

RETROFIT OF CO₂ CAPTURE TO NATURAL GAS COMBINED CYCLE POWER PLANTS

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Background to the Study

The main application of CO_2 capture in the long term is expected to be at new power plants. This has been the main focus of the IEA Greenhouse Gas R&D Programme's studies on CO_2 capture. However, there are various reasons why retrofitting CO_2 capture to existing power plants may be worth considering in some circumstances, for example:

- Power plants have long lives, 40 years or more in many cases. It may be cheaper to retrofit capture to an existing power plant rather than prematurely retire it and build a new power plant with capture.
- Utilities often prefer to extend the lives of existing plants rather than build new ones to minimise permitting problems and make use of existing fuel supply and electricity transmission infrastructure.
- Opportunities may arise to use captured CO₂, e.g. for enhanced oil recovery, in places where there is no need for new power generating capacity.

Most of the power plants currently being built in developed countries are natural gas fired combined cycle plants. Such plants could potentially be good candidates for CO_2 capture retrofit because they are relatively new and have high thermal efficiencies. This study assesses the feasibility and costs of retrofitting CO_2 capture to modern natural gas combined cycle plants. The study was carried out by Jacobs Consultancy Netherland B.V.

Study Description

The study is based on a 785 MW_e natural gas fired combined cycle plant, which includes 2 GE 9FA gas turbines. Similar gas turbines are produced by the other main turbine manufacturers. Five CO₂ capture retrofit options based on existing technology are assessed:

- Post combustion capture of CO₂
- Pre-combustion reforming of natural gas and capture of CO₂ at the power plant site
- Pre-combustion reforming of natural gas and capture of CO₂ at a remote site
- Gasification of coal and pre-combustion capture of CO₂ at the power plant site
- Gasification of coal and pre-combustion capture of CO₂ at a remote site

A preliminary assessment was carried out to select the technologies for use in the plants with CO_2 capture. The post combustion capture plant is based on a mono-ethanolamine (MEA) scrubbing process. The natural gas pre-combustion capture plants are based on air-blown auto-thermal reforming, followed by shift conversion and an amine scrubbing CO_2 separation unit. The coal gasification plants are based on the ChevronTexaco (now GE) slurry feed, oxygen-blown entrained-flow gasifier with water quench of the product gas. The gasifiers are followed by shift conversion and a Selexol physical solvent scrubbing unit for separation of H_2S , which is converted to sulphur, and CO_2 . Post combustion capture was not considered for the gasification plants because it was assumed that it would be less expensive to capture CO_2 from the high pressure/high CO_2 concentration fuel gas than from the low pressure/low CO_2 concentration gas turbine flue gas

In the remote site cases, fuel processing and CO₂ capture is carried out at a plant that is 40 km from the power plant and hydrogen-rich fuel gas is transported by pipeline. Remote capture could be necessary if



there is insufficient plot area or other constraints at the power plant. Post combustion capture at a remote site is not feasible because a large volume of flue gas would have to be transported between the sites.

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

- Netherlands coastal plant location
- Australian bituminous coal
- Natural gas price \$3/GJ, LHV basis (equivalent to \$2.7/GJ HHV basis)
- Coal price \$1.5/GJ, LHV basis (equivalent to \$1.43/GJ HHV basis)
- 10% discount rate (constant money values)
- 25 year overall operating life

It was assumed that CO_2 capture would be retrofitted after 10 years operation of the combined cycle plant. Sensitivities to the year in which the retrofit takes place (± 5 years) were assessed. It was also assumed that the whole plant, including the capture equipment would have zero value at the end of the 25 year operating period. In some cases it may be possible to replace or refurbish the power plant, to obtain a longer operating life for the capture equipment. However, gas turbines that are commercially available in future may not have the same flowrates as existing turbines, so it may be difficult to re-use capture units that are closely matched to the size of existing turbines. It may be easier to re-use capture units that are not closely linked to the power plant and which could be used to supply low-carbon content fuels to plants of any size.

Retrofitting CO₂ capture normally results in a reduction in net power output. In some cases a utility may need to maintain a constant net power output, so installation of additional generating capacity to maintain the net power output was assessed in sensitivity cases.

Results and Discussion

Thermal efficiency

Thermal efficiencies of the plants with and without CO_2 capture retrofit are shown in figure 1, along with the efficiency reductions due to the retrofit.

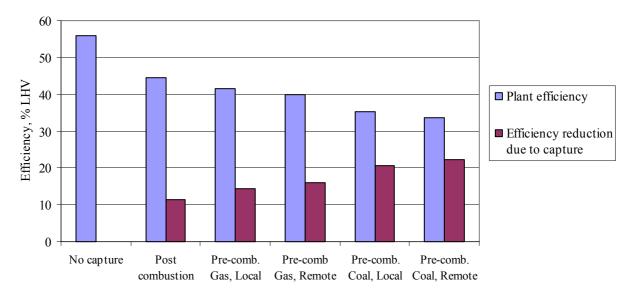


Figure 1: Thermal efficiencies



Post combustion capture has the lowest efficiency reduction due to capture. The highest efficiency reduction is for the coal based retrofits.

Capital cost

The capital costs of plants before and after retrofit are shown in figure 2. The costs are broken down into the costs of the original natural gas combined cycle (NGCC) plant and the costs of the retrofit. The cost of the original NGCC, in terms of \$/kW of net power output, increases after retrofit because the overall net power output decreases, as shown later in figure 7. The capital costs of local natural gas based retrofits (post combustion and pre combustion) are broadly similar to the original costs of the NGCC power plant. The costs of remote plant and coal-based retrofits are substantially higher than the original costs of the NGCC.

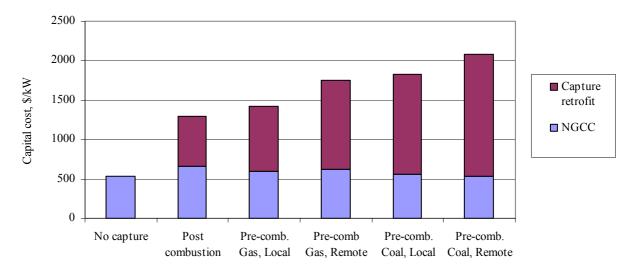


Figure 2: Capital costs

Cost of electricity generation

A power plant operator would be able to recover the cost of retrofitting CO_2 capture either by an increase in the electricity price or by a credit for the quantity of CO_2 emissions avoided, e.g. through a carbon trading scheme. The total cost of electricity generation after retrofit, assuming no carbon credits, and the increase in the cost due to the retrofit are shown in figure 3.

Figure 3 shows that the lowest cost capture retrofit option is post combustion amine scrubbing. For the natural gas and coal prices used in this study (3 and 1.5 \$/GJ respectively), coal-based pre-combustion capture retrofit is slightly more expensive than natural gas pre-combustion retrofit. For pre-combustion capture, retrofit of a capture plant at a remote site is about 0.8c/kWh more expensive than retrofit at the power plant site, assuming there are no special difficulties with on-site retrofit.



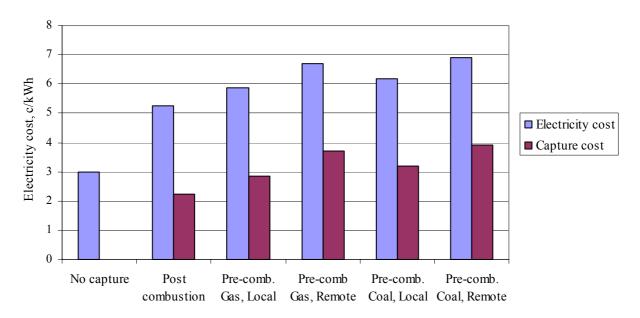


Figure 3: Electricity generation cost after capture retrofit

Fuel prices are different in different locations and they can fluctuate greatly over time. Sensitivities to fuel prices are shown in figure 4. A plant retrofitted with coal-based pre-combustion capture, using coal at \$1.5/GJ, would generate electricity at the same cost as a plant retrofitted with natural gas pre-combustion capture, if the gas price was 3.2-3.4 \$/GJ. For the coal-based retrofit to compete with post-combustion capture retrofit, the natural gas price would have to be \$4.2/GJ. In some places, for example the US, natural gas prices were higher than this at the time this report was written and coal prices were lower than \$1.5/GJ. Coal prices also tend to be more stable than gas prices and supplies may be more secure. Retrofit of coal gasification with CO₂ capture may therefore be competitive with natural gas-based capture retrofit in some places. However, as explained below, CO₂ emissions from coal-based plants tend to be higher, so emissions credits would be lower.

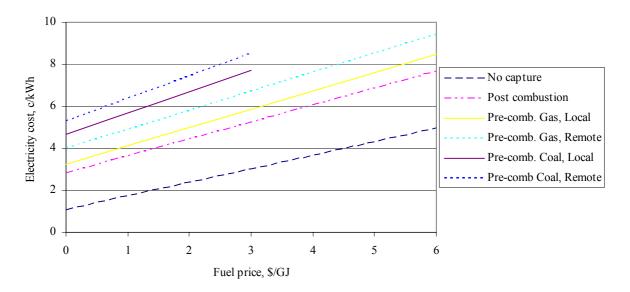


Figure 4: Sensitivity to fuel prices



The costs in this study exclude CO_2 transport and storage. As an illustration, a cost of \$10/t of CO_2 transported and stored would correspond to about 0.4 c/kWh for a gas fired plant and 0.8 c/kWh for a coal fired plant.

Cost of CO₂ emissions avoidance

Figure 5 shows the CO_2 emissions from the plants with and without capture and the quantities of CO_2 emissions avoided. The quantities of CO_2 emissions avoided are calculated by comparing the emissions of the natural gas fired plant without capture and the emissions of the plants after retrofit of capture. The quantities of emissions avoided are less than the quantities captured because extra CO_2 is produced to provide the energy required by the capture processes. In the case of the coal gasification retrofits, the quantity of CO_2 captured is much greater than the emissions avoided because of the change to a more carbon-intensive fuel. All of the retrofits are based on the same percentage CO_2 capture. The CO_2 emissions from the coal-based plants are greater than from the natural gas-fuelled plants because coal is a more carbon intensive fuel and the thermal efficiencies of the coal-based plants are lower.

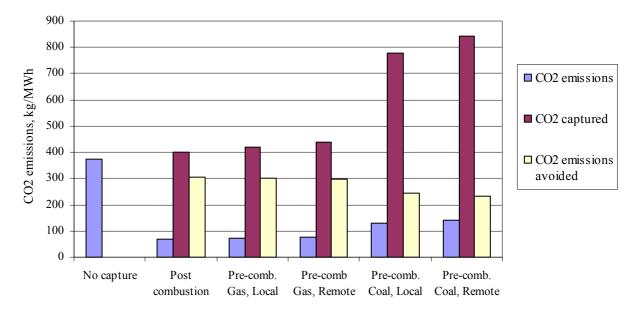


Figure 5: CO₂ emissions

The cost of CO_2 emissions avoidance, i.e. the CO_2 credit that would be required to enable a retrofitted plant to generate electricity at the same overall cost as the original plant without CO_2 capture, is shown in figure 6. Figure 6 also shows the sensitivity to the timing of retrofit. The base case assumption in this study is that CO_2 capture is retrofitted 10 years after the start of operation of the power plant and the sensitivity to retrofitting 5 or 15 years after start of operation is shown.



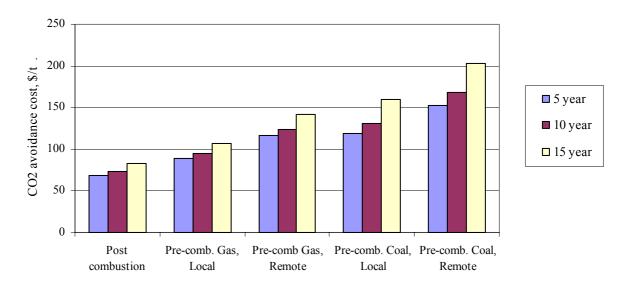


Figure 6: Cost of avoiding CO₂ emissions and the sensitivity to the power plant age when retrofitted

Effect on net power output

Retrofitting CO_2 capture reduces the net power output of an existing combined cycle plant, as shown in figure 7.

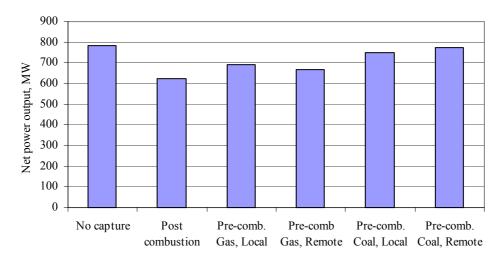


Figure 7: Net power outputs

The fuel feed rate to the plant with post-combustion capture is the same as to the plant without capture. The reduction in power output is therefore directly proportional to the reduction in thermal efficiency, shown in figure 1. In the plants with pre-combustion capture the fuel (natural gas or coal) feed rates depend on the fuel gas requirement of the gas turbine and the energy losses in the fuel processing stages upstream of the gas turbine. The fuel feed rates are higher than in the plant without capture and consequently the reduction in net power output is less than the reduction in thermal efficiency.

In some circumstances a power plant operator may want to maintain its net power output. This could be achieved by installing additional combined cycle generating capacity at each plant that is retrofitted but this extra capacity would be less efficient and more expensive than the original generating plant. Maintaining a constant net power output in this way would reduce the overall efficiency of power generation by between



zero and 2 percentage points and increase the cost of CO₂ emissions avoided by between zero and 5 \$/t of CO₂.

Barriers to retrofit

In general, standard combined cycle power plants are not designed for the future possibility of major modifications. This study identifies possible barriers to retrofitting CO₂ capture to existing combined cycle plants and possible ways to minimise them during the original plant design phase, i.e. making the plants "capture ready".

The CO₂ capture retrofit plants require a considerable plot space. The approximate plot spaces are:

Post combustion capture
 Natural gas pre-combustion capture
 Coal gasification pre-combustion capture
 475x375m

Significant additional plot space is also required during construction. If there insufficient area available at the combined cycle plant, a pre-combustion capture plant could be installed at a remote site but, as shown by figure 2, this increases costs.

Space available within the combined cycle plant for tie-in of large diameter steam and fuel gas pipes may be a constraint in some cases. Other possible site constraints include the need to provide additional cooling and demineralised water, coal supply and storage infrastructure in coal fired cases, and accessibility for delivery of large plant items. Obtaining permits for major modifications to the power plant or construction of a remote capture plant and its fuel gas pipeline could be a barrier in some circumstances.

Gas turbine performance will differ significantly when firing a low-LHV fuel gas from pre-combustion capture plant, which will also lead to changed process conditions in the steam cycle. As no design is exactly the same, it will be necessary to determine possible problems for each installation that is retrofitted. Retrofit of CO_2 capture could also affect plant operating flexibility, such as the ability to operate efficiently at part load

Many of the potential barriers to retrofit could be overcome in the design phase of a new combined cycle power plant. This would lead to minor extra costs but the cost savings at the retrofit stage could be substantial, for example if the need to build a remote capture plant is avoided.

As a sensitivity case, the study briefly assessed retrofit of a capture-ready coal gasification plant, which could be operated efficiently without capture. This option may be attractive in locations where fuel switching from natural gas to coal is economically attractive now but there is no requirement yet to capture CO₂.

Comparison with IEA GHG studies on CO₂ capture in new power plants

Retrofitting CO₂ capture to an existing power plant is inevitably more costly than including it in a new plant. Reasons for this include:

- The capture equipment has a shorter operating life in a retrofit than in a new plant.
- The efficiency is usually lower because of less energy integration between the power plant and capture unit.
- The power plant has to operate at non-optimum conditions.
- Some equipment in the power plant becomes redundant or has to be modified.
- The existing power plant has to be shut down for a period of time during the retrofit.
- Separate utility systems, such as cooling water supply, have to be installed for the capture unit, resulting in less economies of scale.



IEA GHG has recently published cost and performance data for post combustion CO₂ capture in new power plants, on the same basis as this study¹. The cost of post combustion capture in a new natural gas combined cycle plant was estimated to be \$37-41/tonne of CO₂ emissions avoided, compared to \$73/tonne in the corresponding retrofit case in this study. This higher cost for retrofit is partly due to the reasons given above but a further reason is the different sources of cost data in the new and retrofit plant studies. This retrofit study is based on information provided to Jacobs by UOP, for a conventional MEA scrubbing process. IEA GHG's study on new plants was based on data provided by Fluor and MHI are for their improved scrubbing processes (Econamine FG+SM and KS-1), which have much lower steam consumptions for solvent regeneration. The efficiency penalty for post combustion capture in this study is 11.3 percentage points but the penalty is 8.2 and 6.0 percentage points in Fluor and MHI's studies. The specific capital cost penalty for CO₂ capture in this retrofit study is approximately twice as great as in IEA GHG's new plant study. The data provided by UOP is conservatively based on eight parallel CO₂ absorbers, compared to 3 and 2 in Fluor's and MHI's studies. The resulting economies of scale account for a significant proportion of the cost difference. Despite the conservative data used for post combustion capture in Jacobs' study, post combustion capture is still the lowest cost retrofit option. Use of Fluor's or MHI's processes would not have affected this conclusion.

IEA GHG has also published a study on CO₂ capture in new IGCC plants², which was carried out by Foster Wheeler. The cost and performance data for gasification plants based on Chevron Texaco gasification in that study are broadly consistent with those in Jacobs' study. The thermal efficiency and capital cost are both lower in Foster Wheeler's study but the differences are not great enough to affect the conclusions of this study.

Expert Group Comments

The draft study report was sent to expert reviewers for comment. The main comments related to fuel prices. US reviewers pointed out that the gas price used in the study is low compared to current US prices. They also pointed out that one of the options considered in the study, conversion to coal gasification, would only be attractive if gas prices were much higher than the base case price used in the study. These and other comments from the reviewers are taken into account in the final version of the study report or in this study overview.

Major Conclusions

Retrofitting CO₂ capture to natural gas combined cycle plants would increase the cost of electricity by about 2-3c/kWh, corresponding to about 70-90 \$/tonne of CO₂ emissions avoided.

Post combustion capture is the lowest cost capture retrofit option.

Remote fuel processing and CO₂ capture plants could provide low-carbon fuel gas to a combined cycle plant but the cost would be about 0.8c/kWh higher than for on-site CO₂ capture retrofit.

There are several potential barriers to retrofit of CO₂ capture to existing combined cycle power plants but most of them could be overcome if the possibility of retrofit was taken into account when the power plant was designed.

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¹ Improvement in power generation with post-combustion capture of CO₂, IEA GHG report PH4/33, Nov. 2004.

² Potential for improvement in gasification combined cycle power generation with CO₂ capture, IEA GHG report PH4/19, May 2003



Retrofitting a coal gasification plant with CO_2 capture could be an attractive option in some countries where gas costs are high and coal costs are low. Capture-ready gasification plants could be built if there is currently no requirement to capture CO_2 .

Recommendations

No further work on retrofit of CO₂ capture to natural gas combined cycle plants is recommended at this time.

Work by others on retrofit of CO_2 capture to coal fired power plants, involving upgrading to ultrasupercritical boilers, should be monitored and compared to the results of IEA GHG's studies.



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- 2. Fuel/CO₂ capture plants simplified process schemes and mass balances
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1. MANAGEMENT SUMMARY

This report describes the results of a study conducted to evaluate several options for retrofitting an existing natural gas fired Combined Cycle Power Plant (CCPP) to a CCPP with a CO₂ capture plant.

This retrofit is set to take place after 10 years of operating the power plant as a standard CCPP.

The CO₂ capture options evaluated are:

- Post combustion CO₂ capture based on amine scrubbing of the CCPP's flue gases (case 1).
- Pre combustion CO₂ capture based natural gas as a fuel. This is done by reforming of natural gas in both a local (at the power plant site) case (case 2.1) and a remote (at 40 km distance) case (case 2.2).
- Pre combustion CO₂ capture based coal as a fuel. This is done by gasification of coal in both a local (at the power plant site) case (case 3.1) and a remote (at 40 km distance) case (case 3.2).

These options are visualized in following figure.

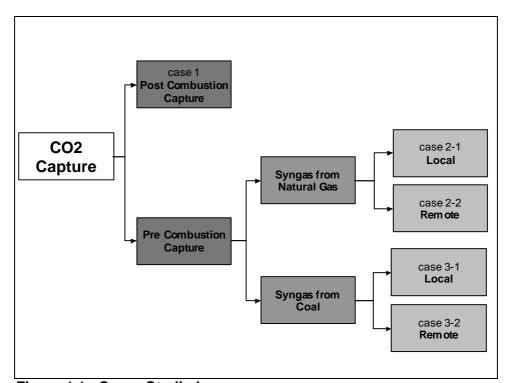


Figure 1.1 - Cases Studied

As part of the report a separate chapter (chapter 4) is dedicated to technology selection aspects for several process steps in a CO_2 capture Combined Cycle Power Plant. The technologies described and selected in this chapter are the basis for the five CO_2 capture cases as described in chapter 5.

For all cases considered, following characteristics have been established:

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- Performance
- Avoided CO₂ emission
- Capital investment
- Operation & maintenance costs

Using the IEA economic model, modified for evaluation of retrofit options, following results have been obtained:

- Electricity production costs
- Cost of avoided CO₂

The results of these evaluations are summarized below:

		Ref.	Case	Case	Case	Case	Case
			1	2.1	2.2	3.1	3.2
Additional ¹⁾ capital expen	diture						
for CO ₂ capture plant	(mln. USD)		395	569	750	962	1194
Net power production	(MWe)	785	626	694	667	751	775
Overall efficiency	(%)	55.9	44.6	41.5	39.9	35.4	33.6
Spec. total investment	(USD/MWe)	529	1294	1419	1746	1833	2077
Electricity costs	(USD/MWh)	30.0	52.4	58.6	67.1	61.9	69.1
CO ₂ emission	(ton/MWh)	0.373	0.067	0.072	0.075	0.130	0.140
Avoided CO ₂	(ton/MWh)		0.306	0.301	0.299	0.243	0.233
Avoided CO ₂	(% of ref.)		82.1	80.6	80.0	65.2	62.5
Cost of avoided CO ₂	(USD/ton CO ₂)		73.2	95.1	124.3	131.4	168.1

Notes:

From the study it becomes clear that a retrofit of CO_2 capture to a natural gas fired CCCP requires a significant cost of investment and results also in a significant reduction of the overall electric efficiency. The post combustion CO_2 capture option is strongly preferred from a performance and financial point of view compared to the natural gas reforming and the coal gasification based pre combustion CO_2 capture plants.

The post combustion option shows the smallest but still significant efficiency reduction in combination with the lowest capital expenditures and the best specific CO₂ emission.

The main disadvantage of the post combustion option is the requirement of installing the plant almost next to the existing CCCP because of the large atmospheric flue gas flow. As the plant requires also a large plot space, this could be a problem for retrofitting.

Other conclusions are:

- All options comply with the CO₂ capture efficiency of 85%.
- The remote pre combustion options require a higher cost of investment and have a lower efficiency due to transportation of the fuel gas.
- The overall power generation availability of the retrofitted plant is "identical" to the reference CCCP.

Taking this as a basis, sensitivity analyses have been made for:

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¹⁾ On top of capital expenditure for reference plant: 415 mln. USD



Fuel price : +100% and -50%
 Discount rate : 5% (instead of 10%)

Year of retrofit : 5 years and 15 years after start of CCPP (instead of 10

years)

- Sensitivity analyses on fuel price show a different behaviour of the cost of avoided CO₂ for the coal-based plants compared to the natural gas fuelled plants. An increase of the fuel price results in an increase in the cost of avoided CO₂ for the natural gas fuelled plants and a decrease of cost for the coal fuelled plants. In case of a fuel price reduction the opposite occurs. Sensitivity analysis on discount rate show, as expected, a reduction of the costs of avoided CO₂ for all cases considered with a reduced discount rate.
- Sensitivity analyses on the year of retrofit show as expected that when the retrofit is executed at a later time, the cost of avoided CO₂ increase.
- The post combustion option remains the best option from a financial point of view for all sensitivities considered.

Additionally one chapter (chapter 8) is dedicated to issues related to future retrofitting, which can be anticipated for in the design stage of the original Combined Cycle Power Plant.

Indications are given for:

- Plot space requirements of the various retrofit options. They range from 175x150 to 475x375 m.
- Additional required cooling water capacities. These additional capacities range from 21,000 to 83,000 m³/h.
- Additional required space for 12" to 36" additional fuel gas line to the gas turbine when retrofitting.
- Additional required space for 36" LP steam line from the CCPP steam turbine to the CO₂ capture plant in the local cases.

In this chapter some notes on availability and the effect on CO_2 capture of failure of some process units are also given. In all cases, provided that the CCPP is allowed to operate temporarily without capturing 85% CO_2 , the availability is not affected by installing a capture plant.

Furthermore some capex reduction options and performance improvement potential have been identified.

Additional Tasks

Two additional tasks were carried out by Jacobs as a supplement to the study:

Task 1 – Same Output Retrofit

In all cases, the action of retrofitting the CCPP to capture 85% of the CO_2 , results in a reduction in net generation capacity. However, some operators may be contracted to retain the original plant output.

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In order to achieve this it is necessary in most cases to install supplementary combined cycle power plant either with additional flue gas scrubbing capacity or fuelled from an enlarged capture plant.

The results of these evaluations are summarised below:

Additional Power Requirements	Ref.	1	2-1	2-2	3-1	3-2	
Total Overall Plant Net Power Output	784.8	625.9	693.7	667.4	751.2	774.6	MWe
Additional Power Required	-	158.9	91.1	117.4	33.6	10.2	MWe
Additional Combined Cycle Gas Turbine Type	-	GE9EA	GE6FA	GE9EA	GE6B	-	
Revised Overall Plant Net Power Output	784.8	780.2	786.9	805.4	793.9	784.0	MWe
Revised Overall Plant Net Electrical Efficiency	55.9	43.8	40.6	37.9	34.2	33.6	%

The study demonstrates that the reference case output can be closely matched with CO₂ capture using additional gas turbines.

In all cases the overall efficiency is reduced. This is because the additional gas turbines are all less efficient than the GE 9FA used in the CCPP. This increases specific CO_2 emissions and the increase in capacity increases overall CO_2 emissions.

In all cases the total capital costs are increased, but in the specific capital cost differ marginally compared to the results of the original study.

Additional Capital Expenditures	Ref.	1	2-1	2-2	3-1	3-2	
Additional Capital Costs ¹	-	584	712	978	1045	1210	Million US \$
Specific Total Investment	529	1280	1432	1729	1839	2073	US \$/MWe
Costs of Avoided CO ₂	-	74.3	98.2	128.9	136.9	167.5	US \$/ton

Notes

- 1. On top of capital expenditure for reference plant of 415 million US \$
- 2. Calculated with electricity at 30.0 US \$/MWh

Task 3 _ Pre-implementation Retrofit

A major problem facing an intended new power plant investor is the choice between a plant design that cannot capture CO_2 and one that can only operate with CO_2 capture. With the former, he will face penalties under any carbon tax levy for which his only recourse is to pay. The latter choice will give him an uncompetitive plant for today that produces by-product CO_2 to no benefit.

An option is to design a fuel plant which is CO_2 capture ready based on the designs for Cases 3-1 and 3-2, renamed Cases 3-3 and 3-4 respectively. These designs could be operated to advantage without CO_2 capture. The fuel gas diluent of nitrogen and water vapour, both of which are energy intensive to use, could be replaced simply by leaving the CO_2 in the fuel gas. Here it acts as the diluent and is eventually discharged up the stacks of the CCPP and Power Block.

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The results of these calculations are summarised below.

Plant Performance Output	Ref.	3-3	3-4	
Combined Cycle Power Plant Net Electrical Output	784.8	846.6	820.8	MWe
Overall Plant Net Power Output	784.8	973.6	932.6	MWe
Total Plant Fuel Consumption (LHV)	1404.6	2388.7	2390.7	MWth
Overall Plant Net Electrical Efficiency	55.9	40.8	39.1	%

The economic results are shown in the table below.

Additional Capital Expenditure	Ref.	3-3	3-4	
Additional Capital Costs ¹	-	949	1102	Million US \$
Specific Total Investment	529	1401	1627	US \$/MWe
Costs of Electricity	30.3	44.4	49.8	US \$/MWh

Notes

1. On top of capital expenditure for reference plant of 415 million USD

A fuel plant can be built which is CO_2 capture ready and used to refuel an existing gas turbine at similar efficiencies and costs to a traditional IGCC without the ability to capture CO_2 . The prices for natural gas and coal as used in the study means that the cost of electricity produced by such a plant is not competitive with electricity produced from natural gas in a combined cycle. However, there are some parts of the world, most notably North America where the price differential between coal (or petroleum coke) and natural gas would mean that refuelling a natural gas combined cycle with syngas are commercially attractive.

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2. INTRODUCTION

The International Energy Agency Greenhouse Gas R&D Programme (IEA GHG) was established in 1991 to evaluate technologies that could be used to avoid emissions of greenhouse gas emissions, particularly from the use of fossil fuels. IEA GHG is an international organisation, supported by sixteen countries worldwide, the European Commission and several industrial organisations. From this perspective IEA GHG selected Jacobs Consultancy to study the feasibility and costs of retrofitting CO₂ capture to modern natural gas combined cycle power plants. Jacobs Consultancy is part of the internationally operating Jacobs Engineering Group, with extensive experience in retrofitting, power plant technology/projects and fuel reforming.

Fossil Fuel fired power stations are responsible for a large part of the worlds CO_2 emissions. Decreasing their emissions is an important step in decreasing the total CO_2 emission caused by human activity. Increasing their efficiency helps because less fuel is consumed for the same amount of electricity produced, but major efficiency improvements are difficult to obtain in today's modern installations. A different approach is to avoid the CO_2 being emitted by capturing it before it is emitted to the atmosphere.

Most of the power stations currently being built in developed countries are natural gas fired Combined Cycle Power Plants (CCPP). These plants could potentially be good candidates for CO₂ capture retrofit because they are relatively new and have high thermal efficiencies. This study will assess the feasibility and costs of different options for retrofitting CO₂ capture to modern natural gas combined cycle plants.

In this study two main concepts with a different approach are distinguished. The first concept is post-combustion CO_2 capture, where the flue gasses from a natural gas fired power plant are being led through a CO_2 scrubber, which removes the CO_2 from the flue gas.

The other concept is pre-combustion CO_2 capture. This comprises the reforming and treating of standard fuels to a fuel without carbon contents. When these synthesis fuels are combusted, no CO_2 is emitted to the atmosphere and therefore no flue gas cleaning is needed.

This study will describe and discuss the different techniques that are available for these concepts. The most promising techniques are compared to a standard power plant without CO_2 capture, to evaluate the consequences when CO_2 capture is applied. Hereto one reference case and several CO_2 capture cases are defined:

• Reference: Standard 800 MWe Combined Cycle Power Plant

• Case 1: Post Combustion CO₂ Capture

Case 2: Pre Combustion CO₂ Capture: Reforming natural gas

• Case 3: Pre Combustion CO₂ Capture: Gasifying Coal



In addition to this, cases 2 and 3 are divided into two subcases: a local case and a remote case. The difference between those cases is that in the local case the power plant is supplied with syngas from the Fuel/CO $_2$ Capture Plant, which is on or near the power plant site. In the remote case, the Fuel/CO $_2$ Capture Plant is located at a 40 km distance from the power plant.

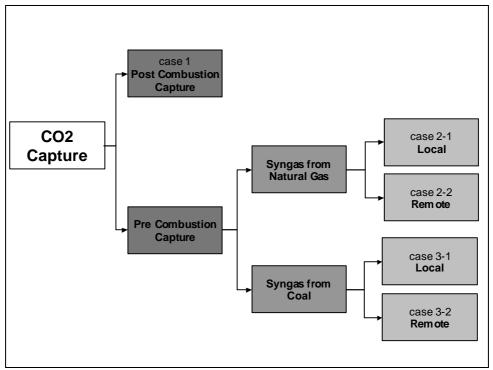


Figure 2.1 - Cases Studied

Retrofitting a CCPP to CO₂ capture requires modifications to be performed to the existing installation, as well as completely new installations to be installed. For some cases these measures will be alike, while major differences between the cases also appear. The study gives a description of these modifications and add-on installations that are needed for each individual case.

Performance calculations for the different cases are executed to compare the different options with respect to the technical performance. This includes mass and heat balance calculations with dedicated computer software, which give an exact view on the total plant performance.

Cost estimates of investment costs for retrofitting a standard power plant to a plant with CO₂ capture are based on vendor data as well as in-house information from Jacobs Engineering.

Together with the performance calculations, the cost estimates for retrofitting give the basis of the economic analysis, in which the different cases are compared with respect to economic feasibility.

Several barriers exist to retrofitting an existing power plant. These can be economical and/or technical barriers, which are often created because in the design phase of the



power plant, no special attention is paid to the possibility of future adjustments or expansion. When a plant is designed for future retrofit and these barriers are defined beforehand, they can be avoided which makes retrofitting less difficult, less costly and less time-consuming.

The study will define the possible barriers to retrofit an existing installation and indicate how, when designing a new power plant, a future retrofit to CO₂ capture can be taken into account. Furthermore the possibilities for process integration of the Capture Plant and the power plant are considered.

The report is built up as follows. Chapter 3 contains the basis of design, which incorporates all general starting points and assumptions. In Chapter 4 the technology selection for the CO_2 capture cases is substantiated. The process descriptions for the Fuel/ CO_2 capture and power plant configurations can be found in Chapter 5, together with the technical performances for each case. Chapter 6 contains the capital cost and owners cost calculations, and is followed by Chapter 7 with the economic analysis. Chapter 8 describes the barriers that can arise when an existing plant is retrofitted to CO_2 capture and assesses the possibilities to avoid these barriers by designing for future retrofit. Overall conclusions can be found in Chapter 9.

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3. DESIGN BASIS

The design basis gives the starting points and assumptions for the study, which are not specific for one case. If, for a specific reason it is decided to deviate from these starting points, it will be mentioned in the case description of individual cases in Chapter 5.

3.1 REFERENCE PLANT

The reference plant comprises two trains of GE Frame 9FA gas turbines each fitted with a triple pressure, reheat, heat recovery steam generator in combined cycle with a condensing seawater cooled steam turbine. The total plant produces approximately 800 MWe.

3.2 FEEDSTOCK

There are two types of feedstock; natural gas and coal. The feedstock data depicted below is provided by IEA.

3.2.1 Natural Gas

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian offshore reserves.

Component	Volume %
Methane	83.9
Ethane	9.2
Propane	3.3
Butane +	1.4
CO ₂	1.8
Nitrogen	0.4

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3.2.2 Coal

The coal specification is based on an open-cut coal from Eastern Australia.

Proximate Analysis	Weight %
coal (dry, ash-free)	78.3
ash	12.2
moisture	9.5
Ultimate Analysis	Weight %
Carbon	82.5
Hydrogen	5.6
Nitrogen	1.8
Chlorine	0.0
Sulphur	1.1
Oxygen	9.0
Ash Composition	Weight %
Silica as SiO ₂	50.0
Aluminium as Al ₂ O3	30.0
Iron as Fe ₂ O3	9.7
Titanium as Ti₂O3	2.0
Calcium as CaO	3.9
Magnesium as MgO	0.4
Sodium as Na₂O	0.1
Potassium as K ₂ O	0.1
Phosphorus as P₂O5	1.7
Sulphate as SO3	1.7
Gross Calorific Value (kJ/kg)	27060
Net Calorific Value (kJ/kg)	25870
Ash Fusion Point (reducing Atmosphere)	1350°C

3.3 PRODUCTS PRE COMBUSTION CAPTURE PLANT

The CO₂ capture plant for the pre combustion capture cases delivers its products at conditions described in this paragraph.

3.3.1 Carbon Dioxide

The captured carbon dioxide is dried and delivered to the battery limits at 110 bar(g) and 40 $^{\circ}$ C. The CO₂ is sulphur free and suitable for use in Enhanced Oil Recovery (EOR).

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3.3.2 Fuel Gas

The fuel gas for the gas turbines in the pre-combustion capture cases is delivered to the gas turbine at a minimum of 25 bar(g).

3.3.3 Fuel Gas Diluent

Fuel gas diluent delivered to the gas turbines in the pre combustion capture cases at which the diluent is delivered separately from the fuel gas is delivered at a pressure of at least 24 bar(q).

3.4 ENVIRONMENTAL CONSTRAINTS

3.4.1 Gaseous Emissions

The gaseous emissions are in general compliance with the large Combustion Plant Directive (2001/80/EC), current requirements for maximum permitted emission levels for power stations in the EU with a capacity in excess of 500 MW_{th} .

Approximately 85% of the carbon in the primary fuel gas is captured as CO_2 in all cases. In the natural gas fuelled cases, Case 1, Case 2-1 and Case 2-2, the primary fuel gas is natural gas. In the coal gasification cases, Case 3-1 and Case 3-2, the primary fuel gas is the raw synthesis gas from the gasifier high temperature cooling system.

3.4.2 Liquid Effluent

Most liquid discharge is treated to a sufficient standard so that it can be discharged into UK inland waterway.

A minimal amount of liquid effluent may be sent to a controlled landfill.

3.4.3 Solid Effluent

Most solid effluents are treated to a sufficient standard so that they can be sold e.g. sulphur or solid slag.

Some solid effluent is sent to specialist contractors for recovery e.g. spent catalysts and absorbents

The proportion of solid waste sent to controlled landfill is minimised.



3.5 ADDITIONAL CAPACITY, AVAILABILITY AND SPARES

3.5.1 Additional Capacity

There is no additional power generation capacity installed in the existing combined cycle power plant to replace that used to capture or compress the CO₂.

3.5.2 Availability

The overall availability of the power station on the primary fuel after retrofit is minimal 90%.

3.5.3 Spares Philosophy

All rotating equipment, except steam and gas turbines and generators, are spared on a "plus one" basis, i.e. one 100% pump has a 100% spare; two 50% pumps have one 50% spare. Certain other pieces of equipment such as sulphur treatment plants, solids handing units and gasification units may also be spared to maintain the overall availability after retrofit of 90%.

3.6 SITE INFORMATION

3.6.1 Location

The Power Station is located in North East Netherlands, close to the North Sea. For the remote pre combustion CO_2 capture cases 2-2 and 2-3, the capture plants are located 40 km from the power station and also close to the North Sea.

3.6.2 Meteorological/ Site Data

For all cases including remote pre combustion CO₂ capture, the following conditions apply:

Elevation 2m above mean sea level Barometric Pressure 1.013 bara – Design

Ambient Temperature 9 °C Relative Humidity 60 %

3.7 UTILITIES

The utilities required at the battery limit of the unit including the required conditions are described in this paragraph.

3.7.1 Open Circuit Sea Water Cooling

Seawater is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary closed water system is used for smaller coolers and machinery.



Supply: Temperature 12 °C

Pressure 1.6 barg

Design class ANSI 150 lb Rating

Material As for return

Return: Temperature 19 °C

Pressure 0.5 barg

Design class ANSI 150 lb Rating

Material Cement Lined Carbon Steel 300 NB and larger

Epoxy lined /carbon Steel 250 NB and smaller

3.7.2 Fresh Water Cooling Small Coolers and Machinery

22 °C Supply: Temperature

Pressure 3.9 barg

ANSI 150 lb Rating Design class Material Carbon Steel

37 °C Return: Temperature

> Pressure 3.0 barg

Design class ANSI 150 lb Rating Galvanised Carbon Steel Material

Note: the use of this utility is minimised.

Plant Water 3.7.3

Pressure 2.7 barg Temperature 30 °C

Design class ANSI 150 lb Rating Material Galvanised Carbon Steel

3.7.4 **Electricity**

110 kV Voltage Frequency 50 Hz

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3.8 BATTERY LIMITS DEFINITION

3.8.1 Reference Case

The battery limits for the existing reference plant are given in the following table.

Commodity	Battery Limits
Import:	
Natural gas	Natural gas inlet flange
Fresh water	Pipe flange
Sea water	Sea water intake
Export:	
Electricity	Primary transformer terminals
Waste water	Pipe flange
Sea water	Sea water discharge

ISBL Scope

CCPP: Combined Cycle Power Plant:

- Primary transformers and switchgear
- Seawater intake and discharge structure and pumps
- · Demineralised water treatment plant

Ancillaries Excluded from Scope

Connections to the electricity grid system

3.8.2 Case 1 Post-combustion Capture

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

Commodity	Battery Limits
Import:	
Flue gases	HRSG flue gas outlet flange
Low pressure steam	HRSG LP steam line
Fresh water	Pipe flange
Electricity	110 kV cable (from existing plant)
Sea water	Sea water intake
Export:	
CO ₂	CO ₂ export pipe flange
Waste water	Pipe flange
Sea water	Sea water discharge
Condensate	Condensate system



ISBL Scope

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

New Capture Plant:

- · Flue gas scrubbing unit
- CO₂ compressor and dryer
- Utilities including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, roads and buildings.

Ancillaries Excluded from Scope

· Connections to the electricity grid system

3.8.3 Case 2-1 - Natural Gas Pre-combustion Capture (Local)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

Commodity	Battery Limits
Import:	
Natural gas	Natural gas inlet flange
Fresh water	Pipe flange
Electricity	110 kV cable (from existing plant)
Sea water	Sea water intake
Export:	
Fuel gas	Import flange on CCPP
CO ₂	CO ₂ export pipe flange
Waste water	Pipe flange
Sea water	Sea water discharge

ISBL Scope

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

New Capture Plant:

- Fuel gas production plant
- CO₂ compressor and dryer
- Utilities including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, flare system, roads and buildings.

Ancillaries Excluded from Scope

• Connections to the electricity grid system

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3.8.4 Case 2-2 - Natural Gas Pre Combustion Capture (Remote)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

Commodity	Battery Limits
Import:	
Natural gas	Natural gas inlet flange
Fresh water	Pipe flange
Electricity	110 kV cable (from grid)
Sea water	Sea water intake
Export:	
Fuel gas	Inlet flange at existing CCPP
CO ₂	CO ₂ export pipe flange
Waste water	Pipe flange
Sea water	Sea water discharge

ISBL Scope

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Demineralised Water Treatment Plant (extension)

New Capture Plant

- Fuel gas production plant
- Sea water intake and discharge structures
- · Fuel gas pipeline
- CO₂ compressor and dryer
- Utilities including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, flare system, roads and buildings.

Ancillaries Excluded from Scope

Connections to the electricity grid system

3.8.5 Case 3-1 - Coal based Pre-combustion Capture (Local)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

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Commodity	Battery Limits
Import:	
Coal	Coal storage pile
Fresh water	Pipe flange
Electricity	110 kV cable (from existing plant)
Sea water	Sea water intake
Export:	
Fuel gas	Import flange on CCPP
CO ₂	CO ₂ export pipe flange
Waste water	Pipe flange
Sea water	Sea water discharge

ISBL Scope

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

New Capture Plant

- · Fuel gas production plant
- Sea water intake and discharge structures
- Coal reclaimer, conveyors, grinding and slurrying plant
- Black water treatment plant
- · Fuel gas pipeline
- CO₂ compressor and dryer
- Utilities including primary and secondary cooling water, demineralised and wastewater treatment plant, firewater, instrument air, flare system, back-up fuel tank, roads and buildings.

Ancillaries Excluded from Scope

- Connections to the electricity grid system
- Coal delivery system

3.8.6 Case 3-2 - Coal based Pre-combustion Capture (Remote)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.



Commodity	Battery Limits
Import:	
Coal	Coal storage pile
Fresh water	Pipe flange
Electricity	110 kV cable (from grid)
Sea water	Sea water intake
Back-up fuel	Inlet flange
Export:	
Fuel gas	Inlet flange at existing CCPP
CO ₂	CO ₂ export pipe flange
Waste water	Pipe flange
Sea water	Sea water discharge

ISBL Scope

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)
- Demineralised Water Treatment Plant (extension)

New Capture Plant

- Fuel gas production plant
- Sea water intake and discharge structures
- · Coal reclaimer, conveyors, grinding and slurrying plant
- Black water treatment plant
- Fuel gas pipeline
- CO₂ compressor and dryer
- Utilities including primary and secondary cooling water, demineralised and wastewater treatment plant, firewater, instrument air, flare system, back-up fuel tank, roads and buildings.

Ancillaries Excluded from Scope

- Connections to the electricity grid system
- Coal delivery system



4. TECHNOLOGY SELECTION CO₂ CAPTURE

4.1 CASE 1 – POST-COMBUSTION CAPTURE

In Case 1, CO_2 capture is effected by installing a scrubbing unit to absorb the carbon dioxide from the gas turbine flue gases. The absorbent solution is regenerated by heating and the CO_2 is compressed, dried and exported from the Capture Plant.

There are two generic types of solvents for CO₂; chemical solvents such as amines, and physical solvents such as poly-glycols. These are usually used as a solution in water. Both of these solvent types were developed for refinery and petrochemical applications where the process streams are at elevated pressure and in reducing atmospheres. With flue gas scrubbing, the process stream is necessarily at atmospheric pressure and in an oxidising environment.

The CO_2 partial pressure in gas turbine exhaust is especially low because large volumes of un-combusted air are used to cool combustion flames, moderation air is used to control the TIT (Turbine Inlet Temperature), and air is also used to cool stator and rotor blades. The typical CO_2 content of gas turbine exhaust is 3-4% by volume, which compares starkly with a typical figure of 10-15% for fired boilers

This means that absorption is weak and large volumes of solvent are required. The low partial pressure of CO_2 in the flue gas also means that solution regeneration by simple pressure reduction, or flash, is not possible. Therefore regeneration has to be achieved by stripping the rich solvent with steam. The steam is usually generated by simply boiling part of the water component in the solution. The large volumes of solution and the absence of any advantage from pressure flash mean that heating (regenerator reboiler) load is very high.

The problem of an environment that is oxidising, rather than reducing, for which the solvents were developed, is rapid degradation of the solvent. The oxidation products tend to form a solid sludge, which is filtered from the solution, and the system is "topped up " with fresh solvent on a regular basis.

The low partial pressure of the CO_2 means that chemical solvents such as amines are preferred rather than physical solvents. These have a stronger affinity for the CO_2 and therefore less solvent is required. Because of the oxidising nature of the oxygen rich flue gas, simple amines such as MEA are chosen rather than the more active and expensive amines such as MDEA.

Therefore Case 1 comprises the CCPP fuelled with natural gas followed by flue gas scrubbing with an MEA solution. The solution is regenerated in a reboiled stripping column with the heat provided by low-pressure steam taken from the steam cycle of the CCPP.

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4.2 CASE 2 – PRE-COMBUSTION CAPTURE FROM NATURAL GAS

In Case 2, capture is effected by removing the carbon before combustion, also in the form of carbon dioxide, but generated this time through a two stage chemical process of converting the natural gas to a mixture of hydrogen and carbon dioxide.

Such pre-combustion capture of CO₂ requires that the natural gas is converted to CO₂ and hydrogen in the Capture Plant before hydrogen rich fuel gas is fed to the CCPP.

The Capture Plant first converts natural gas to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a series of shift reactors and then a liquid solvent is used to remove the CO_2 to produce the hydrogen rich fuel gas. For NO_x control, the fuel gas is saturated with water.

There are two basic technologies, which can be used to convert natural gas into synthesis gas, plus two basic CO₂ removal technologies. Each of these has a variety of implementation options and several possible methods of NO_x control.

Figure 4.1 shows a simplified decision tree for the choice of technology for the precombustion capture of CO₂ from natural gas. It should be noted that for the remote case steam injection is applied rather than water saturation.

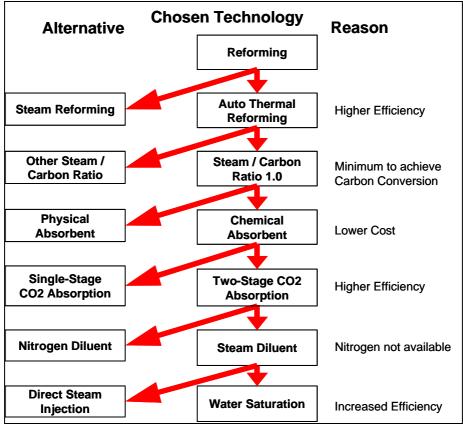


Figure 4.1 - Technology Selection case 2

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4.2.1 Reforming

The chemical conversion of natural gas into mainly hydrogen and oxides of carbon is generally carried out through catalytic reaction with steam (steam reforming) or a mixture of steam and oxygen (auto-thermal reforming).

Steam Reforming

Steam reforming is the reaction of natural gas with steam over a catalyst at elevated temperature and pressure according to the reactions below:

Steam Reforming

$$C_x H_{2y} + x H_2 O \to x CO + (x + y) H_2$$
 (1)

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{2}$$

The reactions are endothermic and better conversion is achieved at high temperatures. The reactor is therefore configured as a series of tubes filled with catalyst inside a fired heater. The process conditions are typically 25 bar(g) and 850°C and are limited by the metallurgy of the reactor tubes. The heater is fired with either more natural gas, or in the case of a carbon capture plant, some of the carbon-free fuel gas.

The efficient conversion of the natural gas to syngas is crucial, as any unconverted carbon-containing methane left in the syngas cannot be captured as CO₂. The methane slip is inversely proportional to the partial pressure of the reactant steam and therefore a high steam to natural gas ratio is used. A further advantage is that conversion of the CO produced in the reformer to CO₂ in the shift reactor is also facilitated by the presence of large amounts of steam. A disadvantage is that the large amount of steam increases the sensible heat load in the reformer which in turn increases the fuel required by the fired heater and lowers the overall efficiency of the plant to less than 70% including auxiliary power.

Auto Thermal Reforming

Auto-thermal reforming is the reaction of natural gas with oxygen and steam over a catalyst at elevated temperature and pressure according to the reactions below:

Total Oxidation of Higher Hydrocarbons

$$C_x H_y + \frac{4x+y}{4} O_2 \to x C O_2 + \frac{y}{2} H_2 O$$
 (1)

Total Oxidation of Methane

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \tag{2}$$

Steam Reforming of methane

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$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{3}$$

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{4}$$

The high temperature of the reactor, typically 1050 °C ensures that equation (3) is driven to the right, minimising the methane content of the reformed gas. This means that the amount of steam used is lower than for steam only reforming, and the exit syngas is rich in CO. The overall efficiency of the total plant including auxiliary power is just under 78%.

The capital cost of autothermal reforming is similar to steam reforming but it is significantly more efficient. Therefore autothermal reforming is chosen for the study.

The simplest way of providing oxygen for the ATR is to use air. This has the advantage of adding nitrogen to dilute the hydrogen fuel gas at the same time. The efficiency of the process is also improved by utilizing the heat from the discharge of the air compressor.

The disadvantage is that the nitrogen so introduced increases the volumetric and mass flow of the gas through the ATR, which requires more oxygen to be consumed to heat up the additional nitrogen.

The alternative is to use oxygen from an ASU. The advantages are that:

- 1. No nitrogen diluent is present in the ATR feed and therefore less oxygen is consumed than in the air blown case.
- 2. No nitrogen is present in the syngas and therefore the downstream equipment; shift, syngas cooling and acid gas removal sections are smaller and less expensive.

The disadvantage is that the ASU cost far exceeds that of the air compressor and more power is required to drive the ASU and compress the oxygen and nitrogen than is required by the air compressor alone.

Therefore as the additional capital cost of the ASU exceeds the cost savings in the downstream equipment and the parasitic power demand of the ASU is higher than that of the air compressor, an air blown ATR is chosen.

4.2.2 Varying Steam to Carbon Ratio in the Autothermal Reformer

A variety of steam to carbon ratios were considered. It was found that as the steam to carbon ratio was reduced, overall conversion of the natural gas decreased but the overall thermal efficiency increased. The overall capital cost of the different configurations did not vary much, but with steam to carbon rations of less than 1.25, catalyst life is reduced by 20%. The increase in efficiency more than compensates for the increased catalyst costs and therefore unit costs decrease with decreasing steam to carbon ratio. The limiting factor is then the related reduction in conversion of

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hydrocarbon to CO_2 . At a steam to carbon ratio of 1.0, the overall carbon capture is just over 85%. Therefore a steam to carbon ratio of 1.0 is selected.

4.2.3 CO Shift system

In order to achieve the specified 85% capture of carbon, the CO in the reformed gas has to be converted to CO₂. Studies have shown that there is sufficient surplus steam from the reforming process to achieve this in a combination of a High Temperature (HT) and a Low Temperature (LT) catalytic shift reactor.

4.2.4 CO₂ removal Section

There are many commercial methods used for the removal of CO_2 from process gas streams. These include using solvents, pressure swing adsorption, temperature swing adsorption, cryogenic separation and membrane separation. For the bulk removal of CO_2 from high pressure process streams, pressure swing adsorption, temperature swing adsorption, cryogenic separation or membrane separation are not considered to be feasible and all large scale commercial applications use solvents.

There are two generic types of solvents for CO_2 , chemical solvents such as amines and physical solvents such as poly-glycols. These are usually used as a solution in water. The CO_2 is absorbed from the syngas in an absorber column and regenerated either by simple pressure flash or by stripping with steam. The steam is usually generated by simply boiling part of the water component in the solution.

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Solvent Selection

The advantage of chemical solvents over physical solvents is that they have a strong affinity for the CO_2 and therefore much less solvent is required. This means that process equipment, such as absorber and stripper columns, pumps and pipework is smaller. The strong affinity for CO_2 is also useful for removing CO_2 from process streams at low to moderate partial pressures. However, the stronger affinity for CO_2 also means that the regeneration energy requirement is larger.

For pre-combustion capture of CO_2 from natural gas, the partial pressure of CO_2 is less than 5 bar(a). Under these conditions, an amine-based system is selected as the reduced capital costs outweigh the slightly reduced efficiency when compared with physical solvents.

Process Configuration

There are several possible configurations of the amine CO_2 removal unit. Because of the low partial pressure of CO_2 in the product gas, the rich amine solution cannot be regenerated by simple pressure flash alone. Therefore some of the amine has to be regenerated using a steam stripper in order to become lean enough to absorb sufficient CO_2 from the syngas.

