	Cost	
Gasifier fuel gas cooler (water tube	MW transferred	0
	Number	0
	Cost	
Candle filter (400C)	kmol/s feed	0
	Number	0
	Cost	
PFBC combustor	MW fuel feed	0
	Number	0
	Cost	
FBC	MW fuel feed LHV	0
	Number	0
	Cost	0.00
CO2 regeneration	Kg/s CO2 captured	0
	Number	0
	Cost	0.00
Gas absorption for CO2 capture	Kg/s total gas flow	0
	Number	0
	Cost	0.00
Gas reforming	Kg/s potential CO2	0
	Number	0
	Cost	0.00
Gas shift reaction	Kg/s CO2 in outlet	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	0.00
Other	User Defined	0
	Number	0
	Cost	379.06
Electrical distribution	MWe gross	500
	Number	1

Israeli-Russian cryo

	Cost	11.48
Multi Criteria		
Feed Material		2
Feed Material Qualifier		1
Temp max		1
Press max		3
Process Conditions Qualifer		1
Construction Materials		2
Construction Materials Qualifier		2
No of Recycles		0
Novelty		3
Novelty Qualifer 1		2
Novelty Qualifer 2		7
Safety Risk		2
Safety Risk Qualifer		1
Environmental Impact		3
Environmental Impact Qualifier		1
Average Risk Level		16
Controlling Risk Level		63
Controlling Risk is		Process novelty
Comparison		
CO2 Penalty	$/tonne	
CO2 Emissions	kg/kWh	
CO2 Emissions Cost	ct/kWh	
Factors		
Raw Mats		90
Raw Mats Extra Cost	ct/kWh	0
Process Conditions		90
Process Conditions Extra Cost	ct/kWh	0
Novelty		95
Novelty Extra Cost	ct/kWh	0
Complexity		80
Complexity Extra Cost	ct/kWh	0
Safety		80
Safety Extra Cost	ct/kWh	0
Environmental		50
Environmental Extra Cost	ct/kWh	0
Fuel Cost	$ct/kWh	2.141158
CO2 Charge	$ct/kWh	1.946802
Base Capex	$ct/kWh	6.213061
Extra Capex	$ct/kWh	0.714502
Other Opex	$ct/kWh	0
Total	$ct/kWh	11.01552
Fuel Mix		
Solid	frac	1
Liquid	frac	0
Gas	frac	0
Solid LCV		25000
Liquid LCV		42000
Gas LCV		50013
Mixture LCV		25000
Fuel Costs		
Gas		3
Liquid		3
Solid		1.5

Other Input		20
Residue		20
PPAPLite Data		
Use PPAPLite		TRUE
CO2 compression power	MW	25
O2 compression power	MW	0
HRSG on GT	MW	0
GT power	MW	0
ST power	MW	812.4
Percent of heat available to Steam	MW	100
Overall electrical efficiency after lo	MW	25.22
Efficiency GT Cycle	MW	0
Efficiency ST cycle	MW	40
Overall power output	MW	500
Other power from GT/ST waste he	MW	0
Solids handling:		
Fuel		0
Sorbant		0
Residue		0
Oxygen Production		0
Combustor fans (PF)		0
FGD		0
Cooling water system		0
Misc		0
H2S Sepn		0
CO2 Sepn		227
Other		0