It is possible to have either a single or a two-stage CO₂ absorber.

In the two-stage absorber, the bulk (over 70%) of the CO_2 is removed in the lower section and the solution is partially regenerated by pressure flash. The partially regenerated (or semi-lean) amine solution is then returned to the top of the lower section of the absorber. The remainder of the CO_2 is removed in the upper section of the absorber by washing with lean amine solution which has a much lower residual CO_2 content because it has been regenerated with steam in a stripper column. The much lower CO_2 content of the lean amine means that it can absorb, on a tonne for tonne basis, much more CO_2 than the semi-lean solution.

Thus, if more lean solution is circulated, the duty of the semi-lean solution circuit is reduced. This reduces the pumping duty and the size of the absorber. However the size of the stripper column and the reboiler duty is correspondingly increased.

The logical extension is to have a single stage absorber and circulate only lean solution, thus removing the semi-lean solution system all together. The single stage CO_2 absorber is smaller in diameter and overall height than a two-stage absorber, and the pumping duty is reduced by over 60%. The disadvantage is that the diameter of the stripper column increases by over 60%, and the reboiler duty by over 170%. This additional heat requirement, of 50 MW_{th}, would have a significant impact on the overall plant efficiency.

The two-stage absorber option is therefore selected.



4.2.5 Fuel Gas Conditioning

At the exit of the CO_2 absorber, the fuel gas contains 42% H_2 plus 39% N_2 , together with small amounts of CO_2 , CO, CH_4 and Ar. This gas has a high adiabatic flame temperature and, if fed directly to a gas turbine, would generate unacceptable levels of NO_x . The flame temperature can be reduced and controlled either by the addition of nitrogen or water vapour.

Selection of Diluent

As the Auto Thermal Reformer (ATR) is blown with air, there is no Air Separation Unit (ASU); therefore a dedicated proprietary nitrogen generator would have to be used to provide nitrogen. This would consume electricity to drive the generator and compress the nitrogen, and require an expensive new unit operation. Water vapour addition is more cost effective and is therefore selected.

Water Vapour Addition

Water vapour can be added to the fuel gas either by direct steam addition, or by using a saturator. A saturator consists of a packed column, which directly contacts the fuel gas with hot water. Surplus water from the bottom of the column plus make-up water is pumped through a series of heat exchangers where it is reheated and returned to the top of the column. There is a small blow-down stream.

Alternatively, steam can be injected directly into the combustion chamber of the gas turbine. This steam can be taken either from the Capture Plant steam system or from the HRSG of the CCPP.

Water saturation is more capital intensive than direct steam addition because more process equipment is required, namely the saturator column, pumps and heat exchangers, however it is more efficient because it can use low grade heat from the Capture Plant which may otherwise be rejected to the cooling system. Direct steam addition is less efficient because the steam added is medium pressure, superheated steam which could otherwise be used to generate more electricity in the steam cycle.

When the Capture Plant is located close to the CCPP (Case 2-1), low-grade heat is available; therefore water saturation is selected because it is more efficient.

When the Capture Plant is remote from the CCPP (Case 2-2), there is no unused low-grade heat available, and because it is unfeasible to transmit low-grade heat over large distances, direct steam addition from the CCPP steam cycle is therefore selected.

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4.3 CASE 3 – PRE-COMBUSTION CAPTURE FROM COAL

In Case 3, capture is again effected by removing the carbon in the form of carbon dioxide before combustion following a similar process route to the natural gas cases. However, this time, the first of the two stage chemical process of converting coal to a mixture of hydrogen and carbon dioxide consists of a gasifier rather than a reformer.

In essence, the Capture Plant converts the coal to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a shift reactor. The sulphur containing gases and CO_2 are removed with a solvent, and nitrogen and / or water added to the fuel gas for NO_x control.

There are several gasification technologies a number of possible shift systems, two basic CO_2 removal technologies, each with implementation options, and two forms of NO_x control.

Figure 4.2 shows a simplified decision tree for the choice of technology for the precombustion capture of CO_2 from coal.

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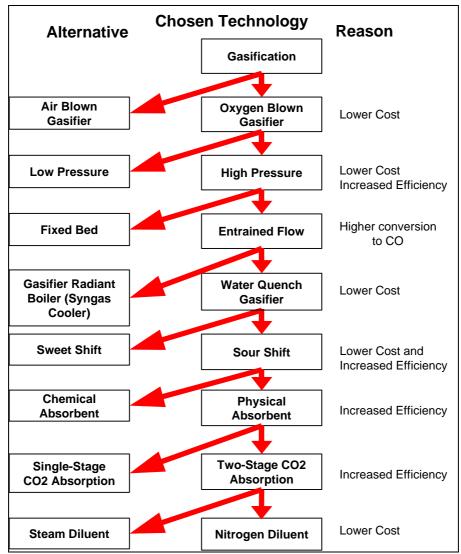


Figure 4.2 - Technology Selection case 3

4.3.1 Gasification

Oxidant

The oxygen required for the partial oxidation or gasification of the coal can be supplied either as air or as oxygen separated from air. Using air has the double advantage of not requiring the capital investment of an ASU and directly adds nitrogen to the fuel gas, which then acts as a diluent for NO_x control (see section 3.5 Fuel Gas Conditioning). The disadvantages of using air are that it is inefficient and expensive.

The capital costs of a gasification based capture plant are proportional to the volume flow through the plant. This includes the gasifier, cooling train, shift reactors and acid gas removal. Lower flowrates, mean lower capital costs.

Air contains less than 21% oxygen by volume. Therefore, to provide the quantity of oxygen required for gasification using air requires a volume flow of air nearly five times



more than the corresponding flow of pure oxygen. All the nitrogen associated with the oxygen in the air will pass through the plant, raising the capital cost substantially. The use of pre-separated oxygen rather than air keeps the volume throughput at a minimum and hence the capital cost at a minimum. This reduction in cost more than outweighs the cost of an Air Separation Unit (ASU).

Using oxygen rather than air is also more efficient. If air is used, all of the nitrogen present in air has to be heated to the gasification temperature, in excess of 1400°C. The source of energy for this is oxidation of the coal. Therefore more coal has to be oxidised, and more air used, than if pure oxygen alone were used. The sensible heat in the nitrogen is recovered in the cooling systems, but that enthalpy is lost from the fuel gas and the overall process becomes less efficient.

Oxygen is therefore selected as the oxidant.

Many optimisation studies have been carried out on the effect of oxygen purity on gasification based fuel gas plants. The general conclusion is that an oxygen purity of 95 vol% is the most cost effective.

The oxygen purity selected is therefore 95 vol%.

Operating Pressure

The Capture Plant gasifier can operate at a range of pressures from 35 bar(g), sufficient to deliver fuel gas to a local CCPP without further compression, up to 63 bar(g), which is the highest operating pressure yet used in a commercial coal fed gasifier.

The efficiency of a gasification based Capture Plant increases with pressure for three reasons:

- 1. More power can be generated through an expander, letting the syngas down from gasification pressure to gas turbine feed pressure, than is used in compressing the oxidant above gas turbine feed pressure.
- 2. Higher operating pressures increase the temperature at which surplus steam in the syngas will condense and hence aid efficient heat recovery.
- 3. More CO₂ can be recovered by pressure flash and less reboil is required.

The capital cost of a gasification based capture plant is proportional to the volume flow through the plant. This includes the gasifier, cooling train, shift reactor and acid gas removal. Higher operating pressures mean lower capital costs despite the design requirement for thicker vessel walls.

The selected operating pressure is therefore 63 bar(g) - the highest commercially proven operating pressure to date.

Gasifier Selection

There are two basic gasifier types for the continuous gasification of coal to syngas:

- Entrained Flow
- Fixed Bed

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Entrained Flow

Entrained flow gasifiers are fed with pulverised feedstock entrained in either water as a slurry, or in a dense phase flow under pressure with nitrogen. Main examples are ChevronTexaco and ConocoPhillips (formerly Global Energy E-Gas) – both are slurry fed; Future Energy (formerly Noell) – both slurry and dense phase flow fed; and Shell – dense phase flow fed only.

The temperature in the gasification chamber is sufficient to melt the ash. The ash becomes an inert slag or "frit" and over 95% of the carbon and hydrocarbons in the coal are converted to carbon oxides and hydrogen. Water is an important moderating reactant and in the case of the dry feed gasifiers, is added as steam.

Sulphur in the coal is converted to H_2S with a little COS, and the other compounds reduced to their elements. Hydrocarbons in the exit gases are less than 1% and limited to methane.

Fixed Bed

Fixed bed gasifiers are gravity fed with lump feedstock through a lock hopper system at the top of the gasifier. The oxidant and steam moderator are injected at the bottom where most of the carbon in the coal is gasified to carbon oxides and hydrogen. As the feedstock moves down the bed, it is gradually heated by the hot gases rising from the bottom of the gasifier. The feedstock is pyrolysed, driving off the volatile hydrocarbons and sulphur compounds before they reach the bottom of the gasifier. Therefore the hydrocarbon content of the exit gases can be up to 25%, containing a large proportion of heavy hydrocarbons including tar, phenol and cresols. The sulphur is also present in complex compounds.

As fixed bed gasifiers do not convert sufficient carbon in the feedstock to carbon oxides, to be able to capture 85% of the carbon as CO₂, entrained flow gasifiers are selected.

High Temperature Cooling

Raw syngas exits an entrained flow gasifier at very high temperatures (> 1000°C) and is cooled by either raising high pressure steam in a specially designed boiler, or by being quenched in a water bath.

In the Capture Plant, the carbon monoxide in the raw syngas is converted to carbon dioxide (see section 4.2.3 CO Shift system for more details) ready for capture in a shift reactor according to the equation:

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2$$

This is an equilibrium (reversible) reaction and to encourage conversion of CO, the mole fraction of the steam should be as high as possible.



The mole fraction of steam in the raw syngas from an entrained flow gasifier is low, typically 5-10%, depending on the feedstock and gasifier type. Therefore much more steam has to be added to effect the conversion of the CO to CO₂.

If a high pressure boiler is fitted to cool the raw syngas from the gasifier, then the generated steam can be directly injected into the syngas upstream of the shift reactor. This steam is "clean" i.e. it is produced from high quality demineralised water (demin water) and does not contain sulphur or other contaminants. Therefore it can be used in a sweet shift reactor as well as a sour shift reactor, (see section 4.3.2 Shift System for more details). The disadvantage is that direct steam injection consumes large volumes of demin water and the make-up plant has to be sized for this duty.

An alternative is to fit a direct water quench to the outlet of the gasifier. The enthalpy in the raw syngas exiting the gasifier generates steam intimately mixed with the syngas and ready for the shift reaction. The advantage of water quenched gasifiers for shifted schemes over gasifiers fitted with boilers is that the quench is a small and simple, relatively low temperature, low cost vessel. Whereas high temperature "dirty" (the hot raw syngas contains all the ash and sulphur in the feedstock) waste heat boilers are large, complex and therefore expensive.

A previous IEA GHG study¹ in which various options have been evaluated, has shown that for Integrated Gasification Combined Cycle (IGCC) plant, the lowest cost electricity is produced by designs which use water quench gasifiers. This is because the lower efficiency of the water quench design is outweighed by the lower capital cost. As the Capture Plant and the CCPP together are in effect an IGCC, it is logical that the same economic drivers apply.

Hence for this application, especially where the addition of a large quantity of steam is required for shifting of the syngas, a quench cooled gasifier is selected.

Gasifier Technology

An oxygen blown, entrained flow gasifier, operating at a pressure of 63 bar(g) and fitted with a quench cooler, is therefore selected. There is only one commercial gasification technology, which satisfies all of these requirements, and that is the ChevronTexaco (CVX) gasifier.

4.3.2 Shift System

The shift system catalytically converts CO to CO₂ with co-product hydrogen according to the equation:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

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¹ "Potential for Improvement in Gasification Combined Cycle Power Generation with CO₂ Capture" IEA GHG 2003



The shift catalyst can either be sulphur tolerant, and is then termed a "sour" shift catalyst, or it is poisoned by sulphur in which case it is known as a sweet shift catalyst.

Sweet shift catalysts can be used only with feed gases which contain very low levels of sulphur compounds, typically less than 2 ppm. The syngas from a coal gasifier contain typically 0.5% $\rm H_2S$ which would very quickly poison a sweet shift catalyst. Therefore sweet shift catalysts have to be installed downstream of a sulphur removal unit.

Commercial sulphur removal technologies are highly active towards H_2S , but have difficulty in removing COS from the 100 ppm present in the raw syngas down to below 2 ppm required by the sweet shift catalyst. Therefore COS hydrolysis is required upstream of the sulphur removal unit. COS hydrolysis catalyst promotes the COS hydrolysis reaction:

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

To use a sweet shift system, the Capture Plant therefore comprises, gasification unit and high temperature cooling, COS hydrolysis reactor, low temperature cooling, sulphur removal, reheating, steam injection or water saturation, sweet shift reactors, cooling and CO₂ removal.

The alternative is to use a sour shift catalyst which promotes the water gas shift reaction, COS hydrolysis reaction and the HCN hydrolysis reaction:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

COS Hydrolysis

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

HCN Hydrolysis

$$HCN + H_2O \Leftrightarrow CO + NH_3$$

The conversion of COS to H₂S occurs simultaneously with the conversion of CO to CO2 and the level of COS in the shifted syngas is low enough to use commercial sulphur removal technologies.

Therefore, using a sour shift system, the Capture Plant comprises, gasification unit and high temperature cooling with saturation of raw syngas, sour shift reactor, low temperature cooling, sulphur and CO₂ removal in the same unit.

The flow schemes used in this study contain a desaturator which greatly increases the mole fraction of steam at the inlet to a sour shift reactor such that greater than 85% carbon capture can be achieved using a single bed of sour shift catalyst.

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As a previous IEA study (1) has shown, the advantage of using a sour shift catalyst system is that it is simpler and lower capital cost than a sweet shift system. A sour shift system requires only one cooling train and one acid gas removal unit compared to the two cooling trains, a heating train and water saturation system, and two acid gas removal units required by a sweet shift system.

Therefore, a single bed sour shift system is selected

4.3.3 Acid Gas Removal

In a gasification based Capture Plant there are two acid gas species to be removed, sulphur compounds and CO₂. Sulphur compounds exiting an entrained flow gasifier are mainly H₂S with a small amount of COS. Other sulphur compounds are negligible.

The two generic types of solvents for CO_2 removal are chemical solvents such as amines, and physical solvents such as poly-glycols. Both are normally used as a solution in water. The CO_2 is absorbed from the syngas in an absorber column and regenerated either by simple pressure flash or by stripping with steam. The steam is usually generated by simply boiling part of the water component in the solution.

Neither amines nor poly-glycols have strong affinity to COS. If COS is present in the feed to the acid gas removal unit, significant amounts of sulphur will "slip" through the unit and sulphur emission limits exceeded. COS can be hydrolysed to H_2S either over a sour shift catalyst or in a dedicated COS hydrolysis reactor see section 4.2.3 CO Shift system for more details.

Solvent Selection

The advantages of chemical solvents over physical solvents is that they have a strong affinity for H_2S and CO_2 and therefore much less solvent is required. This means that process equipment, such as absorber and stripper columns, pumps and pipework is smaller. However the stronger affinity also means that the regeneration energy is also larger.

The advantage of physical solvents over chemical solvents is that for CO_2 absorption at high pressure, the solvent can be regenerated using simple pressure flash. Also, most of the CO_2 is recovered at 5 bar(g), greatly reducing the CO_2 compressor power and costs. Thermal stripping is still required to recover the more strongly absorbed H_2S from the solvent, but the regeneration energy is much less than that required by physical solvents.

For pre-combustion capture from gasified coal, the partial pressure of CO_2 is about 20 bar(a). Under these conditions, a poly-glycol (trade name Selexol) based system is selected as the lower energy demand, both for regeneration and CO_2 compression, outweighs the increased capital costs when compared with chemical solvents.

Process Configuration

To avoid corrosion in the CO_2 export pipeline, the regenerated CO_2 needs to be free of H_2S . To avoid overloading the sulphur recovery plant, the H_2S in the feed to the



sulphur plant needs to be kept high. i.e. the unit needs to recover the H₂S and the CO₂ from the solvent in two separate steams.

This is carried out by absorbing the sulphur compounds first and then absorbing the CO₂.

Because of the low partial pressures of H_2S and CO_2 in the fuel gas after CO_2 capture, the rich Selexol solution cannot be regenerated by simple pressure flash alone. Therefore some of the Selexol has to be regenerated using a steam stripper in order to become lean enough to absorb sufficient H_2S and CO_2 from the syngas.

The acid gas removal system developed by UOP consists of separate H₂S and CO₂ absorber columns, a third column to concentrate the H₂S in the rich liquor and a steam stripper column to regenerate the Selexol.

4.3.4 Sulphur recovery

There are a variety of sulphur recovery technologies commercially available.

Because oxygen is available at low cost from the ASU, an oxygen blown Claus unit is selected for sulphur recovery. The tail gas from the Claus unit is compressed and returned to the inlet of the H_2S absorber column and the water effluent is returned to the de-saturator.

There are no normal sulphur emissions to atmosphere other than through the gas turbine exhaust.

4.3.5 Fuel Gas Conditioning

At the exit of the CO_2 absorber, the fuel gas contains 75% H_2 plus 16% N_2 , together with small amounts of CO_2 , CO, CH_4 and Ar. This gas has a high adiabatic flame temperature and, if fed directly to a gas turbine, would generate unacceptable levels of NO_x . The flame temperature can be reduced and controlled either by the addition of nitrogen or water vapour.

Selection of Diluent

There is a large flow of waste nitrogen available from the ASU, which is normally vented to atmosphere. This can be compressed and added to the fuel gas as a convenient inert diluent for both pre-capture coal cases.

Water vapour can be added to the fuel gas either by direct steam addition, or by using a saturator. A saturator consists of a packed column, which directly contacts the fuel gas with hot water. Surplus water from the bottom of the column plus make-up water is pumped through a series of heat exchangers where it is reheated and then returned to the top of the column. There is a small blow-down stream.

Alternatively, steam can be injected directly into the combustion chamber of the gas turbine. The steam is either taken from the Capture Plant steam system or from the HRSG of the CCPP.



Studies carried out by Jacobs have shown that for IGCC plants, where the low grade heat can be used efficiently, the cost of electricity production using water injection or saturation (including water purchase and purification) is higher than for schemes using nitrogen dilution. The flowschemes used in this report all include a desaturator which upgrades all of the low-grade heat so that it can be used to generate low pressure steam.

Therefore for Case 3-1, nitrogen is selected as the diluent when the capture plant is local to the CCPP.

In Case 3-1 where the Capture Plant is located local to the CCPP, the nitrogen can be injected directly into the combustion cans of the gas turbine. As the combustor cans are at a lower pressure than the fuel delivery system, the diluent nitrogen can be delivered at a lower pressure than the fuel gas thus saving on parasitic compressor power.

In Case 3-2, where the Capture Plant is remote from the CCPP, the diluent nitrogen is compressed to the full fuel gas pressure, which can be up to 60 bar(g), for pipelining purposes.

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5. PROCESS DESCRIPTIONS AND PERFORMANCES

This chapter contains the process descriptions for the considered cases. The configurations for the different capture plants are discussed, together with the modifications that are needed to the CCPP. The first paragraph describes the reference case, which contains a standard CCPP fired on natural gas. The power plant configurations for the other cases are all based on this reference case but modifications are required. These modifications are assessed as well.

The technical performances of the different cases are described and compared on a basis of electrical efficiency and CO₂ emission.

Reference is made to appendix 1 for CCPP simplified process scheme and mass balance. Reference is made to appendix 2 for simplified process schemes and mass balances of Fuel/CO₂ capture plants. Reference is made to appendix 3 for plot layouts of all plants. Reference is made to appendix 4 for equipment lists of Fuel/CO₂ capture plants. Reference is made to appendix 5 for overview of power consumption/production and utility usage in all designs for Fuel/CO₂ capture plants.

5.1 REFERENCE CASE: STANDARD COMBINED CYCLE POWER PLANT

This paragraph describes the process design and performance of the reference case, which consists of a standard combined cycle power plant, including the most significant design parameters for the major equipment and systems. This case represents the reference plant without CO_2 capture, to which the other (retrofitted) cases are compared.

5.1.1 CCPP Description

The study is based on an 800 MWe power plant, consisting of two identical trains of natural gas fired, standard combined cycle units. Each of the two combined cycle trains comprises:

- One gas turbine
- One triple pressure, non fired, natural circulation Heat Recovery Steam Generator (HRSG) with reheat section
- One steam turbine with HP, IP and LP-condensing sections

The gas turbine and steam turbine for each unit are connected to a common hydrogen cooled generator. (i.e. single shaft configuration)

The overall plant design, including the selected components, has been based on state of the art proven technology.

A GE Frame 9FA gas turbine (approximately 260 MW $_{\rm e}$), with a dry low NO $_{\rm x}$ combustion system has been selected as a typical representative proven design gas turbine in the power range considered.

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Туре	GE PG9351(FA)
ISO Base Rating	255.6 MWe
Heat rate	9759 kJ/kWh
Pressure ratio	15.4
Mass flow	623.7 kg/s
Exhaust Temperature	609 °C

Table 5.1 - GE Frame 9FA Gas Turbine Performance Data

This gas turbine can be considered as the current proven state of the art within its power range. Alternative gas turbines within this power range are (ISO base rating between brackets):

Alstom GT26 (263.0 MWe)
 Siemens V94.3A (265.9 MWe)
 Mitsubishi M701F (270.3 MWe)

It shall be noted that the required modifications to these gas turbines when fired on low LHV fuel gas will differ for each type of gas turbine. With other words, the modifications as described in this report for the General Electric 9FA gas turbine should not be considered to be representative for gas turbines from other manufacturers.

For evaluation purposes the following starting points are used:

- Fuel: natural gas (Reference is made to paragraph 3.2.1)
- Ambient conditions as described in paragraph 3.6.2
- · Gas turbine base load operation
- No degradation
- No fouling
- Other starting points:

Inlet pressure drop	10 mbar
Exhaust pressure drop	30 mbar

Table 5.2 - Reference Case Starting Points

The HRSG of the standard power plant is a non-fired triple pressure natural circulation boiler with single reheat. As the installation is considered to be a base load operating power plant the design is optimized with respect to the overall efficiency of the system. The higher overall efficiency will consequently result in a reduction of the fuel gas consumption and CO₂ emission compared to a non-optimised installation.

In the simplified process diagram of the standard design (see appendix 1) only major components are presented. Additional facilities, which are required for operation of the plant over the complete operating range such as de-superheating equipment, closed cooling water system and instrument air, etcetera are not shown. The HRSG supplies steam at the following pressures and temperatures:

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	Pressure	Temperature
HP: High pressure	120 bara	560 °C
IP: Intermediate pressure	27 bara	560 °C
LP: Low pressure	4.6 bara	300 °C

Table 5.2 - HRSG Pressure/Temperature Levels

In order to achieve the given steam conditions the HRSG process design is according to *Table 5.3*.

High pressure superheater	Steam temperature	560	°C
Medium pressure superheater/ reheater	Steam temperature	560	°C
Medium pressure superheater	Steam temperature	300	°C
Low pressure superheater	Steam temperature	300	°C
High pressure economizer	Degrees of subcooling	3	°C
Medium pressure economizer	Degrees of subcooling	3	°C
Low pressure economizer	Degrees of subcooling	3	°C
Water preheater	Exit temperature	90	°C
Evaporator (low, medium and high pressure)	Pinch delta temperature	8	°C

Table 5.3 - HRSG process design

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the seawater temperature of 12°C, a maximum allowed temperature rise of 7°C and an approach temperature of 10°C.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency. Therefore the deaerator system will operate at a pressure of 1.2 bar; 105°C with a condensate feed water temperature of 90°C (The feed water temperature shall be approximately 15 °C below the deaerator temperature to ensure a high deaerator efficiency). LP steam will be used for deaeration and heating of the condensate.

The condensate from the condenser will be heated from 29°C to 90°C by means of a closed water loop, which is using the flue gas heat from the stack to preheat the condensate. Direct heating the condensate with flue gas is not preferred because the condensate entry temperature is below the dew point of the flue gas.

List of remaining starting points:

- For calculation of the auxiliary power consumption all the pumps used have an overall efficiency of 75%.
- The generator efficiency is 98.3%
- Blow down and deaerator vent is set at 0%
- Minor steam losses, such as the ejector steam and gland steam are neglected.

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The steam turbine is split up in the following sections:

- A HP section, which is supplied with steam from the HP superheater
- A MP section, which is supplied with a mixture of steam from the MP superheater and steam from the HP turbine which is reheated in the reheat section
- A LP section, which is supplied with a mixture of steam from the LP superheater and steam from the MP turbine section

The steam turbine has the following characteristics:

Section	isentropic efficiency	Inlet pressure	Inlet temperature	Outlet pressure	Outlet temperature
High pressure	87.0%	120 bara	560 °C	27.4 bara	346 °C
Intermediate pressure	88.5%	27 bara	560 °C	4.6 bara	320 °C
Low pressure	90.0%	4.6 bara	318 °C	0.04 bara	29 °C

Table 5.4 - Steam Turbine Data

An additional loss of 1% of the steam turbine shaft power output is used to take account for the shaft and other losses.

CCPP Performance

The resulting energy balance for the standard power plant firing natural gas is shown in *Table 5.5*:

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Power Plant Energy Ba	lance				
Gas Turbine Energy Inpu	Gas Turbine Energy Input		MWth		
	Fuel Consumption LHV			1404.9	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			-0.3	MWth
	Total Gas Turbine Energy Input		•	1404.6	MWth
Gas Turbines		525.9	MW		
	GT Gross power			554.4	MW
	GT losses			-28.6	MW
	Net GT output			525.9	MW
Steam Turbines		282.8	MW		
	ST Shaft power			285.7	MW
	ST losses			-2.9	MW
	Net ST output			282.8	MW
Generator losses		-14.0	MW		
Balance of Plant losses		-9.8	MWe		
	Boiler feed water pumps			-2.8	MWe
	Cooling water pumps			-6.0	MWe
	Condensate pumps			-0.2	MWe
	Remaining losses (0.1%)			-0.8	MWe
	BOP losses		•	-9.8	MWe
Total Plant net power		784.8	MWe		
Net electrical efficiency		55.9	%		

Table 5.5 - Reference Case Power Plant Energy Balance

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^{*} Remaining losses are assumed to be 0.1% of the plant gross power output. These losses comprise small power consumers like the closed cooling water system pumps, instrument air compressor, HVAC, etc.



5.2 CASE 1: POST COMBUSTION CO2 CAPTURE

The first case comprises post combustion CO_2 capture, which is effected by using direct scrubbing of the flue gas with a proprietary amine solution. This is a so-called "end of pipe" method, as the capture plant is located downstream of the power plant and CO_2 is removed from the flue gas of the CCPP, see *Figure 5.1*.

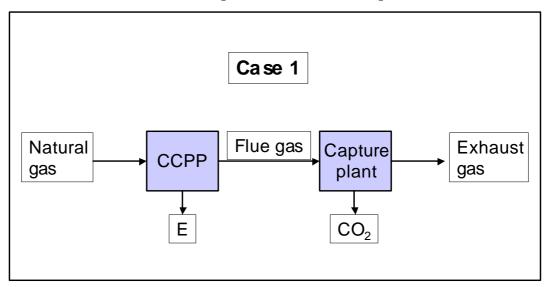


Figure 5.1 - Case 1 Scheme

5.2.1 CCPP Description

This case does not require significant modifications to the equipment of the reference power plant. The CO₂ capture installation will be a strictly add-on plant, only to consume energy from the power plant required for the flue gas scrubbing.

All assumptions, starting points and equipment data concerning the power plant are equal to the reference case.

Main process modifications to the reference CCPP are:

- Tie-in to LP steam system to supply LP steam from the power plant to the reboiler section(s)
- Tie-in to the condensate system(s) to receive the cooled condensate from the reboiler section(s)
- Tie-in to the stack of the HRSG's in order to discharge the fluegas to the CO₂ capture plant.

For overall availability reasons it may be preferred to install switch over dampers which allow for base load operation with and without CO₂ capture.

Each CCPP unit is equipped with a scrubbing unit, which removes the CO_2 from the flue gasses. This scrubbing unit is located downstream of the Heat Recovery Steam Generator, before the flue gasses leave the stack. Paragraph 5.2.3 describes the complete CO_2 capture installation in detail.

The capture installation needs a significant amount of heat for its internal process. This heat is supplied in the form of superheated low pressure steam from the CCPP

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steam cycle, which is extracted upstream of the condensing LP steam turbine section. A direct consequence is that the condensing LP steam turbine section will be operated at low load, with about 10% of the design steam flow through the section.

The capture unit returns 100% of the extracted steam as sub-cooled condensate, which is cooled to 30 °C in seawater cooled heat exchangers and mixed with the condensate flow from the CCPP main condenser.

The condensate flow from the condensing steam turbine section to the condenser decreases because of this extracted steam. The main condenser duty is therefore significantly lower in comparison to the design case, and the cooling water flow is decreased to 60% of the flow in the reference case. It is required to discharge the condensate heat to the surface water, as there are no low-grade heat consumers available.

The scrubber unit will introduce an additional pressure drop at the flue gas side. If no action is taken this would result in exceeding allowable pressure limits for the HRSG and gas turbine ducting. To anticipate this an induced draft flue gas fan is introduced to overcome the extra exit pressure loss. This will introduce an additional auxiliary power consumer in the capture unit. It should be noted that installation of the induced draft fan prevents loss of performance of the gas turbine due to increased backpressure of the HRSG.

5.2.2 CCPP Performance

Table 5.6 shows the energy balance for the CCPP in case 1. The energy input and gas turbine output are unchanged compared to the reference case. This is expected, as the process conditions for the gas turbine have not changed.

However, the steam turbine power output decreased considerably, which is due to the LP steam extraction. The condensing steam turbine section is almost bypassed, and this causes the output to fall from 283 MWe in the reference case to 157 MWe.

As a result, the CCPP electrical efficiency decreased to 47.3%.

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Power Plant Energy Ba	ance				
	Gas Turbine Energy Input		MWth		
0,7 1	Fuel Consumption LHV			1404.9	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			-0.3	MWth
	Total Gas Turbine Energy Input		•	1404.6	MWth
Gas Turbine		525.9	MW		
	GT Gross power			554.4	MW
	GT losses			-28.6	MW
	Net GT output			525.9	MW
Steam Turbine		157.1	MW		
	ST Shaft power			158.7	MW
	ST losses			-1.6	MW
	Net ST output			157.1	MW
Generator losses		-11.5	MW		
Balance of Plant losses		-7.1	MWe		
	Boiler feed water pumps			-2.8	MWe
	Cooling water pumps			-3.6	MWe
	Condensate pumps			0.0	MWe
	Remaining losses (0.1%)			-0.7	MWe
	BOP losses			-7.1	MWe
Total Plant net power		664.3	MWe		
Net electrical efficiency		47.3	%		
Steam supply to CO ₂ cap	ture plant(@ 4.6 bar, 318°C)	309.6	t/hr		

Table 5.6 - Case 1 Power Plant Energy Balance

5.2.3 Capture Plant Description

The Capture Plant captures CO_2 after combustion from the exhaust gas from the CCPP. The exhaust gas from the CCPP is first cooled in a water quench where most of the steam in the flue gas is condensed. The cooled exhaust gas is fed to the CO_2 absorber where CO_2 is scrubbed from the exhaust gas by an amine solution. The CO_2 lean flue gas is then vented. The rich amine solution is regenerated by thermal stripping, and the captured carbon dioxide is compressed and dried for export.

Quench

The gas turbine exhaust leaving the HRSG is both too hot, (typically 100°C) and it contains too much steam to be fed directly to the CO₂ absorber. The quench column both cools the exhaust stream to near ambient and condenses most of the steam.

The quench column is a large packed tower in which a large amount of water which cascades down the packing. The gas turbine exhaust flows up the quench column and is cooled by direct contact cooling. A significant volume of circulating water is required to contact the exhaust gas to remove the sensible and latent heat.

The water from the bottom of the quench column is cooled against sea water in the quench water cooler and returned to the top of the quench column. The excess water,

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condensed from the gas turbine exhaust gas, is purged and sent to waste water treatment.

The cooled gas turbine exhaust leaves the top of the quench column at 38°C and is then blown to the CO₂ absorber column by the absorber feed fan.

Acid Gas Removal

Carbon dioxide is removed from the cooled gas turbine exhaust by scrubbing with MEA. The carbon dioxide is absorbed into the amine solution, which is then regenerated in a stripping column where the carbon dioxide is stripped from the amine solution with steam. The performance data for the stripper unit was obtained from vendor data for this study.

The flue gas is blown from the absorber feed fan to the bottom of the absorber column. It flows up the packed column against a down flowing aqueous solution of MEA. The solution is "lean" in carbon dioxide content and enters the column at 34° C. The carbon dioxide is absorbed from the gas turbine exhaust, making a 'rich' solution, which leaves the bottom of the absorber column.

The gas turbine exhaust, after having any droplets of MEA washed out of it in a demin water wash section at the top of the column, leaves at 42°C, lean in carbon dioxide.

The absorbed carbon dioxide is stripped from the rich solution in the stripper column. The rich solution is pumped from the bottom of the absorber column and is then heated to 107°C in the rich/ lean exchanger. The hot rich solution passes to the top of the stripping column and flows down against an upflow of steam that desorbs the carbon dioxide from the solution. The steam is generated in the stripper reboiler from the water in the amine solution. Heat for the stripper reboiler is supplied by low pressure steam from the CCPP HRSG.

The carbon dioxide, together with some steam, exits the top of the column at 112°C and passes to the stripper condenser where it is cooled to 70°C, condensing most of the steam. The remaining vapour flows into the stripper trim condenser where it is cooled to 22°C against sea water. Condensate is collected after each condenser in knock out drums and is then pumped by the stripper reflux pump back to the top of the stripping column.

The MEA solution leaves the bottom of the stripping column at 125°C, lean in carbon dioxide, and passes through the rich / lean exchanger. It is then pumped by the lean amine pump through the lean amine air cooler and then the lean amine trim cooler where it is cooled to 38°C against sea water. Finally the lean amine is returned to the top of the absorber column.

CO₂ Compression and Drying

The CO₂ removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a "no loss" configuration, which recycles the regeneration off gas back to the CO₂ compressor.

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The CO₂ compressor is an 8-stage integral gear machine with full intercooling after stages 1 to 5, partial intercooling after stage 6 and no intercooling after stage 7.

Cooling Water

Seawater, from a new intake, is circulated once through major coolers and condensers and then discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

Water Treatment

The water treatment plant treats the quench water purge and produces demin water make-up for the acid gas removal unit.

A small quantity of sludge is produced for disposal offsite.

5.2.4 Capture Plant Performance

Table 5.7 shows the performance of the capture plant in case 1. There is no fuel input in this case, neither there is syngas output. The capture plant does require an amount of electricity for the process, next to the steam import from the CCPP (which is not shown in the table).

A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The CO_2 capture efficiency is calculated by taking the actual CO_2 emission, compensate for the CO_2 in the inlet air to the gas turbine, and divide this by the maximum CO_2 emission from burning the original fuel (before reforming).

CO ₂ Capture Plant Energy Balance		
Capture Plant Fuel Energy Input (LHV)	-	MWth
Capture Plant Syngas Output (LHV + Heat)	-	MWth
CO ₂ Capture Plant Auxiliary Power Consumption	-38.5	MWe
CO ₂ Capture Plant Power Production	-	MWe
Capture Plant Net Power Output	-38.5	MWe
CO ₂ Capture Efficiency	85.7	%

Table 5.7 - Case 1 Energy Balance Capture Plant

5.2.5 Overall Plant Balance

The energy balance for the post combustion CO_2 capture power plant is shown in *Table 5.8*. The net power production decreased in comparison with the reference case. This is caused by the decreased production in the CCPP because of steam extraction to the capture plant and by the electrical power consumption in the capture plant.

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Total Overall Plant Energy Balance		
Total Overall Plant Energy Input (LHV)	1404.6	MWth
Combined Cycle Power Plant Net Electrical Output	664.3	MWe
CO ₂ Capture Plant Auxiliary Power Consumption		MWe
CO ₂ Capture Plant Power Production	0.0	MWe
Total Overall Plant Net Power Output	625.9	MWe
Net Overall Plant Electrical Efficiency	44.6	%

Table 5.8 - Case 1 Overall Plant Energy Balance

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5.3 CASE 2-1: PRE COMBUSTION CO₂ CAPTURE BY LOCAL H₂ PRODUCTION FROM NATURAL GAS

In case 2-1, capture is effected by removing the carbon from natural gas fuel before combustion. This carbon removal is done in the $\rm CO_2$ Capture Plant, after which the carbon-free syngas is fed to the gas turbine. This syngas has a significantly lower heating value compared with natural gas. Firing this fuel will require modifications to the gas turbines.

The Capture Plant is located at or near the power plant plot and therefore this case is a "local" case, in contrast to case 2-2, at which the Capture Plant is located at 40 km distance from the CCPP (remote case).

The capture plant is located upstream of the CCPP, see Figure 5.2.

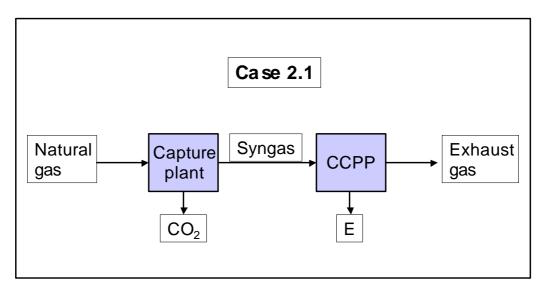


Figure 5.2 - Case 2-1 Scheme

5.3.1 Capture Plant Description

This section is to be read in conjunction with the process block diagram for case 2-1 and the mass balance for case 2-1. P03-2101.

The Capture Plant converts a feed of natural gas to a fuel gas mixture of hydrogen and nitrogen. First the gas is led through a desulphurisation section in which the H_2S in the natural gas is captured by using a bed of ZnO. After desulphurisation the Capture Plant consists of a reforming stage, where a mixture of natural gas with steam and air is converted to synthesis gas, or syngas, which is a mixture of H_2 , CO, CO_2 and N_2 . The reformer is followed by two stages of shift reaction, where the carbon monoxide and residual steam are converted to hydrogen and carbon dioxide. The reaction stages are followed by the removal of CO_2 from the shifted syngas, using a chemical solvent, and delivery of the fuel gas to battery limits. The CO_2 is regenerated from the solvent and compressed for delivery to battery limits for subsequent disposal. The resulting hydrogen rich syngas is saturated with water to control NO_x formation during combustion in the gas turbines.

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The Capture Plant recovers waste heat from the high temperature sections of the process by generating high-pressure superheated steam. Some of this steam is used in the process and the remainder is used to generate electricity, which is used within the plant. For the remaining electricity demand, additional electricity is imported from the external grid.

Auto-Thermal Reformer

Natural gas is first pre-heated to 380°C and passed through a desulphurisation reactor where all of the sulphur components are converted to H₂S, which is then absorbed. The reforming and shift catalysts can easily be poisoned by sulphur and therefore only a very low level (less than 1 ppm) can be tolerated.

The gas is then mixed with process steam, sufficient to give a steam to carbon ratio of 1.0, heated further and passed to an air-blown auto-thermal reformer (ATR). In the ATR, the natural gas is sub-stoichiometricly combusted with air. It is then passed over a high temperature reforming catalyst, which promotes the formation of synthesis gas according to the following reactions:

Partial Oxidation of Higher Hydrocarbons

$$C_x H_y + \frac{1}{2} O_2 \to xCO + \frac{y}{2} H_2$$

Partial Oxidation of Methane

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2$$

Steam Reforming of Methane

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2$$

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

The high temperature of partial oxidation maximises reforming of the gas and minimises its methane content.

High Temperature Cooling

The syngas stream leaves the ATR at 950°C, and it is cooled by raising and superheating high pressure steam and by preheating the feed stream to the ATR.

CO Shift

The syngas from the ATR contains 14 mol%(dry) CO which must be converted to CO₂ in order to facilitate the removal of carbon. This conversion is carried out in two shift

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reactors, namely the high-temperature and the low-temperature (HT shift and LT shift). The shift reaction is exothermic and the heat of reaction is recovered after the HT shift reactor by raising more HP steam and by preheating the boiler feed water.

Cooling and Condensation

The enthalpy of the syngas exiting the LT Shift provides heat for the saturator, heating of the fuel gas product and preheating of demineralised water feed to the deaerator. The gas stream is finally cooled to 50° C in an air cooler and fed to the CO_2 absorber in the acid gas removal unit. The condensate is separated from the syngas and the dissolved gases are stripped out in the steam system.

Acid Gas Removal

The CO₂ absorber is a two-stage counter-current column where the CO₂ rich syngas is contacted first with a "semi-lean" solution of MDEA solvent, then with a "lean" solution to absorb the carbon dioxide, leaving the hydrogen/nitrogen fuel gas.

The CO_2 -rich stream leaving the bottom of the absorber is regenerated by depressurisation in three stages. In the first stage the liquid stream passes to the HP flash column where the pressure is reduced from about 30 bar(g) to about 5.5 bar(g), allowing CO_2 gas to flash off. The liquor then passes to the LP flash column, which operates at about 0.2 bar(g), where further flashing takes place and some stripping as the liquid passes through a packed bed counter-current with the vapour stream from the final stage. At the bottom of this column the liquid is sufficiently "lean" to be recycled to the absorber as "semi-lean" solvent.

Approximately 85% of the liquid from the LP flash column is recycled to the absorber, while the remaining 15% passes to the third stage of regeneration. This stage is a reboiled stripper column, where the liquid is contacted with steam in a packed bed. The steam is generated by boiling some of the water present in the MDEA solution. The liquor from the bottom of the column is sufficiently low in CO₂ to be recycled to the absorber as "lean" solution. The vapour overhead from the stripper column passes through the LP flash column, as described above, and is cooled in the LP flash column condenser. The off-gas from the condenser passes to the CO₂ compressor.

CO₂ Compression

The CO_2 removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a "no loss" configuration, which recycles the regeneration off gas back to the CO_2 compressor.

Gas Conditioning

Carbon dioxide free syngas from the top of the CO_2 absorber is heated and passed to a saturator to raise the water content, which together with the nitrogen present, are sufficient to control NO_x formation in the gas turbine combustor to 25 ppmvd. It is then superheated to 230°C against circulating demineralised water, before being sent to the local combined cycle power plant at 27.5 bar(g).

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Steam System

Superheated steam is generated at 122 bar(g) by heat recovery from the ATR product gas stream. The outlet steam from the first stage, at 37 bar(g), is reheated by heat exchange with the ATR product gas stream. Part of this steam is used to strip the process condensate of the dissolved gases and the whole stream is fed to the ATR as process steam. The remainder of the 37 bar(g) superheated steam passes to the second stage of the turbine. Pass out steam is taken from the second stage of the turbine and condensed at 2.5 bar(g) to provide reboil for the stripper column in the acid gas removal unit. The remainder of the steam passes to the condensing stage of the turbine.

Condensate from the final stage of the turbine passes to a deaerator for eventual recycle to the HP boiler. Process condensate separated from the syngas during cooling is also recycled after passing through a stripping column to remove dissolved process gases. A make-up stream of demineralised water is fed to the deaerator to replace the process steam consumed in the reformer.

Power Block

The superheated steam raised in the high temperature cooling is fed to a 3-stage condensing steam turbine in the power block. The power generated is used for onsite consumption.

Cooling Water

Seawater, taken from a dedicated intake, is circulated once through the major coolers and condensers and discharged directly back to the sea through a dedicated discharge system. A secondary fresh water system is used for smaller coolers and machinery.

5.3.2 Capture Plant Performance

Table 5.9 shows the performance of the capture plant. The fuel input in MW is given, based on the LHV value of the feedstock. The fuel output is presented in MW, which is based on LHV of the produced syngas plus the sensible heat of the syngas. This is important in the local cases as the fuel is heated to around 230 °C, which gives a significant part of the heat input to the gas turbine.

Furthermore the net electricity consumption is presented, which exists from the consumed electricity for all power consumers minus the electricity production from the power block of the capture plant.

A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The CO_2 capture efficiency is calculated by taking the actual CO_2 emission, compensate for the CO_2 in the inlet air to the gas turbine, and divide this by the maximum CO_2 emission from burning the original fuel (before reforming).

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CO. Continuo Blant Francis Balanca		
CO ₂ Capture Plant Energy Balance		
Capture Plant Fuel Energy Input (LHV)	1672.4	MWth
Capture Plant Syngas Output (LHV + Heat)	1417.3	MWth
CO ₂ Capture Plant Auxiliary Power Consumption	-158.9	MWe
CO ₂ Capture Plant Power Production	43.0	MWe
Capture Plant Net Power Output	-115.9	MWe
CO ₂ Capture Efficiency	85.6	%

Table 5.9 - Case 2-1 Capture Plant Energy Balance

5.3.3 CCPP Description

The overall process flow scheme of the power plant is not modified with respect to the reference power plant. However modifications are required to the gas turbines to enable the firing of a fuel with a significantly lower heating value. The different fuel also has a large impact on the gas turbine control and the process parameters of the power plant.

Main process modifications to the reference CCPP are:

- Replacement of gas turbine Dry Low NO_x(DLN) combustion system by a conventional dual fuel(natural gas and syngas) system provided with steam injection for NO_x abatement.
- Tie-in in MP steam system for steam supply to the gas turbine steam injection system. A steam injection system is needed in all cases, to limit NO_x emissions when the unit is operated on the back-up fuel (natural gas).
- Demin water plant capacity to be enlarged for steam injection or additional demin water plant needed.

Because of the high hydrogen content in the fuel it is not possible to use a DLN combustion system. This means that the DLN combustors need to be removed and replaced by conventional combustors. To keep the NO_x emissions within the limit of 25 ppmv (dry @15% O_2), it is necessary to prepare the fuel composition with diluents, e.g. by adding N2 or by applying steam injection. Both methods decrease the flame temperature and limit the thermal NO_x formation.

When feeding the gas turbine with the same fuel input as in the natural gas application, the fuel mass flow into the gas turbine increases significantly when firing low LHV fuel. In order to keep the compression ratio of the gas turbine at design level in order to avoid potential compressor surge, the expander inlet flow should be kept at design level as well. This is realised by decreasing the inlet air flow. This is achieved by controlling the Inlet Guide Vanes (IGV's), which can be partly shut to decrease the air intake.

The consequence of decreasing the inlet flow to the GT compressor by IGV control is a decrease in the amount of compressor work. The turbine still receives the same flow as in the design case, because of the increased fuel flow. These effects result in an increase in the overall gas turbine power output.

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Information from GE showed that the maximum net electrical power output of their frame 9 gas turbine is limited to 286 MWe (design value = +/- 260 MWe). Therefore it is necessary to lower the combustor exit temperature in order to control the power output.

To increase the efficiency of the power plant it can be feasible to apply fuel preheating when the gas turbine is fired on natural gas. Fuel preheating increases the sensible heat input to the combustion chamber and reduces the amount of fuel energy needed (and therefore the fuel consumption). The heat for fuel heating is usually taken from the steam cycle, which will cost some electrical power (as this is not available for expansion in the steam turbine). The overall effect on net electrical efficiency is however positive.

When the gas turbine is fired on a low-LHV fuel, the positive effect of fuel heating increases significantly. This is the consequence of the much higher fuel flow to the combustion chamber. Fuel preheating should therefore be applied with these kinds of fuels.

The fuel is delivered from the fuel processing plant already at a temperature of 230 °C. The fuel is not preheated to a higher temperature, and this should be considered as an option for optimization.

5.3.4 CCPP Performance

Table 5.10 below shows the gas turbine parameters fired on the low-LHV syngas in comparison to the gas turbine parameters when fired on natural gas.

Case	Reference Case	Case 2-1
Fuel LHV	46,855 kJ/kg	7,476 kJ/kg
Fuel Flow / Temperature	15.0 kg/s / 10 °C	89.7 kg/s / 230 °C
Steam Injection Flow / Temperature	-	-
Air Inlet Flow	618 kg/s	535 kg/s
Combustor Exit Temperature	1352 °C	1270 °C
Exhaust flow / Temperature	633 kg/s / 608 °C	625 kg/s / 565 °C
Net Power Output	258.8 MW	286.0 MW
Net Electric Efficiency (LHV)	36.8 %	42.6 %

Table 5.10 - Case 2-1: Gas Turbine performance

The table shows that the net electric power output of the gas turbine increases to 286 MWe, which is an increase of almost 11%. This 286 MWe is the maximum net power output for this gas turbine, according to information provided by General Electric. The exhaust gas flow rates are similar but due to the lower Combustor Exit Temperature the exhaust gas temperature has decreased to 565 °C. This means that the HRSG section will work at different flue gas conditions. The low-LHV fuel will influence the performance of the steam cycle. Off-design calculations show that the HRSG and steam turbine can operate properly at the given conditions without modifications.

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The following table shows the overall energy balance for the combined cycle power plant.

Power Plant Energy Ba	lance				
Gas Turbine Energy Input		1417.3	MWth		
	Fuel Consumption LHV			1341.6	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			75.7	MWth
	Total Gas Turbine Energy Input		•	1417.3	MWth
Gas Turbine		581.2	MW		
	GT Gross power			609.7	MW
	GT losses		_	-28.6	MW
	Net GT output		•	581.2	MW
Steam Turbine		252.0	MW		
	ST Shaft power			254.5	MW
	ST losses		_	-2.5	MW
	Net ST output			252.0	MW
Generator losses		-14.2	MW		
Balance of Plant losses		-9.3	MWe		
	Boiler feed water pumps			-2.6	MWe
	Cooling water pumps			-5.7	MWe
	Condensate pumps			-0.2	MWe
	Remaining losses (0.1%)		_	-0.8	MWe
	BOP losses		•	-9.3	MWe
Total Plant net power		809.6	MWe		
Net electrical efficiency		57.1	%		

Table 5.11 - Case 2-1 Energy Balance Power Plant

The mass and heat balance for the most important streams are shown in Appendix 1.

5.3.5 Overall Plant Performance

The overall energy balance for the combined CO₂ capture plant and CCPP is shown in *Table 5.12*, which combines the results from *Table 5.9* and *Table 5.11*.

Total Overall Plant Energy Balance		
Total Overall Plant Energy Input (LHV)	1672.4	MWth
Combined Cycle Power Plant Net Electrical Output	809.6	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	-158.9	MWe
CO ₂ Capture Plant Power Production	43.0	MWe
Total Overall Plant Net Power Output	693.7	MWe
Net Overall Plant Electrical Efficiency	41.5	%

Table 5.12 - Case 2-1 Overall Plant Energy Balance

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5.4 CASE 2-2: PRE COMBUSTION CO₂ CAPTURE BY REMOTE H₂ PRODUCTION FROM NATURAL GAS

Case 2-2 is similar to case 2-1, except for the fact that the fuel processing plant is located at 40 km distance from the power plant plot. The syngas is transported through pipelines from the fuel plant to the power plant, see *Figure 5.3*.

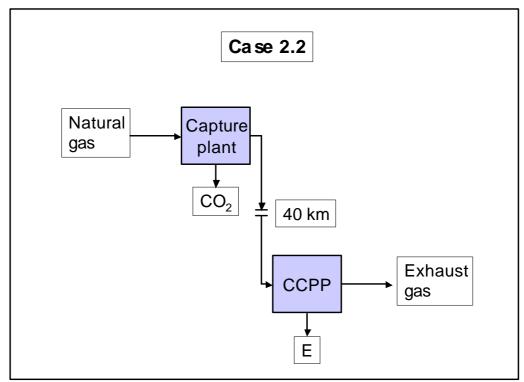


Figure 5.3 - Case 2-2 Scheme

5.4.1 Capture Plant Description

This section is to be read in conjunction with the process block diagram for case 2-2 and the mass balance for case 2-2 P03-2201.

The Capture Plant converts natural gas to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a series of catalytic reactors. The CO_2 is removed by an absorbent solution and the resultant hydrogen rich syngas is compressed, dried and exported from the site at ambient temperature for piping to the CCPP. NO_x formation on combustion in the CCPP is controlled by direct injection of steam taken from the CCPP steam cycle. The captured CO_2 is dried and compressed before being exported from the Capture Plant site.

Most of the process steps are equal to the process steps in case 2-1 and will not be repeated. The items that are different are described here.

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Auto Thermal Reformer

Reference is made to paragraph 5.3.1.

High Temperature Cooling

Reference is made to paragraph 5.3.1.

CO Shift

Reference is made to paragraph 5.3.1.

Cooling and Condensation

Reference is made to paragraph 5.3.1.

Acid Gas Removal

Reference is made to paragraph 5.3.1.

CO₂ Compression

Reference is made to paragraph 5.3.1.

Gas Conditioning

Carbon dioxide free syngas from the top of the CO₂ absorber in the AGR is dried and compressed to 39 bar(g) in order to transfer the fuel to the remote combined cycle power plant.

In the CCPP steam is added to the fuel gas for NO_x control and then the combined fuel gas stream is heated using steam to 230°C before being fed to the gas turbine combustors.

Steam System

Reference is made to paragraph 5.3.1.

Power Block

Reference is made to paragraph 5.3.1.

Cooling Water

Seawater, from a new intake, is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

Fuel Gas Pipeline

The 40 km pipeline for the transportation of fuel gas between the Capture Plant and the CCPP site is made of carbon steel. No special metallurgy is required, as the fuel gas is dried before transportation. The line size is 36 " and the fuel gas inlet and outlet pressures are respectively 39.0 barg and 30.6 barg.



5.4.2 Capture Plant Performance

Table 5.13 shows the performance of the capture plant in case 2-2. In comparison with the performance of the capture plant of case 2-1, which is shown in *Table 5.9*, a few differences can be recognised.

The syngas output in MW is lower, while the feedstock input in MW is approximately the same. This can be explained by the fact that however the syngas mass flows are similar, in case 2-2 the syngas leaves the fuel plant at low temperature, i.e. the sensible heat content is almost zero. The fuel preheating in this case takes place in the CCPP, and will cause a loss in power production there. Because the fuel is not preheated in the capture plant, more heat is available for power production in the power block, and this results in a higher capture plant power production in comparison to case 2-1.

The power consumption has increased, which is a direct consequence of the need for compressing the syngas, so that it can be transported through the 40 km pipeline to the CCPP plot. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The CO_2 capture efficiency is calculated by taking the actual CO_2 emission, compensate for the CO_2 in the inlet air to the gas turbine, and divide this by the maximum CO_2 emission from burning the original fuel (before reforming).

CO ₂ Capture Plant Energy Balance		
Capture Plant Fuel Energy Input (LHV)	1671.0	MWth
Capture Plant Syngas Output (LHV + Heat)	1344.7	MWth
CO ₂ Capture Plant Auxiliary Power Consumption	-168.0	MWe
CO ₂ Capture Plant Power Production	71.1	MWe
Capture Plant Net Power Output	-96.9	MWe
CO ₂ Capture Efficiency	85.7	%

Table 5.13 - Case 2-2 Energy Balance Capture Plant

5.4.3 CCPP Description

The fuel is delivered at the power plant at a low temperature of 21.5 °C (compared to a temperature of 230 °C in the local case 2-1). This is due to the 40 km transportation distance between the two sites.

In paragraph 5.3.3 it was stated that preheating the fuel is a feasible option to increase the overall efficiency of the power plant. In this case the heat for the fuel preheating is supplied from the CCPP steam system.

Main process modifications to the reference CCPP are:

- Replacement of gas turbine Dry Low NO_x(DLN) combustion system by a conventional dual fuel(natural gas and syngas) system provided with steam injection for NO_x abatement.
- Tie-in in MP steam system for steam supply to the gas turbine steam injection system
- Pre-mix system for mixing syngas with MP steam

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 Demin water plant capacity to be enlarged for steam injection or additional demin water plant needed

To avoid NO_x emissions above permitted levels it is necessary to add extra diluents to the fuel. It is possible to do this at the fuel processing plant, but this would mean that the extra diluent is transported together with the fuel over 40 km of pipeline. When the diluent is added at the power plant plot, the extra compression energy is avoided. At the power plant plot, steam is available as diluent. The steam is injected directly into the gas turbine combustion chamber, without premixing it with the fuel. In the combined cycle power plant in this study, IP steam of about 330 $^{\circ}C$ @ 27 bara is available for steam injection.

In this study the fuel is preheated until the temperature of the mixture of fuel and steam is about 230 °C. At this temperature no extra measures need to be taken to materials in the existing equipment. The temperature level can be subject to optimization, as this is not considered in this study.

5.4.4 CCPP Performance

Table 5.14 shows the gas turbine performance for case 2-2 in comparison to the reference case.

Case	Reference Case	Case 2-2
Fuel LHV	46,855 kJ/kg	8,622 kJ/kg
Fuel Flow / Temperature	15.0 kg/s / 10 °C	77.9 kg/s / 215 °C
Steam Injection Flow / Temperature	-	12.0 kg/s / 337 °C
Air Inlet Flow	618 kg/s	536 kg/s
Combustor Exit Temperature	1352 °C	1268 °C
Exhaust flow / Temperature	633 kg/s / 608 °C	626 kg/s / 564 °C
Net Power Output	258.8 MW	288.8 MW
Net Electric Efficiency (LHV)	36.8 %	42.6 %

Table 5.14 - Case 2-2 gas turbine performance

The following table shows the energy balance for the complete combined cycle power plant.

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Power Plant Energy Ba	lance				
Gas Turbine Energy Input		1344.7	MWth		
	Fuel Consumption LHV			1343.0	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			1.8	MWth
	Total Gas Turbine Energy Input			1344.7	MWth
Gas Turbine		580.7	MW		
	GT Gross power			609.3	MW
	GT losses			-28.6	MW
	Net GT output		•	580.7	MW
Steam Turbine		204.9	MW		
	ST Shaft power			207.0	MW
	ST losses			-2.1	MW
	Net ST output		•	204.9	MW
Generator losses		-13.3	MW		
Balance of Plant losses		-8.1	MWe		
	Boiler feed water pumps			-2.4	MWe
	Cooling water pumps			-4.7	MWe
	Condensate pumps			-0.2	MWe
	Remaining losses (0.1%)			-0.8	MWe
	BOP losses		•	-8.1	MWe
Total Plant net power		764.3	MWe		
Net electrical efficiency		56.8	%		

Table 5.15 - Case 2-2 Energy Balance Power Plant

When *Table 5.15* is compared to the case 2-1 performance, the decreased steam turbine power generation attracts the attention. This is caused by the fact that steam is used to preheat the syngas fuel at the CCPP plot. This steam is extracted from the CCPP steam cycle and is no longer available for expansion in the LP steam turbine section. Therefore the power generation from the steam turbine is lower than in the local case. The amount of heat which is transferred to the fuel by preheating is equal to 58.2 MWth.

The mass and heat balance for the most important streams are shown in Appendix 2.

5.4.5 Overall Plant Performance

The overall energy balance for the combined CO₂ capture plant and power plant is shown in *Table 5.16*, which is a combination of *Table 5.13* and *Table 5.15*.

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Total Overall Plant Energy Balance		
Total Overall Plant Energy Input (LHV)	1671.0	MWth
Combined Cycle Power Plant Net Electrical Output	764.3	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	-168.0	MWe
CO ₂ Capture Plant Power Production	71.1	MWe
Total Overall Plant Net Power Output	667.4	MWe
Net Overall Plant Electrical Efficiency	39.9	%

Table 5.16 - Case 2-2 Overall Plant Energy Balance

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5.5 CASE 3-1: PRE COMBUSTION CO₂ CAPTURE BY LOCAL H₂ PRODUCTION FROM COAL

In case 3-1, capture is effected by removing the carbon from the Coal feedstock before combustion. The Capture Plant converts the coal by partial oxidation (gasification) to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. After capture of CO₂ the carbon-free syngas is fed to the gas turbine, see *Figure 5.4*. In case 3-1 the capture plant is located at or near the power plant plot, in comparison to case 3-2 where the capture plant is located at 40 km distance from the power plant.

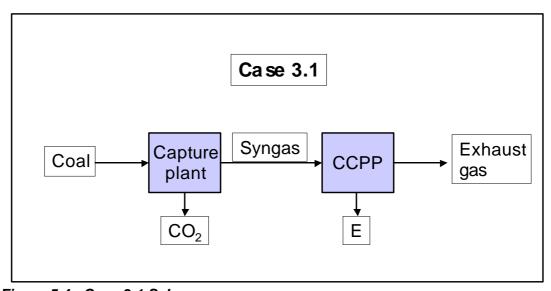


Figure 5.4 - Case 3-1 Scheme

5.5.1 Capture Plant Description

The Capture Plant converts a feed of coal to a fuel gas mixture of hydrogen and nitrogen suitable for a gas turbine. The plant consists of a gasification stage where a mixture of coal and water is partially oxidised with oxygen from an air separation unit (ASU). The synthesis gas, or syngas, which is a mixture of H_2 , CO, CO_2 and N_2 produced in the gasification unit, is fed to a CO shift reactor, where the carbon monoxide and residual steam are converted to H_2 and CO_2 . The CO_2 and H_2S are removed from the shifted syngas, using a physical solvent, and then the pressure of the hydrogen rich fuel gas is reduced to gas turbine inlet pressure through an expander. The fuel gas is heated before and after the expander to increase the overall efficiency of the Capture Plant. The hydrogen rich fuel gas has nitrogen added to reduce NO_x formation during combustion in the gas turbines. Nitrogen from the ASU is compressed, heated and injected directly into the combustors of the CCPP for NO_x control.

The CO_2 is regenerated from the solvent, dried and compressed for delivery to battery limits for subsequent disposal. An H_2S rich gas stream is reacted with oxygen in a Claus Unit to form a solid sulphur product.

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The waste heat from the Capture Plant is used to generate steam, which is superheated in the HRSG of a small gas turbine for generation of electric power for internal use. Additional electricity is imported from the grid.

This section is to be read in conjunction with the process block diagram for case 3-1 and the mass balance for case 3-1 P03-3101.

ASU

Oxygen for the gasification and Claus units is separated from air in a cryogenic air separation unit (ASU). The nitrogen is used to dilute the fuel gas for NO_x control. The ASU is operated at low pressure and all of the feed air is supplied by dedicated air compressors driven by electric motors.

The oxygen is pumped to high pressure as a cryogenic liquid to remove the requirement for an oxygen compressor and vaporised against a stream of condensing high pressure air within the ASU main heat exchanger. The gaseous oxygen, at a purity of 95 vol%, is preheated with low pressure steam before being fed to the gasifier at 79 bar(g).

A small side stream is taken off at low pressure for the burners in the Claus unit. The majority of the product nitrogen stream, which contains less than 10 ppm O_2 , is compressed, and some is added to the fuel gas stream to reduce the hydrogen content with the majority injected directly into the combustors of the gas turbines for NO_x control. Some additional nitrogen is used in concentrating the H_2S in the Selexol unit, a small amount is used for purging and inerting, and the remainder is used internally within the ASU.

Coal Storage and Preparation

Coal is delivered to the site and stored in a stockpile normally sized for 3 days operation at full load. There is also an inactive coal storage pile sized for 30 days storage.

The coal is crushed and slurried with process water to 66 wt% and then pumped to one of a pair of day storage tanks. From the storage tank the slurry is pumped to 68 bar(g) and delivered to the gasifier.

Gasification

The coal slurry is gasified in a high pressure, top fired, ChevronTexaco gasifier fitted with a water quench. The temperature in the gasifier is sufficient to melt all the ash to slag. The coal is converted to synthesis gas, or syngas containing primarily H_2 and CO, together with some steam, CO_2 , N_2 , CH_4 , and Ar. The sulphur in the coal is converted to H_2S with some COS; other sulphur containing compounds are not considered in this study. The chlorine in the coal is converted to HCI. Small amounts of HCN and NH_3 are also produced. A small amount of carbon remains as soot.

The syngas, slag and soot exit from the bottom of the gasifier and are passed at 63 bar(g) to a water quench for cooling. The solids are removed through a lock-hopper system at the bottom of the quench, and the syngas, now saturated with water vapour, leaves at the top of the quench chamber. To prevent the build-up of soluble

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compounds, a blowdown stream, called black water, is taken from the quench, cooled in a cascade of flash drums at decreasing pressure and sent to the waste water treatment unit.

The saturated syngas is scrubbed with filtered process water, recycled from the bottom of the desaturator to remove particulates and then passed to the gas processing section. The scrubber water together with more process water is fed to the quench as make-up.

CO Shift

The scrubbed syngas is heated to above 290°C and passed to the sour shift reactor where most of the CO is converted to CO₂ over a catalyst according to the reaction:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

At the same time most of the COS is converted to H₂S and HCN to NH₃ according to the reactions:

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

and

$$HCN + H_2O \Leftrightarrow NH_3 + CO$$

The shift reaction is exothermic and the shifted syngas exits the reactor at above 430 °C.

Cooling and Condensation

The syngas from the outlet of the shift reactor is cooled initially by raising HP (135 bar(g)) steam. It is further cooled against the inlet stream to the shift reactor and then against demineralised water. Some of this water is used as BFW, and the remainder is circulated to the back of the plant to provide preheat to the expander and gas turbine. Final cooling and condensation is carried out in a desaturator.

The desaturator is a direct contact gas / liquid exchanger which consists of a packed or trayed column down which a liquid (water in this case) flows against a condensing gas steam passing upwards. The main effect is to preheat the condensate against the incoming hot gas.

Some of the hot water from the bottom of the desaturator is recycled to the quench / scrubber as make-up. The balance is used to raise LP steam, and to provide reboil duty for the sulphur removal unit before the majority is recycled back to the centre section of the desaturator. The remainder is then cooled by preheating incoming BFW. A small stream is fed to the coal preparation unit for coal slurrying, and the remainder is used as a cold water recycle to the desaturator.



In this way, the syngas is c0ooled to below 40° C, without the use of cooling water, before being fed to the H_2 S absorber in the AGR unit.

The HP and LP process steam is sent to the power block for superheating in the HRSG's before passing to the steam turbine.

Acid Gas Removal

The sulphur compounds and CO_2 are removed from the syngas in two stages. First, the sulphur compounds are removed in an H_2S absorber, and then syngas passes to a CO_2 absorber where the CO_2 is removed.

The CO₂ absorber is in two stages. Lean Selexol liquor from the stripper column is fed to the upper section of the CO₂ absorber and CO₂ is removed to the required specification. A much larger flow of "semi-lean" solution is fed to the lower section of the absorber to remove the bulk of the CO₂.

The Selexol stream from the bottom of this column, now rich in CO_2 is split into two streams. The majority of the flow is directed to a series of flash vessels operating at successively reducing pressure. The overhead vapour from the first vessel, which still contains considerable amounts of H_2 , is recycled back to the inlet of the H_2S absorber using the flash gas compressor. The overhead from the remainder of the flash vessels is sent to the CO_2 compressor. The Selexol, which is now semi-lean in CO_2 , is cooled and pumped back to the lower section of the CO_2 absorber.

The remainder of the CO_2 rich Selexol stream from the bottom of the CO_2 absorber is cooled and pumped to the top of the H_2S absorber where the sulphur compounds are absorbed. The Selexol from the bottom of the H_2S absorber, now rich in H_2S and containing about 25% of the inlet CO_2 , is pumped to the H_2S concentrator column which operates at a slightly higher pressure than the H_2S absorber column via the rich / lean interchanger. The overhead from the H_2S concentrator is recycled directly to the inlet of the H_2S absorber. The liquor from the bottom of the H_2S concentrator is flashed down to low pressure to remove the remainder of the CO_2 . The overhead vapour, which contains some H_2S , is recycled back to the inlet of the H_2S absorber using the flash gas compressor.

The Selexol is finally regenerated by steam stripping. The reboil duty for the stripper column is provided by hot process water from the gas treatment section. The overhead vapour from the stripper column, which contains 40% vol H_2S , is fed to the Claus unit where it is reacted with oxygen to form a solid sulphur product. The tail gas stream from the Claus reactor is compressed and recycled back to the inlet of the H_2S absorber.

Selexol plants often use refrigeration. This is avoided in this design by having a higher solvent flowrate than would be necessary with a design using refrigeration. This increases the capital costs of the absorber and stripper columns themselves but overall costs of the Selexol unit is lower because a refrigeration package is not required.

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Gas Conditioning

Sulphur and carbon dioxide free syngas from the top of the CO_2 absorber in the AGR unit is heated by exchange with hot demineralised water, and then expanded to the gas turbine fuel supply pressure, in an expander to generate power. Nitrogen from the ASU is added to dilute the hydrogen fuel gas stream as per GE's specifications, it is then superheated to 230°C against circulating demineralised water. A separate nitrogen stream is compressed, and superheated to 230°C again against circulating demineralised water before being fed directly to the gas turbine combustor. The combined effect of the two nitrogen streams is sufficient to control the NO_x formation in the gas turbine to the required level.

Sulphur Recovery

The H_2S is converted to pure sulphur in an oxygen blown Claus unit. The tail gas is compressed and recycled to the inlet of the H_2S absorber removing any atmospheric sulphur emissions from the sulphur removal or recovery units. The sour water produced is pumped to the desaturator.

Power Block

The power block consists of a GE 6B gas turbine, modified for combustion of syngas, fitted with a modified HRSG. A new gas turbine is included to enable the steam from the gasification plant to be superheated without interfering with the existing HRSG. The steam produced in the capture plant of case 2 is superheated by the effluent gases from the ATR, and therefore no new gas turbine is required in that particular case. After superheating the steam passes to a condensing steam turbine. The exhaust from the steam turbine passes to a deaerator-condenser, which operates at a pressure of 40 mbar(a). The boiler feed water from the deaerator-condenser is pumped back to the gas treatment section.

The generators, transformers and switchgear for the power block are included in this section.

CO₂ Compression and Drying

The CO₂ removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a "no loss" configuration, which recycles the regeneration off gas back to the CO₂ compressor.

Cooling Water

Seawater, taken from a new intake, is circulated once through the major coolers and condensers and discharged directly back to the sea through a new discharge structure. A secondary fresh water system is used for smaller coolers and machinery.

Water Treatment

The feed water plant takes raw water and softens it to remove hard water anions. This is used as make-up water for the desaturator. A small stream is taken for the demin water plant.

The waste water plant takes black water from the quench blowdown and first filters it to remove soot, slag fines and other particulate matter. The filtered solids are recycled

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back to the coal grinding plant to recover the unconverted carbon. The filtered water is then treated by means of pH control, coagulation and flocculation, and finally ion exchange to meet the required specification. A small quantity of sludge is produced for disposal offsite.

5.5.2 Capture Plant Performance

Table 5.17 shows the performance of the capture plant in case 3-1.

CO ₂ Capture Plant Energy Balance		
Capture Plant Fuel Energy Input (LHV)	2121.2	MWth
Capture Plant Syngas Output (LHV + Heat)	1405.3	MWth
CO ₂ Capture Plant Auxiliary Power Consumption	-244.9	MWe
CO ₂ Capture Plant Power Production	190.1	MWe
Capture Plant Net Power Output	-54.8	MWe
CO ₂ Capture Efficiency	85.8	%

Table 5.17 - Case 3-1 Energy Balance Capture Plant

Compared to the capture plant performances in case 2, it becomes clear that the coal reforming process is more energy intensive than the natural gas reforming process. The power consumption increased significantly (245 MWe compared to 159 MWe in case 2-1), which is mostly due to the power consumption of the larger CO_2 compressor and the Nitrogen compressor.

The power generation in case 3-1 is also increased. This can be explained by the fact that the power block consists of a complete combined cycle power plant, which produces a significant amount of electricity. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The CO_2 capture efficiency is calculated by taking the actual CO_2 emission, compensate for the CO_2 in the inlet air to the gas turbine, and divide this by the maximum CO_2 emission from burning the original fuel (before reforming).

5.5.3 CCPP Description

The syngas, which is fed to the gas turbine combustion chamber, is a low-LHV fuel, and the gas turbine needs to be adjusted and controlled in the same way as with the previous pre combustion CO_2 capture cases.

The capture plant is located near the power plant plot and the syngas fuel is delivered at a temperature of 230 °C. For this study the fuel is not preheated to a higher temperature, which could lead to higher efficiencies. This should be considered as an option for optimization.

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5.5.4 CCPP Performance

The table shows the gas turbine data for case 2-2 in comparison to the reference case.

Case	Reference Case	Case 3-1
Fuel LHV	46,855 kJ/kg	6,416 kJ/kg
Fuel Flow / Temperature	15.0 kg/s / 10 °C	103.7 kg/s / 230 °C
Steam Injection Flow / Temperature	-	-
Air Inlet Flow	618 kg/s	523 kg/s
Combustor Exit Temperature	1352 °C	1274.9 °C
Exhaust flow / Temperature	633 kg/s / 608 °C	627 kg/s / 565 °C
Net Power Output	258.8 MW	286.1 MW
Net Electric Efficiency (LHV)	36.8 %	43.0 %

Table 5.18 - Case 3-1 Gas Turbine Performance

Table 5.19 shows the energy balance for the combined cycle power plant.

Power Plant Energy Ba	lance				
Gas Turbine Energy Inpu	ut	1405.3	MWth		
	Fuel Consumption LHV			1330.1	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			75.2	MWth
	Total Gas Turbine Energy Input			1405.3	MWth
Gas Turbine		581.4	MW		
	GT Gross power			609.9	MW
	GT losses			-28.6	MW
	Net GT output		•	581.4	MW
Steam Turbine	Steam Turbine		MW		
	ST Shaft power			250.5	MW
	ST losses			-2.5	MW
	Net ST output		•	248.0	MW
Generator losses		-14.2	MW		
Balance of Plant losses		-9.2	MWe		
	Boiler feed water pumps			-2.5	MWe
	Cooling water pumps			-5.7	MWe
	Condensate pumps			-0.2	MWe
	Remaining losses (0.1%)			-0.8	MWe
	BOP losses		•	-9.2	MWe
Total Plant net power		806.0	MWe		
Net electrical efficiency		57.4	%		

Table 5.19 - Case 3-1 Power Plant Energy Balance

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5.5.5 Case 3-1 Overall Plant Balance

The overall energy balance for the combined CO₂ capture plant and power plant is shown in *Table 5.20*, which is composed of *Table 5.17* and *Table 5.19*.

Total Overall Plant Energy Balance		
Total Overall Plant Energy Input (LHV)	2121.2	MWth
Combined Cycle Power Plant Net Electrical Output	806.0	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	-244.9	
CO ₂ Capture Plant Power Production	190.1	MWe
Total Overall Plant Net Power Output	751.2	MWe
Net Overall Plant Electrical Efficiency	35.4	%

Table 5.20 - Case 3-1 Overall Plant Energy Balance

The table shows that the overall plant net electrical efficiency decreased significantly compared to the reference case.

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5.6 CASE 3-2: PRE COMBUSTION CO₂ CAPTURE BY REMOTE H₂ PRODUCTION FROM COAL

In case 3-2, capture is effected by removing the carbon from Coal before combustion with the capture plant located at 40 km distance from the power plant, see *Figure 5.5*. The Capture Plant converts the coal by partial oxidation (gasification) to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon-free syngas is fed to the gas turbine.

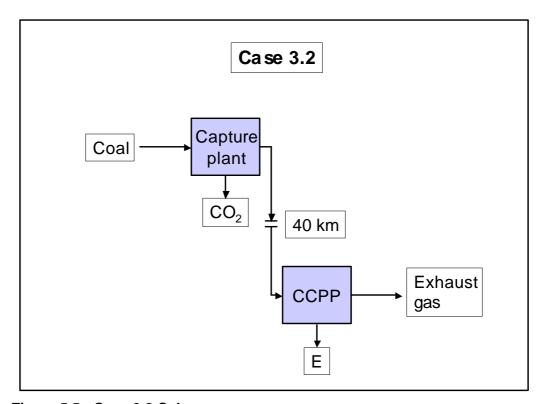


Figure 5.5 - Case 3-2 Scheme

5.6.1 Capture Plant Description

The Capture Plant converts a feed of coal to a fuel gas mixture of hydrogen and nitrogen suitable for refuelling a gas turbine. The plant consists of a gasification stage where a mixture of coal and water is partially oxidised with oxygen from an air separation unit (ASU). The synthesis gas, or syngas, which is a mixture of H_2 , H_2 , H_2 , H_2 , H_3 , H_4 , H_2 , H_4

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The waste heat from the Capture Plant is used to generate steam, which is superheated in the HRSG's of two small gas turbines and generate electric power for internal use.

This section is to be read in conjunction with the process block diagram for case 3-2 and the mass balance for case 3-2 P03-3201.

Most of the process steps are equal to the process steps in case 2-1 and will not be repeated. The items that are different are described here.

ASU

Reference is made to paragraph 5.5.1.

Coal Storage and Preparation

Reference is made to paragraph 5.5.1.

Gasification

Reference is made to paragraph 5.5.1.

CO Shift

Reference is made to paragraph 5.5.1.

Cooling and Condensation

Reference is made to paragraph 5.5.1.

Acid Gas Removal

Reference is made to paragraph 5.5.1.

Gas Conditioning

Sulphur and carbon dioxide free syngas from the top of the CO₂ absorber in the AGR is dried and diluted with compressed nitrogen from the ASU. The fuel gas is then transferred to the remote combined cycle power plant.

Sulphur Recovery

Reference is made to paragraph 5.5.1.

Power Block

The power block consists of two GE 6B gas turbines, modified for combustion of syngas, fitted with HRSG's. The HP and LP steam from the gas treatment section is superheated in the HRSG's and passes to a condensing steam turbine. The exhaust from the steam turbine passes to a de-aerator condenser, which operates at a pressure of 40 mbar(a). The boiler feed water from the deaerator-condenser is pumped back to the gas treatment section.

The generators, transformers and switchgear for the power block are included in this section.

CO₂ Compression and Drying

Reference is made to paragraph 5.5.1.

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Cooling Water

Seawater, from a new intake, is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

Water Treatment

Reference is made to paragraph 5.5.1.

5.6.2 Capture Plant Performance

Table 5.21 shows the performance of the capture plant in case 3-2.

CO2 Capture Plant Energy Balance		
Capture Plant Fuel Energy Input (LHV)	2306.4	MWth
Capture Plant Syngas Output (LHV + Heat)	1344.3	MWth
CO ₂ Capture Plant Auxiliary Power Consumption	-269.1	MWe
CO ₂ Capture Plant Power Production	269.4	MWe
Capture Plant Net Power Output	0.4	MWe
CO ₂ Capture Efficiency	85.5	%

Table 5.21 - Case 3-2 Energy Balance Capture Plant

Compared to the local case 3-1 a higher power production can be distinguished. A larger power plant is installed in the power block of the capture plant and this increases the electricity that is produced. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The CO_2 capture efficiency is calculated by taking the actual CO_2 emission, compensate for the CO_2 in the inlet air to the gas turbine, and divide this by the maximum CO_2 emission from burning the original fuel (before reforming).

5.6.3 CCPP Description

The fuel is delivered at the power plant at a low temperature of 21.5 °C (compared to a temperature of 230 °C in the local case 3-1). This is due to the 40 km transportation distance between the two sites.

In paragraph 5.3.3 it was stated that preheating the fuel is a feasible option to increase the overall efficiency of the power plant. In this case the fuel is preheated by heat exchangers, which are fed with steam generated by the HRSG's in the power plant.

When fuel preheating is applied, steam injection is needed to limit the NO_x emissions below the permitted limit.

In this study the fuel is preheated until the temperature of the mixture of fuel and steam is about 230 °C. At this temperature no extra measures need to be taken to materials in the existing equipment. The temperature level can be subject to optimization, as this is not considered in this study.

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5.6.4 CCPP Performance

The table shows the gas turbine data for case 3-2 in comparison to the reference case.

Case	Reference Case	Case 3-2
Fuel LHV	46,855 kJ/kg	7,480 kJ/kg
Fuel Flow / Temperature	15.0 kg/s / 10 °C	89.7 kg/s / 223 °C
Steam Injection Flow / Temperature	-	5.9 kg/s / 340.6 °C
Air Inlet Flow	618 kg/s	532 kg/s
Combustor Exit Temperature	1352 °C	1274.9 °C
Exhaust flow / Temperature	633 kg/s / 608 °C	627 kg/s / 567 °C
Net Power Output	258.8 MW	286.0 MW
Net Electric Efficiency (LHV)	36.8 %	42.6 %

Table 5.22 - Case 3.2 Gas Turbine Performance

Table 5.23 shows the energy balance for the complete combined cycle power plant.

Power Plant Energy Ba	lance				
Gas Turbine Energy Inpu	ıt	1344.3	MWth		
	Fuel Consumption LHV			1341.4	MWth
	Fuel Sensible Heat Input (Tref. 15 °C)			3.0	MWth
	Total Gas Turbine Energy Input			1344.3	MWth
Gas Turbine		581.1	MW		
	GT Gross power			609.7	MW
	GT losses			-28.6	MW
	Net GT output			581.1	MW
Steam Turbine		215.0	MW		
	ST Shaft power			217.1	MW
	ST losses			-2.2	MW
	Net ST output			215.0	MW
Generator losses		-13.5	MW		
Balance of Plant losses		-8.3	MWe		
	Boiler feed water pumps			-2.4	MWe
	Cooling water pumps			-5.0	MWe
	Condensate pumps			-0.2	MWe
	Remaining losses (0.1%)			-0.8	MWe
	BOP losses			-8.3	MWe
Total Plant net power		774.3	MWe		
Net electrical efficiency		57.6	%		

Table 5.23 - Case 3-2 Power Plant Energy Balance

The amount of heat added to the fuel by preheating is equal to 63.5 MWth.

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5.6.5 Overall Plant Balance

Table 5.24 shows the overall energy balance for the combined CO₂ capture plant and CCPP. It is composed from *Table 5.21* and *Table 5.23*.

Total Overall Plant Energy Balance		
Total Overall Plant Energy Input (LHV)	2306.4	MWth
Combined Cycle Power Plant Net Electrical Output	774.3	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	-269.1	MWe
CO ₂ Capture Plant Power Production	269.4	MWe
Total Overall Plant Net Power Output	774.6	MWe
Net Overall Plant Electrical Efficiency	33.6	%

Table 5.24 - Case 3-2 Overall Plant Energy Balance

5.7 OVERALL RESULTS AND CONCLUSIONS

The performance results for the different cases are described in the following table for comparison.

Total Overall Plant Energy Balance	Ref.	1	2-1	2-2	3-1	3-2	
Total Overall Plant Energy Input (LHV)		1404.6	1672.4	1671.0	2121.2	2306.4	MWth
Combined Cycle Power Plant Net Electrical Output	784.8	664.3	809.6	764.3	806.0	774.3	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	0.0	-38.5	-158.9	-168.0	-244.9	-269.1	MWe
CO ₂ Capture Plant Power Production	0.0	0.0	43.0	71.1	190.1	269.4	MWe
Total Overall Plant Net Power Output	784.8	625.9	693.7	667.4	751.2	774.6	MWe
Net Overall Plant Electrical Efficiency	55.9	44.6	41.5	39.9	35.4	33.6	%

Table 5.25 - Comparison Overall Plant Energy Balances

Table 5.25 shows clearly that CO_2 Capture has significant impact on the power plant electrical efficiency. This is due to the high power consumption of the capture plant. The reference plant without CO_2 capture reaches an efficiency of 55.9% and in the case of pre combustion CO_2 capture by syngas production from coal (case 3-2), this efficiency decreased with more then 20%-points to 33.6%.

The post combustion CO_2 capture case has the best electrical efficiency compared to the CO_2 capture cases.

The table also shows that the CCPP electrical output is about 32 to 35 MWe lower in the remote cases in comparison to the local cases. This is caused by the steam bleed, which is needed for the preheating of the fuel in the remote cases. As this steam is used for the fuel preheating, it is no longer available for expansion in the steam turbine. This effect is partially compensated by the higher power production in the CO_2 Capture Plant. In the local cases the fuel is preheated in the capture plant, and in the remote cases the fuel is preheated with steam from the CCPP. Therefore in the remote case the capture plant has more steam available for power production. The

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overall difference in efficiency between a local and its remote case (transport loss) is between 1.6 and 1.8%-points.

Because the different fuels have different CO_2 emissions and the different cases have different power generation efficiencies, it is interesting to look at the CO_2 emission per kWh electricity produced for each case. By adding a price tag to avoided CO_2 production, the premium on the electricity price can be calculated for the CO_2 capture power plant.

CO ₂ emission per kWh electricity	Ref.	1	2-1	2-2	3-1	3-2	
Total Overall Plant Net Power Output	784.8	625.9	693.7	667.4	751.2	774.6	MWe
CO ₂ emission in kg/s	81.4	11.7	13.9	13.9	27.1	30.2	kg/s
CO ₂ emission per kWh	373.3	67.0	72.3	74.8	129.9	140.1	g CO2/kWh

Table 5.26 - CO₂ emission per kWh generated electricity

Table 5.26 shows an important conclusion, which should be taken into account when CO_2 capture rates are discussed. The CO_2 capture rate for all cases is at least 85%, when based on the amount of CO_2 , which is avoided on a per kg fuel basis.

However the CO_2 captured per kWh electricity produced is much lower. This is due to the decreased electrical efficiency of the CCPP with CO_2 capture, which implies that the specific fuel consumption per kWh electricity has increased. For the overall plant performance this is a more appropriate figure to compare cases, as it takes the additional energy consumption of the capture plant into account.

Table 5.27 results from Table 5.26 and shows the relative CO_2 emissions per kWh net electricity production compared to no CO_2 capture from the natural gas fired CCPP from the reference case.

CO₂ Capture	Ref.	1	2-1	2-2	3-1	3-2	
Relative CO ₂ emission	100.0	17.9	19.4	20.0	34.8	37.5	%
Relative CO ₂ Capture efficiency	0.0	82.1	80.6	80.0	65.2	62.5	%

Table 5.27 - CO₂ Capture

It is clear to see that the coal based pre combustion cases perform less efficiently compared to the gas based pre combustion cases. The efficiency of the local cases is better then the remote cases, which is expected, as the remote cases demand a high amount of compression power to transport the fuel gas over the 40 km distance and does not allow waste heat utilisation for fuel preheating in the pre combustion plant. Case 1, which is the post combustion case, has the best performance with respect to total electrical efficiency as well as ${\rm CO_2}$ Capture efficiency per kWh electricity produced.

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6. CAPITAL EXPENDITURE

6.1 INTRODUCTION

To evaluate the economic feasibility of retrofitting a standard natural gas fired power plant with post- or pre-combustion CO₂ capture it is required to have an overview of the capital and operational expenditures for all alternatives considered.

The capital cost figures of the 2 * 400 MW $_{\rm e}$ power plant and the post- and precombustion CO $_{\rm 2}$ capture plants have been based on the following general starting points:

- The processes to be assessed will be state-of-the art for construction in the year 2004.
- The plants will be assumed to be on the NE coast of the Netherlands, within 1 km of the sea (i.e. availability of seawater for cooling purposes and ship unloading facilities).
- A green field site with no special civil work implications will be assumed
- The plants will be built on a turnkey basis and are provided with all required (auxiliary) systems. The power plant and the capture plants both have dedicated auxiliary systems (i.e. minimum integration). Facilities and infrastructure required outside the plant limits, e.g. HV connection, fuel supply, transport and storage of CO₂, etc. are not included in the cost estimate.
- The CCPP and the capture plant will not be realized simultaneously. In case of a local capture plant it is assumed the new plant is located next to the existing power plant. In case of a remote capture plant a distance of 40 km between both sites is considered. The high pressure fuel gas line from the fuel plant to the power plant will be routed underground. The pipeline is assumed to be through agricultural land, with no passage through urban areas.
- All cost figures are presented in USD (exchange rate used: EUR/USD = 1.23).

Besides the general starting points also the following specific cost estimating approach will be applicable:

CCPP

The capital cost for the power plant will be based on actual cost figures from plants recently taken into operation and/or under construction. All costs with respect to the power plant will be presented as one total cost figure.

Capture Plant

The capital cost for the capture plant will be based on actual cost figures for the individual equipment with an installation factor per equipment. The individual equipment costs have been obtained by price calculation of the equipment based on the actual design information and price comparison with prices available of similar equipment, obtained from vendor data. The installation factors, used for cost estimating, are based on the experience of Jacobs with similar units/processes. All costs with respect to the capture plant are presented for the following main plant sections:

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Case 1 Post combustion CO2 capture

- Acid Gas Removal
- CO₂ Compression and drying
- · Offsites and Utilities

Case 2.1 Pre combustion CO₂ capture by local H₂ production from natural gas

- Air Compression
- · Reforming and HT Cooling
- · Shift and LT Cooling
- · Acid Gas Removal
- CO₂ Compression and drying
- Power Generation
- · Offsites and Utilities

Case 2.2 Pre combustion CO₂ capture by remote H₂ production from natural gas

Reference is made to case 2.1

Case 3.1 Pre combustion CO₂ capture by local H₂ production from coal

- Air Separation Unit
- Coal Receiving, grinding and slurry preparation
- · Gasification unit
- · Gas Treatment Package
- · Acid Gas removal
- Product Gas Exports
- Power Generation (combined cycle unit)
- · Offsites and Utilities

Case 3.2 Pre combustion CO₂ capture by remote H₂ production from coal

Reference is made to case 3.1

Reference is made to appendix 4 for a summary list of the equipment (no design details) concerned per case.

Per plant section the split up for the following cost items is presented:

- Direct materials
- Construction
- Engineering and construction services

The individual cost for all individual systems/activities such as individual equipment, auxiliary systems, civil, electrical, instrumentation, etc. will not be presented. To present an accurate cost overview for all individual systems/activities a great effort is required as this is only possible with a detailed break down per system/activity. As a (detailed) break down will not contribute to the aim of this study the above mentioned estimating approach has been followed.

The overall accuracy of the overall cost estimates is in the range of $\pm 25\%$.

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For determining the overall project cost the following additional charges are applicable:

- A cost of 7% of the installed plant cost (overnight construction) will be assumed to cover the owners cost (i.e. process/patent fees, fees for agents or consultants, legal and planning costs land purchase, surveys, general site preparation, etc.)
- A cost of 10% of the installed plant cost (overnight construction) will be assumed to cover project contingency.

6.2 CAPITAL EXPENDITURE

A summary of the capital expenditure (excluding interest during construction) and specific costs in USD per kWe of installed capacity for the reference power plant and the capture plants are presented in *Table 6.1* and *Table 6.2*.

			Reference
Capital Expenditures			ССРР
Overnight construction costs		M USD	354.7
Owners cost	7%	M USD	24.8
Contingency	10%	M USD	35.5
Total installed cost		M USD	415.0
Specific investment		USD/kWe	529

Table 6.1 - Capital Expenditure Reference case

					Case		
Additional Capital Expenditures			1	2-1	2-2	3-1	3-2
Overnight construction costs		M USD	337.7	486.4	641.2	822.4	1,020.7
Owners cost	7%	M USD	23.6	34.0	44.9	57.6	71.4
Contingency	10%	M USD	33.8	48.6	64.1	82.2	102.1
Total additional installed cost		M USD	395.1	569.1	750.3	962.2	1,194.2
Specific additional investment		USD/kWe	631	820	1,124	1,281	1,542

Table 6.2 - Additional Capital Expenditures Capture plants

Reference is made to appendix 6 for the split up of the capital cost estimate of the various cases.

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7. ECONOMIC ANALYSIS

7.1 INTRODUCTION

An economic analysis will be executed to evaluate the economic performance of the CO₂ capture retrofitted combined cycle power plants against the reference power plant. The economic calculations will be based on the starting points as provided by IEA GHG.

The results will be expressed in power production cost and CO₂ emission avoidance cost.

Both values will be calculated for a Net Present Value (NPV) of zero (0) for the complete project 25 years after the initial start-up of the CCPP.

7.2 CASH FLOW CALCULATIONS

7.2.1 Background

Using cash flow calculations one can determine the real cost of electricity production and CO_2 avoidance. This paragraph shows the calculation method and the criteria used. As a result the cost of CO_2 avoidance for the different plant configurations is summarised. The cash flow calculations are executed with the IEA GHG economic assessment model applicable for assessment of levelled costs of generation in new power plants. As the original model is not suitable for the assessment of retrofits the spreadsheet has been modified in order to evaluate retrofitting.

The cash flow calculation shows the cash flows of a power plant throughout its lifetime and calculates the net present value of these cash flows. The net present value (NPV) is the value of a project today if all future cash flows (including investments) are discounted to today's value using a discount ratio.

The cash flows include the following items:

- Revenues
- Fossil Fuel costs
- Maintenance costs
- Labour costs
- · Chemicals and consumables costs
- Insurance
- Capital expenditures
- Working capital
- De-commissioning costs

The cash flow is calculated for 2 years of construction of the reference natural gas fired CCPP followed by 25 years of operation. The production costs per kWh of electricity are calculated by setting the NPV of the power plant to zero. This can be



achieved by varying the kWh price until the revenues balance the costs over the whole lifetime of the power plant.

The calculated kWh price at which the NPV of the reference case is zero, is maintained for the calculations to the different cases. The CO₂ avoidance cost are varied until the NPV of each of the cases is zero.

For the retrofit cases it is assumed that the new capture plants are constructed while the CCPP is still in operation. The CCPP will only be taken out of operation to allow for making the required tie-ins with the new plant and realize the required internal modifications (e.g. replace gas turbine combustion system). The 25 years of operation evaluation criteria for the CCPP will not change. There is no residual value at the end of the lifetime of the CCPP.

Sensitivity analyses will be made to evaluate the economic performance of the various options when varying one parameter at the time.

Parameters to be varied are:

- Fuel price (-50%/+100%)
- Discount rate (5%)
- Year of retrofit (-5/+5 year)

7.2.2 Starting points

The yearly cash flow is calculated using the IEA GHG criteria.

Criteria that need further explanation are discussed below:

Discount rate and cost of capital

All cash flows will be discounted using a discount rate of 10%. These cash flows also include the debts made during the design, construction and commissioning.

Year of retrofit

The retrofitted CCPP will be commissioned/started-up 10 years after the initial start-up of the CCPP. Design and construction period of the capture plant starts 2 (natural gas fuelled plant) or 3 (coal fuelled plant) years earlier.

Escalation

In accordance with the IEA GHG criteria, no escalation has been included.

Commissioning

A 3-month commissioning period will be allowed for all types of plant. In effect this means that during the first year the load factor of the plant is reduced by 25%. The reference power plant will operate at a load factor of 90% during the first year; by adding a commissioning period of 3 months, the load factor will be reduced to 67.5%. When the retrofitted plant is started up the identical approach is applicable for natural gas fuelled plants. However for the coal fuelled plants a load factor of 60 % is applicable for the first year, which has to be corrected for the 3-month commissioning period, resulting in a load factor of 45%.



Load Factor

The natural gas fuelled power plant(s) will operate at a load factor of 90% during a normal year. The coal-fuelled power plant(s) will operate at a load factor of 85% during a normal year. The load factor affects the electricity production, consumption of all consumables, disposal of wastes and maintenance costs. It does not reduce the labour costs and insurance.

De-commissioning

The costs associated with shut down of the plant can be taken as a percentage of the capital investment. However, since these costs occur only once at the end of the lifetime of the (power) plant the discounted cash flow is reduced to a minimum. As a result the de-commissioning costs only comprise 0.1 to 0.2% of the kWh price and are insignificant and therefore neglected.

Maintenance

The Maintenance expenditures are 2% p.a. of the installed costs for the CCCP and the gas conversion and treatment plants. For "coal handling" plants, maintenance expenditures of 4% p.a. of the installed plant costs are used.

Contingencies

An allowance is made for estimating error and process unknowns / development. This allowance is set as a percentage of the overnight construction cost. A contingency factor of 10% covers most of the risks.

<u>Labour</u>

The labour cost for one operator is set to 75.000 USD/year. A percentage is added to the labour cost for indirect costs for supervision (20%) and administration + overhead (30%). The number of operators (5 shift) necessary for each plant is assumed to be:

- Ten (10) operators for the NG fired CC reference power plant
- Fifteen (15) operators, power plant operators included, for the post-combustion CO₂ capture option
- Twenty (20) operators, power plant operators included, for the local natural gas fuelled pre-combustion CO₂ capture options
- Twenty (20) operators, power plant operators excluded for the remote natural gas fuelled pre-combustion CO₂ capture options
- Twenty five (25) operators, power plant operators included, for the local coal fuelled pre-combustion CO₂ capture options
- Thirty (30) operators, power plant operators excluded for the remote coal fuelled pre-combustion CO₂ capture options

Consumables and Working Capital

The consumables consist of the following components:

- Chemicals for boiler water treatment
- Chemicals for waste water treatment
- Lubricants
- Potable water

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- M(D)EA solution + additives
- Catalyst + internals
- Solexol solvent

Working capital for storage of consumables is assumed to be 30 days.

Fuel Price

The fuel price is set at 3.0 USD/GJ (LHV) for natural gas and 1.5 USD/GJ (LHV) for coal.

Waste Disposal

For hazardous waste disposal the following costs are used:

- Small quantities 250 €/ton
- Large quantities 150 €/ton

It is assumed that the gasifier slag produced in the coal cases is a product, which can be sold. For the economical analysis it is assumed that the profits equal the disposal costs.

7.3 RESULTS

The results from the cash flow calculations are presented in *Table 7.2*. Reference is made to appendix 7 to the detailed calculation results. The results are given for the reference natural gas fired CCPP and the various CO_2 capture retrofitted cases. *Table 7.1* shows the specific investments and electric efficiencies.

The total specific investment is defined as the overall investment of CCCP and fuel/ CO_2 capture plant without inflation correction, divided by the net power output after the retrofit. The overall electric efficiency presented for the fuel/ CO_2 capture plants is also applicable for the retrofitted situation. Up to the retrofit the overall electric efficiency of the reference CCCP is applicable.

		Total Specific Investment	Overall Electric Efficiency
		USD/kWe	%
ССРР	Reference power plant	529	55.9
Case 1		1294	44.6
Case 2.1		1419	41.5
Case 2.2		1746	39.9
Case 3.1		1833	35.4
Case 3.2		2077	33.6

Table 7.1 – Investments and Efficiencies

7.4 CALCULATION OF CO₂ COST

Costs per ton of avoided CO_2 resulting from decarbonisation are calculated by varying the CO_2 avoidance costs until the NPV of the case is zero, at an electricity price equal to the price at which the NPV of the reference power plant is zero.

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Electricity production costs are calculated as described in section 7.2.1. Specific CO_2 emission is calculated by dividing the emitted amount of CO_2 per year accountable to the fuel (i.e. absolute CO_2 emission is corrected for the CO_2 in the combustion air) by the yearly net power production. Both figures assume 8760 yearly hours and the applicable load factor. The CO_2 emission avoidance cost is defined to be the value at which the NPV of the considered option is zero.

	Electricity Production Cost USD/MWh	Specific avoided CO ₂ Ton CO ₂ /MWh	Cost of avoided CO ₂ USD/Ton CO ₂
ССРР	29.97	1011 002/1111111	000/10/1002
Case 1	29.97	0.306	73.24
Case 2.1	29.97	0.301	95.05
Case 2.2	29.97	0.299	124.33
Case 3.1	29.97	0.243	131.36
Case 3.2	29.97	0.233	168.13

Table 7.2 - CO₂ Emission Avoidance Cost

7.5 RESULTS SENSITIVITY ANALYSIS

The following parameters were altered in order to perform a sensitivity analysis:

- A. Fuel price increase of 100%
- B. Fuel price decrease of 50%
- C. Discount rate decreased from 10% to 5%
- D. Year of retrofit (5 years after start-up of CCPP in stead of 10 years)
- E. Year of retrofit (15 years after start-up of CCPP in stead of 10 years)

Electricity production costs and costs of avoided CO₂ have been recalculated for all cases. The electricity production costs for the reference plant are recalculated using an altered fuel price or discount rate in the sensitivity analyses A, B and C.

These recalculated electricity production costs for the reference cases are kept constant for the corresponding cases and the CO₂ avoidance costs are calculated by finding the appropriate value at which the NPV is zero for each separate case.

7.5.1 Fuel price sensitivity

The influence of fuel price levels on electricity production cost and cost of avoided CO_2 is shown in *Table 7.3* and *Table 7.4*. An increased price level of fuel results in increased electricity production cost, having a negative impact on the cost of avoided CO_2 production for 1 and 2 and a positive impact on case 3. The specific difference in fuel costs between natural gas and coal increases, which is beneficial for coal firing compared to natural gas firing.

The opposite is true for a fuel price *decrement*.



Sensitivity calculation Fuel Price +100%	Electricity production cost	Cost of avoided CO2	Change of avoided Cost of CO2	
	USD/MWh	USD/Ton CO2	%	
CCPP Ref.	49.31			
Case 1	76.65	89.27	21.9	
Case 2.1	84.63	117.33	23.4	
Case 2.2	94.14	150.17	20.8	
Case 3.1	77.38	115.29	-12.2	
Case 3.2	85.44	154.95	-7.8	

Table 7.3 - Sensitivity analysis results A

Sensitivity calculation Fuel Price -50%	Electricity production cost	Cost of avoided CO2	Change of avoided Cost of CO2	
	USD/MWh	USD/Ton CO2	%	
CCPP Ref.	20.31			
Case 1	40.30	65.23	-10.9	
Case 2.1	45.57	83.91	-11.7	
Case 2.2	53.56	111.42	-10.4	
Case 3.1	54.24	139.40	6.1	
Case 3.2	61.07	174.72	3.9	

Table 7.4 - Sensitivity analysis results B

7.5.2 Discount rate sensitivity

The influence of the discount rate on electricity production cost and cost of avoided CO_2 is shown in *Table 7.5*. As expected, lowering the discount rate has a positive impact on the electricity production cost as well as the costs of avoided CO_2 for all cases studied.

Sensitivity calculation Discount rate 5% (instead of 10%)	Electricity production cost	Cost of avoided CO2	Change of avoided Cost of CO2
,	USD/MWh	USD/Ton CO2	%
CCPP Ref.	27.03		
Case 1	45.23	59.43	-18.9
Case 2.1	50.82	79.02	-16.9
Case 2.2	51.93	102.47	-17.6
Case 3.1	50.22	95.27	-27.5
Case 3.2	55.92	123.88	-26.3

Table 7.5 - Sensitivity analysis results C

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7.5.3 Retrofit year sensitivity

The influence of the moment of retrofit on electricity production cost and cost of avoided CO_2 is shown in *Table 7.6* and *Table 7.7*. Earlier retrofit results in reduced costs of avoided CO_2 because more CO_2 is captured over the lifetime of the plant. The more years the power plant is operated in "capture mode" the more money it makes compared to the reference cases, which are retrofitted 10 years after startup. A five year earlier retrofit lowers cost of avoided CO_2 per ton with 6% to 10%, whereas a "delay" in retrofit increases the cost of avoided CO_2 per ton with 13% to 22%.

Sensitivity calculation Retrofit year - 5 (5 years from start up)	Electricity production cost	Cost of avoided CO2	Change of avoided Cost of CO2	
(5 years from start up)	USD/MWh	USD/Ton CO2	%	
CCPP Ref.	29.97			
Case 1	51.11	69.02	-5.8	
Case 2.1	56.92	89.53	-5.8	
Case 2.2	64.82	116.76	-6.1	
Case 3.1	58.90	118.92	-9.5	
Case 3.2	65.54	152.58	-9.3	

Table 7.6 - Sensitivity analysis results D

Sensitivity calculation Retrofit year + 5 (15 years from start up)	Electricity production cost	Cost of avoided CO2	Change of avoided Cost of CO2
(15 years from start up)	USD/MWh	USD/Ton CO2	%
CCPP Ref.	29.97		
Case 1	55.32	82.77	13.0
Case 2.1	62.34	107.49	13.1
Case 2.2	72.18	141.42	13.7
Case 3.1	68.82	159.71	21.6
Case 3.2	77.43	203.56	21.1

Table 7.7 - Sensitivity analysis results E

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8. RETROFITTING ISSUES

When a standard combined cycle power plant is retrofitted to a low CO₂ emission power plant, modifications to the installation are needed or new add-on installations are required. These modifications are often not foreseen at the design phase of the original power plant, and this can therefore create barriers to the retrofit, either technical or economical. This chapter identifies the possible barriers and describes how action taken during the design phase of a new power plant can be used to minimize barriers to a future retrofit and even optimize the overall plant configuration by allowing future integration of capture plant and power plant.

8.1 BARRIERS TO RETROFIT

In general a standard combined cycle power plant is not designed for the future possibility of major modifications due to retrofitting the plant. Especially for modern power plants, standardization and modularization are getting more and more important as manufacturers are trying to find ways to cut engineering and erection costs. This however also complicates a retrofit, as there is not much space left for expansion or adjustments to the installation. Furthermore current plants are optimized based on the original design parameters and a change to the process parameters or plant design often leads to a sub optimal design, which may not survive in a competitive market environment.

This paragraph aims to identify possible barriers to retrofitting existing combined cycle power plants to a power plant with CO₂ capture. The barriers are listed below:

Plot Space

A fuel processing plant as well a post combustion CO_2 capture unit (flue gas scrubber) requires a considerable amount of plot space. This plot space needs to be available in the near surroundings of the plot. When the plant is situated in a residential area or a heavily industrialised area this plot space is not always available.

Especially for a post combustion unit with large atmospheric flue gas flows, the capture unit needs to be installed literally next to the CCCP. It is not desirable to transport these large quantities of flue gas over even a short distance. From a technical point of view the resulting higher pressure loss will to a great extent affect the performance. From an economical point of view the costs for this large diameter piping are high.

In case of a fuel processing plant, the distance between the CCPP and fuel plant is less critical from a technical point of view. However, the longer the distance is, the higher the costs are for connecting the plants. Furthermore it shall be clear that the area classification for the fuel plant is an important issue in the plot location. Of course these remarks are a less critical issue in the remote cases, at which the choice for the location of the fuel plant is "open".

Also significant plot space is required for construction. This is an important item with respect to the overall construction cost and time schedule. With little construction space available, items need to be delivered as prefab installations as much as possible (no place to construct on-site) and planning of the activities becomes very important (no place to store materials/equipment).

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Available Space within installation

The existing installation is designed to take up the least plot space as possible. When tie-ins are required, problems can arise with the available place within the installation itself.

For example, in the pre combustion case the fuel supply piping has to be replaced as fuel flows increase significantly. In the post combustion case additional LP steam piping of approximately 36 inch is needed for steam supply from the power plant to the capture plant.

Fitting the large diameter piping in the existing CCPP will create difficulties, as the installation is not designed for this extra piping. Depending on the actual situation, a certain amount of effort will be needed to enable the tie-inns and because of this costs will rise.

Accessibility

The delivery of large equipment can be a problem when the power plant is situated in an industrial surrounding. This is the case at both the post combustion as well as the pre combustion cases (except for the remote options). It might be necessary to deliver very large equipment blocks in parts and build the equipment on-site. This can influence the cost of retrofitting negatively and have great influence on the time schedule.

To illustrate this, the largest new equipment items for the different options are listed here:

•	Case 1	CO ₂ absorber:	9.7 m. diameter by 20 m. tan-tan
•	Case 2-1	CO ₂ absorber:	6.5 m. diameter by 39 m. tan-tan
•	Case 2-2	CO ₂ absorber:	6.5 m. diameter by 39 m. tan-tan
•	Case 3-1	CO ₂ absorber:	6.4 m. diameter by 31 m. tan-tan
		ASU main column:	5.3 m. diameter by 50 m. tan-tan
•	Case 3-2	CO ₂ absorber:	6.5 m. diameter by 31 m. tan-tan
		ASU main column:	5.5 m. diameter by 50 m. tan-tan

Changed process conditions

The gas turbine performance will differ significantly when fired on a low-LHV fuel, which is the case with pre combustion CO_2 capture. The standard power plant has been designed for firing on natural gas, and the changed gas turbine performance will lead to different process conditions in the installation. This can lead to technical problems that can be hard to overcome.

For instance the lower exhaust temperature of the gas turbine exhaust gas will lead to a lower steam temperature at the HP superheater outlet. This can create problems in the condensing section of the steam turbine, causing too high moisture content in the steam, which damages the last blade rows in the steam turbine condensing section. For the post combustion case the added flue gas scrubber introduces an additional pressure loss at the flue gas side. Additional measures have to be taken to overcome and/or reduce this pressure loss. This kind of problems may even lead to the complete replacement of parts of the existing equipment, with equipment that is designed for the new process conditions.

Whether this kind of problems will occur, depends on the design of the installation. As no design is exactly the same, it will be necessary to determine possible problems for

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each installation that is retrofitted. This applies not only to base load operation, but also to different part load situations, at several ambient conditions.

Demin Water Capacity

Injection of high quality steam is needed in case gas turbine DLN burners are replaced with conventional burners. Hence demin water plant capacity is to be enlarged for steam injection.

In case of a local CCPP and remote capture plant an additional demin water plant is needed, which requires extra plot space.

The demin water consumption for each case can be found in Appendix 5. These consumptions represent the water consumptions in normal operation. When the CCPP is fired on secondary fuel (i.e. natural gas), higher demin water consumption is applicable for all cases, as steam injection is needed to restrict NO_x emissions.

Cooling Water Capacity

The fuel processing plant will increase the cooling water demand and cooling water duty significantly. The CCPP cooling system will probably not be sufficient to meet this increase in demand and therefore a new system might be necessary. It will not be a problem to install new piping and cooling water pumps, as these are simply add-on installations. When the spare capacity of the cooling water intake and outlet is too low, the implications are greater. Increasing the capacity demands for extensive civil works and sufficient space may not be available for these expansions. In that case cooling tower systems may be required.

Operational flexibility

Inlet Guide Vane control is used to operate the gas turbine when fired on low-LHV fuels. These IGV's are normally used to enable more efficient part load operation of the CCPP. Using them at full load means that the part load efficiency will be affected in a negative way, as this control can no longer be used in its full extent for part load operation.

CCPP units are generally spoken very flexible with respect to the time required for start up and shut down. In the pre combustion case, a complete fuel plant is added, which complicates start up and shut down as this plant has to start/stop as well.

Permitting

In practice it is time consuming and expensive to get the needed permits for expansions or modifications to an installation. Retrofitting an existing CCPP means that the emissions to air and water change, the noise level can increase, more cooling duty is required, etcetera. This will probably lead to the need for new or adjusted permits. The time and effort, which is consumed when new permits are needed, should not be underestimated. This will especially apply to high-pressure fuel lines near urban areas.

Fuel storage and transport

In case of coal fired plants a large open space is needed for coal storage. Because the coal in store is subject to self-ignition, hence the storage spreads smoke and smell, it is preferred to keep the plant away from residential area's and safe zones.

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High pressure fuel lines are needed to transport syngas in the case a Fuel/CO₂ capture plant is built remotely from the existing CCPP. Routing of the HP fuel lines is complex because off the line size of 30-36 inch and the probable interference with road crossings and areas with explosion safety demands, which do not allow an HP fuel line to cross.

8.2 DESIGN FOR FUTURE RETROFIT

In the previous paragraph the barriers were discussed, which could arise when an existing combined cycle power plant is to be retrofitted to a low ${\rm CO_2}$ emission power plant. This paragraph discusses the options to design the plant in such a way that a future retrofit can be executed without major costs and technical difficulties, caused by these barriers, while still maintaining an optimal performance before and after retrofit. First step is to point out the possible barriers and try to remove them by implementing additional design requirements. Next to removing barriers for future retrofit, there are also possibilities for process integration between the fuel plant and the power plant. These can increase the economical feasibility of the project with a considerable amount.

Without being studied in detail, some indications are given to illustrate the impact that these issues may have.

8.2.1 Avoiding potential barriers

In paragraph 8.1 the barriers to retrofitting are discussed. When a CCPP is designed for future retrofit, these potential barriers should be avoided in the design phase. In this paragraph the possible solutions are mentioned to each of the above-mentioned barriers.

Plot Space

In the ideal situation of a completely new and empty site, the design should also include the additional required plot space for the fuel processing plant or the flue gas scrubber. The most ideal location for the installations with respect to the CCPP can be determined.

When the CCPP is placed in an area with little additional space available, the nearest possible free plot space should be determined and reserved. In this way no new building activities are deployed on that lot, until the final decision for retrofitting is made.

When post combustion CO₂ capture is decided, it is however necessary to reserve additional plot space at the CCPP plot. It is not desirable to transport the large flue gas volume over big distances.

In Appendix 3 the plot plans with sizes for the different installations can be found.

In addition to the required space for the installations themselves, attention should be paid to the space required for the construction activities. When space is available to store materials, tools and installation parts on site, the construction work can be done cheaper in comparison to an off-site construction area.

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Reserving more plot space then strictly necessary for the CCPP plant only will result in higher project costs in the first phase, but will save expenses when retrofit is carried out.

Indications of plotspace needed for building the capture plants are:

Case 1: post combustion capture plant 250x150 m.

Case 2.1 and 2.2: gas reformed based pre combustion is capture plant 175x150 m.

Case 3.1 and 3.2: coal gasification based pre combustion capture plant 475 x 375 m.

Available space in installation

When the CCPP is designed for future retrofit, the future tie-ins have to be defined and the space they require becomes an additional design requirement.

For the pre combustion capture case this implies that space has to be reserved for large diameter (12"-36" dependant on the option concerned) fuel feed pipes to the gas turbine. The same applies for the large diameter low pressure steam line (approx. 36") in the post combustion option. Also when the replacement of equipment components is foreseen, the design should anticipate the incorporation of the new (possibly larger) component, as well as enable the replacement work itself. For example it might be necessary to replace the existing HRSG superheater section, to adjust the CCPP to the new process conditions. Taking these issues into account will lead to minor extra costs, while the cost savings at the retrofit stage can be significant.

Typically stretching the HRSG with a few meters and allow for some spare room for the heat surfaces concerned allows for a modification.

Accessibility

The accessibility of the plot should be considered as a design requirement at the choice for the most appropriate site location. Usually this aspect will already be part of the selection process for a new CCPP, and extra attention should be paid to the accessibility for the big components of the pre and post combustion capture installations.

Changed process conditions

A new power plant will generally be designed to perform in an optimal way at one set of process conditions, belonging to one type of fuel, one average ambient condition, etcetera. An important option to facilitate retrofitting a CCPP is to design the plant with keeping in mind that process conditions change due to the retrofit.

At the pre combustion capture case the exhaust gas temperature decreases when the gas turbine is fired on low-LHV fuel gas. This implies that the high-pressure steam superheater cannot raise the steam temperature to the original design value, as the surface area is too small at these different flue gas conditions. This could cause technical problems and it may even be necessary to exchange the superheater with a new, larger one.

During the design phase it could be considered to install the larger superheater, which will be able to raise the steam temperature to the original design value. This superheater will then be equipped with an attemperator to cool down the steam temperature when the gas turbine is fired on normal LHV (natural) gas. Installing a larger superheater will be more expensive and reduce efficiency in the CCPP. However it improves efficiency and saves costs in retrofit.

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For the post combustion case there is no remedy to undo the higher pressure loss due to the flue gas scrubber unit. An induced draft fan could be installed during retrofitting in the flue gas ducting to overcome this extra loss, but this will also increase the auxiliary power consumption (because of the power needed to drive the fan). Extra plot space for enabling the installation of this fan should be provided for.

Cooling water capacity

The cooling water intake and outlet stations should be designed to have sufficient capacity to take the increase in cooling water demand because of the fuel processing plant or the flue gas scrubber. The stations can be designed to facilitate for example extra cooling water pumps, without the need for installing these pumps right away. This will give flexibility to increase the cooling water capacity without having to perform large civil works for expansion.

The cooling water capacity for the various capture plants is:

- coal gasification based local pre combustion capture plant 83,000 m³/h.
- gas reformed based local pre combustion is capture plant 21,000 m³/h.
- post combustion capture plant 46,000 m3/h.

The cooling water requirement of the CCPP for the different cases can be found in Appendix 1, stream 5. For the reference case the maximum cooling water load applies, which is approximately 27,000 m³/h.

Operational Flexibility

It is difficult to design for a higher level of operational flexibility when the gas turbines are fired on low-LHV gas. Process integration between the pre combustion capture plant and the CCPP could help, as will be discussed in the following paragraph.

Permitting

As permitting can be a real problem, it is advisable to start the requests for the required permits as early as possible. This could mean that the application for the permits needed for the situation after retrofit, could best be started together with the permits for the CCPP. This will decrease the change on surprises as well as it will avoid lost time when the decision for retrofitting is made.

Construction and Start-up

Planned down time of the CCPP can be minimised when additional facilities for making the tie-ins with the CCPP in operation (Hot-tapping) are allowed for during construction.

8.2.2 Potential process integration

In addition to trying to remove potential barriers to future retrofit, it can be rewarding to design the CCPP in such a way that process integration can be obtained between the CCPP and the post or pre combustion capture plants. This could lead to cost savings as well as performance improvements compared to not-integrated plants. This paragraph indicates the potential options for process integration.

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Gas Turbine Compressor Bleed

The Capture Plant requires high-pressure air, which is supplied by a dedicated compressor. At the power plant however, the gas turbine compressor is partially by-passed by closing the IGV's, in order to retain the fuel gas flow through the gas turbine expander section.

Here process integration can be achieved by using the highly efficient gas turbine compressor section to supply (part of) the high-pressure air for the Capture Plant. This has multiple advantages:

- Gas turbine compressor sections are state of the art compressors, with highest efficiencies. The efficiency of the gas turbine compressor will usually be higher then the efficiency of the dedicated compressor.
- Investment costs will be lower as the dedicated compressor can be designed for a smaller airflow or smaller pressure ratio.
- The gas turbine compressor section will take the airflow it was designed for and at which its efficiency is highest. This contrary to the non-integration case at which IGV's are used to decrease the flow through the compressor.
- The CCPP part load efficiency is increased, as the IGV control is once again completely available to reduce the gas turbine load.

As the natural gas fuelled (local) pre combustion CO_2 capture plant is provided with high efficient air compressor units with minimum intercooling the potential efficiency increase by implementing gas turbine compressor bleed is marginal. However it will have a positive impact on the overall cost of investment because of the reduction of air compressor capacity required. An overall cost reduction of approx. 7% of the fuel/ CO_2 capture plant is expected.

For the coal gasification based (local) pre combustion CO₂ capture plant also potential efficiency increase is expected because for the ASU highly intercooled compressor units are used. This configuration aims for the minimum compressor power required, but results in a high loss of thermal energy via the cooling water system which has a negative impact on the overall plant efficiency.

To achieve a bleed flow from the gas turbine compressor outlet, the gas turbine needs to be equipped with a special bleed system. This will probably be too expensive when an existing gas turbine without air bleed is retrofitted. However when the power plant is designed for retrofit, the gas turbine can be ordered with an air bleed system installed. Of course this process integration is only feasible in the local cases as it will not be efficient to bring the compressed air from the power plant through a 40 km pipeline to the Capture Plant.

Integral water-steam cycle

The pre combustion capture plant has a dedicated steam turbine to expand the steam generated in the process and produce electricity. This steam turbine is a relatively small turbine, with high investment costs and a relatively low efficiency (compared to large scale power plant steam turbines). The power plant has such a large steam turbine generator and therefore process integration can be achieved here by feeding the steam from the Capture Plant to the power plant steam turbine. This has the following advantages:

Small steam turbines have higher specific investment cost, and it is usually less
expensive to purchase a somewhat larger steam turbine for the power plant with an



increased capacity to be able to accept the additional Capture Plant steam production.

- The large steam turbine has a higher efficiency than the small turbine, so the steam
 expansion and electricity production is more efficient in the large turbine. Additional
 advantage is the need for only one cooling water system. The larger steam turbine
 will also come with a larger condenser, so there is no need for a dedicated
 condenser for the fuel plant.
- The integration will save valuable plot space.

However, as the steam generation in the fuel plant (approx 300-550 t/h) is rather significant compared to the CCCP steam production (approx. 2*350 t/h), this will highly effect the steam turbine design of the CCCP. It requires a more detailed study to assess the overall impact and potential.

Again this process integration option is only feasible in the local cases as it will not be efficient to transport high pressure steam over 40 km in the remote cases.

The same arguments as above can be used to plead for a combined instead of a dedicated demin water plant and closed cooling water system.

8.3 OVERALL AVAILABILITY

8.3.1 Availability rating

The overall availability of a plant is mainly dependent on the following issues:

- complexity of the installation and/or process
- project experiences with the type of installation concerned (i.e. references)
- design philosophy of the plant (i.e. redundancy of critical equipment, control and safeguarding systems, etc.).

In *Table 8.1* an overview of the availability rating for the various plants concerned for this study is presented:

	Complexity	References *	Design	Overall rating
Reference plant	++	++	++	++
Case 1	+	0	++	+
Case 2.1	0	0/-	++	0
Case 2.2	0	0/-	++	0
Case 3.1		0/-	++	-
Case 3.2		0/-	++	-

Table 8.1 - Availability Rating

From the table it becomes clear that the expected overall availability for the retrofitted plants is lower than the expected availability for the reference plant. This is in principle an expected result, as the retrofitted plant comprises not only additional plant sections

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^{*} There are presently hardly any CO₂ capture plants realized but in case there are similar types of plants in operation this is also taken into account.



(i.e. additional systems and equipment, which may fail and require maintenance) but also rather complex installations (especially the coal based plants).

However when evaluating the availability of power generation it is possible to obtain a similar availability for all plants by providing sufficient provisions to allow for independent operation of the CCPP. The required provisions for each case are presented below.

In all cases, the capture plant is designed to have an availability of at least 90%. This is achieved by installing spares in key services. For example, all pumps, the gasifiers and sulphur plants in cases 3-1 and 3-2, and the desulphurisation reactors in Cases 2-1 and 2-2 are spared.

In all cases, provided the CCPP is allowed to operate without capturing 85% of the carbon in the feed, then the installation of the Capture Plant does not affect the availability of the CCPP.

8.3.2 Case 1 Post combustion CO₂ capture

A bypass stack with (automatic) switch over facilities between the HRSG sections and the CO_2 capture plant shall be provided in order to discharge the flue gas to the atmosphere or to the CO_2 capture plant.

The effect of the failure of a single quench and acid gas removal train would mean that, provided that the exhaust gases could be vented, CO_2 capture would be reduced by 12.5%. It is unlikely that the additional exhaust gas could be routed through the remaining quench and acid gas removal units, as this would increase pressure drops by up to 70% and overload the absorber feed fan. Failure of multiple quench and acid gas removal trains would result in further reductions in CO_2 capture and increases in the steam turbine generator condenser requirements. Alternatively, the CCPP for the failed quench and acid gas removal train, could be turned down to 75% of capacity, removing the need for venting of exhaust gas.

The effect of failure of a CO₂ compressor and dryer unit would be to reduce the CO₂ capture by 50%. The exhaust gas from the HRSG could be routed to the existing stack and the CCPP operated as before the Capture Plant was installed.

8.3.3 Case 2 Pre combustion CO₂ capture by syngas production from natural gas

The Capture Plant has two trains of desulphurisation, auto-thermal reformer, high temperature cooling, shift, low temperature cooling, acid gas removal, CO_2 compressor and dryer, and gas conditioning. A failure of any one of these process units means that the capture plant train is shut down and the feed of low carbon fuel to one gas turbine is stopped.

Therefore the gas turbine shall be provided with a conventional dual fuel system capable of firing 100 % syngas as well as 100 % natural gas. Steam injection will be required for NO_x abatement during firing natural gas.

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8.3.4 Case 3 Pre combustion CO₂ capture by syngas production from coal

The Capture Plant has two trains of coal slurrying and grinding, gasification, shift, low temperature cooling, acid gas removal, CO_2 compressor and dryer, and gas conditioning. Failure of coal slurrying and grinding, gasification, shift, low temperature cooling, acid gas removal, or gas conditioning results in shut down of one train of the Capture Plant and one gas turbine is running on natural gas in stead of syngas. A spare gasifier is foreseen in the design of the Capture Plant (5 * 25% gasifiers).

Therefore the gas turbine shall be provided with a conventional dual fuel system capable of firing 100 % syngas as well as 100 % natural gas. Steam injection will be required for NO_x abatement during firing natural gas.

If the CO_2 compressor and dryer, CO_2 export pipeline or CO_2 sink fails, then fuel gas can be supplied to the CCPP, which operates as normal, except that CO_2 is vented to atmosphere, rather than being captured.

8.3.5 Availability during start-up

It shall be clear that the provisions mentioned above are also strongly preferred or even required for start-up and shut down purposes and are therefore implemented anyhow and not lead to additional capital cost.

In the year of retrofit the CCPP availability may decrease because of the down time to allow for implementing modifications and tie-in activities. In case of a good preparation and a tight schedule it is considered possible to make all tie-ins and implement the required modifications within approximately 1 month. For case 1, post combustion CO_2 capture, it may even be possible to realize the project without additional down time when all tie-ins have been prepared in advance (i.e. during a planned outage of the CCPP). For the pre combustion CO_2 capture cases a complete new combustion system has to be installed. This system will normally not be installed in advance as it will have a negative impact on the power plant performance (steam injection required when firing natural gas).

In case the modifications are executed during a major overhaul period the impact on the plant availability will be negligible for all cases.

Also during the initial commissioning/operating period the availability will be lower due to the 'normal' issues, which always rise during the initial start-up of an installation. It is normal practice that the higher the complexity of the installation the longer it takes to reach the stable operating mode.

To minimize the CCPP plant availability reduction during the commissioning/start-up period it is preferred to have a postponed schedule for the second power train. Experiences gained during start up of the first train can be used when starting up the second train.

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9. CONCLUSIONS

From the study it becomes clear that a retrofit of CO_2 capture to a natural gas fired CCCP requires a significant cost of investment and results also in a significant reduction of the overall electric efficiency. The post combustion CO_2 capture option is strongly preferred from a performance and financial point of view compared to the natural gas reforming and the coal gasification based pre combustion CO_2 capture plants.

The post combustion option shows the smallest but still significant efficiency reduction in combination with the lowest capital expenditures and the best specific CO₂ emission.

The main disadvantage of the post combustion option is the requirement of installing the plant almost next to the existing CCCP because of the large atmospheric flue gas flow. As the plant requires also a large plot space, this could be a problem for retrofitting.

The main data for all options studied are presented in table 9.1

		Ref.	1	2.1	2.2	3.1	3.2
Capital expenditure*)	MUSD	415	395	569	750	962	1194
Specific electricity cost**)	USD/MWh	30.0					
Cost of avoided CO ₂	USD/ton		73.2	95.1	124.3	131.4	168.1
	CO_2						
Overall efficiency	%	55.9	44.6	41.5	39.9	35.4	33.6
Fuel consumption (LHV)	MWth	1405	1405	1672	1671	2121	2306
Net power production	MWe	785	626	694	667	751	775
CO ₂ emission	kg/s	81.4	11.7	13.9	13.9	27.1	30.2
Specific CO ₂ emission	g/kWh	373	67	72	75	130	140
Relative CO ₂ emission	%	100	17.9	19.4	20.0	34.8	37.5
Relative CO ₂ capture efficiency***)	%	0	82.1	80.6	80.0	65.2	62.5

Table 9.1 – Overall performance comparison

Ref: Natural gas fired CCCP

Post combustion CO₂ capture

2.1 : Pre combustion CO₂ capture (natural gas reforming, local)
2.2 : Pre combustion CO₂ capture (natural gas reforming, remote)

3.1 : Pre combustion CO₂ capture (coal gasification, local)
3.2 : Pre combustion CO₂ capture (coal gasification, remote)

^{*)} The capital expenditures for the fuel/CO₂ capture plant are excluding the cost of the reference CCCP.

^{**)} The specific electricity costs are calculated for the project with a Net Present Value (NPV) of 0.

The absolute capture efficiency for all plants is approx. 85%. However, as retrofitting reduces the efficiency, the relative capture efficiency decreases.



Other conclusions are:

- All options comply with the CO₂ capture efficiency of 85%.
- The remote pre combustion options require a higher cost of investment and have a lower efficiency due to transportation of the fuel gas.
- The overall power generation availability of the retrofitted plant is "identical" to the reference CCCP.
- Sensitivity analyses on fuel price show a different behaviour of the cost of avoided CO₂ for the coal-based plants compared to the natural gas fuelled plants. An increase of the fuel price results in an increase in the cost of avoided CO₂ for the natural gas fuelled plants and a decrease of cost for the coal fuelled plants. In case of a fuel price reduction the opposite occurs. Sensitivity analysis on discount rate show, as expected, a reduction of the costs of avoided CO₂ for all cases considered with a reduced discount rate.
- Sensitivity analyses on the year of retrofit show as expected that when the retrofit is executed at a later time, the cost of avoided CO₂ increase.
- The post combustion option remains the best option from a financial point of view for all sensitivities considered.

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APPENDICES

- 1. CCPP Simplified Process Scheme & Mass Balances
- 2. Fuel/CO₂ Capture Plants Simplified Process Schemes & Mass Balances
- 3. Plot Lay-outs
- 4. Fuel/CO₂ Capture Plants Equipment List
- 5. Fuel/CO₂ Capture Plants Power Consumption/Production & Utility Usage
- 6. Fuel/CO₂ Capture Plants Capital Cost Estimates
- 7. Cash Flow Calculations
- 8. Task 1 Same Output Retrofit
- 9. Task 3 Pre-Implementation Retrofit

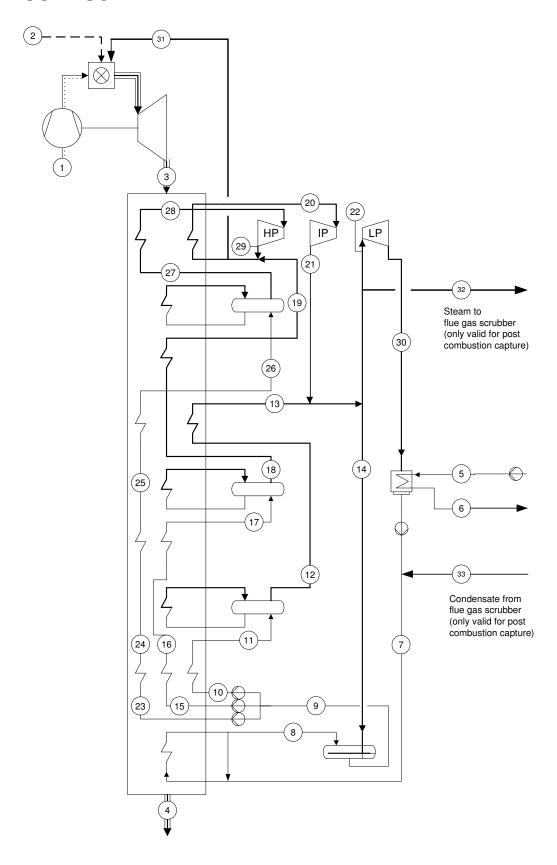
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Appendix 1

CCPP Simplified Process Scheme and Mass Balance

CCPP SCHEME



Mass balance standard power plant Reference Case

		1	2	3	4	5	6	7	8	9	10
Quality		N.A.	N.A.	N.A.	N.A.	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	618.2	15.0	633.2	633.2	7508.0	7508.0	96.9	96.9	99.2	10.7
Pressure	bar	1.0	40.0	1.0	1.0	2.0	1.0	8.0	8.0	1.2	5.0
Temperature	С	9	10	608	99	12	19	29	90	105	105
Enthalpy	kJ/kg	-6	-11	656	87	51	80	122	377	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00
Flow	kg/sec	10.7	10.7	10.7	2.3	11.4	11.4	11.4	11.4	11.4	88.5
Pressure	bar	4.9	4.7	4.6	4.6	28.3	28.2	28.1	27.5	27.4	27.0
Temperature	С	148	150	300	318	105	140	227	229	300	560
Enthalpy	kJ/kg	624	2745	3066	3102	444	591	977	2802	3003	3593

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.93
Flow	kg/sec	88.5	96.9	77.1	77.1	77.1	77.1	77.1	77.1	77.1	96.9
Pressure	bar	4.6	4.6	122.3	122.2	122.1	122.0	121.0	120.0	27.4	0.04
Temperature	С	320	318	107	140	221	323	325	560	346	29
Enthalpy	kJ/kg	3107	3102	457	597	951	1480	2687	3505	3114	2384

		31
Quality		1.00
Flow	kg/sec	0.0
Pressure	bar	27.0
Temperature	С	560
Enthalpy	kJ/kg	3593

Mass balance standard power plant Case 1 Post Combustion

		1	2	3	4	5	6	7	8	9	10
Quality		N.A.	N.A.	N.A.	N.A.	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	618.2	15.0	633.2	633.2	4496.6	4496.6	10.8	96.8	99.2	10.7
Pressure	bar	1.0	40.0	1.0	1.0	2.0	1.0	8.0	8.0	1.2	5.0
Temperature	С	9	10	608	99	12	14	15	90	105	105
Enthalpy	kJ/kg	-6	-11	656	87	51	57	64	376	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00
Flow	kg/sec	10.7	10.7	10.7	2.3	11.4	11.4	11.4	11.4	11.4	88.5
Pressure	bar	4.9	4.7	4.6	4.6	28.3	28.2	28.1	27.5	27.4	27.0
Temperature	С	148	150	300	318	105	140	227	229	300	560
Enthalpy	kJ/kg	624	2745	3066	3102	444	591	977	2802	3003	3593

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00
Flow	kg/sec	88.5	10.8	77.1	77.1	77.1	77.1	77.1	77.1	77.1	10.8
Pressure	bar	4.6	4.6	122.3	122.2	122.1	122.0	121.0	120.0	27.4	0.02
Temperature	С	320	318	107	140	221	323	325	560	346	18
Enthalpy	kJ/kg	3107	3102	457	597	951	1480	2687	3505	3114	2534

		31	32	33
Quality		1.00	1.00	0.00
Flow	kg/sec	0.0	86.0	86.0
Pressure	bar	27.0	4.6	8.0
Temperature	O	560	318	30
Enthalpy	kJ/kg	3593	3102	126

Mass balance standard power plant Case 2-1, local H2, Nat Gas

		1	2	3	4	5	6	7	8	9	10
Quality		N.A	N.A	N.A	N.A	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	535.3	89.7	625.1	625.1	7204.1	7204.1	93.5	93.5	95.3	12.1
Pressure	bar	1.0	30.0	1.0	1.0	2.0	1.0	8.0	8.0	1.2	5.1
Temperature	O	9.0	230.0	565.1	101.8	12	19	29	93	105	105
Enthalpy	kJ/kg	-6	422	631	94	51	80	121	388	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00
Flow	kg/sec	12.1	12.1	12.1	1.8	13.9	13.9	13.9	13.9	13.9	83.2
Pressure	bar	4.9	4.7	4.6	4.6	28.4	28.2	28.1	27.5	27.3	27.0
Temperature	O	149	150	305	306	105	140	230	229	291	531
Enthalpy	kJ/kg	628	2745	3076	3078	444	592	988	2802	2980	3528

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.92
Flow	kg/sec	83.2	93.5	69.3	69.3	69.3	69.3	69.3	69.3	69.3	93.5
Pressure	bar	4.6	4.6	122.1	122.1	122.0	121.9	120.9	120.1	27.3	0.04
Temperature	С	306	306	107	142	225	324	325	526	330	29
Enthalpy	kJ/kg	3077.9	3078	457	606	970	1489	2687	3419	3077	2371

		31
Quality		1.00
Flow	kg/sec	0.0
Pressure	bar	27.0
Temperature	С	530.9
Enthalpy	kJ/kg	3528

Mass balance standard power plant

Case 2-2, remote H2, Nat Gas

		1	2	3	4	5	6	7	8	9	10
Quality		N.A.	N.A.	N.A.	N.A.	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	536.2	77.9	626.1	626.1	6052.5	6052.5	73.2	85.2	86.4	8.3
Pressure	bar	1.0	25.0	1.0	1.0	2.0	1.0	3.0	3.0	1.2	4.9
Temperature	С	9	215	564	103	12	19	27	96	105	105
Enthalpy	kJ/kg	-6	385	630	95	48	75	115	400	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00
Flow	kg/sec	8.3	8.3	8.3	1.2	11.4	11.4	11.4	15.5	11.4	66.1
Pressure	bar	4.9	4.7	4.6	4.6	28.1	28.0	27.9	27.3	27.2	27.0
Temperature	O	151	149	314	334	105	143	230	229	300	539
Enthalpy	kJ/kg	638	2744	3094	3136	444	605	998	2802	3004	3546

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.94
Flow	kg/sec	66.1	73.2	66.8	66.8	66.8	66.8	66.8	66.8	66.8	73.2
Pressure	bar	4.6	4.6	122.0	121.9	121.8	121.7	120.7	120.0	27.2	0.04
Temperature	С	337	334	107	144	228	326	325	539	343	27
Enthalpy	kJ/kg	3141	3136	457	615	982	1499	2688	3452	3107	2403

 31

 Quality
 1.00

 Flow
 kg/sec
 12.0

 Pressure
 bar
 27.2

 Temperature
 C
 337

 Enthalpy
 kJ/kg
 3092

3 stage fuel preheating with saturated steam HP $9.5~{\rm kg/s}$

MP 9.5 kg/s
MP 4.1 kg/s
LP 4.8 kg/s
NOTE: taken from evaporators

Mass balance standard power plant Case 3-1, local H2, Coal

		1	2	3	4	5	6	7	8	9	10
Quality		N.A.	N.A.	N.A.	N.A.	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	523.2	103.7	626.9	626.9	7108.6	7108.6	92.1	92.1	93.9	11.9
Pressure	bar	1.0	25.9	1.0	1.0	2.0	1.0	8.0	8.0	1.2	5.0
Temperature	С	9	230	565	101	12	19	29	93	105	105
Enthalpy	kJ/kg	-6	363	620	91	51	80	121	389	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00
Flow	kg/sec	11.9	11.9	11.9	1.7	13.6	13.6	13.6	13.6	13.6	82.0
Pressure	bar	4.9	4.7	4.6	4.6	28.4	28.2	28.1	27.5	27.3	27.0
Temperature	С	149	150	305	308	105	140	230	229	291	531
Enthalpy	kJ/kg	628	2745	3077	3081	444	592	988	2802	2981	3530

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.93
Flow	kg/sec	82.0	92.1	68.4	68.4	68.4	68.4	68.3	68.3	68.3	92.1
Pressure	bar	4.6	4.6	122.1	122.0	121.9	121.8	120.8	120.1	27.3	0.04
Temperature	С	308	308	107	142	225	324	325	528	333	29
Enthalpy	kJ/kg	3082	3081	457	606	970	1488	2687	3424	3083	2373

		31
Quality		1.00
Flow	kg/sec	0.0
Pressure	bar	27.0
Temperature	С	531
Enthalpy	kJ/kg	3530

Mass balance standard power plant

Case 3-2; remote H2, Coal

		1	2	3	4	5	6	7	8	9	10
Quality		N.A.	N.A.	N.A.	N.A.	0.00	0.00	0.00	0.00	0.00	0.00
Flow	kg/sec	531.7	89.7	627.3	627.3	6417.0	6417.0	77.9	83.8	84.7	8.3
Pressure	bar	1.0	21.0	1.0	1.0	2.0	1.0	3.0	3.0	1.2	4.9
Temperature	С	9	223	567	103	12	19	28	98	105	105
Enthalpy	kJ/kg	-6	371	627	94	48	75	117	409	439	440

		11	12	13	14	15	16	17	18	19	20
Quality		0.00	1.00	1.00	1.00	0.00	0.00	0.01	1.00	1.00	1.00
Flow	kg/sec	8.3	8.3	8.3	1.0	11.2	11.2	11.2	15.6	11.2	70.5
Pressure	bar	4.9	4.7	4.6	4.6	28.1	28.0	28.0	27.4	27.3	27.0
Temperature	О	151	149	315	329	105	144	230	229	300	540
Enthalpy	kJ/kg	639	2744	3096	3125	444	606	999	2802	3005	3548

		21	22	23	24	25	26	27	28	29	30
Quality		1.00	1.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.94
Flow	kg/sec	70.5	77.9	65.2	65.2	65.2	65.2	65.2	65.2	65.2	77.9
Pressure	bar	4.6	4.6	121.9	121.9	121.8	121.7	120.7	120.0	27.3	0.04
Temperature	С	330	329	107	145	228	326	325	543	348	28
Enthalpy	kJ/kg	3128	3125	457	616	985	1500	2688	3460	3118	2397

31 1.00 5.9 27.3

Flow kg/sec Pressure bar Temperature С 341 kJ/kg 3102 Enthalpy

Quality

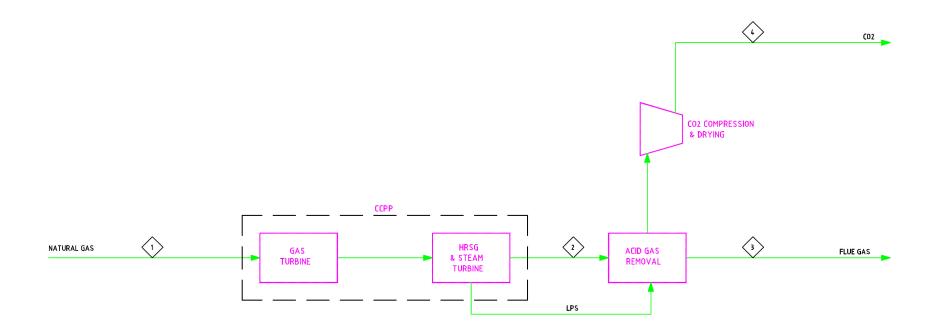
3 stage fuel preheating with saturated steam HP 11.2 kg/s

4.4 kg/s MP LP 4.9 kg/s NOTE: taken from evaporators

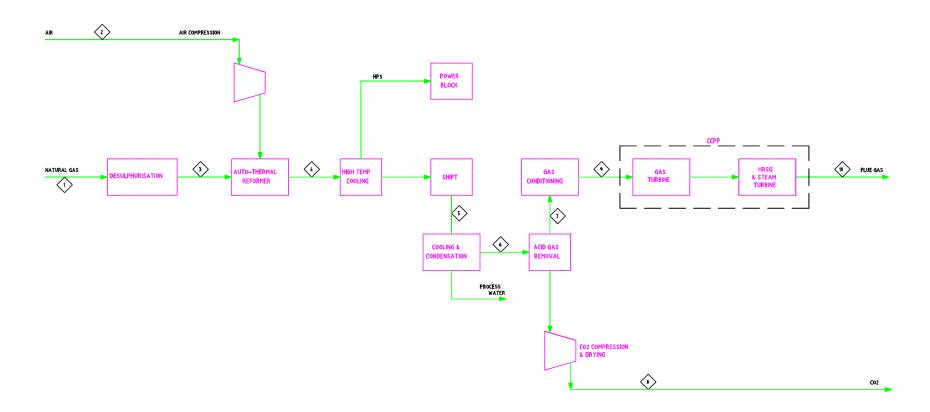
Appendix 2

Fuel/CO₂ Capture Plants Simplified Process Schemes and Mass Balances

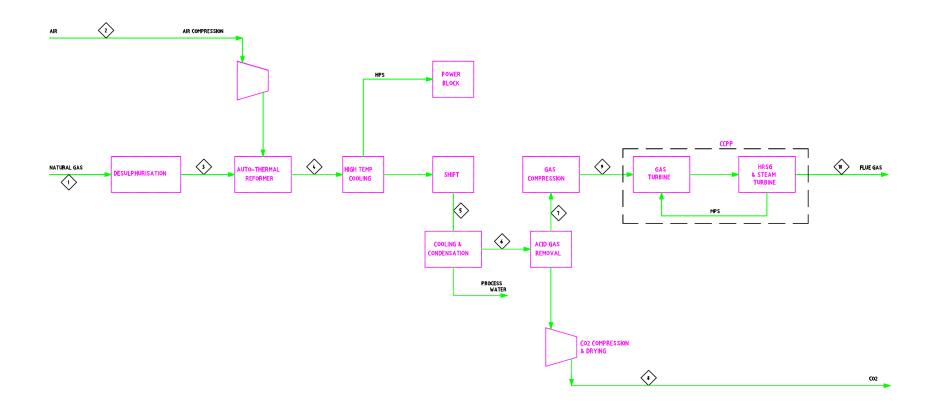
Case 1



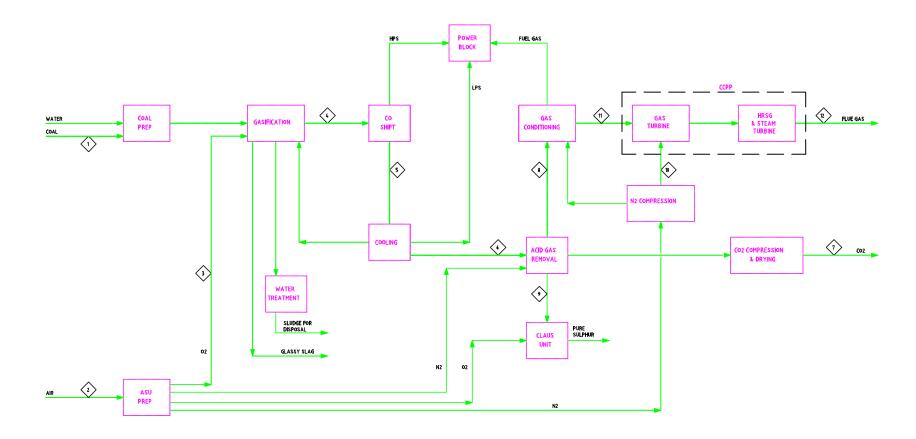
Case 2-1



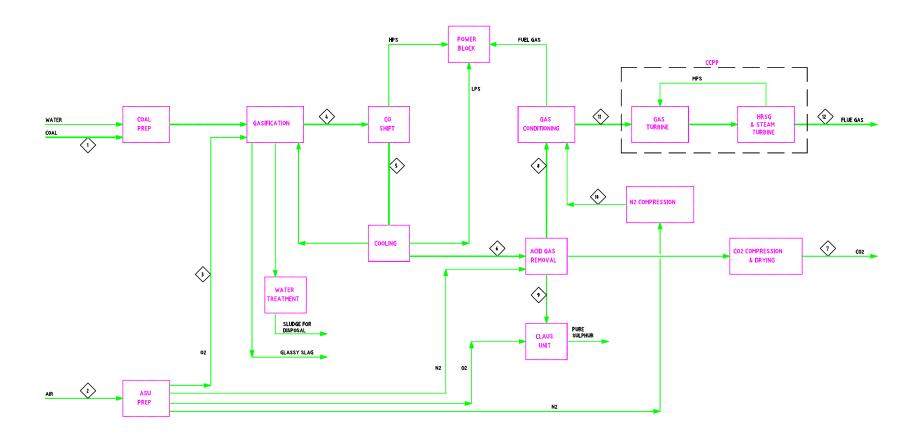
Case 2-2



Case 3-1



Case 3-2





JACOBS ENGINEERING MASS BALANCE

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60-8389-00/P.03/1000/A4 Document No.:

Project No.: 60-8389-00 Client: IEA GHG

Plant: Reference Gas Location: N.E.Netherlands

Case: Case 1

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STREAM NUMBER				2	2		3		4		5		6
STREAM NAME		Fuel	Gas	Gas Turbir	ie Exhaust	Flue	Gas	CO2 E	Export				
COMPONENT	M/V	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Methane	16.042	2335.47	83.90	0.00	0.00	0.00	0.00	0.00	0.00				
Carbon Dioxide	44.010	50.11	1.80	3354.08	4.56	501.77	0.71	2852.31	99.42			-9	
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Nitrogen	28.013	11.13	0.40	59724.97	81.21	59724.26	84.51	0.71	0.02			-2	
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Ethane	30.069	256.09	9.20	0.00	0.00	0.00	0.00	0.00	0.00			-2	
Propane	44.096	91.86	3.30	0.00	0.00	0.00	0.00	0.00	0.00				
Butane	58.122	38.97	1.40	0.00	0.00	0.00	0.00	0.00	0.00			-0	
Argon	39.948	0.00	0.00	712.44	0.97	712.42	1.01	0.02	0.00				
Oxygen	31.999	0.00	0.00	9750.04	13.26	9734.23	13.77	15.80	0.55			-)	
Hydrogen Sulphide	34.082	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00				
22 Y													
												-2	
Temperature	°C	10.0		99.4		38.2		40.0					
Pressure	bar(a)	41.0		1.0		Amb		111.0				-	
Total Dry Molar Flow	(kg.mol/h)	2783.65	100.00	73541.54	100.00	70672.69	100.00	2868.84	100.00				
Water (kg mol/h)	18.015	0.00		6516.74		5454.07		0.00					
TOTAL WET	(kg mol/h)	2783.65		80058.28		76126.76		2868.84					
Total Mass Flow (kg/h)	540			3600		3400		100				
Molecular Weight		19.	.40	28	.46	28	.02	43	.94				
Notes :			Issue:	0	Date	1	Date		Date		Date	-	Date
250 MW Heat Release	Case		Description:	For Fina			ress Added				1		
			Made By:	THLW	04-mei-04	NJE	23-jul-04					-0	
			Checked:	SBJS	05-mei-04	SBJS	26-jul-04						
<u> </u>			Approved:	SBJS	05-mei-04	SBJS	26-jul-04						



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Document No.: 60-8389-00/P.03/2101/A4

Project No.: 60-8389-00 Client: IEA Plant: Autothermal Ref. Location: NE Netherlands

Case: 2-1

Page 1 of 2

STREAM NUMBER			1		2		3		1	5	5		6
STREAM NAME		Feed	Gas	Д	ir	100000	ised Feed as	Reform	ed Gas	Shifte	d Gas	Dry Shi	fted Gas
COMPONENT	MVV	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	66.04	1.92	6960.91	35.28	9358.72	42.29	9358.71	42.30
Nitrogen	28.013	13.24	0.40	8623.06	78.09	74.71	2.17	8697.77	44.09	8697.77	39.31	8697.76	39.31
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	2.73	0.08	2784.02	14.11	386.22	1.75	386.22	1.75
Carbon Dioxide	44.010	59.60	1.80	3.36	0.03	60.33	1.75	1023.44	5.19	3421.26	15.46	3421.13	15.46
Methane	16.042	2778.02	83.90	0.00	0.00	2778.65	80.70	160.06	0.81	160.06	0.72	160.06	0.72
Ethane	30.069	304.62	9.20	0.00	0.00	304.62	8.85	0.00	0.00	0.00	0.00	0.00	0.00
Propane	44.096	109.27	3.30	0.00	0.00	109.27	3.17	0.00	0.00	0.00	0.00	0.00	0.00
Butane	58.122	46.36	1.40	0.00	0.00	46.36	1.35	0.00	0.00	0.00	0.00	0.00	0.00
Argon	39.948	0.00	0.00	102.67	0.93	0.57	0.02	103.23	0.52	103.23	0.47	103.23	0.47
Oxygen	31.999	0.00	0.00	2312.91	20.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen Sulphide	34.082	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002 D39 81 0							NO 61		2 V				
									200				
Temperature	°C	10.0		9.0		379.9		950.0		263.3		50.0	
Pressure	bar(a)	41.0		Ambient		37.5		34.4		32.3		30.4	
Total Dry Molar Flow	(kmol/h)	3311.11	100.00	11042.00	100.00	3443.26	100.00	19729.44	100.00	22127.26	100.00	22127.11	100.00
Water (kmol/h)	18.015	0.00		77.77		0.28		3903.90		1506.09		92.87	
TOTAL WET	(kmol/h)	3311.11		11119.77		3443.55		23633.33		23633.35		22219.99	
Total Mass Flow (kg/h)	643	200	321	000	660	200	458	000	458	000	432	2000
Molecular Weight		19	.40	28	.89	19	.23	19	.37	19	.37	19	.45
Notes : All flows are for	a single strea	m	Issue:	0	Date	1	Date		Date		Date		Date
			Description:	For Fina	l Report	Temp & Pi	ess Added						
			Made By:	THLW	05-apr-04	NJE	16-jul-04						
			Checked:	SBJS	06-apr-04	SBJS	26-jul-04						
<u></u>			Approved:	SBJS	06-apr-04	SBJS	26-jul-04		1				



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Document No.: 60-8389-00/P.03/2101/A4

Project No.: 60-8389-00 Client: IEA

Case: 2-1

Plant: Autothermal Ref. Location: NE Netherlands

Page 2 of 2

STREAM NUMBER			7		В		9	1	0			rage 2 or	1
STREAM NAME		CO2 Lean	Fuel Gas		sed CO2		d Fuel Gas		Gas				
				100									
COMPONENT	M/V	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	9257.52	49.97	35.15	1.01	9257.51	49.97	0.00	0.00				
Nitrogen	28.013	8615.27	46.51	21.02	0.61	8615.27	46.51	60371.02	85.56				
Carbon Monoxide	28.010	382.24	2.06	1.25	0.04	382.24	2.06	0.00	0.00				
Carbon Dioxide	44.010	101.97	0.55	3317.26	95.63	101.97	0.55	591.45	0.84				
Methane	16.042	88.83	0.48	70.60	2.04	88.83	0.48	0.00	0.00				
Ethane	30.069	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Propane	44.096	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Butane	58.122	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Argon	39.948	79.26	0.43	23.40	0.67	79.26	0.43	697.73	0.99				
Oxygen	31.999	0.00	0.00	0.00	0.00	0.00	0.00	8896.61	12.61				
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
No. 1889 N													
									· · · · · · · · · · · · · · · · · · ·				
Temperature	°C	41.1		40.0		230.0		103.8					
Pressure	bara	30.0		111.0		28.7	- 10 - 17	Ambient					
Total Dry Molar Flow	(kmol/h)	18525.09	100.00	3468.69	100.00	18525.08	100.00	70556.80	100.00				
Water (kmol/h)	18.015	39.86		0.00		2399.97	0	12276.32					
TOTAL WET	(kmol/h)	18564.96		3468.69		20925.05		82833.12					
Total Mass Flow (kg/h)	281	000	149	8000	323	3000	225	1000		99		08
Molecular Weight		15	.11	42	.88	15	.44	27	.17				
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date		Date		Date		Date
			Description:	For Fina	al Report	Temp & Pi	ress Added						
			Made By:	THLW	05-apr-04	NJE	16-jul-04						
				SBJS	06-apr-04	SBJS	26-jul-04						
			Approved:	SBJS	06-apr-04	SBJS	26-jul-04						



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Document No.:

60-8389-00/P.03/2201/A4

Project No.: 60-8389-00 Client: IEA

Case: 2-2

Plant: Autothermal Ref. Location: NE Netherlands

Page 1 of 2

STREAM NUMBER			1		2		3	33	4		5		6	
STREAM NAME		Feed	Gas	Д	sir	2000000	rised Feed as	Reform	ed Gas	Shifte	d Gas	Dry Shi	fted Gas	
COMPONENT	MW	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	
Hydrogen	2.016	0.00	0.00	0.00	0.00	65.99	1.92	6985.31	35.32	9389.36	42.34	9389.35	42.34	
Nitrogen	28.013	13.23	0.40	8646.79	78.09	74.64	2.17	8721.44	44.10	8721.44	39.32	8721.43	39.32	
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	2.72	0.08	2796.01	14.14	391.96	1.77	391.96	1.77	
Carbon Dioxide	44.010	59.55	1.80	3.37	0.03	60.28	1.75	1023.57	5.18	3427.63	15.45	3427.50	15.45	
Methane	16.042	2775.71	83.90	0.00	0.00	2776.34	80.70	144.66	0.73	144.66	0.65	144.66	0.65	
Ethane	30.069	304.37	9.20	0.00	0.00	304.37	8.85	0.00	0.00	0.00	0.00	0.00	0.00	
Propane	44.096	109.18	3.30	0.00	0.00	109.18	3.17	0.00	0.00	0.00	0.00	0.00	0.00	
Butane	58.122	46.32	1.40	0.00	0.00	46.32	1.35	0.00	0.00	0.00	0.00	0.00	0.00	
Argon	39.948	0.00	0.00	102.95	0.93	0.56	0.02	103.52	0.52	103.52	0.47	103.52	0.47	
Oxygen	31.999	0.00	0.00	2319.28	20.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Hydrogen Sulphide	34.082	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
1000 1000 100 100 100 100 100 100 100 1			,				-7							
92														
Temperature	°C	10.0		9.0		379.9		950.0		263.3		50.0		
Pressure	bar(a)	41.0		Ambient		37.5		34.4		32.3		31.3		
Total Dry Molar Flow	(kmol/h)	3308.36	100.00	11072.39	100.00	3440.40	100.00	19774.50	100.00	22178.56	100.00	22178.41	100.00	
Water (kmol/h)	18.015	0.00		77.98		0.28	->	3901.28		1497.22	,	89.33		
TOTAL WET	(kmol/h)	3308.36		11150.37		3440.68		23675.77		23675.79		22267.74		
Total Mass Flow (kg/h)	64:	200	322	2000	66:	200	458	000	459	0000	433	3000	
Molecular Weight		19	.40	28	.89	19	.23	19	.37	19	.37	19	.45	
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date		Date		Date		Date	
			Description:	For Fina	al Report	Revise	dT&P							
			Made By:	THLW	05-apr-04	NJE	23-jul-04							
			Checked:	SBJS	28-apr-04	SBJS	26-jul-04							
<u>per</u>			Approved:	SBJS	28-apr-04	SBJS	26-jul-04							



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Document No.: 60-8389-00/P.03/2201/A4

Project No.: 60-8389-00

Client: IEA Case: 2-2 Plant: Autothermal Ref. Location: NE Netherlands

Page 2 of 2

STREAM NUMBER			7		3		9	1	0		11		12
STREAM NAME		CO2 Lean	Fuel Gas	Compres	sed CO2	Conditione	d Fuel Gas	Flue	Gas				
COMPONENT	MW	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	9286.73	50.01	36.58	1.05	9286.73	50.01	0.00	0.00				
Nitrogen	28.013	8638.13	46.51	21.87	0.63	8638.13	46.51	60476.54	85.57				
Carbon Monoxide	28.010	387.88	2.09	1.32	0.04	387.88	2.09	0.00	0.00				
Carbon Dioxide	44.010	102.15	0.55	3327.08	95.68	102.15	0.55	589.08	0.83				
Methane	16.042	77.86	0.42	66.25	1.91	77.86	0.42	0.00	0.00				
Ethane	30.069	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Propane	44.096	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Butane	58.122	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Argon	39.948	78.59	0.42	24.37	0.70	78.59	0.42	696.94	0.99				
Oxygen	31.999	0.00	0.00	0.00	0.00	0.00	0.00	8910.93	12.61				
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
<u>v</u>			,				-7		V-				
Temperature	°C	41.4		40.0		22.0		103.0					
Pressure	bar(a)	31.2		111.0		39.9		Ambient	9				
Total Dry Molar Flow	(kmol/h)	18571.33	100.00	3477.48	100.00	18571.33	100.00	70673.50	100.00				
Water (kmol/h)	18.015	38.42		0.00		0.00		12296.09					
TOTAL WET	(kmol/h)	18609.75		3477.48		18571.33		82969.60					
Total Mass Flow (kg/h)	281	000	149	000	280	0000	225	5000		39		
Molecular Weight		15	.11	42	.90	15	.10	27	.17				
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date		Date	•	Date		Date
			Description:	For Fina	Report	Revise	dT&P				,		
			Made By:	THLW	05-apr-04	NJE	23-jul-04						
			Checked:	SBJS	28-apr-04	SBJS	26-jul-04						
			Approved:	SBJS	28-apr-04	SBJS	26-jul-04						



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Document No.: 60-8389-00/P.03/3101/A4

Project No.: 60-8389-00 Client: IEA GHG Plant: Capture Plant Location: NE Netherlands

Case: 3-1 Coal based GEM local to CCU

Page 1 of 2

STREAM NUMBER		•			2		3	104	4	į.	5		6
STREAM NAME		Coal	Feed	ASU A	r Intake	Oxygen f	or Gasifier	Raw S	Syngas	Shifted	Syngas	Cold 9	Syngas
COMPONENT	MVV	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00			10037.03	55.20	10029.61	55.41
Nitrogen	28.013	0.00	0.00	13580.48	78.10	75.19	2.00			142.99	0.79	142.87	0.79
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00			822.31	4.52	821.74	4.54
Carbon Dioxide	44.010	0.00	0.00	3.34	0.02	0.00	0.00			6993.55	38.46	6940.77	38.34
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00			13.89	0.08	13.85	0.08
Argon	39.948	0.00	0.00	161.69	0.93	112.78	3.00			113.08	0.62	112.75	0.62
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	Confin	25	41.10	0.23	39.34	0.22
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00		S	0.14	0.00	0.14	0.00
Ammonia	17.031	0.00	0.00	0.00	0.00	0.00	0.00		3	20.06	0.11	0.00	0.00
Oxygen	31.999	0.00	0.00	3644.18	20.96	3571.30	95.00			0.00	0.00	0.00	0.00
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00			0.00	0.00	0.00	0.00
NO 185 0													
								9					
Coal	(kg/hr)	133567.55											
Temperature	°C	ambient		ambient		149.0				440.0		30.8	
Pressure	bara	ambient		ambient		79.9				60.7		59.2	
Total Dry Molar Flow	(kmol/h)	0.00	0.00	17389.69	100.00	3759.26	100.00	0.00	0.00	18184.16	100.00	18101.06	100.00
Water (kmol/h)	18.015	778.29		121.55		0.00	-	25226.77		19919.65		14.79	
TOTAL WET	(kmol/h)	778.29		17511.24		3759.26		25226.77		38103.81		18115.85	
Total Mass Flow (kg/h))	148			000		000		1000		000		9000
Molecular Weight	olecular Weight N/A		/A	28	.89	32	.16	18	.02	18.91		19	.82
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date		Date		Date		Date
			Description:	For Fina	l Report	Rev	ised						
			Made By:	THLW	05-apr-04	NJE	15-jul-04						
			Checked:	SBJS	06-apr-04	SBJS	23-jul-04						
			Approved:	SBJS	06-apr-04	SBJS	23-jul-04						



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Document No.: 60-8389-00/P.03/3101/A4

Project No.: 60-8389-00 Plant: Capture Plant
Client: IEA GHG Location: NE Netherlands

Case: 3-1 Coal based GEM local to CCU

Page 2 of 2

STREAM NUMBER			7		3		3		0	1	1	1	12
STREAM NAME		CO2 for	capture	Sweet	Syngas	H2S Ric Claus	h Gas to s Unit	Dilution	Nitrogen	Fuel	l Gas	Flue	Gas
COMPONENT	MVV	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	134.90	1.98	9906.08	74.63	0.00	0.00	0.00	0.00	9019.89	65.07	0.00	0.00
Nitrogen	28.013	16.63	0.24	2148.79	16.19	57.38	35.36	7628.23	100.00	3731.32	26.92	61929.78	85.61
Carbon Monoxide	28.010	28.40	0.42	793.34	5.98	0.00	0.00	0.00	0.00	722.37	5.21	0.00	0.00
Carbon Dioxide	44.010	6637.51	97.30	303.27	2.28	63.77	39.29	0.00	0.00	276.14	1.99	1031.21	1.43
Methane	16.042	0.99	0.01	12.86	0.10	0.00	0.00	0.00	0.00	11.71	0.08	0.00	0.00
Argon	39.948	3.49	0.05	109.70	0.83	0.00	0.00	0.00	0.00	99.89	0.72	703.84	0.97
Hydrogen Sulphide	34.082	0.00	0.00	0.05	0.00	41.05	25.30	0.00	0.00	0.04	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.05	0.00	0.09	0.06	0.00	0.00	0.05	0.00	0.00	0.00
Ammonia	17.031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8675.24	11.99
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00
NO 323 3													
- NO													
Temperature	°C	40.0		33.2		70.0		230.0		230.0		101.3	
Pressure	bara	111.0		59.2		1.7		24.5		28.9		ambient	
Total Dry Molar Flow	(kmol/h)	6821.93	100.00	13274.13	100.00	162.29	100.00	7628.23	100.00	13861.41	100.00	72340.16	100.0
Water (kmol/h)	18.015	0.00		16.63		17.84	,	0.00	, ,	12.45		9501.85	
TOTAL WET	(kmol/h)	6821.93		13290.76		180.13		7628.23		13873.86		81842.00	
Total Mass Flow (kg/h))	No.	.000	121	000	61	40	214	.000	160	000	225	7000
Molecular Weight	Molecular Weight 43.		.07	9.	08	34	.08	28	.01	11	.50	27	.58
Notes: All flows are for	Notes: All flows are for a single stream		Issue:	0	Date	1	Date		Date		Date		Date
			Description:	For Fina	l Report	Rev	ised						
			Made By:	THLW	05-apr-04	NJE	15-jul-04						
			Checked:	SBJS	06-apr-04	SBJS	23-jul-04						
			Approved:	SBJS	06-apr-04	SBJS	23-jul-04						



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Document No.: 60-8389-00/P.03/3201/A4

Project No.: 60-8389-00 Client: IEA GHG Plant: Capture Plant Location: NE Netherlands

Case: 3-2 Coal fed GEM remote from CCPP

Page 1 of 2

STREAM NUMBER		,	1		2		3		4		5		6
STREAM NAME		Coal	Feed	ASU Ai	r Intake	Oxygen f	or Gasifier	Raw S	Syngas	Shifted	Syngas	Cold	Syngas
COMPONENT	M/V	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00			11194.96	55.26	11186.68	55.41
Nitrogen	28.013	0.00	0.00	15147.19	78.10	83.86	2.00			159.49	0.79	159.36	0.79
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00		2	917.18	4.53	916.54	4.54
Carbon Dioxide	44.010	0.00	0.00	3.72	0.02	0.00	0.00			7800.36	38.50	7741.49	38.34
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	Confin		15.49	0.08	15.45	0.08
Argon	39.948	0.00	0.00	180.35	0.93	125.79	3.00			126.13	0.62	125.75	0.62
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00			45.84	0.23	43.88	0.22
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00		\circ	0.15	0.00	0.15	0.00
Ammonia	17.031	0.00	0.00	0.00	0.00	0.00	0.00		3	0.00	0.00	0.00	0.00
Oxygen	31.999	0.00	0.00	4064.59	20.96	3983.30	95.00			0.00	0.00	0.00	0.00
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00			0.00	0.00	0.00	0.00
90 0 92 V													
Coal	(kg/hr)	148976.60						7					
100 p			,										
Temperature	°C	ambient		ambient		149.0				440.0		27.1	
Pressure	bara	ambient		ambient		79.9				60.7		59.2	
Total Dry Molar Flow	(kmol/h)	0.00	0.00	19395.86	100.00	4192.95	100.00	0.00	0.00	20259.60	100.00	20189.30	100.00
Water (kmol/h)	18.015	868.08		135.58		0.00		28128.08		22.38		0.00	
TOTAL WET	(kmol/h)	868.08		19531.43		4192.95		28128.08		20281.98		20189.30	
Total Mass Flow (kg/h))	165	000	564	1000	135	5000	507	000	403	000	400	0000
Molecular Weight	ecular Weight N/A		/A	28	.89	32	.16	18	.02	19	.88	19	.82
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date	2	Date		Date		Date
			Description:	For Fina	al Report	CO2 stre	am added	Rev	ised				
			Made By:	THLW	05-apr-04	THLW	05-mei-04	NJE	16-jul-04				
			Checked:	SBJS	28-apr-04	SBJS	05-mei-04	SBJS	22-jul-04				
			Approved:	SBJS	28-apr-04	SBJS	05-mei-04	SBJS	22-jul-04				



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Document No.: 60-8389-00/P.03/3201/A4

Project No.: 60-8389-00 Plant: Capture Plant
Client: IEA GHG Location: NE Netherlands

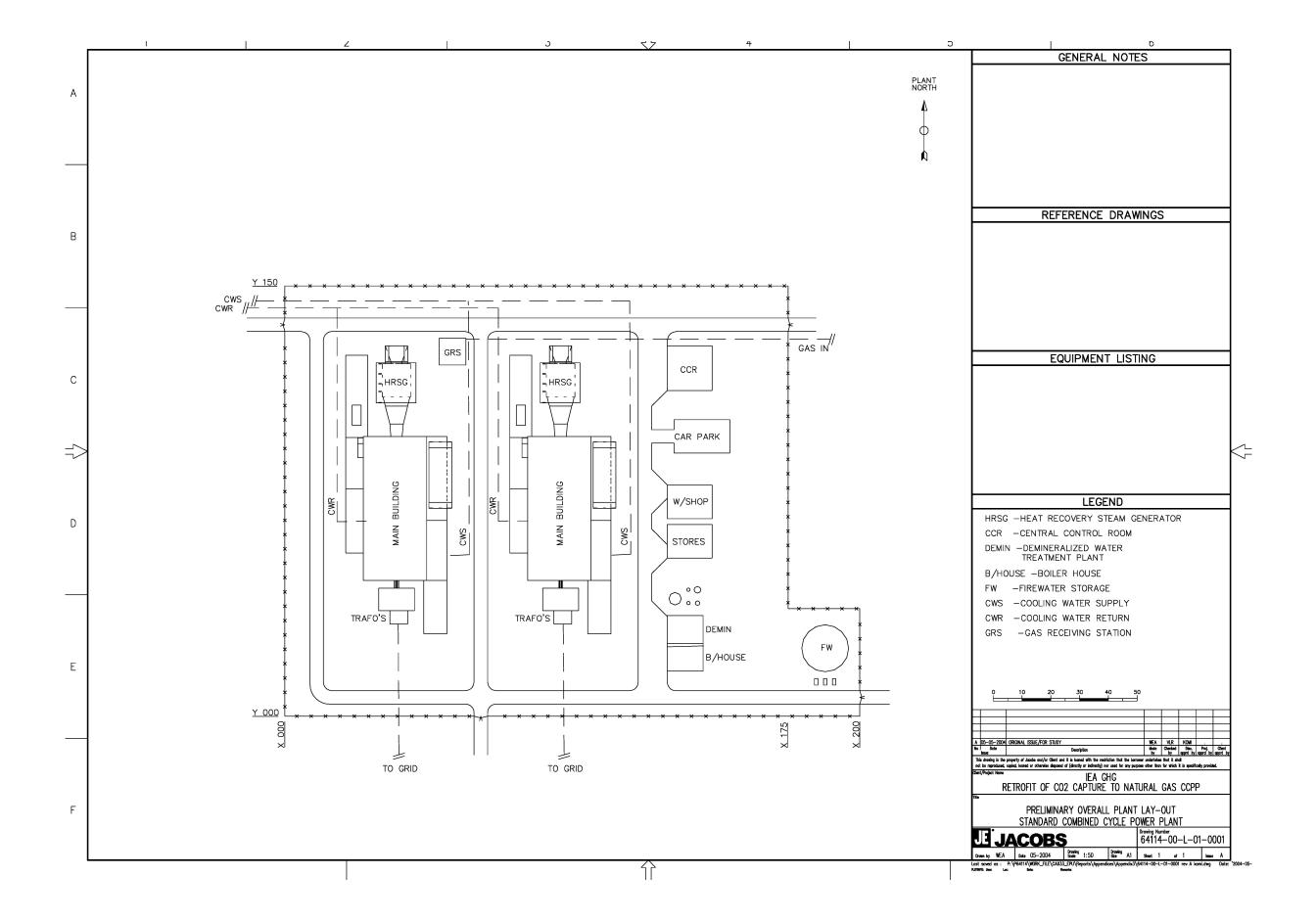
Case: 3-2 Coal fed GEM remote from CCPP

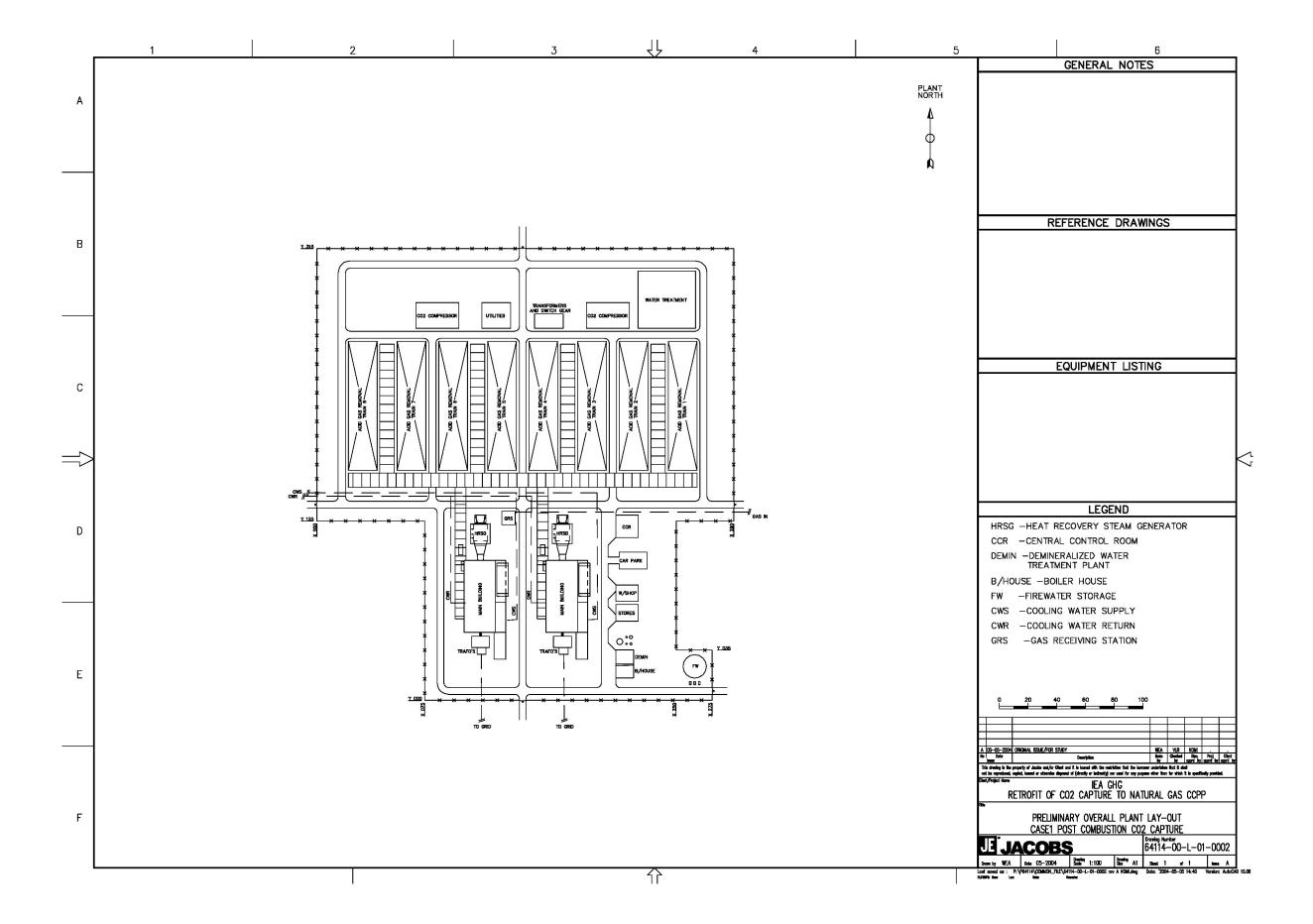
Page 2 of 2

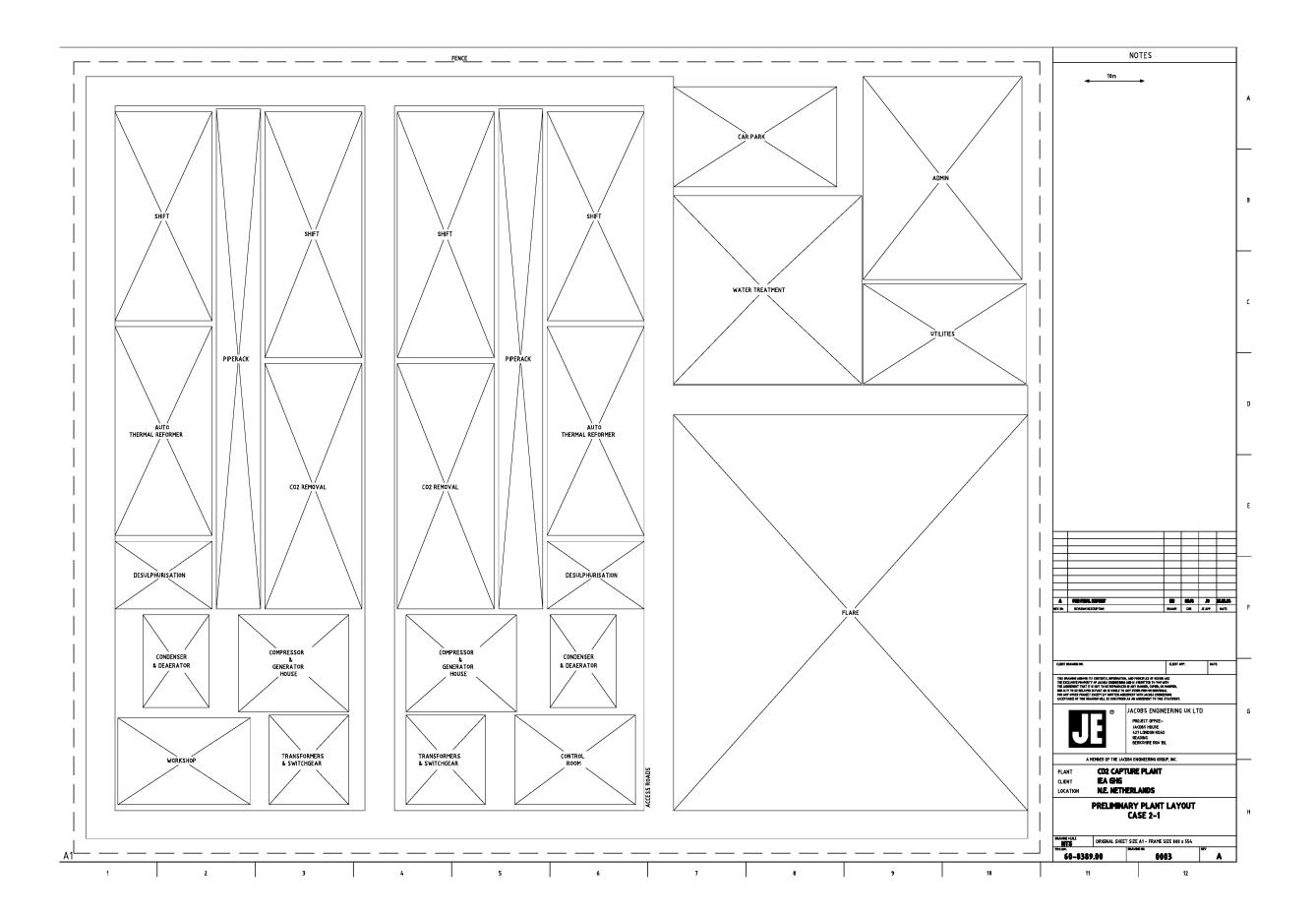
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STREAM NUMBER			7		3	1	9	1	10	1	1		2
STREAM NAME		CO2 fo	r export	Sweet Syngas			ch Gas to s Unit	Dilution	Nitrogen	Fue	l Gas	Flue	Gas
COMPONENT	M/V	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)	kmol/h	mol% (dry)
Hydrogen	2.016	150.46	1.98	11048.48	74.62	0.00	0.00	0.00	0.00	9095.22	46.01	0.00	0.00
Nitrogen	28.013	18.55	0.24	2396.69	16.19	64.00	35.36	9210.14	100.00	9554.86	48.33	60961.72	85.17
Carbon Monoxide	28.010	31.69	0.42	885.26	5.98	0.00	0.00	0.00	0.00	728.75	3.69	0.00	0.00
Carbon Dioxide	44.010	7402.87	97.30	338.23	2.28	71.12	39.29	0.00	0.00	278.44	1.41	1037.30	1.45
Methane	16.042	1.10	0.01	14.35	0.10	0.00	0.00	0.00	0.00	11.81	0.06	0.00	0.00
Argon	39.948	3.89	0.05	122.35	0.83	0.00	0.00	0.00	0.00	100.72	0.51	716.23	1.00
Hydrogen Sulphide	34.082	0.00	0.00	0.05	0.00	45.79	25.30	0.00	0.00	0.04	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.06	0.00	0.10	0.06	0.00	0.00	0.05	0.00	0.00	0.00
Ammonia	17.031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8858.18	12.38
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00
2													
Temperature	°C	40.0		33.2		70.0		22.0	V-	27.0		103.0	
Pressure	bara	111.0		59.2		1.7		61.0		59.2		ambient	
Total Dry Molar Flow	(kmol/h)	7608.56	100.00	14805.47	100.00	181.01	100.00	9210.14	100.00	19769.89	100.00	71573.51	100.00
Water (kmol/h)	18.015	0.00		17.84		19.14		0.00		0.00		10751.65	
TOTAL WET	(kmol/h)	7608.56		14823.31		200.15		9210.14		19769.89		82325.16	
Total Mass Flow (kg/h))	328	8000	135	5000	68	330	258	3000	323	3000	225	9000
Molecular Weight		43	.07	9.	08	34	.15	28	1.01	16	.33	27	.44
Notes: All flows are for	a single strea	m	Issue:	0	Date	1	Date	2	Date		Date		Date
			Description:	For Fina	al Report	CO2 stre	am added	Rev	rised				
			Made By:	THLW	05-apr-04	THLW	05-mei-04	NJE	16-jul-04				
			Checked:	SBJS	28-apr-04	SBJS	05-mei-04	SBJS	22-jul-04				
			Approved:	SBJS	28-apr-04	SBJS	05-mei-04	SBJS	22-jul-04				

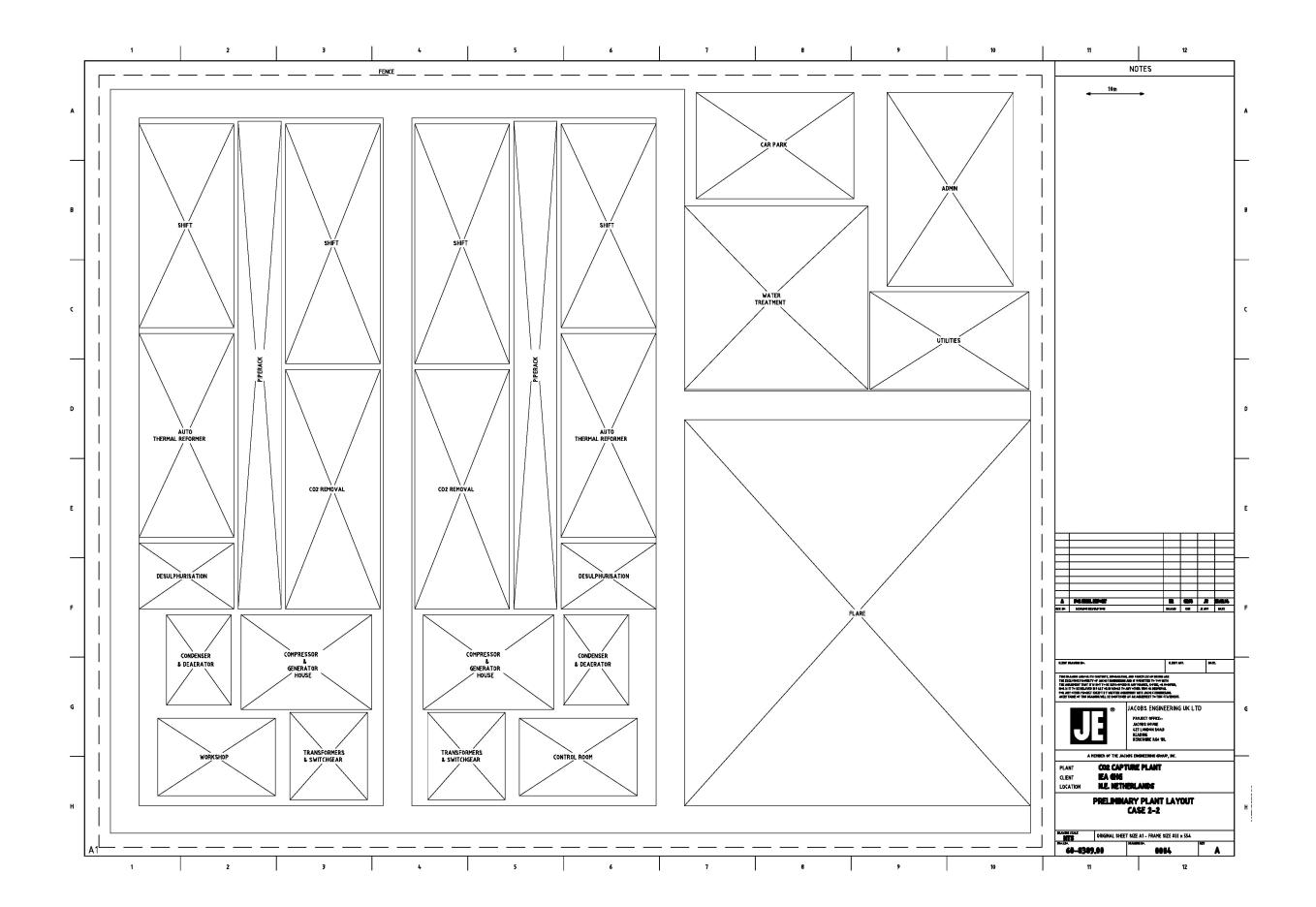
Appendix 3

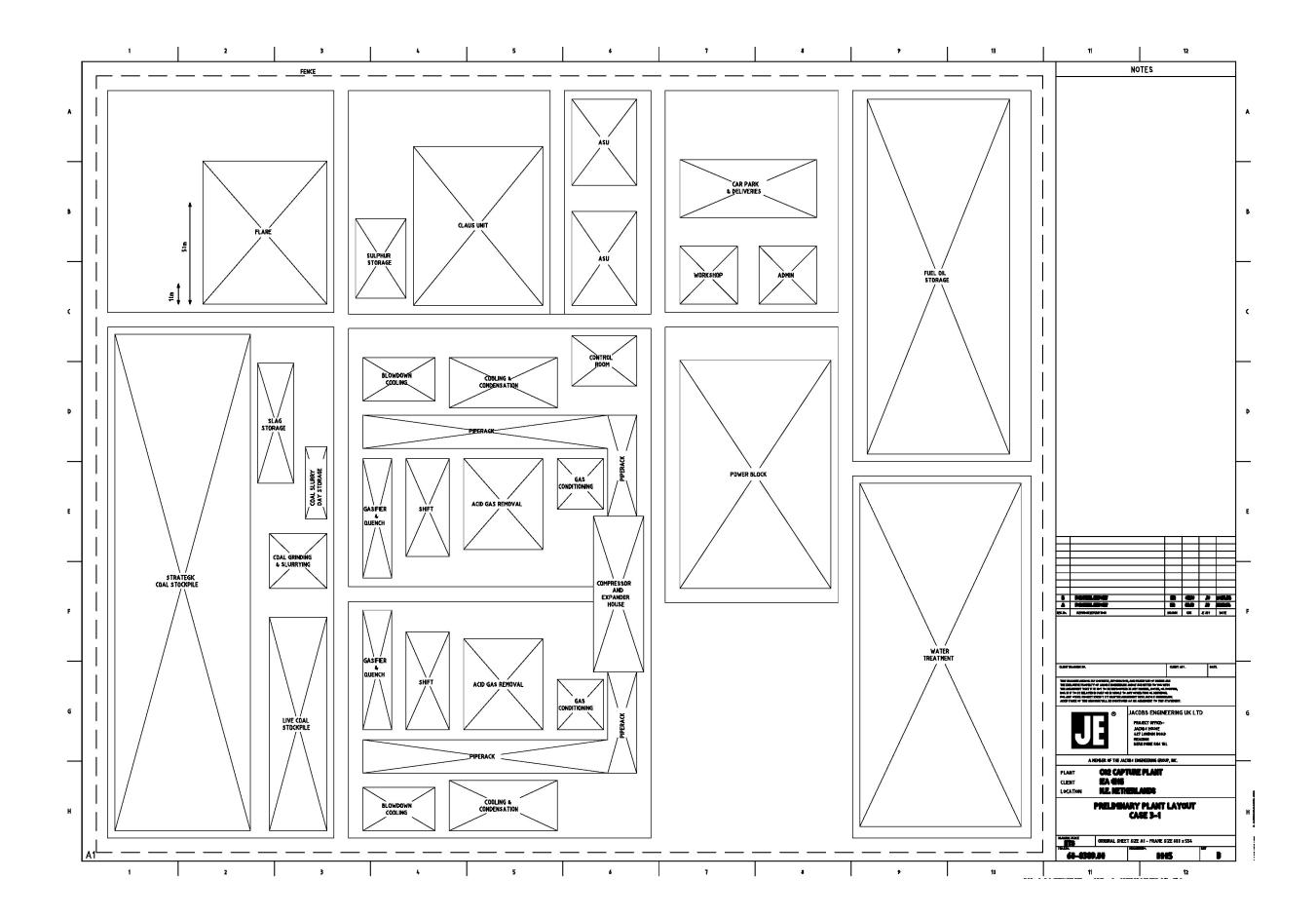
Plot Lay-outs

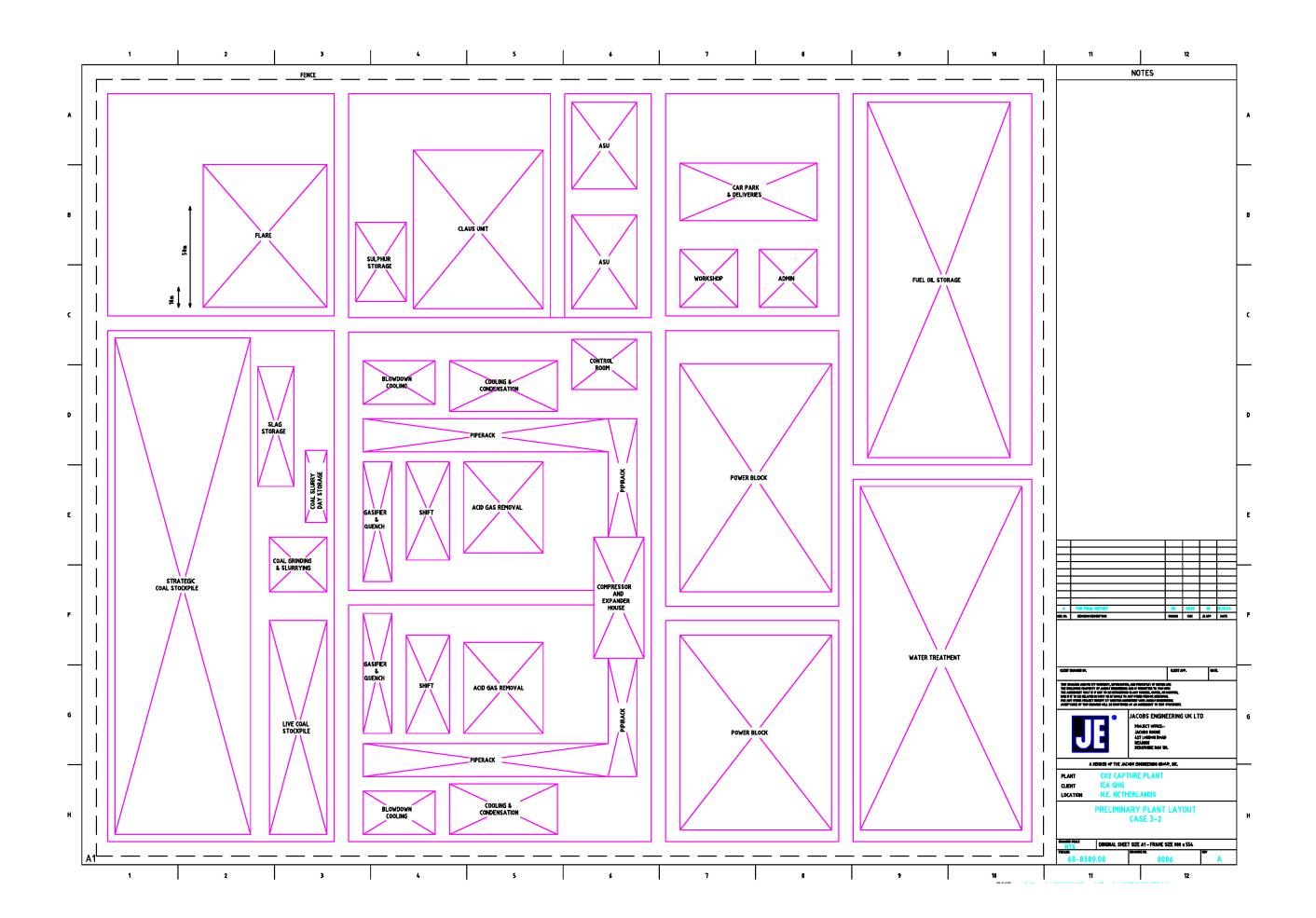












Appendix 4

Fuel/CO₂ Capture Plants Equipment Lists

JACOBS CONSULTANCY FOLIDMENT LIST 60-8389

				EQUIPMENT LIST	60-8389-00/P.03/1100/A4
	PLANT: CC)2 Ca	ptur	e Study Case 1 JOB NO.:	608389
	CLIENT: IEA	4		LOCATION:	NE Netherlands
Rev.	Item	No. In	stalled	Description	Remarks
	Number	W'king	St'by		
				UNIT 400	
				Acid Gas removal	
	10-E-401	8		Quench Water Cooler	
	10-E-402	8		Stripper Condenser	
	10-E-403	8		Stripper Trim Condenser	
	10-E-404	8		Rich/Lean Interchanger	
	10-E-405	8		Lean Amine Air Cooler	
	10-E-406	8		Lean Amine trim Cooler	
	10-E-407	8		Stripper Reboiler	
	10-E-408	8		Condensate cooler	
	10-K-401	8		Absorber Feed Fan	
	10-P-401	8	4	Quench Circulation Pump	
	10-P-402	8	4	Lean Amine Pump	
	10-P-403	8	4	Stripper Reflux Pump	
	10-P-404	8	4	Rich Amine Pump	
	10-P-405	2	2	Condensate Pump	

NOTES:

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0	THLW	10-Mar-04	SBJS	24-Apr-04	SBJS	26-Apr-04	For Final Report	Sheet
1	THLW	30-Apr-04	SBJS	30-Apr-04	SBJS	30-Apr-04	Revised for cond. Cooler	1
2	THLW	04-May-04	SBJS	04-May-04	SBJS	04-May-04	Revised for cond. Pump	of
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	10-1-40		٥	Que	TICH COIC	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,					
	10-T-40	2	8	Abs	orber Co	lumn					
	10-T-40	3	8	Strip	ping Co	lumn					
	10-TK-40	01	1	Ami	ne Stora	ge Tank					
	10-TK-40	02	8	Sum	ıρ						
	10-V-40	1	8	1st S	Stripper (Condens	er Knocl	Out Dru	m		
	10-V-40	2	8	2nd	Stripper	Conden	ser Knoc	k Out Dr	um		
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1	THLW	30-Apr	-04	SBJS	30-Apr-04	SBJS	30-Apr-04	Revised for	or cond. C	ooler	2
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JACOBS JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1100/A4 PLANT: CO2 Capture Study Case 1 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description W'king St'by Number **UNIT 600 Product Gas Exports** 10-K-601 Inc After cooler CO2 Compressor 10-P-601 CO2 Compressor KO Drum Pump 10-V-601 CO2 Compressor KO Drum 10-W-601 Dryer Package NOTES: Made by Checked by Approved by Rev Date Date THLW SBJS SBJS For Final Report 10-Mar-04 0 24-Apr-04 26-Apr-04 Sheet THLW SBJS SBJS 3 1 30-Apr-04 30-Apr-04 30-Apr-04 Revised for cond. Cooler 2 THLW 38111 SBJS 04-May-04 SBJS 04-May-04 Revised for cond. Pump of

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				JNIT 900 Offsites						
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	10-W-90	1 1	٧	Vaste wate	r treatme	nt				
	10-W-90	2 1	S	Secondary o	cooling sy	rstem				
	10-W-90	4 1	F	ire water s	ystem					
	10-W-90	5 1	١	Nitrogen & p	olant air					
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JACOBS JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1200/A4 PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 100** Air Compression 21-K-201 Air Compressor **UNIT 200** Reformer 21-E-201 2 Make Gas Boiler 21-E-202 2 HP Steam Superheater 21-E-203 2 Turbine Steam Reheater ATR Feed Heater 21-E-204 21-E-205 Hot Make Gas Boiler 21-K-101 Hydrogen Recycle Compressor 21-R-201 Auto-Thermal Reactor 21-R-101 Desulphuriser 21-V-201 Make Gas Boiler Steam Drum NOTES: Made by Checked by Approved by Description Date Date THLW 10/3/04 SBJS SBJS For Final Report 6/4/04 6/4/04 Sheet 1 of

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1200/A4 PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 300** Shift Unit 21-E-301 Desulphuriser Feed Heater 21-E-302 2 BFW Heater 21-E-303 2 **DMW Heater** Absorber Feed Cooler 21-E-304 21-E-305 Saturator Pre-heater 21-E-306 2 Fuel Gas Heater 21-E-307 Saturator Water Heater 21-P-301 2 Process Condensate Pump 21-R-301 HT Shift Reactor 21-R-302 LT Shift Reactor 21-T-301 Saturator 21-V-301 Process Condensate Drum 1 21-V-302 2 Process Condensate Drum 2 NOTES: Made by Approved by Description Date Checked by THLW 10/3/04 SBJS SBJS 6/4/04 6/4/04 For Final Report Sheet 2 of

JACOBS JACOBS CONSULTANCY DOCUMENT NO. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1200/A4 PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 400** Acid Gas removal 21-E-401 2 Stripper Reboiler 21-E-402 Lean / Semi-Lean Mdea 21-E-403 Lean Mdea Cooler LP Flash Overhead 21-E-405 21-E-406 LP Flash Overhead Vent Cooler 21-P-401 2 Lean Mdea Pump 21-P-402 2 Lp Flash Reflux Pump 21-P-403 2 Semi-Lean Mdea Pump 21-P-404 2 2 Stripper Feed Pump 21-PT-401 Lean Mdea Pump Turbine 21-T-401 CO₂ Absorber 21-T-402 CO2 Stripper HP Flash Column 21-T-403 21-T-404 2 LP Flash Column NOTES: Approved by Made by Description Date Checked by THLW 10/3/04 SBJS 6/4/04 SBJS 6/4/04 For Final Report Sheet 3 of

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	21-P-60°	1 2	2	CO2	Compre	essor KC	Drum F	ump			
	21-V-60	1 2		CO2	Compre	essor KC) Drum				
	21-W-60	1 2		Drye	r Packa	ge					
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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1200/A4 PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item W'king St'by Number **UNIT 700 Power Block** 21-E-701 2 Alternator Turbine Condenser 21-E-702 2 Condensate Stripper Feed / Product Exchanger BFW Pump 21-P-701 2 2 21-P-702 Turbine Condensate Pump 2 21-Q-701 2 Alternator 21-QT-701 Alternator Turbine 21-T-701 De-Aerator Column 21-T-702 2 Process Condensate Stripper 21-V-701 De-Aerator Vessel 21-V-702 Turbine Condensate Vessel 21-Z-701 Turbine Ejector Unit NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW 10/3/04 SBJS SBJS 6/4/04 6/4/04 For Final Report Sheet 6 of 7

JACOBS CONSULTANCY CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1200/A4 PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description W'king St'by Number **UNIT 900** Offsites 21-P-901 Cooling Water Pump 21-W-901 DMW & Waste water treatment 21-W-902 Secondary cooling system 21-W-903 Flare system 21-W-904 Fire water system 21-W-905 Nitrogen & plant air NOTES: Approved by Made by Date Checked by Description THLW 10/3/04 SBJS 6/4/04 SBJS For Final Report 6/4/04 Sheet 7 of

JACOBS CONSULTANCY Document No. **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item W'king St'by Number **UNIT 100** Desulphurisation 22-K-101 Air Compressor **UNIT 200** Reformer Make Gas Boiler 2 22-E-201 22-E-202 HP Steam Superheater 2 22-E-203 Turbine Steam Reheater ATR Feed Heater 22-E-204 2 22-E-205 Hot Make Gas Boiler 22-K-201 2 Hydrogen Recycle Compressor 22-R-201 Desulphuriser Auto-Thermal Reactor 22-R-202 22-V-201 Make Gas Boiler Steam Drum NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS 7/4/04 SBJS 7/4/04 For Final Report 10-Mar-04 Sheet 1 of 7

JACOBS CONSULTANCY Document No. **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item W'king St'by Number **UNIT 300** Shift Unit Fuel Gas Compressor 22-K-301 22-E-301 2 Desulphuriser Feed Heater 22-E-302 BFW Heater **DMW** Heater 22-E-303 2 Absorber Feed Cooler 22-E-304 22-P-301 Process Condensate Pump 22-R-301 HT Shift Reactor 2 22-R-302 LT Shift Reactor 2 22-V-301 Process Condensate Drum 1 22-V-302 Process Condensate Drum 2 NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS SBJS 7/4/04 7/4/04 For Final Report 10-Mar-04 Sheet 2 of 7

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Description Item W'king St'by Number **UNIT 400 Acid Gas removal** Stripper Reboiler 22-E-401 2 22-E-402 Lean / Semi-Lean Mdea 2 22-E-403 Lean Mdea Cooler LP Flash Overhead 22-E-405 2 LP Flash Overhead Vent 22-E-406 22-P-401 Lean Amine Pump 2 Lp Flash Reflux Pump 22-P-402 2 22-P-403 2 Semi-Lean Amine Pump 22-P-404 Stripper Feed Pump 2 22-PT-401 Rich Amine Pump Turbine 22-T-401 CO₂ Absorber 22-T-402 2 CO2 Stripper 22-T-403 HP Flash Column 2 22-T-404 LP Flash Column NOTES: Checked by Rev Made by Date Date Approved by Date Description SBJS THLW 7/4/04 SBJS 7/4/04 10-Mar-04 For Final Report Sheet 3 7

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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands Rev. No. Installed Remarks Description Item W'king St'by Number **UNIT 600 Product Gas Exports** 22-K-601 CO2 Compressor 22-P-601 CO2 Compressor KO Drum Pump 22-V-601 CO2 Compressor KO Drum 22-W-601 Dryer Package NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS 7/4/04 SBJS 7/4/04 For Final Report 10-Mar-04 Sheet 5 of 7

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item W'king St'by Number **UNIT 700 Power Block** 22-E-701 Alternator Turbine 2 Condenser 22-E-702 2 Condensate Stripper Feed / Product Exchanger BFW Pump 22-P-701 2 2 22-P-702 Turbine Condensate Pump 2 22-Q-701 2 Alternator 22-QT-701 Alternator Turbine 22-T-701 De-Aerator Column 1 22-T-702 2 Process Condensate Stripper 22-V-701 De-Aerator Vessel 22-V-702 Turbine Condensate Vessel 22-Z-701 Turbine Ejector Unit NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS SBJS 7/4/04 7/4/04 For Final Report 10-Mar-04 Sheet 6 of 7

JACOBS CONSULTANCY CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1300/A4 PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description W'king St'by Number **UNIT 900** Offsites 22-P-901 Cooling Water Pump 22-W-901 Waste water treatment 22-W-902 Secondary cooling system 22-W-903 Flare system 22-W-904 Fire water system 22-W-905 Nitrogen & plant air NOTES: Approved by Made by Checked by Date Description THLW SBJS 7/4/04 SBJS For Final Report 7/4/04 10-Mar-04 Sheet 7 of

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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Description Item W'king St'by Number Part of W-301 **UNIT 300 Gasification Unit** LP Flash Condenser 31-E-301 Part of W-301 BFW Heater 1 Part of W-301 31-E-302 31-E-303 BFW Heater 2 Part of W-301 4 Oxygen Heater 31-E-304 31-P-301 Black Water Pump Part of W-301 31-P-302 BFW Pump Part of W-301 6 31-P-303 Grey Water Pump Part of W-301 4 31-R-301 Gasifier Part of W-301 31-T-301 1 Scrubber Part of W-301 NOTES: Rev Made by Checked by Date Date Approved by Date Description SBJS THLW 23/3/04 SBJS 23/3/04 10-Mar-04 For Final Report Sheet 2 of 10

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Description Item W'king St'by Number **UNIT 300 Gasification Unit** 31-V-301 Part of W-301 Quench LP Flash Drum Part of W-301 31-V-302 31-V-303 LP Flash Overhead Cond Drum Part of W-301 4 31-V-304 Knockout Drum Part of W-301 Atmospheric Flash Drum 31-V-305 Part of W-301 Vacuum Flash Drum 31-V-306 Part of W-301 31-W-301 Gasification Package Part of W-301 31-W-302 Vacuum Package Part of W-301 NOTES: Rev Made by Checked by Date Date Approved by Date Description SBJS SBJS THLW 23/3/04 23/3/04 10-Mar-04 For Final Report Sheet 3 of 10

JACOBS JACOBS CONSULTANCY CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 400** Gas Treatment 31-E-401 Shift Interchanger 31-E-402 High Pressure Boiler 31-E-403 High Pressure BFW Heater 31-E-404 High Pressure Water Heater 3 2 31-E-405 High Pressure Water Heater 2 31-E-406 High Pressure Water Heater 1 LP Boiler 31-E-407 2 Low Pressure BFW Heater 31-E-408 31-E-409 **Expander Preheater** 31-E-410 Fuel Gas Heater 31-E-412 N2 Heater 31-K-401 Fuel Gas Expander 31-K-402 Recycle Compressor 31-K-403 Selexol N2 Compressor 31-K-404 N2 Compressor

NOTES:

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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Description Item W'king St'by Number **UNIT 400 Gas Treatment** 31-K-405 Main N2 Compressor Tail Gas Compressor 31-K-406 31-P-401 2 Desaturator Circulation Pump 31-P-402 Low Pressure BFW Pump Intermediate Pressure BFW Pump 31-P-403 2 31-P-404 2 BFW Circulating Pump 2 31-P-405 High Pressure BFW Pump 31-P-409 Process Water Make-up Pump 31-R-401 Shift Reactor 31-T-401 2 Desaturator 31-V-401 HP Steam Drum 31-V-402 LP Steam Drum NOTES: Made by Checked by Rev Date Date Approved by Date Description SBJS SBJS THLW 23/3/04 23/3/04 For Final Report 10-Mar-04 Sheet 5 of 10

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			pture	Study Case	3-1		JOB NO.:			
_	CLIENT: IE	_	T			L	OCATION:	NE Ne	therlands	
Rev.	Item Number	No. In: W'king	St'by	Description					Remarks	
				UNIT 500 Acid Gas re	moval					
	31-E-501	2	9	Stripper Reb	oiler					
	31-E-502	2	9	Stripped Gas	Conder	nser				
	31-E-503	2	l	Lean/Rich Ex	xchange	r				
	31-E-504	2	L	Lean Solven	t Cooler					
	31-E-505	2	5	Semi-Lean C	Cooler					
	31-E-506	2		Loaded Solv	ent Cool	er				
	31-E-507	2	(Compressed	Gas Co	oler				
	31-E-508	2	F	Flash Gas C	ooler					
	31-TK-50			Selexol Stora	age Tank	(
	31-TK-502	2 2		Sump						
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JACOBS **JACOBS CONSULTANCY** CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 500** Acid Gas removal 31-P-501 Lean Solution Pump 31-P-502 2 Rich Solution Pump 31-P-503 10 Semi-lean Pump 31-P-504 Stripper Reflux Pump Loaded Solvent Pump 31-P-505 2 31-PT-506 10 Rich solvent expander 31-T-501 2 H2S Absorber 2 H2S Concentrator 31-T-502 2 CO2 Absorber 31-T-503 2 31-T-504 2 Lean Solution Stripper 31-V-501 2 2 HP Flash Drum 31-V-502 2 MP Flash Drum 31-V-503 2 2 LP Flash Drum 2 Flash Gas KO Drum 31-V-504 31-V-505 Rich Flash 31-V-506 Stripper Overhead Drum 31-W-501 2 2 Claus unit NOTES: Approved by Made by Checked by THLW SBJS **SBJS** For Final Report 10-Mar-04 23/3/04 23/3/04 Sheet 7 10

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						T 600 duct Gas	s Export	۹				
							<u> </u>					
	31-K-60	01	2		CO2	2 Compre	essor					
	31-P-60	01	2	2	CO2	2 Compre	essor KO	Drum F	ump			
	31-V-60	01	2		CO2	? Compre	essor KO	Drum				
	31-W-6	01	2		Drye	er Packa	ge					
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JACOBS JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 700** Power Block 31-E-705 Part of W-701 Low Pressure Superheater 31-E-710 High Pressure Superheater Part of W-701 31-E-715 Steam Turbine Condenser Part of W-701 31-E-715 Steam Dump Condenser 31-K-701 Gas Turbine Part of W-701 31-K-702 Steam Turbine Part of W-701 31-P-704 Part of W-701 Condensate Pump 31-V-701 Part of W-701 De-areator 31-W-701 Combined Cycle Unit Part of W-701 NOTES: Made by Approved by Checked by Date Description THLW SBJS 23/3/04 SBJS For Final Report 10-Mar-04 23/3/04 Sheet 9 of 10

JACOBS CONSULTANCY CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1400/A4 PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 900** Offsites 31-P-901 2 Cooling Water Pump 31-P-902 2 1 Back-up fuel pumps 31-TK-901 Back-fuel storage tank 31-W-901 Waste water treatment 31-W-902 Secondary cooling system 31-W-903 Flare system 31-W-904 Fire water system 31-W-905 1 Nitrogen & plant air NOTES: Made by Checked by Approved by Date Date Description THLW SBJS SBJS For Final Report 23/3/04 10-Mar-04 23/3/04 Sheet 10 10

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						T 100- Seperati	on Unit					
	32-W-10)1	2		Air S	Separatio	n Unit					
						T 200 dstock p	reparati	on				
	32-P-20)1	4	2	Coa	Slurry F	eed Pun	np			Part of W-30	1
	32-W-20)1	2		Coa	l prepara	ation					
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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number Part of W-301 **UNIT 300 Gasification Unit** 32-E-301 LP Flash Condenser Part of W-301 1 BFW Heater 1 32-E-302 Part of W-301 32-E-303 1 BFW Heater 2 Part of W-301 32-E-304 Oxygen Heater 32-P-301 6 Black Water Pump Part of W-301 32-P-302 6 BFW Pump Part of W-301 6 Grey Water Pump 32-P-303 Part of W-301 Part of W-301 32-R-301 Gasifier 32-T-301 Part of W-301 Scrubber NOTES: Made by Checked by Approved by Description THLW SBJS SBJS For Final Report 10-Mar-04 24-Mar-04 24/3/04 Sheet 2 of 11

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Description Item W'king St'by Number **UNIT 300 Gasification Unit** 32-V-301 Part of W-301 Quench LP Flash Drum Part of W-301 32-V-302 32-V-303 LP Flash Overhead Cond Drum Part of W-301 4 Knockout Drum 32-V-304 Part of W-301 Atmospheric Flash Drum 32-V-305 Part of W-301 Vacuum Flash Drum 32-V-306 Part of W-301 32-W-301 Gasification Package Part of W-301 32-W-302 Vacuum Package Part of W-301 NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS SBJS 24/3/04 10-Mar-04 For Final Report 24-Mar-04 Sheet 3 of 11

JACOBS **JACOBS CONSULTANCY** CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 400** Gas Treatment 32-E-401 Shift Interchanger 32-E-402 High Pressure Boiler 32-E-403 High Pressure BFW Heater 32-E-404 High Pressure Water Heater 3 2 32-E-405 2 High Pressure Water Heater 2 32-E-406 2 High Pressure Water Heater 1 LP Boiler 32-E-407 2 Low Pressure BFW Heater 32-E-408 31-E-409 **Expander Preheater** 31-E-410 Fuel Gas Heater 32-K-401 Fuel Gas expander 32-K-402 Recycle Compressor 32-K-403 Selexol N2 Compressor 32-K-404 2 Nitrogen Compressor NOTES: Made by Checked by Approved by THLW SBJS SBJS For Final Report 10-Mar-04 24-Mar-04 24/3/04 Sheet 4 11

JACOBS CONSULTANCY Document No. **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description Number W'king St'by **UNIT 400 Gas Treatment** Main N2 Compressor 2 32-K-405 32-K-406 2 Tail Gas Compressor 32-P-401 Desaturator Circulation Pump 32-P-402 2 Low Pressure BFW Pump Intermediate Pressure BFW Pump 32-P-403 32-P-404 BFW Circulating Pump 32-P-405 2 High Pressure BFW Pump 32-P-409 2 Process Water Make-up Pump 32-R-401 Shift Reactor 32-T-401 Desaturator HP Steam Drum 32-V-401 32-V-402 LP Steam Drum

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JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item Number W'king St'by **UNIT 500 Acid Gas removal** 32-E-501 Stripper Reboiler 2 32-E-502 2 Stripped Gas Condenser 32-E-503 Lean/Rich Exchanger 32-E-504 2 Lean Solvent Cooler 32-E-505 Semi-Lean Cooler 2 32-E-506 Loaded Solvent Cooler 32-E-507 2 Compressed Gas Cooler Flash Gas Cooler 32-E-508 32-TK-501 Selexol Storage Tank 32-TK-502 Sump NOTES: Rev Made by Checked by Date Date Approved by Date Description THLW SBJS SBJS 24/3/04 For Final Report 10-Mar-04 24-Mar-04 Sheet 6 of 11

JACOBS JACOBS CONSULTANCY CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Description W'king St'by Number **UNIT 500** Acid Gas removal 32-P-501 Lean Solution Pump 32-P-502 2 Rich Solution Pump 32-P-503 12 Semi-lean Pump 32-P-504 Stripper Recycle Pump 32-P-505 2 Loaded Solvent Pump 32-PT-506 12 Rich solvent expander 32-T-501 H2S Absorber H2S Concentrator 32-T-502 32-T-503 CO₂ Absorber 32-T-504 Lean Solution Stripper 32-V-501 2 HP Flash Drum 32-V-502 MP Flash Drum 32-V-503 LP Flash Drum Flash Gas KO Drum 32-V-504 32-V-505 Rich Flash 32-V-506 Stripper Overhead Drum 32-W-501 2 Claus unit NOTES: Approved by Made by Checked by Description THLW SBJS SBJS For Final Report 10-Mar-04 24-Mar-04 24/3/04 Sheet 7 11

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description W'king St'by Number **UNIT 600 Product Gas Exports** 32-K-601 CO2 Compressor 32-P-601 CO2 Compressor KO Drum Pump 32-V-601 CO2 Compressor KO Drum 32-W-601 Dryer Package 32-W-602 Fuel Gas Export Pipeline NOTES: Approved by Made by Checked by Description THLW SBJS SBJS For Final Report 24/3/04 10-Mar-04 24-Mar-04 Sheet 8 of 11

JACOBS JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 LOCATION: NE Netherlands CLIENT: IEA No. Installed Remarks Rev. Description Item W'king St'by Number **UNIT 700 Power Block** 32-E-701 Part of W-701 2 Low Temperature Economiser 32-E-702 HRSG Low Pressure Boiler Part of W-701 2 Part of W-701 32-E-703 Intermediate Pressure Economiser 32-E-704 2 Intermediate Pressure Boiler Part of W-701 32-E-706 High Pressure Economiser 1 Part of W-701 32-E-707 2 Intermediate Pressure Superheater 1 Part of W-701 2 High Pressure Economiser 2 Part of W-701 32-E-708 HRSG High Pressure Boiler 32-E-709 2 Part of W-701 32-E-710 High Pressure Superheater 1 Part of W-701 2 32-E-715 2 Steam Turbine Condenser 32-E-716 Steam Dump Condenser Single unit for both streams NOTES: Checked by Approved by Rev Made by Date Date Date Description THLW SBJS SBJS 24/3/04 10-Mar-04 For Final Report 24-Mar-04 Sheet 9 of 11

JACOBS CONSULTANCY Document No. CONSULTANCY **EQUIPMENT LIST** 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description Number W'king St'by **UNIT 700 Power Block** 2 Gas Turbine Part of W-701 32-K-701 32-K-702 Steam Turbine Part of W-701 32-P-703 2 HP BFW Pump Part of W-701 32-P-704 Condensate Pump Part of W-701 2 32-V-701 De-areator Part of condenser HRSG HP Steam Drum 32-V-702 2 Part of W-701 HRSG IP Steam Drum 32-V-703 Part of W-701 32-V-704 HRSG LP Steam Drum Part of W-701 Combined Cycle Unit 32-W-701 Part of W-701

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JACOBS CONSULTANCY EQUIPMENT LIST 60-8389-00/P.03/1500/A4 PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389 CLIENT: IEA LOCATION: NE Netherlands No. Installed Description W'king St'by Number **UNIT 900** Offsites 32-P-901 2 Cooling Water Pump Back-up fuel pumps 32-P-902 2 32-TK-901 Back-fuel storage tank 32-W-901 Waste water treatment 32-W-902 Secondary cooling system 32-W-903 1 Flare system 32-W-904 Fire water system 32-W-905 Nitrogen & plant air

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Appendix 5

Fuel/CO₂ Capture Plants Power Consumption/Production and Utility Usage

CONSULTANCY

JACOBS CONSULTANCY UK LTD

Power schedule

The information contained herein is confidential, the property of JACOBS CONSULTANCY UK LTD, and not for publication. The information is issued on the understanding that no part thereof shall be copied or communicated to a third party without authorisatio

Document No. 60-8389-00/P.03/1100/A4

PLANT: CO2 Capture Study Case 1

LOCATION: NE Netherlands

CLIENT: IΕΑ

PROJECT: 608389 Revised this issu 🔱

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1											
2	Item no.		Item Na	me			no.	Power (k	dW)		
3							operating	Each	Total		
4	Sect										
5	100										
6											
7	200										
8	20 00 00 00 00 00 00 00 00 00 00 00 00 0										
9	300										
10											
11	400 10-K-401		Ahenrhai	Feed Fa	n		8	903	7,224		-
12	400 10 11 401		7 10001001	1 cca i a			ĭ	700	1,224		1
13	10-E-402		Strinner	Condense	N P		8	153	1,223		1
14	10-E-405			ine Air C			8		583		-
15	10-1-400		Lean An	illie All Ci	oolei		٥	73	202		-
16	10 D 401		Ouenek	Oine of eaties			8	CF.	520		-
	10-P-401			Circulation							
17	10-P-402			iine Pump			8		504		
18	10-P-403		Stripper	Reflux Pu	mp		8		64		
19	10-P-404			ine Pump			8		872		
20	10-P-405		Condens	ate Pump)		2	108	215		
21											
22											
23	600 10-K-601		CO2 Cor	npressor			2	10,836	21,673		
24											
25	10-P-601		CO2 Cor	npressor	KO Drum	Pump	2	0	0		
26						SECONDS.					
27	900 10-P-901		Cooling \	Water Pur	mp		2	1,796	3,591		
28			Misc iter		40°			9 99.00	2,000		
29									6.		
30	Plant total								38,470		
31											
32											
33											
34											
35											1
36											1
37											·
38											1
39											1
40											
41											
42											
43											
44											
45											
46											
47											
48											
49											
50											
51	Total Powe	er output i	(MW)						38.5		П
52	NOTE: All de										
Issue		A	Date		Date		Date		Date	Date	
	ription	59.50	Report		90.00.000		40.000		77.500.630.5	35,600,500	Sht.
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Power schedule

Document No. 60-8389-00/P.03/2100/A4

PLANT: CO2 Capture Study Case 2-1

LOCATION: NE Netherlands

CLIENT: IEA

PROJECT: 608389

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1 2			Itaan Mar					D	LAND			
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4	Sect						operating	Lacii	Total			-
5	100 21-K-201		Air Comp	racenr			2		49,583		1	-
6	100 21 10201		VII COMP	100001			-		40,000	49,583		-
7										40,000		
8	200 21-K-101		Hydroger	Recycle	Compress	sor	1		40			
9			, 3							40		
10												
11	300 21-P-301		Process	Condensa	ate Pump		1		79			
12										79		
13												
14	400 21-P-401		Lean Md	ea Pump			1		1,824			
15	21-P-402		Lp Flash				1		3			
16	21-P-403		Semi-Lea				1		8,549			
17	21-P-404		Stripper f				1		304			
18	21-PT-401		Lean Md	ea Pump	Turbine		1		-2,908	100000		
19										7,773		
20	000 04 17 004		0000				3		45.000			-
21	600 21-K-601		CO2 Con	npressor	VO D I	S	1		15,923			-
22 23	21-P-601		CO2 Con	npressor	KO Drum F	-ump	1		8			-
24										15,930		-
25										13,530		
26	700 21-P-701		BFW Pui	mn			1		1,020			
27	21-P-702		Turbine C		te Pumn		1		4			- 1
28	21-QT-701		Alternato		re i dilib		1		-21,504			-
29	21 41101		, atomato	, raibilio						-20,480		-
30										20,.00		
31												
32	900 21-P-901		Cooling V	Vater Pur	np		2		2,039			
33	Misc users	3			small pov	wer			3,000			
34										5,039		
35												
36												
37												
38												
39												
40												
41												-
42												-
43 44												
45												-
46												-
47												-
48												
49												
50												
51	Total Powe	er output ((MW)						58.0			
52	NOTE: All de								40.53.00			
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	ription	3500	Report		POST (175.0)	84	5000000		1200000		300000000000000000000000000000000000000	Sht.
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CONSULTANCY

Approved by

JACOBS JACOBS CONSULTANCY UK LTD

Power schedule

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Document No. 60-8389-00/P.03/2200/A4

CO2 Captute Study Case 2-2 PLANT:

LOCATION: NE Netherlands

CLIENT: IΕΑ

PROJECT: 608389 Revised this issue \downarrow

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1 2 3	Item no.		ltem Na	me			no. operating	Power (Each	kW) Total			
4 5 6 7	22-K-101	Air Comp	oressor				2		49,209	49,209		
8 9 10	22-K-201	Hydrogei	n Recycle	Compres	sor		1		33	33		
11 12 13 14	22-P-301 22-K-301		Condens Compre				1 1		79 4,767	4,845		
15 16 17 18 19 20 21	22-P-401 22-P-402 22-P-403 22-P-404 22-PT-401	Semi-Lea Stripper	Reflux P an Amine Feed Pun	ump Pump np			1 1 1 1 1		1,823 3 8,542 304 -3,109	7,563		
22 23 24 25	22-K-601 22-P-601	CO2 Cor CO2 Cor	npressor npressor	KO Drum	Pump		1		15,937 8	15,945		
26 27 28 29	22-P-701 22-P-702 22-QT-701		Condensa	te			1 1 1		1,019 4 -35,530	-34,506		
30 31 32 33 34	22-P-901	Cooling \	Water Pui	mp			2		2,359 3,000	5,359		
35 36 37 38												
39 40 41 42 43												
44 45 46 47												
48 49 50 51	Total Powe								48.4			
52	NOTE: All da									-	_00000	\Box
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JACOBS JACOBS CONSULTANCY UK LTD Power schedule

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Document No. 60-8389-00/P.03/3100/A4

PLANT: CO2 Captute Study Case 3-1

LOCATION: NE Netherlands

CLIENT: IEA

PROJECT: 608389

Revised this issue 🔱

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3	Item no.		Item Na	me			no. operatin	Power (kW g Each		Total		
5	100 31-W-101	Air Sepa	ration Uni	t			1		44,309	44,309		
7 8	200 31-P-201 31-W-201		rry Feed F	oump			1		466 1,096	44,303		1 A
9	300 31-P-301		ater Pum	า			1		6	1,562		
11	31-P-302 31-P-303	BFW Pu					1		21 28			
13	31-W-301						1	_	259	315		
15 16	400 31-K-401 31-K-402		Expande				1		-7,149 0			
17	31-K-403 31-K-404		N2 Compr				1		3,672 1,886			
19 20	31-K-405 31-P-401	Main N2	Compres:	sor ation Pum	р		1		27,101 825			
21	31-P-402 31-P-403	Low Pres	ssure BFV				1		86 652			
23 24	31-P-404 31-P-405		culating F				1		85 352			
25 26	31-P-409	Process	Water Ma	ake-up Pu	mp		1	·	319	27,828		
27 28	500 31-P-501 31-P-502		lution Pun ution Pum				1		2,003 269			
29 30	31-P-503 31-P-504		n Pump Reflux Pu	mp			5 1		9,521 13			
31 32	31-P-505 31-PT-506		Solvent Pu vent expar				1 5		144 -2,787			
33 34	600 31-K-601	CO2 Cor			12		1		25,617	9,162		5 A
35 36	31-P-601			KO Drum	Pump		1	· ·	2 22 222	25,618		
37 38 39	700 31-K-701 31-K-702	Gas Turb Steam T Losses (urbine				1		-22,000 -65,916 1,072			
40	24 D 704	O4	-t- D				ų.		40			3
42 43 44	31-P-704 900 31-P-901		ate Pump Water Pur				1	· ·	3,392	-86,796		
45	31-P-902 Misc		fuel pump				2	· ·	2,000			
47 48 49	IVIISC								2,000	5,392		
50 51 52	Total Powe								27.4			
Issue		A A	Date		Date		Date		Date	T	Date	+
	ription	50.50	eport		Date	25	Date		Date	%	Date	Sht.
_	by / Revised by	THLW	10-mrt-04									16
Chec	ked by	SBJS	23-mrt-04									of
Appro	oved by	SBJS										20

JACOBS JACOBS CONSULTANCY UK LTD Power schedule

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Document No. 60-8389-00/P.03/3200/A4

PLANT: CO2 Capture Study Case 3-2

LOCATION: NE Netherlands

CLIENT: IEA

PROJECT: 608389

Revised this issue

4.1						-	PROJECT:	608389		Revised ti	iio ioout	· ·
1 2	Item no.		Item Na	ma			no.	Power (I	480			-
3	item no.		item na	ille			operating		Total			-
4							operating	Lacii	Total			4
5	100 32-W-101	Air Sena	ration Uni	t			1		48,179			
6		– - р -							10,110	48,179		
7	200 32-P-201	Coal Slu	rry Feed F	ump			1		487	,		
8	32-W-201	Coal pre							1,223			
9		TOTAL STATE							\$10000E	1,710		
10	300 32-P-301		/ater Pumj	р			1		7			
11	32-P-302	BFW Pu					1		23			
12	32-P-303		ater Pump				1	5.	31			
13	32-W-301	Gasificat	tion Packa	age			1		289	223		
14	THE PERSON AND	15 <u>1</u> 27 148 <u>11</u> 3	18				33		1211	351		
15	400 32-K-401		s_expande				1		-1,211			
16	32-K-402		Compres				1		752			2
17	32-K-403		N2 Compr						3,992			-
18	32-K-404 32-K-405		Compres Compres				4		319 30,662			-
20	32-K-406		Compres				4		964			
21	32-P-401		ator Circul		nn		1		982			
22	32-P-402		ssure BF\		ib		1		96			-
23	32-P-403		liate Press		/ Pumn		1		599			
24	32-P-404		rculating F		1 dilip		1		61			
25	32-P-405		ssure BF				1		329			
26	32-P-409		Water Ma		ımp		1		356			
27					Single Control					37,901		
28												
29	500 32-P-501	Lean So	lution Pun	np			1		2,234			
30	32-P-502		lution Pun	np			1		262			2
31	32-P-503						6		10,619			
32	32-P-504		Recycle F				1		1			
33	32-P-505		Solvent Pu				1		132			
34	32-PT-508	Rich sol	vent expar	nder			6	9	-3,658	0.500		
35	COO 22 1/ CO4	0000					4		27.054	9,590		-
36	600 32-K-601		mpressor	KO D	D		1		27,854			
37 38	32-P-601	CO2 C01	mpressor	KO Drum	Pump		1	9	2	27.050		
39	700 32-K-701	Gas Turk	hino				1		-44,000	27,856		-
40	32-K-701	Steam T					1		-89,451			
41	32-14-7-02	Losses					38		1,622			
42		LUSSES	01 & 31						1,022			
43												
44	32-P-704	Condens	sate Pump)			2		130			
45	4500000000						100			-131,699		
46	900 32-P-901	Cooling 1	Water Pur	mp			2		3,902	4000111111		
47				824			0	8	0			
48	Misc								2,000			
49										5,902		
50	200		1953.00						1000000			
51	Total Pow								-0.2			
52	NOTE: All d		train	_		-						
Issue	•	Α	Date		Date		Date		Date		Date	
Desc	ription	For F	Report									Sht.
Made	by / Revised by	THLW	10-mrt-04									17
-	ked by	SBJS	20-mrt-04			D 0						of
-	oved by	SBJS	0-jan-00	-		*						-
Appr	oved by	3003	o-jan-oo					I				21
												100

JACOBS	
CONSULTANCY	

Utility Schedule Case 1

DOCUMENT No:

60-8389-00/P03/1700/A4

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PLANT: CO2 Capture Study PROJECT: 60.8389.00

Rev.			No.	No. Type of Utility Remarks							Remarks						
		PLANT SECTION	Ор					LP Steam	Condens ate		Fresh CW	DMW	BFW	Elec Power			
								t/h	t/h	m ³ /hr	m ³ /hr	m³/hr	m³/hr	MW			
	100																
	200																
	300																
	400	Acid Gas Removal						619.2	-720.8	29430.5	960.0	17.2	101.6	11.2		NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	500																
	600	Product Gas Exports								14526.8	800.0			21.7		NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	700																
	800																
	900	Offsites & Utilities								1840.0	-1760.0			5.6		NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	Total							619.2	-720.8	45797.2	0.0	17.2	101.6	38.5		NEGATIVE VALUE IMPLIES	
																UTILITY GENERATION	
Notes							Rev.	Made by	Date	Checked by	Date	Approved by	Date	Description			Sheet
							0	THLW	18/3/04		22/3/04	SBJS		For Final F			□ 1
							1	THLW	30/4/04	SBJS	30/4/04	SBJS		Including of	case 1		of
							2	THLW	4/5/04	SBJS	4/5/04	SBJS	4/5/04	revised		ļ	5

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Utility Schedule

Case 2-1

DOCUMENT No:

60-8389-00/P03/1700/A4

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PLANT: CO2 Capture Study

PROJECT: 60.8389.00

Rev.		1	No.					Remarks									
itev.		PLANT SECTION	Op		HP Steam	MP Steam	LP Steam	Candana	of Utilit Sea CW	Fresh CW	DMW	BFW	Elec Power	Oxygen	N ₂	Tomano	
					t/h	t/h	t/h	t/h	m ³ /hr	m ³ /hr	m ³ /hr	m³/hr	MW	t/h	t/h		
	100	Air Compression							4076.3	400.0			99.2			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	200	Reformer			-291.7	140.5	-2.8	-3.1		40.0		297.6	0.1			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	300	Shift						-70.2		20.0		104.3	0.2			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	400	Acid Gas Removal					110.4	-110.4	6166.7	40.0	12.9		15.5			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	500																
	600	Product Gas Exports						-12.3	7173.6	200.0			31.9			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	700	Power Block			291.7	-140.5	-107.6	180.6	2364.4	40.0	189.7	-401.8	-41.0			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	800																
	900	Offsites & Utilities						15.4	770.0	-740.0	-202.6		10.1			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	Total				0.0	0.0	0.0	0.0	20551.0	0.0	0.0	0.0	115.9			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
Notes						Rev.	Made by		Checked by		Approved by	Date	Description				She
						0	THLW	18/3/04	SBJS	22/3/04	SBJS		For Final F	•			_ 2
						1	THLW	30/4/04	SBJS	30/4/04	SBJS		Including	case 1		1	of
						2	THLW	4/5/04	SBJS	4/5/04	SBJS	4/5/04	revised			1	_ 5

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CONSULTANCY	

Utility Schedule

CONSULTANCY UK LTD. The data contained in this document is subject to change during the design stage of any subsequent contract.

Case 2-2

PLANT:

DOCUMENT No:

60-8389-00/P03/1700/A4

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CO2 Capture Study

PROJECT: 60.8389.00

Rev.			No.	Type of Utility Rem								Remarks						
		PLANT SECTION	Op			HP Steam	MP Steam	LP Steam	Condens ate	Sea CW	Fresh CW	DMW	BFW	Elec Power	Oxygen	N ₂		
						t/h	t/h	t/h	t/h	m³/hr	m³/hr	m ³ /hr	m³/hr	MW	t/h	t/h		
	100	Air Compression								4072.9	400.0			98.4			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	200	Reformer				-316.0	140.4	-3.1	-3.4		40.0		322.3	0.1			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	300	Shift							-50.8		20.0			9.7			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	400	Acid Gas Removal						19.4	-19.4	6161.5	40.0	12.9		15.1			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	500																	
	600	Product Gas Exports							-12.3	7167.7	200.0			31.9			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	700	Power Block				316.0	-140.4	-107.2	70.2	10702.7	40.0	109.7	-322.3	-69.0			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	800																	
	900	Offsites & Utilities							15.7	770.0	-740.0	-122.6		10.7			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	Total					0.0	0.0	-90.9	0.0	28874.9	0.0	0.0	0.0	96.9			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
																	OTELLY GENELIATION	
Notes		<u> </u>					Rev.	Made by	Date 18/3/04	Checked by SBJS	Date 22/3/04	Approved by SBJS	Date 25/3/04	Description For Final I	Report		1	Shee
							1	THLW	30/4/04	SBJS	30/4/04	SBJS	30/4/04	Including				of
							2	THLW	4/5/04	SBJS	4/5/04	SBJS	4/5/04	revised				5

JACOBS
CONSULTANCY

Utility Schedule

Case 3-1

PLANT:

DOCUMENT No:

60-8389-00/P03/1700/A4

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CO2 Capture Study

PROJECT: 60.8389.00

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Rev.			No.					Туре	of Utilit							Remarks	
		PLANT SECTION	Ор	HP Steam	MP Steam	LP Steam	Condensa te	Process Conden	Sea CW	Fresh CW	DMW	BFW	Elec Power	Oxygen	N ₂		
				t/h	t/h	t/h	t/h	t/h	m ³ /hr	m ³ /hr	m ³ /hr	m³/hr	MW	t/h	t/h		
	100	ASU							12168				88.62	-229.3		NEGATIVE VALUE IMPLIES	
	200	Feedstock Preparation						57.7		300.0			3.1			UTILITY GENERATION NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	300	Gasification Unit						924.4	4718	30.0	68.4	-68.4	0.6	228.5		NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	400	Gas Treatment unit		-218.0		-335.5		-983.5	5304.6	620.0	490.7	68.4	55.7		113.265	NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	500	Acid Gas Removal				-12.0			6571	140.0	12.1		18.3	0.9			
	600	Product Gas Export						1.4	9725.0	200.0			51.2			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	700	Power Block		218.0		347.5	-565.5		42815.5	240.0			-173.6			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
Î	800																
	900	Utilities and Offsites					565.5		1730.0	-1530.0	-571.2		10.8			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	Total			0.0	0.0	0.0	0.0	0.0	83032.5	0.0	0.0	0.0	54.8	0.0		NEGATIVE VALUE IMPLIES UTILITY GENERATION	
lotes						Rev.	Made by THLW	Date 18/3/04	Checked by SBJS	Date 22/3/04	Approved by SBJS	Date 25/3/04	Description For Final F	Report			Sh
						1	THLW	30/4/04	SBJS	30/4/04	SBJS	30/4/04	Including				\exists
						2	THLW	4/5/04	SBJS	4/5/04	SBJS		revised				- €
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Utility Schedule

Case 3-2

DOCUMENT No:

60-8389-00/P03/1700/A4

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PLANT: CO2 Capture Study

PROJECT: 60.8389.00

Rev.			No.					Туре	of Utilit							Remarks	
		PLANT SECTION	Ор	HP Steam	MP Steam	LP Steam	Condensa te	Process Conden	Sea CW	Fresh CW	DMW	BFW	Elec Power	Oxygen	N ₂		
				t/h	t/h	t/h	t/h	t/h	m³/hr	m³/hr	m³/hr	m³/hr	MW	t/h	t/h		
	100	ASU							13572				96.36	-249.4	-645.8	NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	200	Feedstock Preparation						64.4		300.0			3.4			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	300	Gasification Unit						1033.9	5262	30.0	76.9	-76.9	0.7	248.4	_	NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	400	Gas Treatment unit		-237.0		-465.1		-1098.3	8427.8	420.0	632.3	76.9	75.8		126.332	NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	500	Acid Gas Removal				-13.4			7329	140.0	13.5		19.2	1.0			
	600	Product Gas Export						1.5	1906.8	200.0			55.7		519.5	NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	700	Power Block		237.0		478.5	-715.5		57486.9	240.0			-263.4			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	800																
	900	Utilities and Offsites					715.5		1530.0	-1330.0	-722.7		11.8			NEGATIVE VALUE IMPLIES UTILITY GENERATION	
	Total		-	0.0	0.0	0.0	0.0	1.5	95515	0.0	0.0	0.0	-0.4	0.0	0.0	NEGATIVE VALUE IMPLIES	
																UTILITY GENERATION	
Notes		<u> </u>				Rev.	Made by	Date	Checked by	Date	Approved by	Date	Description		<u>I</u>		Shee
						0	THLW	18/3/04	SBJS	22/3/04	SBJS	25/3/04	For Final I	Report			5
						1	THLW	30/4/04	SBJS	30/4/04	SBJS	30/4/04	Including	case 1			of
						2	THLW	4/5/04	SBJS	4/5/04	SBJS	4/5/04	revised		-		5

Appendix 6

Fuel/CO₂ Capture Plants Capital Cost Estimates



DOCUMENT No:

26 July 2004 For Final Report

Capital Cost Estimate Case 1

26 July 2004

60-8389-00/P03/1200/A4

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PLANT: Capture Plant Case 1

PROJECT: 60.8389.00

CLIENT: IEA GHG

LOCATION: NE Netherlands

	Direct Materials	Construction	Engineeri Construction		Total						
						(*1000,000	n.				
Acid Gas Removal	201.72	37.25		26.51	265.47	US \$	-)				
CO2 Compression & drying	15.91	3.92		10.33	30.15	US\$					
Offsites & Utilities	19.00	8.40		14.62	42.02	US\$					
Total	235.70	49.57		51.45	337.65	US\$					
Contingency					33.76	US\$					
Owners costs					23.64	US\$					
Total Installed costs					395.05	US\$					
Original estimates are 100% in US \$											
	Rev. Made by	Date	Checked by	Date	Approved by	Date	D	escription			105
	0 SBJS	19-apr-04	AH 1	9-apr-04	SBJS	19-apr-04	For repo	ort			
	1 SBJS	05-mei-04	AH 0	5-mei-04	SBJS	05-mei-04		1 & revised	case 2	·	į.
	2 IJJ	05-mei-04			KOMI	07-mei-04	For Fina	l Report			



DOCUMENT No:

Capital Cost Estimate Case 2-1

60-8389-00/P03/1200/A4

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PLANT: Capture Plant Case 2-1 PROJECT: 60.8389.00

	Direct Materials	Construction		ering and on Services	Total						
Plant Section											
						(*1000,00	0)				
Air Compression	53.32			34.62	101.09	US \$					
Reforming & HT Cooling	27.89			12.82	48.75	US \$					
Shift & LT Cooling	24.73	6.65		8.96	40.34	US \$					
Acid Gas Removal	50.64	21.57		45.77	117.99	US \$					
CO2 Compression & drying	19.55	4.82		12.69	37.06	US \$					
Power Generation	40.63	3.63		17.27	61.54	US \$				(*100)	0,000)
Offsites & Utilities*	43.81	15.50		20.34	79.64	US \$	Replac Extensi		A CONTRACTOR OF THE PARTY OF TH		US \$ 16.53 3.69 0.37
Total	260.58	73.36		152.47	486.40	US \$					
Contingency					48.64	US \$					
Owners costs					34.05	US \$					
Total Installed costs					569.09	US \$					
Original estimates are 2.3% in US	\$ and 97.7% in € ((€/US \$ = 1.23)								
	7	20 20 22									
	Rev. Made by	Date	Checked by	Date	Approved by	Date		escription			
	0 SBJS	19-apr-04	AH	19-apr-04	SBJS	19-apr-04	For repo	ort			2
	1 SBJS	05-mei-04	AH	05-mei-04	SBJS	05-mei-04		e 1 & revised	case 2		of
	2 IJJ	07-05-04	KOMI	07-05-04	KOMI	38114		l Report			5
	3 IJJ	26 July 2004			KOMI	26 July 2004	For Fina	I Report			



DOCUMENT No:

Capital Cost Estimate Case 2-2

60-8389-00/P03/1200/A4

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PLANT: Capture Plant Case 2-2

PROJECT: 60.8389.00

	Direct Mate	rials	Construction		ering and on Services	Total						
Plant Section												
							(*1000,00	0)				
Air Compression		53.32	13.15		34.62	101.09						
Reforming & HT Cooling		27.89	8.04		12.82	48.75	100					
Shift & LT Cooling		24.73	10.22		27.02	61.97						
Acid Gas Removal	5	50.64	21.57		45.77	117.99	US \$					
CO2 Compression & drying	1	19.55	4.82		12.69	37.06	US \$					
Power Generation	Ę	57.75	5.16		24.55	87.46	US \$				(*100	0,0
Offsites & Utilities*	9	37.13	47.18		42.63	186.93	US \$	*Offsite	es & Utilit	ies include:		US
								Replac	e GT comb	ustion chambers		16
									on demin w			6
									water intak			0
									stance Fue			99
Total	33	31.02	110.14		200.10	641.24	US \$					9,676
Contingency						64.12	US \$					
Owners costs						44.89	US \$					
							US \$					
Total Installed costs						750.25	US \$					
Original estimates are 7% in US	\$ and 93% in €	(4	€/US \$ = 1.23)								
	Co.											
	Rev. Made	ьу	Date	Checked by	Date	Approved by	Date	0	escription	1		
	0 SBJ	-	19-apr-04	AH	19-apr-04	SBJS	19-apr-04	For repo	rt			
	1 SBJ		05-mei-04	AH	05-mei-04	SBJS	05-mei-04		1 & revised	case 2		Ġ.
	2 IJu		07-05-04	KOMI	07-05-04	KOMI		For Fina				
	3 IJ.							For Fina				



Capital Cost Estimate Case 3-1

60-8389-00/P03/1200/A4

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PLANT: Capture Plant Case 3-1 PROJECT: 60.8389.00

DOCUMENT No:

1	Direct Materials	Construction		ng and on Services	Total						
Plant Section											
1210	200320	o section		100000	6/25/25/25/25	(*1000,00	0)				
ASU	96.52			62.66	182.98	US \$					
Coal Receiving, grinding and slurry pr	The state of the s			21.03	52.30	US \$					
Gasification Unit	109.27			60.43	203.20	US \$					
Gas Treatment Package	35.74			20.98	63.99	US \$					
Acid Gas Removal	24.84			22.45	57.87	US \$					
CO2 Compression & drying	28.83	7.11		18.71	54.65	US \$					
Combined Cycle Unit	52.49	4.69		22.31	79.50	US \$				(*100	00,00
Offsites & Utilities*	62.31	26.44		39.13	127.88	US \$	Replac Extensi	e GT comb on demin w			US 16.5 3.6
Total	430.33	124.33		267.71	822.38	US \$	Cooling	water intak	e/outfall		1.1
Contingency					82.24	US \$					
Owners costs					57.57	US \$					
Total Installed costs					962.18	US \$					
Original estimates are 51% in US \$, 49	% in £ and 45% i	n€	(€/US \$ = 1	1.23, £/US \$	= 1.74)						
	Rev. Made by	Date	Checked by	Date	Approved by	Date	D	lescription			
	0 SBJS	19-apr-04	AH	19-apr-04	SBJS	19-apr-04	For repo	ort			4
T	1 SBJS	05-mei-04	AH	05-mei-04	SBJS	05-mei-04		1 & revised	I case 2		۰
Ī	2 IJJ	07-05-04	KOMI	07-05-04	KOMI	07-05-04	Forfinal				5
	3 IJJ	26 July 2004			KOMI	26 July 2004	For Fina	Report			



Capital Cost Estimate Case 3-2

60-8389-00/P03/1200/A4

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PLANT: Capture Plant Case 3-2 PROJECT: 60.8389.00

DOCUMENT No:

D Plant Section	irect Materials	Construction	Engineerin Constructio		Total					
Trancoscion						(*1000,000	m			
ASU	102.35	25.24		66.44	194.03		-/-			
Coal Receiving, grinding and slurry pre	p 20.16	10.84		20.86	51.86					
Gasification Unit	107.80	33.05		59.61	200.47	US \$				
Gas Treatment Package	50.46	10.26		29.62	90.34	US \$				
Acid Gas Removal	24.51	10.44		22.15	57.10	US \$				
CO2 Compression & drying	30.57	7.54		19.84	57.95	US \$				
Combined Cycle Unit	92.60	8.28		39.36	140.24					(*1000,00
Offsites & Utilities*	111.91			61.20	228.69		*Offsite	es & Utiliti	es include:	US
	111.01	00.00		01.20	220.00	00 (ustion chambers	16.
								on demin w		6.1
								water intak	The state of the s	1.2
Total	540.34	161.23		319.09	1020.66		_	stance Fuel		86.
Contingency					102.07	US \$				
Owners costs					71.45	US \$				
Total Installed costs					1194.18	US \$				
Original estimates are 50% in US \$, 9%	in £ and 41% ir	n€	(€/US \$ = 1	.23, £/US \$	= 1.74)					
			30	-	201					
F	Rev. Made by	Date	Checked by	Date	Approved by	Date	D	escription		2745
	0 SBJS	19-apr-04	AH	19-apr-04	SBJS	19-apr-04	For repo	ort		5
	1 SBJS	05-mei-04	AH	05-mei-04	SBJS	05-mei-04		e 1 & revised	case 2	
	2 IJJ	07-05-04	KOMI	07-05-04	KOMI		For Fina			- 5
	3 IJJ	26 July 2004			KOMI	26 July 2004	For Fina	I Report		

Appendix 7

Cash Flow Calculations

								-																			Version	4.5	
IEA GREENHOUSE GAS R&D P	ROGRAMME	=	-					С	ost Evalua	ation - Refe	erence CAS	SE														-	Date	: July 2004	14
30 jul 2004 11:04																						<u>.</u>							
RF	FERENRETROFI	IT.		0		F	REFEREN	RETROFIT				F	REFERENCE	FTROFIT				5	REFERENCE	FTROFIT		0							2
Production	LIXENIXETIXOTI	<u>'</u>		Capital Co	et		Million \$		0	perating C	nete		IM \$/vearM			Economic I	arameters		CEI EIXEIVI	LINOIII				Results su	ımmanı		+		
J000 0 100 0	1404.6 1404.6	6 MW		Installed co	7/00/51/20		354.7	337.7	100	t 100% load			iiii wryeai iii	ivi wryeai		Discount ra		10	10.0	10	%	Q.	4	Emission a		net	- 0	203.562	¢/+ (
Net power output		9 MW	-	Contingend			10.0%	10.0%		uel	u iactoi		132.9	132.9		Load factor	.c		90.0	90.0	70						ve' to calcula		ΨΙ
CO2 output		9 t/h		Contingent	ries		35.5	33.8		uei faintenance			7.9	152.9		Fuel price			3.00	3.00							ost that give:		21/1
Solid waste output		4 t/h	-	Owners co	ete		7.0%	7.0%		hemicals +		loc	1.7	2.4		CO2 price			203.6	203.6			5	NPV	riissiori avu	Juance co	osi irrai give	0.00	
CO2 emissions		a/kWh	-	Owners co	1515		24.8	23.6		nsurance an			7.1	13.8		Waste disp	acal cost		0.0	307.5				IRR			+	10.00%	
CO2 emissions	3/3 0/	g/kvvii		Dotrofit occ	calation basi	ic voor	24.0	10	100	Vaste dispo		.5	0.0	0.1		Insurance a		00	2%		of installed	d coeth	0	IIXIX			-	10.0070	0
Reference plant data For	calculation of cos	of of omicoi					vels :	0%		vaste dispo Operating lab			1.2	1.8		Number of o		62	10	15	UI IIISLAIICU	a cosby					+		+
CO2 emissions	373	g/kWh			penditure es penditure es	-	arry	0.0%		peraury rai	Jour		1.2	1.0					75.0	75.0	Φ1.6 ·		Si .				-		
	2.997	c/kWh	+			Calation	415.0	395.1								Cost per op Administrati			56%		of operato	ro coet		Breakdow	F . //////		+		
Electricity cost	2.331	C/KVVII	-	Total capi	Lai COST		4 15.0	390.1											2070			is CUSL	0	Fuel	II OT CAKUUN	COST	-	64.49%	
Datrofit upor (n)	100			Washin a C	\i4_I					\ 	 		п	п		Fuel storage			20		days			1					
Retrofit year (n)	100		_	Working C			0.0	0.0	U	ecommiss	ioning cos	L .	U	U		Chemicals:			30	30				Capital			-	26.31%	
Retrofit Expenditure year (n-2)	0%			Chemicals			0.2	0.2								Start up tim			3		months	0		Other cost	S		-	9.20%	0
Retrofit Expenditure year (n-1)	40%			Fuel storag		-	0.0	0.0								Retrofit dow					months					-	-		-
Retrofit Expenditure year (n)	60%	6 -		I otal work	king capital		0.2	0.2								Load factor,	remainder	year i	90	90	%							<u> </u>	
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
'ear	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor		-																								-		-	5
				68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	% 90%	90%	
Equivalent yearly hours				68% 5913		90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884		90% 7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884							-
	0%	6 40%	60%	5913																									-
Expenditure Factor	0%	3 40%	60%	5913																									-
Equivalent yearly hours Expenditure Factor Revenues Electricity	0%	i 40%	60%	5913												7884							7884	7884	7884	7884	4 7884	7884	1
Expenditure Factor Revenues Electricity		5 40%	60%	5913	7884 185.5	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	7884 185.5	1
Expenditure Factor Revenues Electricity CO2 revenues(based on power output		6 40%	60%	5913 139.1	7884 185.5	7884	7884	7884	7884 185.5	7884	7884	7884	7884 185.5	7884	7884	7884	7884	7884	7884 185.5	7884 185.5	7884 185.5	7884	7884	7884	7884	7884	4 7884 5 185.5	7884	1
Expenditure Factor Revenues Electricity CO2 revenues(based on power output			, 30%	5913 139.1 0.0	7884 185.5 0.0	7884 185.5 0.0	7884	7884	7884 185.5	7884	7884	7884	7884 185.5	7884	7884	7884 185.5 0.0	7884	7884	7884 185.5	7884 185.5	7884 185.5	7884	7884 185.5 0.0	7884 5 185.5 0 0.0	7884 185.5 0.0	7884 185.5	4 7884 5 185.5 0 0.0	7884 5 185.5 0.0	5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output) Operating Costs	retrofit case)	0.0	0.0	5913 139.1 0.0 -89.7	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0 -119.6	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 5 185.5 0.0 3 -119.6	7884 185.5 0.0 -119.6	7884 185.5 0.0	4 7884 5 185.5 0 0.0 6 -119.6	7884 185.5 0.0	5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output) Operating Costs Fuel	retrofit case)	0 0.0	0.0	5913 139.1 0.0 -89.7 -5.3	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6	7884 185.5 0.0 -119.6	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0 -119.6	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6	7884 185.5 0.0	7884 185.5 0.0	7884 185.5 0.0 -119.6	7884 185.5 0.0 -119.6	7884 185.5 0.0	7884 185.5 0.0 -119.6 -7.1	7884 5 185.5 0 0.0 6 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.6 0.0 -119.6 -7.1	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1	7884 185.5 0.0 3 -119.8 -7.1	5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output: Operating Costs Fuel Maintenance	retrofit case)	0.0 0 0.0 0 0.0	0.0	5913 139.1 0.0 -89.7 -5.3 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 7884 5 185.5 0 0.0 8 -119.6 -7.1 2 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2	7884 5 185.5 0 0.0 6 -119.6 -7.1 2 -1.2	5 5 1 2 2
Expenditure Factor Revenues Electricity CO2 revenues(based on power output of the content of	retrofit case) 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0	0 0.0	139.1 0.0 -89.7 -5.3 -1.2 -1.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	5 185.5 0 0.0 6 -119.6 -7.1 2 -1.2 5 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.6 0.0 -119.6 -7.1 -1.2 -1.5	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5	5 185.5 0.0 3 -119.6 -7.1 2 -1.2 5 -1.5	3 3 1 2
Expenditure Factor Revenues Electricity CO2 revenues(based on power output of the content of	retrofit case) 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	139.1 0.0 -89.7 -5.3 -1.2 -1.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.8 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	5 185.5 0 0.0 8 -119.6 -7.1 2 -1.2 5 -1.5 0 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0	5 185.5 0 0.0 6 -119.6 -7.1 2 -1.2 5 -1.5 0 0.0	5 5 1 2 5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output) Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	retrofit case) 0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0.00 0.00 0.00 0.00 0.00 0.00	139.1 0.0 -89.7 -5.3 -1.2 -1.1 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	5 185.5 0 0.0 8 -119.6 7-7.1 2 -1.5 0 0.0 1 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1	5 185.5 0 0.0 6 -119.6 7-7.1 2 -1.2 6 -1.5 0 0.0 -7.1	5 5 1 2 5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output: Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	retrofit case) 0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	139.1 0.0 -89.7 -5.3 -1.2 -1.1 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	7884 185.5 0.0 -119.6 -7.1 -1.5 0.0 -7.1	5 185.5 0.0 3 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.5 0.0 -7.1	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0 0.0	5 185.5 0 0.0 6 -119.6 7-7.1 2 -1.2 6 -1.5 0 0.0 -7.1 0 0.0	55
Expenditure Factor Revenues Electricity CO2 revenues(based on power output) Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	retrofit case) 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	139.1 0.0 -89.7 -5.3 -1.2 -1.1 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.8 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	5 185.5 0.0 3 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.5 0.0 -7.1	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0 0.0	5 185.5 0 0.0 6 -119.6 7-7.1 2 -1.2 6 -1.5 0 0.0 -7.1 0 0.0	55
Expenditure Factor Revenues Electricity CO2 revenues(based on power output.) Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	retrofit case) 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 -166.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	5913 139.1 0.0 -89.7 -5.3 -1.2 -1.1 0.0 -7.1 0.0 -0.2	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.8 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5.0.0 -119.6 -7.1.1 -1.2 -1.5 0.0 -7.1.1 0.0	5 185.5 0 0.0 8 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0 0.0 0 0.0	185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5.0.0 -119.6 -7.1.1 -1.5 0.0 -7.1.1 0.0	4 7884 5 185.5 0 0.0 6 -119.6 1 -7.1 2 -1.2 5 -1.5 0 0.0 1 -7.1 0 0.0	7884 5 185.5 0 0.0 6 -119.6 -7.1 2 -1.2 5 -1.5 0.0 -7.1 0.0 0.0	55 55 1 1 2 2 5 5 0

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IEA GREENHOUSE GAS R&D PR	OGRAMI	IE						C	ost Evalu	ation - CAS	E 1																Date :	: July 2004	1
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DEE	RENRETRO	EIT	10	10	Fig.	F4	DEFEDEN	RETROFIT	10	6	0		REFEREN	ETROFIT		FG			REFEREN	ETROFIT									
Production	KENKEIKU	FII		Capital Co	+		Million \$		-	operating C	`actc		1M \$/yearM			Economic	narameter		KEFEKENR	CIKOFII				Results su	mman/				
	04.6 1404	.6 MVV		Installed co			354.7	337.7		t 100% loa		IN IN	ııvı əzyearıv	iivi əzyear		Discount ra		1.	10.0		%				mmary zoidance cos	_		73.241	A4.
		.9 MVV		Contingen			10.0%	10.0%		uel	u ractor		132.9	132.9		Load factor			90.0	90.0	70				Tools' Solv				ΦIL
		.9 t/h		Contingen	cies		35.5	33.8		uei Iaintenance			7.9	152.8		Fuel price			3.00	3.00					r roois soiv nission avoid				0171
		.9 bii 04 t/h		Owners co	nete		7.0%	7.0%		hemicals +		loc	1.7	2.4		CO2 price			73.2	73.2				NPV	nssion avoic	ance cos	it that gives	0.00	
The state of the s		7 a/kWh		OWITEISCO	0515		24.8	23.6		nsurance ar			7.1	13.8		Waste disp			0.0	307.5				IRR			$\overline{}$	10.00%	-
CO2 emissions	3/3 6	r g/kvvii	2	Petrofit es	calation bas	ic voor	24.0	10		Vaste dispo		:5	0.0	0.1		Insurance a		00	2%		of installed	Lonethy		IIXIX				10.0070	
Reference plant data For c	alculation of c	net of amice	ion avoidan				arky	0%		perating lal			1.2	1.8		Number of		E3	10	15	UI IIIStalicu	COSDY					$\overline{}$		
	373	g/kWh	ion avoidan		penditure e: penditure e:	-	arry	0.0%		zperauriy iai	Jour		1.2	1.0		Cost per op	-		75.0	75.0	ΦLA.								
	997	c/kWh		Total capi		Scalation	415.0	395.1		-						Administrat			56%		of operator	re coet		Breakdow	of c/kWh c	oct			
Electricity cost 2	331	C/KVVII		i otai capi	itai cost		410.0	030.1								Fuel storag			J070		days	15 CUSL		Fuel	I OI C/KVVII C	USL		57.14%	
Retrofit year (n)	1	0 -		Working C	^anital					ecommiss	ionina coc		n	n		Chemicals			30		days			Capital				32.30%	
Retrofit Expenditure year (n-2)		· -		Chemicals			0.2	0.2		ecommiss	ioning cos	•	0	U		Start up tim			30		months			Other costs				10.56%	
Retrofit Expenditure year (n-1)	40			Fuel storag		6	0.0	0.2						10.		Retrofit dov			Э	1	months			Other costs				10.3070	
Retrofit Expenditure year (n)	60		-		ye king capita		0.2									Load factor		voor 1	90	90	0/.								
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expenditure Factor		% 409	% 60%	6							0%	40%	60%																П
Revenues				9										2					2										
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	110.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	П
CO2 revenues(based on power output re	trofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.0	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	110.7	
Operating Costs																													
Fuel	(.0 0.	0 0.1	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	
Maintenance		.0 0.	0 0.	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-10.4	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	
Labour	(.0 0.	0 0.1	-1.2	-1.2			-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.8	-1.8			-1.8	-1.8	-1.8	-1.8	-1.8			-1.8	-1.8			
Chemicals & consumables	(.0 0.	0 0.1	-1.1	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-1.6	-2.1			-2.1	-2.1	-2.1	-2.1	-2.1			-2.1	-2.1			
Waste disposal			0 0.					0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1		-0.1	-0.1		-0.1	
Insurance and local taxes		.0	0 0.					-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8			
Fixed Capital Expenditures		.0 -166.						0.0	0.0	0.0	0.0	-158.0	-237.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
. men expres =npermente	1	.0 0.	0 0.1	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital Decommissioning Cost				-										-		-					-					\rightarrow			+
Working Capital		.0 -166.	0 -249.	0 34.5	49.0	49.0	49.0	49.0	49.0	49.0	49.0	-109.0	-192.8	76.4	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	107.3	

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IEA GREENHOUSE GAS R	&D PROGRA	MME								Cost Evalu	ation - CAS	E 2.1																Date :	: July 200	J04
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	REFERENCE	TROFIT						REFEREN	RETROFIT				F	REFERENR	ETROFIT					REFEREN	RETROFI	Г								
Production					Capital Co	st		Million \$	Million \$	(Operating (Costs	N	1M \$/yearM	M \$/year		Economic	parameter	rs						Results sui	mmary				
Fuel feedrate	1404.6	1672.4	MVV		Installed co	osts		354.7	486.4		t 100% loa	d factor					Discount ra	ate		10.0		%			Emission av	voidance cr	ost		95.04	49 \$
Net power output	784.8	693.7	MVV		Contingend	cies		10.0%	10.0%	F	uel			132.9	158.2		Load factor			90.0	90.0	%			(Note: Type	'Tools' So	lver' 'Solve	e' to calculate	fe	T
CO2 output	293.0	50.1						35.5	48.6		/laintenance			7.9	18.7		Fuel price			3.00		\$/GJ						st that gives		VΡ
Solid waste output	0.00	0.01			Owners co	sts		7.0%	7.0%		Chemicals +		iles	1.7	11.1		CO2 price			95.0	95.0				NPV				0.0	
CO2 emissions	373	72	a/kWh					24.8			nsurance ar			7.1	16.8		Waste disp			0.0					IRR				10.009	
			g		Retrofit esi	calation bas	is vear		10		Vaste dispo			0.0	0.0		Insurance a		xes	2%		of installed	cost/v							-
Reference plant data	For calculation	of cost	of emission					early	0%		Operating la			1.2	2.3		Number of		,,,,,	10	20									
CO2 emissions	373		a/kWh			penditure es	,		0.0%		- p						Cost per op			75.0		\$k/y								-
Electricity cost	2.997		c/kWh		Total capi		Januaron	415.0									Administrat			56%		of operator	rs cost		Breakdown	of c/kWh	cost			-
Licensity cost	2.001		O/NY VII		. Jean capi	0031		7.0.0	000.1								Fuel storag			0070 N		days	5 5051		Fuel	V. VINTER			55.379	%
Retrofit year (n)		10	_		Working C	anital				-	Decommiss	ionina cos	t	n	n		Chemicals			30		days			Capital			-	32.969	
Retrofit Expenditure year (n-2)		0%			Chemicals			0.2	1.0			.v.iiiig cos	•	- 0	-		Start up tim			30	3				Other costs				11.679	
Retrofit Expenditure year (n-1)		40%			Fuel storag			0.0									Retrofit dov			J	1	months			Other costs				11.077	70
Retrofit Expenditure year (n)		60%			-	ing capital		0.2									Load factor		rugor 1	90	90	0/								
																														_
CASH FLOW ANALYSIS																														
Million \$	2	005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	4
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	909	1%
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	788-	84
Expenditure Factor		0%	40%	60%								0%	40%	60%			1													
Revenues		0.0	1070		-							0.0	1070	0070																
Electricity					139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	122.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.	ر ا
CO2 revenues(based on power	output retrofit cas	e)			0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	117.4	156.5				156.5	156.5		156.5	156.5		156.5				
Operating Costs		-,			3.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0		100.0	100.0	,00.0	100.0	,00.0	,00.0	100.0	100.0	100.0	100.0	,00.0	,00.0	100.0		
Fuel		0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-106.8	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.	14
Maintenance		0.0	0.0				-7.1		-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-12.6	-16.8				-16.8	-16.8		-16.8	-16.8		-16.8	-16.8		-16.	
Labour		0.0	0.0						-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-12.0	-2.3				-10.0	-10.0		-2.3	-2.3		-2.3	-10.0			
Chemicals & consumables		0.0	0.0							-1.5	-1.5	-1.5	-1.5	-1.4	-7.5	-10.0							-10.0	-10.0		-10.0				
Waste disposal		0.0	0.0	0.0			-1.0		-1.0	0.0	0.0	-1.0	0.0	-1.4	0.0	0.0					-10.0		0.0	0.0		0.0				
Insurance and local taxes		0.0	0.0				-7.1			-7.1	-7.1	-7.1	-7.1	-7.1	-16.8	-16.8					-16.8		-16.8	-16.8		-16.8				
Fixed Capital Expenditures		0.0	-166.0						0.0	0.0	0.0	0.0	-227.6	-341.5	0.0	-10.0			-10.0	-10.0	-10.0		-10.0	-10.0	-10.6	-10.6	-10.0		-10.	
Working Capital		0.0	-100.0	-249.0 N N					0.0	0.0	0.0	0.0	-227.0 N.N	-341.0	-1.0	0.0			0.0				0.0	0.0	-1-	0.0				
		0.0	0.0	U.U	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U.	.0
Decommissioning Cost																														
		0.0	-166.0 -166.0						49.0 -184.5	49.0 -135.5	49.0 -86.5	49.0 -37.5	-178.6 -216.1	-297.2 -513.4	93.2 -420.1	132.0 -288.1				132.0 240.1	132.0 372.1		132.0 636.2	132.0 768.3	132.0 900.3	132.0 1032.4				

																												Version	4.5	
EA GREENHOUSE GAS F	R&D PROG	RAMME					10			Cost Evalu	uation - CAS	SE 2.2																Date	: July 200	04
30 jul 2004 11:04																					8					÷				
	DEFEDEN	RETROFI	T		a.			DEFEDEN	RETROFIT		9 8			REFERENI	PETROFIT		[0]			REFEREN	DETROE	T				0.				
Production	KEFEKEN	KETKOFI			Capital C	act			Million \$		Operating	Carte		MM \$/yearN			Economic	naramoto	re	KEFEKEN	KETKOFI				Results su	mman		+		-
Fuel feedrate	1404.6	1671.0	MAC		Installed c		0	354.7	641.2		at 100% loa			viivi gryeai i	nivi ozyeai		Discount ra		:13	10.0		%			Emission a	-	oct	+	124.33	E
Net power output	784.8				Contingen			10.0%	10.0%		Fuel	iu ractor		132.9	158.1		Load factor			90.0	90.0	70						re' to calcula		O DIE
CO2 output	293.0				Contingen	LIES	5	35.5			ruei Maintenanci			7.9	22.1		Fuel price			3.00		\$/GJ						ost that gives		וטטו
Solid waste output	0.00				Owners c	nete		7.0%	7.0%		Chemicals ·		hles	1.7	10.7		CO2 price			124.3					NPV	moordman	maanee ee	of trial gives		0 1
CO2 emissions	373		g/kWh		OVVIICIS C	3313		24.8			Insurance a			7.1	19.9		Waste disp			0.0					IRR				10.00%	
CO2 CITIISSIBIIS	313	10	gritteri		Retrofit es	calation bas	is vear	27.0	10		Waste disp		.03	0.0	0.0		Insurance a		ayes	2%		of installed	1 cost/v		II XI X			_	10.007	70
Reference plant data	For calcula	tion of cost	of emissio			penditure es		early	0%		Operating la			1.2	3.5		Number of		anco	10			2 COSE 9							
CO2 emissions	373	11.011 01 0001	g/kVVh			penditure es	-	July	0.0%		o por dang to	.boai		1.2	0.0		Cost per or			75.0		\$k/v						-		+
Electricity cost	2.997		c/kWh		Total cap		- January	415.0									Administrat	•		56%		of operato	rs cost		Breakdow	n of c/kWh	cost	 		
	2.001		O1111111														Fuel storac			n		days	.0 0001		Fuel				52.90%	1/6
Retrofit year (n)		10	-		Working (Capital	-				Decommiss	sionina co	st	0	n		Chemicals	_		30		days			Capital				34.979	
Retrofit Expenditure year (n-2)		0%	_		Chemicals			0.2	1.0								Start up tim			3	3				Other costs	3			12.139	
Retrofit Expenditure year (n-1)	10	40%	-		Fuel stora			0.0									Retrofit dov		9	-	1	months								
Retrofit Expenditure year (n)		60%				king capita	1	0.2	1.0								Load factor	r. remainde	er vear 1	90	90	%								7
CASH FLOW ANALYSIS																														1
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	16
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	788	4
Expenditure Factor		0%	40%	60%								0%	40%	60%			1									1.7.7.1		1 1 1 1 1 1	1	
Revenues																	·									8				
Electricity					139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	118.3	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	7 157.7	157.	7
CO2 revenues(based on power	output retrofit	case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.5	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	195.3	3 195.3	195.	3
Operating Costs																														
Fuel		0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-106.7	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	3 -142.3	-142.	3
Maintenance		0.0	0.0	0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	9 -19.9	-19.	9
Labour		0.0	0.0	0.0	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	5 -3.5	-3.	5
Chemicals & consumables	8	0.0	0.0	0.0	-1.1	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-7.2	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	7 -9.7	-9.	7
Waste disposal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.0	0.0		0.0				
Insurance and local taxes		0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	9 -19.9	-19.	9
		0.0		-249.0	0.0	0.0		0.0	0.0	0.0		0.0	-300.1	-450.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0			
			0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.	0
Fixed Capital Expenditures Working Capital		0.0	0.0	0.0	0.2																									
ixed Capital Expenditures Vorking Capital		0.0	0.0	0.0	0.2																									+
ixed Capital Expenditures		0.0		-249.0	34.5	49.0	49.0	49.0	49.0	49.0	49.0	49.0	-251.1	-405.9	111.4	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	7 157.7	157.	.7

																											Version 4	4.5	
EA GREENHOUSE GAS R	&D PROGRAMIV	E						C	Cost Evalu	ation - CAS	SE 3.1																Date :	: July 200	04
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	REFERENRETRO	FIT					REFEREN	RETROFIT				R	EFERENR	TROFIT					REFEREN	RETROFIT	.								-
Production				Capital Co	st		Million \$	Million \$	(perating (Costs	M	IM \$/yearM	VI \$/vear		Economic I	parameter	s					- 1	Results sur	nmary				T
Fuel feedrate	1404.6 2121	2 MVV	9	Installed co	7400000		354.7	822.4		t 100% loa						Discount rat			10.0		%			Emission av		ost		131.36	5 \$
Net power output		2 MVV		Contingen			10.0%	10.0%		uel			132.9	100.3		Load factor			90.0	85.0	%			Note: Type			of to calculat		Ť
CO2 output		6 t/h		Contingen	5100		35.5	82.2		/laintenance			7.9	31.8		Fuel price			3.00		\$/GJ			the CO2 em					IP)
Solid waste output		0 t/h		Owners co	nete		7.0%	7.0%			+ consumat	les	1.7	4.6		CO2 price			131.4	131.4		-		VPV	iooioii avo	idanice coe	i inai givee	0.0	
CO2 emissions	373 13			CVVIICIS CO	3313		24.8				nd local taxe		7.1	23.5		Waste disp	neal cost		0.0	184.5				RR				10.009	
CO2 cirilosions	010 10	g/KVVII		Petrofit es	calation bas	ic vear	27.0	0		Vaste dispo		.3	0.0	2.7		Insurance a		/oc	2%		of installed	costáz	- '	IXIX				10.007	0
Reference plant data	For calculation of co	of of omice	on ovoidon				porty	0%		Operating la			1.2	3.5		Number of o		(62	10	30	oi ilistalleu	cosby	-						\dashv
	373	a/kWh	on avoluani		penditure es penditure es		sarry	0.0%		operating ia	iboui		1.2	3.3					75.0	75.0	Ø1.6 .								-
CO2 emissions	2.997	c/kWh		Total capi		calation	415.0									Cost per op Administrati			75.U 56%		of operator	c coct		Breakdown	of all Mile	aact			+
Electricity cost	2.997	C/KVVN		i otai capi	tai COST		410.0	962.2											56% U		-	S COST			or cakeen	COST		4E 040	1/
Detrefit	- 4			W	\! <u></u>									п		Fuel storage			30		days			Fuel				45.849	
Retrofit year (n)	1			Working C			0.0	0.4		Jecommiss	sioning cos		0	U		Chemicals :			30		days			Capital				40.859	
Retrofit Expenditure year (n-2)	20			Chemicals			0.2	0.4								Start up tim			3	3	months		(Other costs				13.319	/6
Retrofit Expenditure year (n-1)	45			Fuel storag			0.0	9.7								Retrofit dow				1	months								
Retrofit Expenditure year (n)	35	% -		i otal wor	king capital		0.2	10.1								Load factor,	, remaindei	year i	90	60	%								-
																													T
CASH FLOW ANALYSIS																													I
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	+
r'ear	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	859	1/6
Equivalent yearly hours				5913		7884		7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446		744	
Expenditure Factor	0	% 409	60%		1004	1004	1001	1004	1004	1004	20%	45%	35%	0012	1770	1440	1110	1110	1770	1770	1440	1770	1110	1110	1770	1770	1110	1777	_
Revenues	0	/0 40/	007	,							2070	4370	3370																
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	88.8	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.	7
				108.1	100.0	100.0	100.0	100.0				100.0	170.0	94.7	178.9		178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9	178.9		178.	
	output retrofit eace)			0.0	0.01	0.0	0.0	0.0		0.0	0.01	0.0	0.0			170.9	170.9	176.9	170.8	170.9			170.9	170.9	170.9	176.9	170.8	1783	J
CO2 revenues(based on power	output retrofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.7							110.0	110.0					-85.3	-85.	2
CO2 revenues(based on power of Operating Costs		0 0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100 6			05.0	05.0	05.0	05.0	05.7			05.0	05.0	05.0	0F 2			
CO2 revenues(based on power of Dperating Costs Fuel	0	0.	0.0		-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-45.2	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3			
CO2 revenues(based on power of Derating Costs Fuel Maintenance	0	0 0.	0.0	-5.3	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-6.5	-45.2 -14.3	-85.3 -27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-85.3 -27.1	-85.3 -27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.	.1
CO2 revenues(based on power of the control of the c	0 0	0 0. 0 0.	0.0	-5.3 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-6.5 -1.2	-45.2 -14.3 -3.5	-85.3 -27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-85.3 -27.1 -3.5	-85.3 -27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27.1 -3.5	-27. -3.	.1 .5
CO2 revenues(based on power of the control of the c	0 0	0 0. 0 0. 0 0.	0.0	-5.3 -1.2 -1.1	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-6.5 -1.2 -1.4	-45.2 -14.3 -3.5 -2.1	-85.3 -27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-85.3 -27.1 -3.5 -3.9	-85.3 -27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27.1 -3.5 -3.9	-27. -3. -3.	.1 .5
CO2 revenues(based on power operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	0 0 0	0 0. 0 0. 0 0. 0 0.	0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0 -1.1	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-119.6 -7.1 -1.2 -1.5	-6.5 -1.2 -1.4 0.0	-45.2 -14.3 -3.5 -2.1 -1.2	-85.3 -27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-85.3 -27.1 -3.5 -3.9 -2.3	-85.3 -27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27.1 -3.5 -3.9 -2.3	-27. -3. -3. -2.	.1 .5 .9
CO2 revenues(based on power) Departing Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0 0 0	0 0. 0 0. 0 0. 0 0. 0 0.	0.0 0.0 0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0 -1.1 0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0	-119.6 -7.1 -1.2 -1.5 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-6.5 -1.2 -1.4 0.0 -7.1	-45.2 -14.3 -3.5 -2.1 -1.2 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27. -3. -3. -2. -23.	.1 .5 .9 .3
CO2 revenues(based on power of the control of the c	000000000000000000000000000000000000000	0 0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0 -1.1 0 -7.1 0 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1 -192.4	-119.6 -7.1 -1.2 -1.5 0.0 -7.1 -433.0	-6.5 -1.2 -1.4 0.0 -7.1 -336.8	-45.2 -14.3 -3.5 -2.1 -1.2 -23.5 0.0	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27. -3. -3. -2. -23.	.1 .5 .9 .3
CO2 revenues(based on power of the control of the c	0 0 0	0 0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0	0.0 0.0 0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0 -0.0 0 -7.1 0 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-6.5 -1.2 -1.4 0.0 -7.1	-45.2 -14.3 -3.5 -2.1 -1.2 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27. -3. -3. -2. -23.	.1 .5 .9 .5
CO2 revenues(based on power of the control of the c	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	3 -5.3 3 -1.2 3 -1.1 0 0.0 -7.1 0 0.0 0 -7.2	-119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.8 -7.1 -1.2 -1.5 0.0 -7.1 0.0	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1	-119.6 -7.1 -1.2 -1.5 0.0 -7.1 -192.4	-119.6 -7.1 -1.2 -1.5 0.0 -7.1 -433.0	-6.5 -1.2 -1.4 0.0 -7.1 -336.8	-45.2 -14.3 -3.5 -2.1 -1.2 -23.5 0.0	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-85.3 -27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27.1 -3.5 -3.9 -2.3 -23.5	-27.1 -3.5 -3.9 -2.3 -23.5 0.0	-27. -3. -3. -2. -23.	.1 .5 .9 .3 .5

		_	-	-															-								Newson	4.5	
IEA GREENHOUSE GAS R&D F	ROGRAMM	<u> </u>							ost Evalu	ation - CAS	E 3.2																Date	: July 2004	14
30 jul 2004 11:04																													-
DE	FERENRETROI	 :IT					DEFEDEN I	RETROFIT					REFEREN	ETPOFIT					REFERENR	ETPOFIT	•								
Production	EKENKETKO	1		Capital Co	net .		Million \$		-	perating C	`oete		IM \$/yearM			Economic	parameters		ALI LIXLINIA	LIKOIII				Results su	Immany				+
	1404.6 2306	4 MW		Installed co			354.7	1020.7		t 100% loa		IV.	iivi qryeai iv	iivi wryeai		Discount ra		<u> </u>	10.0		%				avoidance co	act		168.131	1 0/
Net power output		6 MW		Contingen			10.0%	10.0%		uel	u lactor		132.9	109.1		Load factor			90.0	85.0	/ 0				e 'Tools' Soli		of to polovilo		1 1
CO2 output		5 t/h		Contingent	cies		35.5	102.1		uei Iaintenance			7.9	36.2		Fuel price			3.00	1.50					mission avoid				DV
Solid waste output		4 t/h		Owners co	noto		7.0%	7.0%		hemicals +	-	loo	1.7	5.2		CO2 price			168.1	168.1				NPV	riissiori avuii	uarice cos	si iriai gives	0.00	
CO2 emissions	373 140			Owners co	7212		24.8	71.4		nsurance ar			7.1	27.5		Waste disp			0.0	184.5				IRR				10.00%	_
CO2 emissions	373 141	y/KVVII		Potrofit oc	calation bas	io voor	24.0	9		isurance ar Vaste dispo		5	0.0	3.0		Insurance a		00	2%		of installed	d cooth.		IIXIX				10.00%)
Reference plant data For	calculation of co	of of omicoi					orke	0%		vaste dispo Operating lal			1.2	4.7		Number of		es	10	270 4N	ui iristallet	a Cusuy							+
			on avoidanc			-	arry	0.0%		perauriy iai	Juui		1.2	4.7					75.0		Φ1,6 ·			5					+
CO2 emissions	373 2.997	g/kWh			penditure es	scalation	415.0									Cost per op			75.U 56%	75.0		re coet		Brookd	n of c/kWh o	2004			+
Electricity cost	2.887	c/kWh		Total capi	Ital COST		415.0	1194.2			-					Administrati			20%		of operato	rs cost		Fuel Fuel	A OT CIKWIN	COST		43.75%	,
Dotrofit upor (n)	10	1		Wantin - C	ital			5 5		ecommiss	 		П	n		Fuel storage Chemicals			30		days			Capital				43.75%	-
Retrofit year (n)				Working C			0.2	0.5	L	recommiss	iorling cos		U	U			9		30		days								
Retrofit Expenditure year (n-2)	209			Chemicals		9	0.2	0.5			16	6				Start up tim			3	3	months			Other costs	3			13.66%	3
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)	45°		_	Fuel storag	ge king capital		0.0	10.5 11.1								Retrofit dov Load factor			90	60	months						-		+
																													1
CASH FLOW ANALYSIS	22								22																				-
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	#
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	6
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	ð
Expenditure Factor	0,	6 40%	60%)							20%	45%	35%																Ť
Revenues																			-					15	-				+
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	91.5	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	э
CO2 revenues(based on power output	retrofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	119.7	226.1	226.1	226.1	226.1	226.1	226.1	226.1	226.1	226.1	226.1	226.1	226.1		226.1	
Operating Costs					3.0	3.0																							1
Fuel	0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-49.1	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	7
Maintenance	- o							-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-16.3	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7			-30.7		-30.7	
Labour	0							-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-4.7	-4.7		-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7			-4.7			
Chemicals & consumables	0	0 0.0						-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-2.3	-4.4		-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	4
Waste disposal	0	0.0						0.0	0.0	0.0	0.0	0.0	0.0	-1.3	-2.5		-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	5
Insurance and local taxes	0	0 0.0		15.5				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-27.5	-27.5			-27.5	-27.5	-27.5	-27.5	-27.5				-27.5			
Fixed Capital Expenditures	0	-166.0						0.0	0.0	0.0	-238.8	-537.4	-418.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-
rixed Capital Experiditures	0							0.0	0.0	0.0	0.0	0.0	0.0	-11.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0		-
			-			-						-										-		-					
Working Capital	0	2																							-		+		+
Working Capital Decommissioning Cost Total Cash Flow (yearly)	0	0 -166.0	-249.0	34.5	49.0	49.0	49.0	49.0	49.0	49.0	-189.8	-488.4 -764.7	-373.7	99.0	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4	236.4 2270.0	

																												Version	4.5	
EA GREENHOUSE GAS R	&D PROGR	AMME								Cost Evalu	iation - Ref	erence CA	SE fuelpri	ce +100%														Date	: July 200)4
30 jul 2004 11:04																														
	REFERENR	ETDAEIT					58	DEFEDEN	RETROFIT			E.		DEFEDEN F	RETROFIT					REFEREN	DETRACI	-				0				0
Production	KEFEKENK	EIROFII			Capital C				Million \$		Operating	Canta		IM \$/yearN			Economic			KELEKEN	KETKOFI	•			Results su					-
Frequency Fuel feedrate	1404.6	1404.6	MAC		Installed c			354.7	337.7		at 100% loa		IV	iivi əzyeariv	nivi əryear		Discount ra		15	10.0		0/6			Emission a		not.	9	203.560	104
	784.8	625.9						10.0%	10.0%		at 100% 16a Fuel	a ractor		265.8	265.8		Load factor			90.0	90.0	70						/		∑ ⊅\(\(\)
Net power output CO2 output	784.8 293.0	41.9			Contingen	cies		35.5	33.8		ruei Maintenance	<u> </u>		7.9	15.4		Fuel price			90.0 6.00		% \$/GJ						re' to calcula ost that gives		DLA
Solid waste output	0.00	0.04			Owners ci	noto		7.0%	7.0%		Mairiteriarice Chemicals -		doe	1.7	2.4		CO2 price			203.6	203.6				NPV	TIISSIOTI AV	Didance co	ist triat gives)) M
CO2 emissions	373	67	a/kWh		OWITEIS C	J515		7.0% 24.8			Insurance a			7.1	13.8		Waste disp			203.0					IRR				10.00%	
CO2 emissions	313	07	grkvvii		Potrofit oc	calation bas	ic voor	24.0	23.0 1N		Waste dispo		:5	0.0	0.1		Insurance a		NOC.	2%		of installed	1 coetá		IIXIX				10.007	0
Reference plant data	For calculation	on of poet	of amicciar					ork	0%		Operating la			1.2	1.8		Number of		3762	10	15		acosby							+
CO2 emissions	373	orr or cost	g/kWh			penditure e:		arry	0.0%		Operating to	iboui		1.2	1.0		Cost per or		<u> </u>	75.0		\$k/v				0	S	S		- 10
Electricity cost	4.931		c/kWh		Total capi		scalation	415.0									Administrat	•		56%		of operato	re coet		Breakdow	n of cikinik	cost			+
Liectricity cost	4.001		C/KVVII		i otai cap	itai cost		410.0	030.1		2						Fuel storag			0070		days	13 0031		Fuel	II OI CANYA	i cost		78.40%	6
Retrofit year (n)		100	_	7	Working (Panital					Decommiss	ionina cos		0	0		Chemicals			30	30				Capital				15.99%	
Retrofit Expenditure year (n-2)		0%			Chemicals			0.2	0.2		Decommis	noning cos					Start up tim			30	3				Other costs				5.61%	
Retrofit Expenditure year (n-1)	9	40%			Fuel stora			0.0									Retrofit dov			J	1	months			Other Costs	3		19	3.017	0
Retrofit Expenditure year (n)		60%				gc king capita		0.2									Load factor		er vear 1	90	90	%								+
Total Englandina your (1)																			,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,											
CASH FLOW ANALYSIS																														
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
																						2004			2004					
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%		90%	90%	90%	90%	90%	90%	90%				
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	7884	4
Expenditure Factor		0%	40%	60%																										_
Revenues																														1
Electricity					228.8	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1			
CO2 revenues(based on power o	output retrofit ca	ase)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	J
Operating Costs																														
Fuel		0.0	0.0	0.0				-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2					-239.2		-239.2	-239.2		-239.2				
Maintenance		0.0	0.0	0.0			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1				-7.1	-7.1		-7.1	-7.1		-7.1	-7.1			
Labour		0.0	0.0	0.0				-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2					-1.2		-1.2	-1.2						
Chemicals & consumables		0.0	0.0	0.0				-1.6		-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6					-1.6		-1.6	-1.6						
		0.0	0.0	0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					0.0		0.0	0.0		0.0				
Waste disposal		0.0	0.0 -166.0	0.0			-7.1	-7.1		-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1		27.101			-7.1		-7.1	-7.1			200.101			
Insurance and local taxes				-249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					0.0		0.0	0.0		0.0				
Insurance and local taxes Fixed Capital Expenditures		0.0	10000																											
Insurance and local taxes ixed Capital Expenditures Vorking Capital		0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes					-0.2 34.5					0.0 49.0	49.0	49.0	49.0	0.0 49.0	0.0 49 N	49.0	0.0				49.0		0.0 49.0	0.0 49.0	0.0					

																												Version ·	4.5	
IEA GREENHOUSE GAS R&D	PROGRAM	IME							C	ost Evalu	ation - Sen	sitivity fue	Iprice +10	0% CASE	1													Date	: July 200	14
30 jul 2004 11:04																														+
RI	FERENRETE	ROFIT						REFEREN	RETROFIT					REFEREN	RETROFIT				P	EFEREN R	FTROFIT									+
Production	- LIXEIVIXE III	10111			Capital Co	ct		Million \$		-	perating (nete		/M \$/yearN			Economic	parameters		LILIXLINIA					Results su	ımmanı				+
Fuel feedrate	1404.6 14	404.6 M	MAZ.		Installed co			354.7	337.7		t 100% loa		-	iliti yryeai i	iiii wiyeai		Discount ra	•		10.0		%				voidance co	net		89.269	<u>α</u> Φ/
Net power output		325.9 M			Contingend			10.0%	10.0%		uel	a ractor		265.8	265.8		Load factor			90.0	90.0	70						e' to calculat		, 4/
CO2 output		41.9 t/l			Contingent	lics		35.5	33.8		dei Maintenance			7.9	15.4		Fuel price			6.00	6.00							st that gives		DV
Solid waste output		0.04 t/l			Owners co	ete		7.0%	7.0%		hemicals +		nlec	1.7	2.4		CO2 price			89.3	89.3				NPV	rnooiorr avo	ruarree eo	n trial gives	0.00	
CO2 emissions	373		ı/kVVh		OWITEIS CO	1212		24.8	23.6		nsurance ar			7.1	13.8		Waste disp	-		0.0	307.5				IRR				10.00%	_
CO2 emissions	3/3	or g	previi		Petrofit eco	alation bas	ic voor	24.0	10		Vaste dispo		20	0.0	0.1		Insurance a		00	2%		of installed	d coetá.		IFXEX	0. 10			10.0070	+
Reference plant data Fo	or calculation of	f oost of	emiccion					arly	0%		vaste dispo Operating lai			1.2	1.8		Number of		65	10	15	UI IIISLAIIEL	a cosby							+
CO2 emissions	373		1/kWh			penditure es penditure es	-	arry	0.0%		zperaury iai	boui		1.2	1.0		Cost per op			75.0	75.0	ΦLA		3						+
Electricity cost	4.931		:/kVVh		Total capit		calduum	415.0	395.1								Administrati			75.U 56%		of operato	re coet		Brookdow	n of c/kWh	cost			+
Electricity cost	4.831	- C	JKVVII		i otai capi	tai cost		4 10.0	333.1			-	-				Fuel storag			J076			I S CUSE		Fuel	II OI C/KVVII	COSL		72.71%	,
Retrofit year (n)	100	10	_		Working C	anital				-	ecommiss	ianina cca		п	n		Chemicals			30		days days	8	8	Capital				20.55%	-
		0%						0.0	0.0		ecommiss	ioning cos	it.		U					30					0.000					
Retrofit Expenditure year (n-2)	10		-		Chemicals			0.2	0.2	0	9						Start up tim	NAME OF TAXABLE PARTY.		3	3	months			Other cost:	5			6.73%	3
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)		40% 60%	-		Fuel storag			0.0				-					Retrofit dov Load factor			90	90	months								+
																														+
CASH FLOW ANALYSIS																														
Million \$	200	5 2	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	÷
Year	00	0	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	#
Load Factor	100				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4
Expenditure Factor		0%	40%	60%								0%	40%	60%																T
Revenues																														T
Electricity					228.8	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	279.7	182.5	243.3	243.3	243.3	243.3	243.3	243.3	243.3	243.3	243.3	3 243.3	243.3	243.3	243.3	243.3	3
CO2 revenues(based on power outpu	t retrofit case)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	101.2	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	э
Operating Costs																														T
Fuel		0.0	0.0	0.0	-179.4	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-219.3	-179.4	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	2
Maintenance		0.0	0.0	0.0			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-10.4	-13.8			-13.8	-13.8	-13.8	-13.8	-13.8				-13.8			
Labour		0.0	0.0	0.0			-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.8	-1.8			-1.8	-1.8	-1.8	-1.8	-1.8			-1.8	-1.8			
Chemicals & consumables		0.0	0.0	0.0			-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-1.6	-2.2			-2.2	-2.2	-2.2	-2.2	-2.2				-2.2			
		0.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1			-0.1	-0.1			
Waste disposal		0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	8
			400.0	-249.0			0.0	0.0	0.0	0.0	0.0	0.0	-158.0	-237.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Waste disposal		0.0	-166.0	-240.0			- 1-	- 1-					0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		-
Waste disposal Insurance and local taxes Fixed Capital Expenditures			-166.0	-243.0	-N 2	0.0	0.0	0.0	0.0	0.0	nn	0.01	11111																	
Waste disposal Insurance and local taxes		0.0			-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2							0.0	0.0	0.0		0.0				-
Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital		0.0			34.5	49.0	49.0	49.0 -233.5	49.0	49.0 -135.5	49.0 -86.5	49.0 -37.5	-109.0 -146.5	-192.8 -339.3	76.4 -263.0	107.3 -155.6			107.3 166.4	107.3 273.7	107.3	107.3 488.4	107.3 595.7	107.3		107.3	107.3 1025.1	107.3		_

								-											-	_						-	Version	4.5	
IEA GREENHOUSE GAS R&D P	ROGRAMIV	E					-	C	ost Evalua	tion - Sens	sitivity fue	price +10	0% CASE 2	2.1										-			Date	: July 200	04
30 jul 2004 11:04																													
RFI	FERENRETRO	FIT				F	REFEREN	RETROFIT		F4		F	REFEREN	ETROFIT		F0 (0)	[]	R	EFERENR	FTROFIT									-
Production	2.12.11.0			Capital Co	st		Million \$		0	perating C	osts		1M \$/yearM			Economic I	parameters							Results su	ummarv		+		-
	1404.6 1672	4 MW		Installed co			354.7	486.4		100% load		- 1	iiii yiycuiii	iiii yiyeai		Discount ra			10.0		%			Emission a		enst	+	117.335	15 ¢
		.7 MVV		Contingend			10.0%	10.0%		uel	11000		265.8	316.4		Load factor			90.0	90.0	70			(Note: Type			ve' to calcul		U 4
		.1 t/h		Contingent	103		35.5	48.6		aintenance			7.9	18.7		Fuel price			6.00	6.00				the CO2 en					IDV
Solid waste output		11 t/h		Owners co	ete		7.0%	7.0%		hemicals +	-	les	1.7	11.2		CO2 price			117.3	117.3				NPV	modionave	Siderice co	of that give.	0.00	
CO2 emissions		2 g/kWh		Ovviici 3 co	313		24.8	34.0		surance an			7.1	16.8		Waste disp	neal cost		0.0	307.5				IRR			+	10.00%	_
002 01113310113	010	gzkvvii		Retrofit esc	alation hasi	s vear	27.0	10		/aste dispo:		.3	0.0	0.0		Insurance a		29	2%		of installed	l cost/v		HXIX				10.0070	
Reference plant data For	calculation of co	st of emiss	nn avoidan				rlv	0%		perating lab			1.2	2.3		Number of o		6.3	10	20	or mistance	a cosby					+		+
CO2 emissions	373	g/kW/h	Dir av Olaani		oenditure es		ii iy	0.0%		perating lat	Jour		1.2	2.0		Cost per op			75.0	75.0	\$1/A						1		+
	4.931	c/kWh		Total capit		Calabon	415.0	569.1								Administrati			56%		of operator	rs cost		Breakdow	m of cikWh	a cost	+		+
Electricity cost	1.001	Critiviii		rotar capi	iai oosi		710.0	000.1								Fuel storage			0070		days	10 0001		Fuel	II OI GIRIII		+	71.26%	3/6
Retrofit year (n)	11	n -		Working C	anital				n	ecommissi	oning cos		0	п		Chemicals :			30		days			Capital			+	21.21%	
Retrofit Expenditure year (n-2)	0'			Chemicals			0.2	1.0		ecommiss.	oming cos	•				Start up tim	9		3		months			Other costs	ic.		+	7.53%	
Retrofit Expenditure year (n-1)	40'	1.5		Fuel storag			0.0	0.0								Retrofit dow				1	months			Other costs	•		19	1.0070	0
Retrofit Expenditure year (n)	60'			Total work			0.2	1.0								Load factor,		voor 1	90	90	0/4					-	+		+
CASH FLOW ANALYSIS Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	4
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	7
. • • • • • • • • • • • • • • • • • • •			Y	•	-		-											10				10							7
a control at a management of the control of the con				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%						
Load Factor																								1 7884	7004	7884	4 7884		14
				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	1004	7884	7 004	4 7004	7884	14
Equivalent yearly hours	0'	% 40%	60%	4010	7884	7884	7884	7884	7884	7884	7884 0%	7884 40%	7227 60%	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	1 7004	7884	1884	4 100.	/884	14
Load Factor Equivalent yearly hours Expenditure Factor Revenues	0	% 40%	60%	4010	7884	7884	7884	7884	7884	7884				5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7004	7884	1004	4 700	/884	14
Equivalent yearly hours Expenditure Factor	0	% 409	60%	4010		7884	7884	7884	7884 305.1	7884 305.1				5913 202.3	7884 269.7	269.7	7884 269.7	7884 269.7	7884 269.7	7884 269.7	7884 269.7	7884 269.7	7884 269.7	7 269.7	269.7	269.7		269.7	
Equivalent yearly hours Expenditure Factor Revenues		% 409	60%	9010							0%	40%	60%			269.7							269.7	7 269.7	269.7	269.7	7 269.7	269.7	.7
Equivalent yearly hours Expenditure Factor Revenues Electricity		% 409	60%	9010					305.1	305.1	0%	40%	60%	202.3	269.7	269.7	269.7	269.7	269.7	269.7	269.7	269.7	269.7	7 269.7 2 193.2	269.7 193.2	269.7	7 269.7	269.7 193.2	.7
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r			, 00%	228.8 0.0	305.1				305.1	305.1	0%	40%	60%	202.3 144.9 -213.6	269.7	269.7	269.7	269.7	269.7	269.7	269.7	269.7	269.7	7 269.7 2 193.2	269.7 193.2	269.7 ! 193.2	7 269.7 2 193.2	269.7 193.2	.7
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs	retrofit case)	0.0	0.0	228.8 0.0	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	305.1 0.0	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	0% 305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	279.7 0.0 -219.3 -6.5	202.3 144.9 -213.6 -12.6	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8 -16.8	7 289.7 2 193.2 3 -284.8 3 -16.8	269.7 193.2 -284.8 -16.8	269.7 193.2 -284.8	7 269.7 2 193.2 8 -284.8 8 -16.8	269.7 193.2 -284.8	.7 .2 .8
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel	retrofit case)	0.0 0.0 0.0 0.0	0.0	228.8 0.0 -179.4 -5.3	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2	305.1 0.0 -239.2	305.1 0.0 -239.2	305.1	305.1 0.0 -239.2 -7.1 -1.2	0% 305.1 0.0 -239.2 -7.1 -1.2	305.1 0.0 -239.2	279.7 0.0 -219.3	202.3 144.9 -213.6 -12.6 -2.3	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8 -16.8 -2.3	7 289.7 2 193.2 3 -284.8 3 -16.8 3 -2.3	269.7 193.2 -284.8 -16.8 -2.3	269.7 193.2 -284.8 -16.8	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3	269.7 193.2 -284.8 -16.8 -2.3	.7 .2 .8 .8
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output in the control of the contr	retrofit case)	0.0 0.0 0.0 0.0	0.0	228.8 0.0 -179.4 -5.3 -1.2	305.1 0.0 -239.2 -7.1 -1.2	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	0% 305.1 0.0 -239.2 -7.1	305.1 0.0 -239.2 -7.1	279.7 0.0 -219.3 -6.5	202.3 144.9 -213.6 -12.6 -2.3 -7.5	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3 0 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	.7 .2 .8 .8 .3
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	retrofit case) 0 0 0 0 0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	228.8 0.0 -179.4 -5.3 -1.2 -1.2	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	0% 305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	40% 305.1 0.0 -239.2 -7.1 -1.2 -1.8 0.0	279.7 0.0 -219.3 -6.5 -1.2 -1.4	202.3 144.9 -213.6 -12.6 -2.3 -7.5 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3 0 -10.0 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	.7 .2 .8 .8 .3 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	retrofit case) 0 0 0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	228.8 0.0 -179.4 -5.3 -1.2 -1.2 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.8	305.1 0.0 -239.2 -7.1 -1.2 -1.6	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	0% 305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	40% 305.1 0.0 -239.2 -7.1 -1.2 -1.8 0.0 -7.1	279.7 0.0 -219.3 -6.5 -1.2 -1.4 0.0	202.3 144.9 -213.6 -12.6 -2.3 -7.5 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3 0 -10.0 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0	.7 .2 .8 .8 .3 .0 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	retrofit case) 0 0 0 0 0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	228.8 0.0 -179.4 -5.3 -1.2 -1.2 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	0% 305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0	40% 305.1 0.0 -239.2 -7.1 -1.2 -1.8 0.0	279.7 0.0 -219.3 -6.5 -1.2 -1.4	202.3 144.9 -213.6 -12.6 -2.3 -7.5 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3 0 -10.0 0 0.0 8 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0	.7 .2 .8 .8 .3 .0 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	retrofit case) 0 0 0 0 0 0	.0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	228.8 0.0 -179.4 -5.3 -1.2 -1.2 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	0% 305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	40% 305.1 0.0 -239.2 -7.1 -1.2 -1.8 0.0 -7.1	279.7 0.0 -219.3 -6.5 -1.2 -1.4 0.0	202.3 144.9 -213.6 -12.6 -2.3 -7.5 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0 0 0.0 3 -16.8	269.7 193.2 -284.8 -16.8 -10.0 0.0 -16.8	269.7 193.2 1-284.8 1-16.8 1-2.3 1-10.0 0.0 1-16.8	7 269.7 2 193.2 8 -284.8 8 -16.8 3 -2.3 0 -10.0 0 0.0 8 -16.8	269.7 193.2 -284.8 -16.8 -10.0 0.0 -16.8	.7 .2 .8 .8 .3 .0 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output r Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	retrofit case) 0 0 0 0 0 0 0 0 0	.0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 -249.0	228.8 0.0 -179.4 -5.3 -1.2 -1.2 0.0 -7.1 0.0 -0.2	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1 0.0	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1	0% 305.1 0.0 -239.2 -7.1 -1.2 -1.6 0.0 -7.1 0.0	40% 305.1 0.0 -239.2 -7.1 -1.2 -1.8 0.0 -7.1 -227.6	60% 279.7 0.0 -219.3 -6.5 -1.2 -1.4 0.0 -7.1 -341.5	202.3 144.9 -213.6 -12.6 -2.3 -7.5 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 -16.8 -0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8 0.0	7 269.7 2 193.2 3 -284.8 3 -16.8 3 -2.3 0 -10.0 0 0.0 8 -16.8 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.8 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.6 0.0	7 269.7 2 193.2 8 -284.8 8 -16.8 9 -23.0 0 -10.0 0 0.0 8 -16.8 0 0.0	269.7 193.2 -284.8 -16.8 -2.3 -10.0 0.0 -16.6 0.0	.7 .2 .8 .8 .3 .0 .0 .0

				-																								Version	4.5	-
IEA GREENHOUSE GAS R&D P	ROGRAMI	ΛE							0	Cost Evalu	ation - Sen	sitivity fue	Iprice +10	0% CASE:	2.2													Date	: July 200	J4
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RFF	RENRETRO	OFIT						REFEREN	RETROFIT	0	9	0.	-	REFEREN	RETROFIT				F	REFERENCE	ETROFII	-								
Production					Capital Co	st		Million \$			perating (Costs		/M \$/yearN			Economic	parameter							Results su	ımmanı				+
	404.6 167	1.0 MV	V		Installed co			354.7	641.2		t 100% loa		Ī		,		Discount ra			10.0		%	4		Emission a		nst		150.172	2 \$/t
		7.4 MV			Contingenc			10.0%	10.0%		uel			265.8	316.2		Load factor			90.0	90.0							e' to calculat		. 472
		9.9 t/h			Contingenc	100		35.5	64.1		daintenance			7.9	22.1		Fuel price			6.00		\$/GJ						st that gives		PVI
Solid waste output		.01 t/h		(Owners co	sts		7.0%	7.0%		hemicals +		nles	1.7	10.8		CO2 price			150.2	150.2				NPV	incolori dvo		indi givoo	0.00	
CO2 emissions		75 a/k	Wh		01111010 00	510		24.8	44.9		nsurance ar			7.1	19.9		Waste disp			0.0	307.5				IRR				10.00%	_
CO2 CITIIODICITO	010	- grit	******	F	Retrofit esc	alation has	is vear	21.0	10		Vaste dispo			0.0	0.0			and local tax	res.	2%		of installe	d cost/v	9	II XI X				10.007	1
Reference plant data For a	alculation of c	cost of er	nission a					arly	0%		operating la			1.2	3.5		Number of			10	30	Or infocultion	a ccca y							
CO2 emissions	373		VVh		Retrofit Exp		-	y	0.0%		- p - c - c - c - c - c - c - c - c - c						Cost per or		100	75.0		\$k/v								+
	.931		VVh		Total capit			415.0	750.3								Administrat			56%		of operato	rs cost		Breakdow	n of c/kWh	cost			
Zicourony cool	.001	City															Fuel storac			n		days	,, 0 0001		Fuel		••••		69.18%	6
Retrofit year (n)	<u> </u>	10 -		ì	Working C	apital				Г	ecommiss	ionina cos	it	0	0		Chemicals	9		30		days			Capital				22.87%	-
Retrofit Expenditure year (n-2)		n% -	-		Chemicals			0.2	1.0	-			-	3			Start up tim			3	3	months			Other cost:				7.95%	
Retrofit Expenditure year (n-1)		0% -			Fuel storag	_		0.0	0.0			100					Retrofit dov			-	1	months	4		Other cost				1.007	1
Retrofit Expenditure year (n)		0% -			Total work			0.2	1.0									r, remainder	vear 1	90	90	%								+
Million \$	2005	200	06	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	+
Year	000	0	10	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	1 7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4
Expenditure Factor	(0%	40%	60%								0%	40%	60%																
Revenues																														
Electricity					228.8	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	279.7	194.6	259.5	5 259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	259.5	5
CO2 revenues(based on power output r	etrofit case)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	176.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	а
Operating Costs																														
Fuel		0.0	0.0	0.0	-179.4	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-219.3	-213.4	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.6	-284.8	â
Maintenance		0.0	0.0	0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	3
Labour		0.0	0.0	0.0	-1.2	-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5			-3.5	-3.5	-3.5	-3.5	-3.5			-3.5	-3.5			
Laboui		0.0	0.0	0.0	-1.2	-1.6		-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-7.3	-9.7			-9.7	-9.7	-9.7	-9.7	-9.7			-9.7	-9.7			
Chemicals & consumables		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0			0.0	0.0			-
Chemicals & consumables Waste disposal			0.0	0.0	-7.1	-7.1		-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-19.9	-19.9			-19.9	-19.9	-19.9	-19.9	-19.9			-19.9	-19.9			
Chemicals & consumables Waste disposal Insurance and local taxes		0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-300.1	-450.2	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0		-
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures			166.0	-249.0	0.0	0.0	U.U	0.0	0.0	0.0	0.0	0.0					0.0	0.0	0.0											0
Chemicals & consumables Waste disposal			0.0	-249.0 0.0	-0.2	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital		0.0 -											-251.1 -288.6	-405.9 -694.5	-1.0 111.4 -583.1	157.7 -425.4	7 157.7	157.7	157.7	157.7 205.5	157.7 363.2	157.7 520.9	157.7 678.6	157.7		157.7	157.7		157.7	7

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IEA GREENHOUSE GAS F	R&D PROGRAI	MIME							<u> </u>	Cost Evalu	ation - Sen	sitivity fue	Iprice +10	00% CASE	3.1													Date	: July 2004	1
30 jul 2004 11:04																														
	REFERENRET	DOELT						REFEREN	DETROEIT					REFEREN	ETDOEIT		0 0			REFERENR	ETDOEIT		9							
Production	REFERENCE	KUFII			Capital Co			Million \$			Operating (`		MM \$/yearN			Economic			KEFEKENK	EIKUFII				Results su					-
	1404.0 0	2121.2	N 45 0 7					777	822.4					viivi əzyearii	nivi əzyear				• .	10.0		%	G.						115.288	A4.
Fuel feedrate					Installed co			354.7			t 100% loa	a ractor		005.0	000.7		Discount ra			10.0		70			Emission a			77		DU C
Net power output		751.2	11111		Contingenc	iles		10.0%	10.0%		uel			265.8	200.7		Load factor			90.0	85.0	1.5						e' to calculat		21.42
CO2 output	293.0	97.6			_			35.5	82.2		/laintenance			7.9	31.8		Fuel price			6.00	3.00					nission avc	ildance cos	st that gives		
Solid waste output	0.00		t/h		Owners co	sts		7.0%	7.0%		Chemicals +			1.7	4.7		CO2 price			115.3	115.3				NPV				0.00	
CO2 emissions	373	130	g/kWh					24.8	57.6		nsurance ar		es	7.1	23.5		Waste disp			0.0	184.5	****			IRR				10.00%	-
					Retrofit esc				9		Vaste dispo			0.0	2.7		Insurance a		es	2%		of installed	d cost/y							-
Reference plant data	For calculation of						-	arly	0%	(Operating la	bour		1.2	3.5		Number of o			10	30									
CO2 emissions	373		g/kVVh		Retrofit Exp		calation		0.0%					Cost per op			75.0	75.0									1			
Electricity cost	4.931		c/kWh		Total capit	al cost		415.0	0.0%					Administrati	-		56%		of operato	rs cost		Breakdow	n of c/kWh	cost						
																	Fuel storage	е		0	30	days			Fuel				62.80%	
Retrofit year (n)		10	-		Working C	apital					Decommiss	ioning cos	t	0	0		Chemicals	storage		30	30	days			Capital				28.07%	
Retrofit Expenditure year (n-2)		20%	-		Chemicals	storage		0.2	0.5								Start up tim	ie		3	3	months			Other cost	S			9.13%	
Retrofit Expenditure year (n-1)		45%	-		Fuel storag	e		0.0	19.4		8						Retrofit dow	vn time			1	months								
Retrofit Expenditure year (n)		35%			Total work	ing capital		0.2	19.9								Load factor	, remainder	year 1	90	60	%								
Million \$	20	005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	01	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	-
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure Factor		0%	40%	60%								20%	45%	35%																
Revenues																														
Electricity					228.8	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	279.7	146.0	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	275.8	
CO2 revenues(based on power	output retrofit case)			0.0	0.0	0.0	0.0	0,0	0.0	0.0	0.0	0.0	0.0	83.1	157.0		157.0	157.0	157.0	157.0	157.0	157.0		100000000000000000000000000000000000000					_
Operating Costs		1																								,				
Fuel		0.0	0.0	0.0	-179.4	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-219.3	-90.3	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	-170.6	
Maintenance		0.0	0.0	0.0		-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.3	-27.1		-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	
Labour		0.0	0.0	0.0		-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5		-3.5	-3.5	-3.5	-3.5	-3.5	-3.5							
Chemicals & consumables		0.0	0.0	0.0		-1.6		-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-2.1	-4.0		-4.0	-4.0	-4.0	-4.0	-4.0	-4.0							
Waste disposal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.2	-2.3		-2.3	-2.3	-2.3	-2.3	-2.3	-2.3							
Insurance and local taxes		0.0	0.0	0.0	-7.1			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-23.5	-23.5		-23.5	-23.5	-23.5	-23.5	-23.5	-23.5							
Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-192.4	-433.0	-336.8	0.0	n n	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n n	0.0	0.0	0.0			
a - aprisar map with tent and		0.0	0.0	0.0	-0.2	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	-19.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
Morking Capital		0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital Decommissioning Cost												-												0				-	-	-
		0.0	-166.0	-249.0	34.5	49.0	49.0	49.0	49.0	49.0	49.0	-143.4	-384.0	-292.5	74.3	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	201.8	

																												Version -	4.5	
EA GREENHOUSE GAS F	R&D PROG	RAMME								Cost Evalu	uation - Ser	sitivity fue	elprice +10	0% CASE	3.2													Date	: July 200	4
30 jul 2004 11:04																														
	REFEREN	DETROEI	-	9				DEFEDEN	RETROFIT					REFEREN	PETROEIT					REFERENI	DETROEI						4	20.		0.
Production	KEFEKEN	KETKOFI			Capital C				Million \$		Operating	Canta		1M \$/yearN			Economic	n avamata		KEFEKENI	KETKOFI				Results su					-
Fuel feedrate	1404.6	2306.4	MAZ		Installed c			354.7			at 100% loa		IV.	nvi pryearis	iivi əryear			•	5	10.0		%			Emission av	-	oot		154.947	ተ
	784.8							10.0%	1020.7		Fuel	d ractor		265.8	218.2		Discount ra			90.0	85.0	7.0			(Note: Type					ΦIL
Net power output CO2 output	784.8 293.0				Contingen	cies		35.5			ruei Maintenance			205.8 7.9	36.2		Load factor Fuel price			6.00		% \$/GJ			the CO2 en					21.71
Solid waste output	0.00				Owners c	noto		7.0%	7.0%		Mairiteriarice Chemicals -		oloc	1.7	5.3		CO2 price			154.9	154.9				NPV	iission avo	naance co	si inai gives	0.00 0.00	
CO2 emissions	373	140	g/kWh		OWITEISC	USIS		7.0% 24.8			Insurance a			7.1	27.5		Waste disp			0.0	184.5				IRR				10.00%	
CO2 emissions	3/3	140	yrkvvii		Dotrofit oc	calation bas	cic voor	24.0	0		Waste dispo		55	0.0	3.0		Insurance a		VOC	2%		of installed	Leoetáz		IIXIX				10.00%	
Reference plant data	For calcula	tion of oact	of omiccio	n avoidanc		penditure e:		orly	0%		Operating la			1.2	4.7		Number of		762	10	40	UI IIIStalieu	COSDY						7	+
CO2 emissions	373	nion or cost	g/kWh	n avoluanc		penditure e:		arry	0.0%		Operating ia	boui	100	1.2	4.1		Cost per op			75.0		\$k/y								-
Electricity cost	4.931		c/kWh		Total cap		Scalation	415.0									Administrat			56%		of operator	re nnet		Breakdown	of cikinih	cost			-
LICCUICKY COST	4.001		CIKVVII		i otai cap	itai GUSL		4 13.0	1 134.2								Fuel storag			00% N		days	2 CO2F		Fuel	I OI CAKAALI	CUSL		60.80%	
Retrofit year (n)		10			Working	Canital					Decommiss	ionina cos		0	n		Chemicals			30		days			Capital				29.69%	
Retrofit Expenditure year (n-2)		20%			Chemical			0.2	0.5		Decommis	sioning cos	, L		- 0		Start up tim			20					Other costs				9.51%	
Retrofit Expenditure year (n-1)		45%	-		Fuel stora			0.2									Retrofit dov			3	1	months			Other costs				8.0170	
Retrofit Expenditure year (n)		35%	-			ye king capita	ı	0.0									Load factor		rvoor 1	90	60	0/.								+
terone experiantare year (ii)		3070			Total Wol	King Capita		0.2	21.0								Load ractor	r, remainae	i year i	00		,,,								
CASH FLOW ANALYSIS																														
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	1
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	-
Load Factor					68%		90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7448	
Expenditure Factor		0%	40%	60%								20%	45%	35%																
Revenues																	5													
Electricity					228.8	305.1	305.1	305.1	305.1	305.1	305.1	305.1	305.1	279.7	150.6	284.4			284.4	284.4	284.4	284.4	284.4	284.4		284.4	284.4			
CO2 revenues(based on power	r output retrofit	case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.3	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	208.4	
Operating Costs																														
Fuel		0.0	0.0	0.0	-179.4	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-239.2	-219.3	-98.2	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	-185.5	
Maintenance		0.0	0.0	0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-16.3	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	
Labour		0.0	0.0	0.0				-1.2		-1.2		-1.2	-1.2	-1.2	-4.7	-4.7			-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	5555555	-4.7	-4.7	-4.7	-4.7	
Labour		0.0	0.0	0.0	-1.2	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-2.4	-4.5				-4.5	-4.5	-4.5	-4.5	-4.5		-4.5				
Chemicals & consumables		0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.3	-2.5				-2.5	-2.5	-2.5	-2.5	-2.5		-2.5	-2.5			
				0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	
Chemicals & consumables Waste disposal Insurance and local taxes		0.0	0.0									000.0	-537.4	-418.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & consumables Waste disposal Insurance and local taxes		0.0				0.0		0.0	0.0	0.0		-238.8	-037.4	-710.0									0.0							
Chemicals & consumables Waste disposal		0.0						0.0		0.0		-238.8	-537.4	0.0	-21.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Vorking Capital		0.0		-249.0											-21.6	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures		0.0	0.0	-249.0 0.0	-0.2	0.0	0.0	0.0	0.0		0.0				-21.6 88.9	237.4				237.4	237.4		0.0	237.4		237.4		3.0		

												a= c .															Daniero I	4.5	
IEA GREENHOUSE GAS R	&D PROGRAIVI	ME							Cost Evalu	ation - Ref	erence CA	SE fuelpr	ice -50%														Date	: July 2004	1
30 jul 2004 11:04																													
	REFERENRETR	OFIT					REFEREN	DETROFIT					REFEREN	PETPOEIT					REFEREN	PETDOFI	т								
Production	KLI LKLIKLIK	0111		Capital Co	net		Million \$			Operating	Costs		MM \$/yearl			Economic	parameter		XLI LIXLIVI	CINOII				Results s	ımmanı				
Fuel feedrate	1404.6 140	04.6 MVV		Installed co			354.7	337.7		t 100% loa			min wrycan	illii wrycai		Discount ra	•		10.0		%				voidance c	net		203.562	\$#.00
Net power output		25.9 MVV		Contingen			10.0%	10.0%		uel	u ractor		66.4	66.4		Load factor			90.0	90.0	70						e' to calculat		DIL CC
CO2 output		11.9 t/h		Contingen	CIES		35.5	33.8		Maintenance			7.9	15.4		Fuel price			1.50		\$/GJ		5				st that gives		21/1
Solid waste output		0.04 t/h		Owners co	nete		7.0%	7.0%			= + consumal	loc	1.7	2.4		CO2 price			203.6	203.6				NPV	riissiori avi	nuance cos	st triat gives	0.00	
CO2 emissions		67 g/kWh	8	OWITEISC	0515		24.8	23.6			nd local taxi		7.1	13.8		Waste disp	accal cost		0.0	307.5				IRR				10.00%	
CO2 emissions	313	or g/kvvii	2	Dotrofit oc	calation bas	cic voor	24.0	10		Vaste dispo		55	0.0	0.1		Insurance a		00	2%		of installe	d coeth		IFXFX	9			10.0076	
Deference plant data	For coloulation of	and of amina	ion avaidan				orb.	0%					1.2	1.8		Number of		.65	10	15		u cosuy							-
Reference plant data	For calculation of					-	arry	0.0%		Operating la	iboui		1.2	1.0									6		(f	0			
CO2 emissions	373	g/kWh			penditure e	scalation	145.0									Cost per op			75.0		\$k/y		2	Duankal	E . II. 1831.				-
Electricity cost	2.031	c/kWh		Total cap	ILAI COST		415.0	395.1								Administrat			56%		of operato	JIS COST		Breakdow	III OT CIKWI	COST		47.500/	
D. I. G (-)		00	15		<u> </u>	13										Fuel storag			0		days	8		Fuel	13	8		47.59%	
Retrofit year (n)		00 -		Working (9			L	ecommis	sioning cos	t	0	0		Chemicals			30		days			Capital	33		-	38.82%	
Retrofit Expenditure year (n-2)		0% -		Chemicals			0.2	0.2								Start up tim	11.00		3	3	months			Other cost	S			13.59%	-
Retrofit Expenditure year (n-1)		- 0%		Fuel stora			0.0	0.0								Retrofit dov				1	months								-
Retrofit Expenditure year (n)		30% -		i otal wor	king capita	AI .	0.2	0.2			8					Load factor	r, remainder	year i	90	90	%	S							
CASH FLOW ANALYSIS																													
Million \$	2008	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	203
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	2
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	90%	90%	90%	
Equivalent yearly hours		-		5913			7884	7884	7884	7884	7884	7884	7884	7884	7884		7884	7884	7884	7884		7884				7884		200000	
Expenditure Factor		0% 409	% 60%		1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	100	1001	1001	1001	1001	1001	
Revenues	0 0	070 40	70 007	0																									
Electricity				94.2	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.	7 125.7	125.7	125.7	125.7	125.7	
CO2 revenues(based on power	nutnut retrofit esco)		9	0.0		123.7	120.7	120.7	0.0	0.0	0.0	120.7	120.7	120.7	120.7	123.7	120.7	120.7	120.7	120.7	120.7	120.7	120.	120.7	123.7	12J.7	0.0	0.0	
Operating Costs	output retront case)			0.0	0.0	0.0	0.0	0.0	0.0	0:0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	-
Fuel Fuel	8	0.0	.0 0.0	-44.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.1	-59.8	-59.8	-59.8	-59.8	-59.8	
Maintenance			.0 0.1					-59.8	-58.6	-59.8	-28.8	-59.8	-59.8	-58.6	-7.1		-7.1	-59.6	-59.8	-58.6	-59.6	-59.6				-58.6			_
Labour		0.0	.0 0.0					-1.1	-1.1	-7.1	-1.1	-1.1	-1.1	-1.1	-1.1			-1.1	-1.1	-7.1									
Chemicals & consumables			.0 0.0					-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.5	-1.2			-1.2	-1.2	-1.2									
Waste disposal			.0 0.1				-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5						-1.5			
			.0 0.0					-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	0.0	-7.1	-7.1	-7.1	-7.1						-7.1			
Insurance and local taxes		0.0 -166					-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1	-7.1 0.0	-7.1	- <i>f</i> .1	-7.1 n n	-7.1 0.0	-7.1	-7.1 0.0		-7.1 0.0				-7.1 0.0			_
Fixed Capital Expenditures	0 0						- 1-		- 1-	0.0	-1-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- 1-			-						
Working Capital Decommissioning Cost		0.0 0	.0 0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U.U	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U.I	J 0.0	0.0	0.0	0.0	0.0	
Total Cash Flow (yearly) Total Cash Flow (cumulated)		0.0 -166 0.0 -166						49.0 -184.5	49.0 -135.5	49.0 -86.5	49.0 -37.5	49.0 11.5	49.0 60.5	49.0 109.5	49.0 158.5		49.0 256.5	49.0 305.5	49.0 354.5	49.0 403.5		49.0 501.5				49.0 697.4			

								-																-	-	-	Version	4.5	
IEA GREENHOUSE GAS R&D PRO	GRAMME	<u>:</u>						С	ost Evaluat	tion - Sens	itivity fue	lprice -50°	6 CASE 1														Date	: July 200	.04
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REFEF	RENRETROF	IT				F	EFERENE	RETROFIT		- 10		F	EFERENR	ETROFIT				R	EFERENR	ETROFIT									
Production		Ť		Capital Co	st		Million \$		Op	perating C	osts		IM \$/yearM			Economic	parameter							Results su	ummarv	-	_	_	
Fuel feedrate 1404	4.6 1404.f	3 MVV	-	Installed co			354.7	337.7	1000	100% load		- 1		,		Discount ra			10.0		%			Emission a		cost	_	65.231	11 \$/t 0
		B MVV		Contingend			10.0%	10.0%	Fu				66.4	66.4		Load factor			90.0	90.0				(Note: Type			ve' to calcu		. 41.
CO2 output 29		3 t/h		Contingent			35.5	33.8		aintenance			7.9	15.4		Fuel price			1.50	1.50							ost that give		JPV1
		4 t/h		Owners co	sts		7.0%	7.0%	11112	nemicals +		les	1.7	2.4		CO2 price			65.2	65.2				NPV	IIIOOIOII GV	Jiaanioo oo	Joi mai give		00 M
	73 67			01111010 00	2.0		24.8	23.6		surance an			7.1	13.8		Waste disp			0.0	307.5				IRR			1	10.00%	
002 01110010110	0,	gritterii	-	Retrofit esc	alation hasi	s vear	21.0	10		aste dispos			0.0	0.1		Insurance a		PS	2%		of installed	d cost/v	0	II XI X			-	10.007	
Reference plant data For cald	culation of cos	st of emissic					rly	0%		perating lab			1.2	1.8		Number of		-	10	15	O. IIIOZGIIOO	. 0000					1		
	73	g/kWh		Retrofit Exp		-		0.0%								Cost per op	-		75.0	75.0	\$k/v							-	
Electricity cost 2.03		c/kWh		Total capit		0.0.00.0	415.0	395.1								Administrat			56%		of operator	rs cost		Breakdow	vn of c/kWh	n cost	1		
																Fuel storag			Π.		days			Fuel			-	40.00%	%
Retrofit year (n)	10	_		Working C	apital				De	ecommissi	onina cos	t	n	n		Chemicals			30		days		-	Capital			-	45.22%	
Retrofit Expenditure year (n-2)	0%	-		Chemicals			0.2	0.2								Start up tim			3		months			Other costs	18	-		14.78%	
Retrofit Expenditure year (n-1)	40%	•		Fuel storag		100	0.0	0.0			- 6					Retrofit dov		16	-	1	months			Curior cost.			-	11.107	70
Retrofit Expenditure year (n)	60%			Total work			0.2	0.2								Load factor		vear 1	90	90	%						+	1	_
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013 2	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	90%	% 90%	6 90%	%
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5040	7884	7884	7884							4 7884	7004	7884	34 7884	4 7884	34
						7004	1004	7004	1004	1004	1004	1004	1221	5913	7004	1001	7884	7884	7884	7884	7884	7884	7884	4 /884	7884	100			
Expenditure Factor	0%	6 40%	60%			7004	7004	7004	7004	1004	0%	40%	60%	5813	7004	1001	7884	7884	7884	7884	/884	7884	7884	4 /884	7884	100	100		
Expenditure Factor Revenues	0%	5 40%	60%			7004	7004	7004	7004	1004				5913	7004	1001	7884	7884	7884	7884	/884	7884	7884	4 7884	7884	100			
10 gard 1 market market and the control of the cont	0%	6 40%	60%	94.2	125.7	125.7	125.7	125.7	125.7	125.7				75.2	100.2	100.2	100.2	100.2	7884 100.2	100.2	100.2	7884 100.2	7884 100.2					2 100.2	2
Revenues		6 40%	60%	94.2	125.7						0%	40%	60%			100.2	100.2						100.2	2 100.2	100.2	2 100.2	.2 100.2		
Revenues Electricity		6 40%	60%		125.7				125.7		0%	40%	60%	75.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2	2 100.2	100.2	2 100.2	.2 100.2		
Revenues Electricity CO2 revenues(based on power output retro			50%	0.0	125.7 0.0 -59.8				125.7		0%	40%	60%	75.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2	100.2 98.6	2 100.2 6 98.6	100.2 98.6	2 100.2 3 98.6	.2 100.: .6 98.6	6 98.6	.6
Revenues Electricity CO2 revenues(based on power output retro Operating Costs	ofit case)	0.0	0.0	-44.8	0.0	125.7	125.7	125.7 0.0	125.7 0.0	125.7	0% 125.7 0.0	40% 125.7 0.0	60% 115.2 0.0	75.2 74.0	100.2 98.6	100.2 98.6 -59.8	100.2 98.6 -59.8	100.2 98.6	100.2	100.2 98.6	100.2 98.6	100.2 98.6	100.2 98.6 -59.8	2 100.2 6 98.6 8 -59.8	100.2 98.6 -59.8	2 100.2 3 98.6 3 -59.8	.2 100.3 .6 98.6	6 98.6 8 -59.8	.6
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel	ofit case)	0.0	0.0	-44.8 -5.3	-59.8	125.7 0.0 -59.8	125.7 0.0 -59.8	125.7 0.0 -59.8	125.7 0.0 -59.8	125.7 0.0 -59.8	0% 125.7 0.0	40% 125.7 0.0 -59.8	60% 115.2 0.0 -54.8	75.2 74.0 -44.8	100.2 98.6 -59.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8	100.2 98.6 -59.8	100.2 98.6 -59.8	100.2 98.6 -59.8	100.2 98.6 -59.8	100.2 98.6 -59.8 -13.8	2 100.2 6 98.6 8 -59.8 8 -13.8	100.2 98.6 -59.8 -13.8	2 100.2 6 98.6 3 -59.8 3 -13.8	.2 100.3 .6 98.6 .8 -59.6	6 98.6 8 -59.8 8 -13.8	.6 .8
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance	ofit case)	0.0	0.0	-44.8 -5.3 -1.2	-59.8 -7.1	125.7 0.0 -59.8 -7.1	125.7 0.0 -59.8 -7.1	125.7 0.0 -59.8 -7.1	125.7 0.0 -59.8 -7.1	125.7 0.0 -59.8 -7.1	0% 125.7 0.0 -59.8 -7.1	40% 125.7 0.0 -59.8 -7.1	60% 115.2 0.0 -54.8 -6.5	75.2 74.0 -44.8 -10.4	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8	100.2 98.6 -59.8 -13.8 -1.8	2 100.2 6 98.6 8 -59.8 8 -13.8 8 -1.8	100.2 98.6 -59.8 -13.8 -1.8	2 100.2 6 98.6 3 -59.8 3 -13.8 3 -1.8	.2 100.3 .6 98.6 .8 -59.6 .8 -13.6 .8 -1.6	6 98.6 8 -59.8 8 -13.8 8 -1.8	.8 .8 .8
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour	ofit case)	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0	-44.8 -5.3 -1.2 -1.1	-59.8 -7.1 -1.2	125.7 0.0 -59.8 -7.1 -1.2	125.7 0.0 -59.8 -7.1 -1.2	125.7 0.0 -59.8 -7.1 -1.2	125.7 0.0 -59.8 -7.1 -1.2	125.7 0.0 -59.8 -7.1 -1.2	0% 125.7 0.0 -59.8 -7.1 -1.2	40% 125.7 0.0 -59.8 -7.1 -1.2	60% 115.2 0.0 -54.8 -6.5 -1.2	75.2 74.0 -44.8 -10.4 -1.8 -1.6 -0.1	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1	2 100.2 6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	2 100.2 6 98.6 3 -59.8 3 -1.8 3 -1.8	.2 100 .8 98.6 .8 -59.0 .8 -1.0 .1 -2.	6 98.6 8 -59.6 8 -13.6 8 -1.6 1 -2.1	.8 .8 .8
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables	ofit case)	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	-44.8 -5.3 -1.2 -1.1 0.0	-59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	0% 125.7 0.0 -59.8 -7.1 -1.2 -1.5	40% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	60% 115.2 0.0 -54.8 -6.5 -1.2 -1.4 0.0	75.2 74.0 -44.8 -10.4 -1.8 -1.6	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	100.2 98.8 -59.8 -13.8 -1.8 -2.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	2 100.2 6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1	2 100.2 3 98.6 3 -59.8 3 -1.8 4 -2.1	.2 100.1 .8 98.6 .8 -59.6 .8 -13.6 .8 -1.1 .1 -2.1 .1 -2.1	6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1	1.8 1.8 1.8 1.1
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	ofit case) 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0	-44.8 -5.3 -1.2 -1.1 0.0 -7.1	-59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0	125.7 0.0 -59.8 -7.1 -1.2 -1.5	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0	0% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0	40% 125.7 0.0 -59.8 -7.1 -1.2 -1.5	60% 115.2 0.0 -54.8 -6.5 -1.2 -1.4	75.2 74.0 -44.8 -10.4 -1.8 -1.6 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.8 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	2 100.2 6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1 8 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	2 100.3 98.6 3 -59.8 3 -13.8 3 -1.8 1 -2.3 1 -0.3	.2 100.1 .8 98.6 .8 -59.8 .8 -13.6 .8 -1.1 .1 -2. .1 -0.8	6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1 8 -13.8	1.8 1.8 1.8 1.1 1.1
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	ofit case) 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 -249.0	-44.8 -5.3 -1.2 -1.1 0.0 -7.1	-59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	0% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	40% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	60% 115.2 0.0 -54.8 -6.5 -1.2 -1.4 0.0	75.2 74.0 -44.8 -10.4 -1.8 -1.6 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	2 100.2 6 98.6 8 -59.8 8 -13.8 8 -1.8 1 -2.1 1 -0.1 9 -13.8 0 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	2 100.2 6 98.6 3 -59.6 3 -13.6 1 -2.7 1 -0.1 3 -13.6	.2 1003 .8 98.0 .8 -59.1 .8 -13.0 .8 -1.1 .1 -2.1 .1 -0.0 .8 -13.0	8 -59.6 8 -13.6 8 -1.2.1 1 -2.1 1 -0.1 8 -13.6	1.6 1.8 1.8 1.1 1.1 1.8
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	ofit case) 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 -249.0	-44.8 -5.3 -1.2 -1.1 0.0 -7.1	-59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1 0.0	125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	0% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1	40% 125.7 0.0 -59.8 -7.1 -1.2 -1.5 0.0 -7.1 -158.0	60% 115.2 0.0 -54.8 -6.5 -1.2 -1.4 0.0 -7.1 -237.0	75.2 74.0 -44.8 -10.4 -1.8 -1.6 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	2 100.2 6 98.6 8 -59.8 8 -13.8 1 -2.1 1 -2.1 1 -0.1 8 -13.8 0 0.0	100.2 98.6 -59.8 -13.8 -1.8 -2.1 -0.1 -13.8 0.0	2 100.0 6 98.6 8 -59.8 8 -13.8 8 -1.8 9 -1.9 1 -2. 1 -0.0 0.0	.2 100.3 .6 98.0 .8 -59.0 .8 -13.0 .8 -1.1 .1 -2.1 .1 -0. .8 -13.0 .0 0.0	8 -59.8 8 -13.8 8 -1.6 1 -2.1 1 -0.1 8 -13.8 0 0.0	1.8 1.8 1.8 1.1 1.1 1.8 1.0

																							-				Version	4.5	
IEA GREENHOUSE GAS R&D P	ROGRAMI	ΛE						C	Cost Evalu	ation - Sen	sitivity fue	Iprice -50	% CASE 2.	1													Date	: July 200	04
30 jul 2004 11:04																													
REF	ERENRETRO	DEIT					REFEREN	RETROFIT					REFEREN	RETROFIT					REFERENR	ETROFIT									+
Production	LINETINE			Capital C	ost		Million \$			perating (Costs		/IM \$/yearN			Economic	parameter		LI LIKLINI					Results su	mmane				-
	404.6 1673	2.4 MW		Installed			354.7	486.4		t 100% loa			inii yryeani	iiii wiyeai		Discount ra			10.0		%			Emission a		net	-	83.908	10 ¢/
Net power output		3.7 MVV		Continger			10.0%	10.0%		uel	u lactoi		66.4	79.1		Load factor			90.0	90.0	70						e' to calculat		υ Ψ
CO2 output		0.1 t/h		Continger	licies	0	35.5	48.6		laintenance			7.9	18.7		Fuel price		10	1.50	1.50							st that gives		IDV
Solid waste output		.01 t/h	-	Owners o	nete		7.0%	7.0%		hemicals +		nlec	1.7	11.1		CO2 price			83.9	83.9				NPV	riiooitiri avti	uance coa	Si inai gives	0.00	
CO2 emissions		72 g/kW	/h	OWNICIS	,0313		24.8	34.0		nsurance ar			7.1	16.8		Waste disp			0.0	307.5				IRR			_	10.00%	_
CO2 emissions	373	z g/KVV	711	Retrofit e	scalation ba	cic vear	24.0	10		Vaste dispo		53	0.0	0.0		100	and local tax	00	2%		of installed	d coetA/		IIXIX				10.0070	0
Reference plant data For	ealculation of a	oost of emi	eeion avoi	danc Retrofit E			aarky	0%		perating la			1.2	2.3		Number of		C3	10	20	OI IIIStalict	u cosby							+
CO2 emissions	373	g/kW			xpenditure e	-	arry	0.0%		peraung ia	boui		1.2	2.0		Cost per op	-		75.0	75.0	¢LA.	0	S				-		+
	2.031	c/k/V		Total car		Scalation	415.0									Administrat			56%		of operato	re coet		Breakdow	n of c/kWh	cost	-	-	+
Encouncity cost		C/KVV	CLT .	i viai ca	,ai 003t		→ 10.0	505.1								Fuel storag			0070 O		days	113 CUSL		Fuel	. OI O/RYY(I	-V3L		38.28%	0/6
Retrofit year (n)		10 -		Working	Canital				-	ecommiss	ionina cos	+	n	n		Chemicals			30		days			Capital			-	45.58%	
Retrofit Expenditure year (n-2)		0% -		Chemica			0.2	1.0		/ecommiss	ioning cos					Start up tim			30		months			Other costs			-	16.14%	
Retrofit Expenditure year (n-1)		0% -	19	Fuel stora			0.0				0					Retrofit dov			J	1	months			Other costs	•		-	10.1470	0
Retrofit Expenditure year (n)		0% -			aye rking capita	-1	0.2									_	r, remainder	voor 1	90	90	0/.							-	+
CASH FLOW ANALYSIS Million \$	2005	2006	3 200	7 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	1
																													1
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	+
Load Factor				68%			100.00000	90%	90%	90%	90%	90%	83%	68%	90%		90%	90%	90%	90%	90%	90%	90%		90%	90%			
Equivalent yearly hours				591	3 7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	,4
Expenditure Factor	(0% 4	10%	60%							0%	40%	60%																
Revenues																													
Electricity				94.	2 125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	115.2	83.3	111.1		111.1	111.1	111.1	111.1	111.1	111.1	111.1	111.1	111.1	111.1		111.1	
CO2 revenues(based on power output i	etrofit case)			0.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.6	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	138.2	.2
Operating Costs																													
Fuel			0.0	0.0 -44.				-59.8	-59.8	-59.8	-59.8	-59.8	-54.8	-53.4	-71.2			-71.2	-71.2	-71.2	-71.2	-71.2			-71.2	-71.2			
Maintenance			0.0	0.0 -5.				-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-12.6	-16.8			-16.8	-16.8	-16.8	-16.8	-16.8			-16.8	-16.8			
Labour			0.0	0.0 -1.				-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-2.3	-2.3			-2.3	-2.3	-2.3	-2.3	-2.3			-2.3	-2.3			
Chemicals & consumables			0.0	0.0 -1.				-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-7.5	-10.0			-10.0	-10.0	-10.0	-10.0	-10.0			-10.0	-10.0			
10 (a aka ali a a a a al		0.0	0.0	0.0 0.				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0			0.0	0.0			
Waste disposal		0.0	0.0	0.0 -7.				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-16.8	-16.8	-16.8		-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8			
Insurance and local taxes		0.0 -16	36.0 -2	49.0 0.				0.0	0.0	0.0	0.0	-227.6	-341.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-
Insurance and local taxes Fixed Capital Expenditures				0.0 -0.	2 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	.0
Insurance and local taxes		0.0	0.0	0.0 -0.																									+
Insurance and local taxes Fixed Capital Expenditures Working Capital				49.0 34.		49.0	49.0	49.0	49.0	49.0	49.0	-178.6	-297.2	93.2	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0	0

																											Version •	4.5	
IEA GREENHOUSE GAS R&D PI	ROGRAMM	E							ost Evalua	tion - Sen	sitivity fue	Iprice -50	% CASE 2.:	2													Date	: July 200)4
30 jul 2004 11:04																													
REF	RENRETRO	IT					REFEREN	RETROFIT		[9.		-	REFEREN	RETROFIT				R	EFERENR	ETROFIT	•		F-1						
Production		1		Capital Co	nst		Million \$		0	perating C	osts		/IM \$/yearN			Economic	parameter		LI LIKEIII				-	Results su	ımmanı				+
	104.6 1671	0 MW		Installed co			354.7	641.2		t 100% loa			inii yryeani	iiii wiyeai		Discount ra			10.0		%				voidance co	net		111.419	Q \$/t
		4 MVV		Contingen			10.0%	10.0%		uel	u ractor		66.4	79.0		Load factor			90.0	90.0	70						e' to calculat		3 47
		9 t/h		Contingent	LIES		35.5	64.1		uei aintenance			7.9	22.1		Fuel price			1.50	1.50			S.				e to calculat st that gives		DVI
Solid waste output		1 t/h		Owners co	nete		7.0%	7.0%		hemicals +		aloc	1.7	10.7		CO2 price			111.4	111.4				NPV	mosion avoi	iuanice co.	n mai gives	0.00	
CO2 emissions		g/kWh		Owners co	7212		24.8	44.9		surance ar			7.1	19.9		Waste disp		-	0.0	307.5				IRR				10.00%	
CO2 emissions	3/3 /3	y y Kvvii		Dotrofit oo	calation bas	io upor	24.0	10		surance ar /aste dispo		52	0.0	0.0		100	and local tax		2%		of installed	d ===+6.		IIXIX				10.00%	0
Reference plant data For a	alculation of co	of of oppioni	on ovoidon				orke	0%		vaste dispo perating lal			1.2	3.5		Number of		es	10	30	oi installet	a cosby							+
			Un avuluani		•	-	ally	0.0%		perating iai	Juui		1.2	3,0			-		75.0		Φ1.4.		ST .						+
CO2 emissions	373 .031	g/kWh			penditure es	scalation	415.0	750.3								Cost per op			75.U 56%	75.0		ro coct		Drogleda	n of c/kWh				+
Electricity cost 2	.031	c/kWh		Total capi	Ital COST		415.0	/50.3			-					Administrat			56% O		of operato	rs cost			n ot cikwin	COST		05.000	
D-1-5			13					3 3	_							Fuel storag			U		days	8	15	Fuel	3 3	>		35.96%	-
Retrofit year (n)	10			Working C					U	ecommiss	ioning cos	it	0	0		Chemicals		100	30		days		-	Capital			-	47.54%	
Retrofit Expenditure year (n-2)	0'		10	Chemicals			0.2	1.0								Start up tim			3	3	months		6	Other costs	S		-	16.49%	0
Retrofit Expenditure year (n-1)	409			Fuel storage	~		0.0	0.0								Retrofit dov				1	months						1		+
Retrofit Expenditure year (n)	609	/6 -	3	Total worl	king capita	ıl .	0.2	1.0								Load factor	r, remainder	year 1	90	90	%		3					S	
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	+
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	4
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4
Expenditure Factor	0.	6 40%	60%)							0%	40%	60%																
Revenues																													
Electricity				94.2	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	115.2	80.1	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	106.9	9
CO2 revenues(based on power output re	trofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	131.3	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	0
Operating Costs																													T
Fuel	0	0.0	0.0	-44.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-54.8	-53.4	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	-71.1	1
Maintenance	0	0.0	0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	9
Labour	0	0.0	0.0	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5			-3.5	-3.5	-3.5	-3.5	-3.5			-3.5	-3.5			5
	0	0.0	0.0	-1.1	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-7.2	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	7
Chemicals & consumables		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Chemicals & consumables Waste disposal		0 00	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9	9
	0	U.U		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-300.1	-450.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Waste disposal Insurance and local taxes		-	-249.0	0.0	0.0							0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Waste disposal	0	0 -166.0					0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0							0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0	0 -166.0					0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0						0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Waste disposal Insurance and local taxes Fixed Capital Expenditures	0 0	0 -166.0	0.0	-0.2	0.0	0.0	49.0	49.0	49.0	49.0	49.0	-251.1	-405.9	111.4	157.7	7 157.7	157.7	157.7	157.7	157.7	157.7	157.7				157.7			7

																												Version 4	4.5	
EA GREENHOUSE GAS R	&D PROGRA	MME							(Cost Evalu	ation - Ser	sitivity fue	lprice -50°	6 CASE 3.1														Date :	: July 20	104
30 iul 2004 11:04							9																							-
30 Jul 2004 11:04		-													-										-					+
	REFEREN RE	TROFIT						REFEREN	RETROFIT				F	REFERENR	ETROFIT					REFEREN	RETROFI	Т								
Production					Capital Co	st		Million \$	Million \$	(Operating (Costs	M	IM \$/yearM	M \$/year		Economic	parameter	s						Results su	mmary				
Fuel feedrate	1404.6	2121.2	MVV		Installed co	osts		354.7	822.4	a	t 100% loa	d factor					Discount ra	ite		10.0		%			Emission av	oidance c	ost		139.40	J5 \$
Net power output	784.8	751.2	MVV		Contingend	cies		10.0%	10.0%	F	uel			66.4	50.2		Load factor			90.0	85.0	%			(Note: Type	'Tools' Sc	lver' 'Solve	e' to calculat	te	
CO2 output	293.0	97.6	t/h					35.5	82.2	P	/laintenance	9		7.9	31.8		Fuel price			1.50	0.75	\$/GJ			the CO2 em	nission avo	oidance cos	st that gives	a zero N	IPV
Solid waste output	0.00	1.70	t/h		Owners co	sts		7.0%	7.0%	(Chemicals -	+ consumal	oles	1.7	4.6		CO2 price			139.4	139.4	\$/t			NPV				0.0	JO
CO2 emissions	373	130	a/kVVh					24.8	57.6	1	nsurance ai	nd local tax	es	7.1	23.5		Waste disp	osal cost		0.0	184.5	\$/t			IRR				10.009	%
					Retrofit esc	calation bas	is vear		9	1	Vaste dispo	osal		0.0	2.7		Insurance a		xes	2%	2%	of installed	d cost/v							
Reference plant data	For calculation	of cost o	of emission					early	0%		Operating la			1.2	3.5		Number of			10	30		,							\neg
CO2 emissions	373		a/kVVh			penditure es	,		0.0%								Cost per op			75.0		\$k/y							107	+
Electricity cost	2.031		c/kVVh		Total capi		June	415.0									Administrat			56%		of operato	rs cost		Breakdown	of c/kWh	cost			+
	2.001		will fill		. Jean Japi			4.5.0	002.2								Fuel storag			n		days			Fuel	winter			29.769	9/4
Retrofit year (n)		10	_		Working C	anital					Decommiss	ioning cos		0	n		Chemicals			30		days			Capital				52.969	
Retrofit Expenditure year (n-2)		20%	-		Chemicals			0.2	0.4		200111111133	norming cos		-	-		Start up tim			3	3				Other costs				17.289	
Retrofit Expenditure year (n-1)		45%	-		Fuel storac			0.2						0.			Retrofit dov			3	1	months			Other costs				17.207	70
Retrofit Expenditure year (n)		35%	-			ing capital		0.2	1.10					-			Load factor		rugor 1	90	60	0/								+
																														4
CASH FLOW ANALYSIS																														Ť
Million \$	2	005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	859	%
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	744	46
Expenditure Factor		0%	40%	60%		,,,,,					,,,,,	20%	45%	35%			11.0			- 1110										-
Revenues		0,0	1070	0070								20,0	1070	0070																-
Electricity					94.2	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	115.2	60.1	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.	B
CO2 revenues(based on power	output retrefit cae	-/-			04.2		120.7		0.0	0.0	0.0	0.0	0.0	0.0	100.5	189.8		189.8	189.8		189.8		189.8	189.8		189.8				
Operating Costs	output retront Cast	-)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.3	100.0	108.0	108.6	108.6	100.0	100.0	100.0	100.0	100.0	100.0	100.0	103.0	100.0	108.	.0
Fuel		0.0	0.0	0.0	-44.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-54.8	-22.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.6	-42.	6
Maintenance		0.0	0.0	0.0			-7.1		-7.1	-59.8	-59.8	-58.8	-59.8	-54.8	-22.0	-42.6		-42.6	-42.6	-42.6	-42.6		-42.6	-42.6	-42.6	-42.6	-42.6		-42. -27.	
Labour		0.0	0.0	0.0					-1.1	-1.1	-1.2	-7.1	-7.1	-0.0	-14.3	-27.1		-27.1	-27.1		-27.1		-27.1	-27.1		-27.1				
Chemicals & consumables	9 9	0.0	0.0	0.0						-1.2	-1.2	-1.2	-1.2	-1.4	-3.5	-3.9		-3.9	-3.9				-3.9	-3.9		-3.9				
			0.0																											
Waste disposal		0.0	0.0	0.0	0.0		0.0		0.0	0.0	0.0	0.0	0.0	0.0	-1.2	-2.3		-2.3	-2.3				-2.3	-2.3		-2.3				
Insurance and local taxes		0.0	0.0	0.0			-7.1			-7.1	-7.1	-7.1	-7.1	-7.1	-23.5	-23.5		-23.5						-23.5		-23.5				
Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0				0.0	0.0	0.0	-192.4	-433.0	-336.8	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.	
Working Capital Decommissioning Cost		0.0	U.U	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.	.U
otal Cash Flow (yearly)		0.0	-166.0	-249.0	34.5 -380.5		49.0	49.0	49.0	49.0	49.0	-143.4 -229.9	-384.0	-292.5 -906.5	88.1	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200.4	200. 1987.	

																												Version 4	4.5	
IEA GREENHOUSE GAS R	&D PROGRAI	MME								Cost Evalu	ation - Ser	sitivity fue	elprice -50°	% CASE 3.2	!													Date :	: July 20	J04
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30 Jul 2004 11:04																														+
	REFEREN RET	ROFIT						REFEREN	RETROFIT					REFEREN						REFEREN	RETROFI	Т								
Production					Capital Co	st		Million \$	Million \$	(Operating	Costs	N	IM \$/yearM	M \$/year		Economic	parameter	rs						Results su	mmary				
Fuel feedrate	1404.6 2	2306.4	MVV		Installed co	osts		354.7	1020.7		at 100% loa	d factor					Discount ra	ate		10.0		%			Emission av	voidance c	ost		174.72	23 \$
Net power output	784.8	774.6	MVV		Contingend	cies		10.0%	10.0%	F	Fuel			66.4	54.6		Load factor			90.0	85.0	%			(Note: Type	e 'Tools' So	ilver' 'Solve	e' to calculate	te	
CO2 output	293.0	108.5	t/h					35.5	102.1	1	Maintenance	9		7.9	36.2		Fuel price			1.50	0.75	\$/GJ			the CO2 en	nission avc	idance cos	st that gives	a zero N	√P
Solid waste output	0.00	1.84	t/h		Owners co	osts		7.0%	7.0%	(Chemicals -	+ consuma	bles	1.7	5.2		CO2 price			174.7	174.7	\$/t			NPV				0.0	JO
CO2 emissions	373	140	g/kVVh					24.8	71.4	1	nsurance a	nd local tax	es	7.1	27.5		Waste disp	osal cost		0.0	184.5	\$/t			IRR				10.009	%
					Retrofit esc	calation bas	is year		9	1	Waste dispo	osal		0.0	3.0		Insurance a	and local ta	xes	2%	2%	of installed	d cost/y							
Reference plant data	For calculation	of cost o	of emission	n avoidanc	Retrofit Ex	penditure es	scalation y	early	0%	(Operating la	bour		1.2	4.7		Number of	operators		10	40									
CO2 emissions	373		a/kVVh		Retrofit Ex	penditure es	scalation		0.0%								Cost per op	perator		75.0	75.0	\$k/y								
Electricity cost	2.031		c/kWh		Total capi			415.0									Administrat			56%		of operato	rs cost		Breakdown	n of c/kWh	cost			
•					-												Fuel storag			0		days			Fuel				28.029	%
Retrofit year (n)		10	-		Working C	apital				1	Decommiss	sionina cos	st	0	0		Chemicals			30		days			Capital				54.489	
Retrofit Expenditure year (n-2)		20%	_		Chemicals			0.2	0.5						-		Start up tim			3	3				Other costs				17.509	
Retrofit Expenditure year (n-1)		45%	_		Fuel storac			0.0									Retrofit dov				1	months			01.101 00010				11.00	,,
Retrofit Expenditure year (n)		35%				king capital	ı	0.2									Load factor		r vear 1	90	60	%						-		
CASH FLOW ANALYSIS Million \$	20	005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	_
MIIIIOII 4		,00	2000	2007	2000	2003	2010	2011	2012	2013	2014	2013	2010	2017	2010	2013	2020	2021	2022	2023	2024	2023	2020	2027	2020	2025	2030	2031	2002	
r'ear ear	0	100	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	859	%
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	744	46
Expenditure Factor		0%	40%	60%								20%	45%	35%																
Revenues																														
Electricity					94.2	125.7	125.7	125.7	125.7	125.7	125.7	125.7	125.7	115.2	62.0	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.1	117.	1
CO2 revenues(based on power of	output retrofit case	()			0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	124.4	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235	0.0
Operating Costs		-			3.0			7.0																						_
Fuel		0.0	0.0	0.0	-44.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-59.8	-54.8	-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.	4
Maintenance		0.0	0.0	0.0			-7.1		-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-16.3	-30.7		-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7		-30.7	-30.7		-30.	
Labour		0.0	0.0	0.0	-1.2				-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-4.7	-4.7			-4.7	-4.7	-4.7		-4.7	-4.7		-4.7			-4.	
Chemicals & consumables		0.0	0.0	0.0						-1.5	-1.5	-1.5	-1.5	-1.4	-2.3	-4.4					-4.4		-4.4	-4.4		-4.4				
Waste disposal		0.0	0.0	0.0	0.0		0.0		0.0	0.0	0.0	0.0	0.0	0.0	-1.3	-2.5					-2.5		-2.5	-2.5		-2.5				
Insurance and local taxes		0.0	0.0	0.0	-7.1		-7.1			-7.1	-7.1	-7.1	-7.1	-7.1	-27.5	-27.5								-27.5		-27.5				
Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0				0.0	0.0	0.0	-238.8	-537.4	-418.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0	0.0		0.0			0.	
		0.0	0.0	0.0	-0.2				0.0	0.0	0.0	0.0	0.0	0.0	-5.8	0.0			0.0				0.0	0.0		0.0				
Morking Canital		0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		.0
Norking Capital Decommissioning Cost Fotal Cash Flow (yearly)		0.0	-166.0	-249.0	34.5	49.0	49.0	49.0	49.0	49.0	49.0	-189.8	-488.4	-373.7	104.0	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.9	235.	.9

				_																							Version	4.5	
IEA GREENHOUSE GAS R&D PRO	GRAMME	£						С	ost Evalua	tion - Refe	erence CAS	SE discou	nt rate 5%														Date	: July 2004	J4
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REFER!	ENRETROFI	iT				F	REFEREN	RETROFIT				F	REFERENR	ETROFIT				R	EFEREN R	ETROFIT							-		+
Production				Capital Co	st		Million \$		0	perating C	osts	N	IM \$/yearM	M \$/vear		Economic	parameters							Results su	ummarv				_
Fuel feedrate 1404	1.6 1404.6	i MVV		Installed co			354.7	337.7	1000	: 100% load						Discount ra			5.0		%				avoidance c	cost		203.562	2 \$/t
Net power output 784		3 MVV		Contingenc			10.0%	10.0%		uel			132.9	132.9		Load factor	-		90.0	90.0	%						ve' to calcula		-
CO2 output 293		3 t/h		Contangono			35.5	33.8	-	aintenance			7.9	15.4		Fuel price			3.00	3.00							ost that give		IPV)
Solid waste output 0.0		t/h		Owners co:	ists		7.0%	7.0%			consumab	les	1.7	2.4		CO2 price			203.6	203.6				NPV	111001011 440	Jiddi ioo oo	Trial gives	0.00	
CO2 emissions 37							24.8	23.6			nd local taxe		7.1	13.8		Waste disp	osal cost		0.0	307.5				IRR			1	5.00%	
31		9		Retrofit esc	calation basi	s vear	21.0	10	-	/aste dispo			0.0	0.1		Insurance a		es.	2%		of installed	Loost/v	2					0.0070	
Reference plant data For calcu	ulation of cos	t of emissic					rly	0%		perating lab			1.2	1.8		Number of			10	15	Or moramor						1		
CO2 emissions 37		g/kVVh			penditure es			0.0%		p a r a a a r a a a a a a a a a a a a a						Cost per op			75.0	75.0	\$k/v						1		+
Electricity cost 2.70		c/kWh		Total capit		Calabon	415.0	395.1	-		-		-			Administrati			56%		of operato	rs cost		Breakdow	n of c/kWh	n cost	+		+
2.10	-	GINTIN														Fuel storage			n		days			Fuel			1	71.52%	1/6
Retrofit year (n)	100			Working C	anital				D	ecommissi	ioning cost		n	n		Chemicals			30		days			Capital			-	18.27%	
Retrofit Expenditure year (n-2)	0%	-		Chemicals			0.2	0.2								Start up tim	-		3		months			Other cost:	.0		-	10.20%	
Retrofit Expenditure year (n-1)	40%	-		Fuel storag			0.0	0.0			6		19.	- 10		Retrofit dov				1	months			Other cost	_		1	10.2070	•
Retrofit Expenditure year (n)	60%			Total work	_		0.2	0.2								Load factor		vear 1	90	90	%						+		+
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
	_	-		68%	0001				000/	90%	90%	000/			90%	90%	90%	90%	000/	90%	000/			90%	90%	90%	6 90%	90%	1/6
Load Factor				0070	90%	90%	90%	90%	90%	3070	3070	90%	90%	90%	9070			3070	90%	9070	90%	90%	90%	90%					
				5913		90% 7884	90% 7884	90% 7884	7884	7884	7884	7884	90% 7884	90% 7884	7884		7884	7884	7884	7884	7884	90% 7884				7884	4 7884	7884	4
Equivalent yearly hours	0%	5 40%	60%	5913																						7884	4 7884	7884	14
Load Factor Equivalent yearly hours Expenditure Factor Revenues	0%	40%	60%	5913																						788	4 7884	7884	14
Equivalent yearly hours Expenditure Factor	0%	40%	60%	5913	7884											7884							7884	7884	7884				
Equivalent yearly hours Expenditure Factor Revenues		40%	60%	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884			167.2	.2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol		40%	60%	5913	7884	7884	7884	7884	7884 167.2	7884 167.2	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884 167.2	7884 167.2	7884	7884	7884	7884		2 167.2	167.2	.2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol				5913 125.4 0.0	7884	7884	7884	7884	7884 167.2	7884 167.2	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884 167.2	7884 167.2	7884	7884 167.2 0.0	7884 2 167.2 0 0.0	7884 167.2 0.0	? 167.2) 0.0	2 167.2 0 0.0	167.2	.2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs	fit case)	0.0	0.0	5913 125.4 0.0 -89.7	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 2 167.2 0.0 3 -119.6	7884 167.2 0.0 -119.6	2 167.2 0 0.0	2 167.2 0 0.0 6 -119.6	167.2 0.0 -119.6	.2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel	fit case)	0.0	0.0	5913 125.4 0.0 -89.7 -5.3	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0 -119.6	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0	7884 167.2 0.0 -119.6	7884 167.2 0.0 -119.6	7884 167.2 0.0 -119.6 -7.1	2 167.2 0 0.0 3 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	2 167.2 0 0.0 3 -119.6 -7.1	2 167.2 0 0.0 6 -119.6 1 -7.1	167.2 0.0 -119.6 -7.1	.2 .0 .6
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel Maintenance	fit case)	0.0	0.0	5913 125.4 0.0 -89.7 -5.3 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 2 187.2 0 0.0 3 -119.8 -7.1 2 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	2 167.2 0.0 3 -119.6 -7.1 2 -1.2	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2	167.2 0.0 -119.6 -7.1 -1.2	.2 .0 .6 .1
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrot Operating Costs Fuel Maintenance Labour	fit case) 0.0 0.0 0.0	0.0	0.0	5913 125.4 0.0 -89.7 -5.3 -1.2 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 187.2 0.0 -119.8 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 187.2 0.0 -119.8 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	7884 167.2 0.0 -119.8 -7.1 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2	2 167.2 0 0.0 6 -119.6 -7.1 2 -1.2 3 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	2 167.2 0.0 3 -119.6 -7.1 2 -1.2	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 6 -1.6	187.2 0.0 -119.6 -7.1 -1.2	.2 .0 .6 .1 .2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel Maintenance Labour Chemicals & consumables	fit case) 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0.0	125.4 0.0 -89.7 -5.3 -1.2 -1.2	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.8	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 3 -1.6 0 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	2 167.2 0 0.0 3 -119.6 -7.1 2 -1.2 3 -1.6	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 6 -1.6 0 0.0	167.2 0.0 -119.6 -7.1 -1.2 -1.6	.2 .0 .6 .1 .2
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0	0.0 0.0 0.0 0.0 0.0	5913 125.4 0.0 -89.7 -5.3 -1.2 -1.2 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.8 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	2 167.2 0 0.0 8 -119.6 7-7.1 2 -1.2 3 -1.6 0 0.0 1 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	2 167.2 0 0.0 3 -119.6 -7.1 2 -1.2 3 -1.6 0.0	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 6 -1.6 0 0.0 1 -7.1	167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	.2 .0 .6 .1 .2 .6 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 -166.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0	-89.7 -5.3 -1.2 -1.2 -0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 187.2 0.0 -119.6 -7.1 -1.2 -1.8 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	2 167.2 0.0 3 -119.6 -7.1 2 -1.2 3 -1.6 0 0.0 1 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	2 167.2 0.0 6 -119.6 7-7.1 2 -1.2 6 -1.6 0 0.0	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 6 -1.6 0 0.0 1 -7.1	167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	.2 .6 .1 .2 .6 .0
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrol Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	fit case) 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 -166.0	0.0 0.0 0.0 0.0 0.0 0.0 -249.0	5913 125.4 0.0 -89.7 -5.3 -1.2 -1.2 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.8 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 187.2 0.0 -119.6 -7.1 -1.2 -1.8 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1	2 167.2 0 0.0 8 -119.6 -7.1 2 -1.2 6 -1.6 0 0.0 1 -7.1 0 0.0	7884 167.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	2 167.2 0.0 6 -119.8 7-7.1 2 -1.2 6 -1.8 0.0 0.0 0.0	2 167.2 0 0.0 6 -119.6 1 -7.1 2 -1.2 6 -1.6 0 0.0 1 -7.1 0 0.0	187.2 0.0 -119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	.2 .0 .6 .1 .2 .6 .0 .1

																											Version	4.5	
IEA GREENHOUSE GAS R&D PRO	GRAMME	•						0	ost Evalua	ation - Disc	ount rate (% CASE	1														Date	: July 2004	1
30 jul 2004 11:04																													
REFER	NRETROF	т		0			REFEREN	RETROFIT		9	4		EFERENR	ETROFIT				P	EFEREN R	FTROFIT								9	
Production	LINETROI			Capital Co	ct		Million \$		-	perating C	nete		IM \$/yearM			Economic p	arameters		LILIXLINX	LIKOIII				Results su	mman		-		
Fuel feedrate 1404	.6 1404.6	M\A/		Installed co			354.7	337.7		t 100% load		- 1	iiii wryeai iii	iiii wryeai		Discount rat			5.0		%			Emission a		net	+	59.429	\$/+ 0
Net power output 784		MVV		Contingenc			10.0%	10.0%		uel	Tactor		132.9	132.9		Load factor	.0		90.0	90.0	/ 0						re' to calcula		ψ/L V
CO2 output 293		t/h		Contingent	163		35.5	33.8		laintenance			7.9	15.4		Fuel price		10	3.00	3.00							st that gives		ועו
Solid waste output 0.		t/h		Owners co	ete		7.0%	7.0%		hemicals +	- Indian	loc	1.7	2.4		CO2 price			59.4	59.4				NPV	moonor avo	nuance co	of trial gives	0.00	
CO2 emissions 37				OWITEIS CO	515		24.8	23.6		nsurance an			7.1	13.8		Waste dispo	neal coet		0.0	307.5				IRR			+	5.00%	-
COZ EITIISSIOTIS 31	3 07	y/KVVII		Petrofit esc	alation basi	e vear	24.0	10		Vaste dispo		3	0.0	0.1		Insurance a		20	2%		of installed	costá		IFXFX				3.0070	
Reference plant data For cald	ulation of cos	f of omiccio					orky	0%		vaste uispo Operating lab			1.2	1.8		Number of o		59	10	15	UI IIIStalleu	CUSUY					-		
CO2 emissions 37		g/kWh			enditure es enditure es	-	arry	0.0%		peraury rai	ioui		1.2	1.0		Cost per op			75.0	75.0	\$1.A.								
Electricity cost 2.70		c/kWh		Total capit		Lalation	415.0	395.1								Administrati			56%		of operator	o coet		Breakdow	a af alk\\\		-		
Electricity cost 2.70	3	CIKVVII		i otal capit	ai cost		4 10.0	333.1				-				Fuel storage			0070 N			S CUSE		Fuel	I OI C/KVVII	COSL	-	62.05%	
Retrofit year (n)	10	10 mg		Working C	anital				-	ecommissi	anina ass		n	n		Chemicals			30		days days		8	Capital		·		25.48%	
	0%						0.2	0.2	L	ecommissi	oning cos		U	U					30		months			0.000				12.46%	
Retrofit Expenditure year (n-2)				Chemicals	-			0.2					(a)			Start up time			3					Other costs	i			12.40%	
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)	40% 60%			Fuel storag Total work			0.0	0.0								Retrofit dow Load factor,		1	90	90	months						+		-
, , , ,																				30.00									
AAGU EL OM ANAL VOIG																													
CASH FLOW ANALYSIS Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20

Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	7884	
Expenditure Factor	0%	40%	60%								0%	40%	60%					***************************************											
Experial are 1 actor																													
Revenues																										133.4	4 133.4	133.4	
				125.4	167.2	167.2	167.2	167.2	167.2	167.2	167.2	167.2	153.3	100.0	133.4	133.4	133.4	133.4	133.4	133.4	133.4	133.4	133.4	133.4	133.4	155.4		100.4	
Revenues	fit case)			125.4 0.0	167.2	167.2	167.2	167.2	167.2	167.2	167.2 0.0	167.2	153.3 0.0	100.0 67.4	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8	133.4 89.8		133.4 89.8	133.4 89.8			
Revenues Electricity CO2 revenues(based on power output retro	fit case)			125.4	167.2	167.2 0.0	167.2 0.0	167.2			167.2																		_
Revenues Electricity CO2 revenues(based on power output retro	fit case)	0.0	0.0	125.4 0.0 -89.7	167.2 0.0 -119.6	167.2 0.0 -119.6	167.2 0.0	167.2 0.0			167.2 0.0													89.8			89.8	89.8	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs			0.0	-89.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.4	89.8	89.8	89.8	89.8	89.8	89.8	89.8	89.8	89.8	-119.6	89.8	89.8	89.8 3 -119.6	89.8 -119.6	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel	0.0	0.0		-89.7 -5.3	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	67.4	89.8 -119.6	89.8 -119.6	89.8 -119.6	-119.6	89.8 -119.6	89.8 -119.6	-119.6	89.8 -119.6	89.8 -119.6	-119.6 -13.8	89.8 -119.6	-119.6	89.8 3 -119.6 3 -13.8	-119.6 -13.8	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance	0.0	0.0	0.0	-89.7 -5.3 -1.2	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-119.6 -7.1	-109.6 -6.5	-89.7 -10.4	89.8 -119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8	-119.6 -13.8 -1.8	-119.6 -13.8	-119.6 -13.8	89.8 3 -119.6 3 -13.8 3 -1.8	-119.6 -13.8 -1.8	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour	0.0	0.0 0.0 0.0	0.0	-89.7 -5.3 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-119.6 -7.1 -1.2	-109.6 -6.5 -1.2	-89.7 -10.4 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8	-119.6 -13.8 -1.8	89.8 6 -119.6 3 -13.8 3 -1.8 2 -2.2	-119.6 -13.8 -1.8	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables	0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	0.0 0.0 0.0	-89.7 -5.3 -1.2 -1.2	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6	-109.6 -6.5 -1.2 -1.4	-89.7 -10.4 -1.8 -1.6	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2	-119.6 -13.8 -1.8 -2.2	89.8 -119.6 3 -13.8 3 -1.8 2 -2.2 1 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	-89.7 -5.3 -1.2 -1.2	-119.6 -7.1 -1.2 -1.6	-119.6 -7.1 -1.2 -1.6 0.0	-119.6 -7.1 -1.2 -1.6 0.0	-119.6 -7.1 -1.2 -1.6 0.0	-119.6 -7.1 -1.2 -1.6 0.0	-119.6 -7.1 -1.2 -1.8	-119.6 -7.1 -1.2 -1.6 0.0	-119.6 -7.1 -1.2 -1.6 0.0	-109.6 -6.5 -1.2 -1.4 0.0	-89.7 -10.4 -1.8 -1.6 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 1 -0.1 3 -13.8	-119.6 -13.8 -1.8 -2.2 -0.1	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 -166.0	0.0 0.0 0.0 0.0	-89.7 -5.3 -1.2 -1.2 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.8 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-109.6 -6.5 -1.2 -1.4 0.0 -7.1	-89.7 -10.4 -1.8 -1.6 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	-119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8	-119.8 -13.8 -1.8 -2.2 -0.1 -13.8	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	3 89.8 3 -119.6 3 -13.8 3 -1.8 2 -2.2 1 -0.1 3 -13.8 0 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 -166.0	0.0 0.0 0.0 0.0 0.0 -249.0	-89.7 -5.3 -1.2 -1.2 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1 -158.0	-109.6 -6.5 -1.2 -1.4 0.0 -7.1 -237.0	67.4 -89.7 -10.4 -1.8 -1.6 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	3 89.8 3 -119.6 3 -13.8 3 -1.8 2 -2.2 1 -0.1 3 -13.8 0 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	
Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 -166.0	0.0 0.0 0.0 0.0 0.0 -249.0	-89.7 -5.3 -1.2 -1.2 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1 0.0	-119.6 -7.1 -1.2 -1.6 0.0 -7.1	-119.6 -7.1 -1.2 -1.6 0.0 -7.1 -158.0	-109.6 -6.5 -1.2 -1.4 0.0 -7.1 -237.0	-89.7 -10.4 -1.8 -1.6 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	-119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8	8 89.8 6 -119.6 3 -13.8 3 -1.8 2 -2.2 1 -0.1 3 -13.8 0 0.0	89.8 -119.6 -13.8 -1.8 -2.2 -0.1 -13.8 0.0	

IEA ODEENHOUGE GAO DE	D DDOODAN	anar-							-	F l	-di Di		F0/ OACE	0.4															4.5	
IEA GREENHOUSE GAS R	&D PROGRAM	/IIVIE	-						- 10	ost Evalu	ation - Disc	ount rate	5% CASE	2.1														Date	: July 2004	ł
30 jul 2004 11:04																														
	REFERENRETE	ROFIT						REFEREN	RETROFIT					REFEREN	RETROFIT					REFERENR	ETROFIT									
Production	REFERENCE				Capital Co	st		Million \$			perating (costs		MM \$/yearN			Economic	narameters		LI LIKLINI	L III OI II				Results s	ummanı				
Fuel feedrate	1404.6 18	672.4 N	M\A/		nstalled co			354.7	486.4		t 100% loa			ini viyean	iiii qiyeai		Discount ra			5.0		0%				avoidance c	net		79.020	\$/t C
Net power output		693.7 N			Contingenc			10.0%	10.0%		uel	u ractor		132.9	158.2		Load factor	ic.		90.0	90.0	70				ne 'Tools' So		e' to calcula		W.C
CO2 output	293.0	50.1 t			Contingent	163		35.5	48.6		dei Maintenance			7.9	18.7		Fuel price			3.00	3.00								s a zero NPI	izi
Solid waste output			/h		Owners co	ete		7.0%	7.0%		hemicals +	-	loc	1.7	11.2		CO2 price			79.0	79.0				NPV	mosionave	ruance cos	n triat gives	0.00	
CO2 emissions	373	72 0			OWITEIS CO	313		24.8	34.0		nsurance ar			7.1	16.8		Waste disp	ocal cost		0.0	307.5	***			IRR				5.00%	
CO2 emissions	313	72 (y/KVVII		Dotrofit occ	alation bas	io voor	24.0	10				33	0.0	0.0		Insurance a		00	2%		of installed	1 cooth	2	IIXIX				3.0076	
Reference plant data	For calculation o	of poot of	Comiccion					orb.	0% Operating labour			1.2	2.3		Number of o		62	10	270	UI IIIStallet	a cosby									
	373						-	ally	0.0%			1.2	2.3					75.0	75.0	CL4.										
CO2 emissions	2.703		g/kWh c/kWh			enditure es	calation	14E ^							Cost per op			75.U 56%			t		Dua alcal ···	/n of c/kWh						
Electricity cost	2.703	. (C/KVVII		Total capit	ai COST		415.0	0.0%						Administrati			20%		of operato	rs cost			n ot c/kd/n	COST		50.7007			
2.1.61	8	40															Fuel storage			U		days	8		Fuel				59.72%	
Retrofit year (n)		10	-		Working C					L.	ecommiss	ioning cos	τ	0	0		Chemicals			30		days			Capital				26.24%	
Retrofit Expenditure year (n-2)		0%	-		Chemicals			0.2	1.0								Start up tim			3	3	months			Other cost	.S		1	14.04%	
Retrofit Expenditure year (n-1)		40%	-		Fuel storag			0.0	0.0								Retrofit dov				1	months						-		
Retrofit Expenditure year (n)		60%	-		i otai work	ing capital		0.2	1.0								Load factor	, remainder	year i	90	90	%		ST.						
CASH FLOW ANALYSIS																														
Million \$	200	05 :	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20
Year	00	00	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	2
Load Factor					68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Equivalent yearly hours			-		5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884		7884	7884			
Expenditure Factor		0%	40%	60%	0010	1004	1004	1001	1001	1001	1001	0%	40%	60%	2010	1007	1004	1001	1001	1001	1001	1001	1004	, 30-	1004	1001	1001	1004	1001	
Revenues		070	7070	0070								0 70	7070	0070																
Electricity					125.4	167.2	167.2	167.2	167.2	167.2	167.2	167.2	167.2	153.3	110.9	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	147.8	
CO2 revenues(based on power or	utput retrefit cocc				120.4	107.2	107.2	107.2	107.2	107.2	107.2	107.2	0.0	193.3	97.6	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1			130.1	130.1		130.1	
Operating Costs	utput retront case)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.0	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	130.1	
Fuel Fuel	3 3	0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-106.8	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	
		0.0	0.0	0.0	-89.7	-119.6	-119.6	-7.1	-7.1	-7.1	-119.6	-7.1	-7.1	-109.6		-142.4		-142.4	-142.4	-142.4	-142.4	-142.4								
Maintenance		0.0	0.0	0.0						-1.1					-12.6								-16.8							
Labour	9 9	0.0	0.0	0.0	-1.2	-1.2 -1.6		-1.2	-1.2		-1.2	-1.2	-1.2 -1.6	-1.2 -1.4	-2.3	-2.3 -10.0		-2.3	-2.3	-2.3 -10.0	-2.3	-2.3	-2.3 -10.0							
Chemicals & consumables				0.0	-1.2			-1.6	-1.6	-1.6	-1.6	-1.6			-7.5			-10.0	-10.0		-10.0	-10.0								
Waste disposal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0							
Insurance and local taxes		0.0	100.0	0.0	-7.1			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8							
Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-227.6	-341.5	0.0	U.U	U.U	0.0	0.0	0.0	0.0	0.0	0.0	- 10						
		0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U.U	0.0	-1.0	U.U	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
A STATE OF THE STA										-								100		-						-	`	-	-	-
Working Capital Decommissioning Cost Total Cash Flow (yearly)		0.0	-166.0	-249.0	20.8	30.7 -363.5		30.7	30.7	30.7	30.7 -210.0	30.7 -179.3	-196.9 -376.2	-314.0 -690.2	61.3 -628.9	89.5 -539.5		89.5	89.5	89.5 -181.6	89.5	89.5	89.5 86.9		5 89.5 265.8			89.5 534.3		

								-			-																Version	4.5	
IEA GREENHOUSE GAS R&D PE	OGRAMIN	/IE						<u> </u>	Cost Evalu	ation - Disc	ount rate	5% CASE	2.2														Date	: July 20	.04
30 jul 2004 11:04																											-		-
REFI	RENRETRO	FIT					REFEREN	RETROFIT					REFEREN	ETROFIT				R	EFERENR	ETROFIT									+
Production		· · ·		Capital C	ost		Million \$			perating (osts		IM \$/yearM			Economic	parameter							Results s	ummarv				
	04.6 167	1.0 MVV		Installed of			354.7	641.2		t 100% loa		T i	iiii qiyeaiii	iiii qiyedi		Discount ra			5.0		%				avoidance c	net		102.47	70 \$/
		7.4 MW		Continger			10.0%	10.0%		uel	u iuotoi		132.9	158.1		Load factor			90.0	90.0							re' to calcula		-
		9.9 t/h		Continger	icies		35.5	64.1		dei Maintenance			7.9	22.1		Fuel price			3.00	3.00							ost that gives		IDV
		.01 t/h		Owners o	octe	-	7.0%	7.0%		hemicals +		loc	1.7	10.8		CO2 price			102.5	102.5				NPV	rriiooiori avi	nuance co	Si inai gives	0.0	
CO2 emissions		75 a/kVV	h	Owners	USIS		24.8	44.9		nsurance ar			7.1	19.9		Waste disp		-	0.0	307.5				IRR			+	5.00	
CO2 emissions	3/3 /	5 yikvv	III 2	Dotrofit o	adation boo	nia . mar	24.0	10				:5	0.0	0.0			and local tax		2%			d oosti.	0	IIKIK				0.00	/0
Reference plant data For c	da, datiam af a			lanc Retrofit E	calation bas		mul			Vaste dispo			1.2	3.5				es	10	30	of installe	u cusuy					+		+
						-	ariy	0%		Operating la	Dour		1.2	3.0		Number of	-	10	7.50		AL /	3			5	8	-	-	+
	373	g/kW			kpenditure e	scalation	445.0	0.0%								Cost per op			75.0	75.0				Daniel d	# . 11.51.11		-		+
Electricity cost 2	703	c/kW	П	Total cap	ITAI COST		415.0	750.3						-		Administrat	-		56%		of operato	ors cost			n of c/kWh	COST	-	FO 701	0.6
					<u> </u>	0.00										Fuel storag			0		days			Fuel			-	56.70	
Retrofit year (n)		10 -		Working						ecommiss	ioning cos	t	0	0		Chemicals			30		days			Capital				28.54	
Retrofit Expenditure year (n-2))% -		Chemical			0.2	1.0								Start up tim			3	3	months			Other cost	S		1	14.76	1/6
Retrofit Expenditure year (n-1)		- 0%		Fuel stora	~		0.0	0.0								Retrofit dov	wn time			1	months								_
Retrofit Expenditure year (n)	60	3% -		Total wo	king capita	d	0.2	1.0								Load factor	r, remainder	year 1	90	90	%								
Million \$	2005	2006	200	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	-
'ear	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	90%	6 90%	90	%
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	7884	7884	4 7884	788	34
Expenditure Factor		3% 4	0% 1	0%						2000000000	0%	40%	60%					1	100000000000000000000000000000000000000	100000000000000000000000000000000000000									
Revenues														-										15					\forall
Electricity				125.4	167.2	167.2	167.2	167.2	167.2	167.2	167.2	167.2	153.3	106.7	142.2	142.2	142.2	142.2	142.2	142.2	142.2	142.2	142.	2 142.2	142.2	142.2	2 142.2	142	2
CO2 revenues(based on power output re	rofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.7	161.0			161.0	161.0	161.0	161.0	161.0							
Operating Costs				-	3.0	5.0	0.0				0.0	0.0		.20.1								.01.0			.07.0	.01.0	1.51.0		-
10 C 1 C 1 C 1 C 1 C 1 C 1 C 1 C 1 C 1 C	1	1.0	n n	0.0 -89.	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-106.7	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	-142.3	3 -142.3	-142.3	-142.3	3 -142.3	-142	3
FUEL			0.0	0.0 -5.3			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.9	-19.9			-19.9	-19.9	-19.9	-19.9								
Fuel Maintenance			0.0	0.0 -1.1			-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5			-3.5	-3.5	-3.5	-3.5								
Maintenance		0.0					-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-7.3	-9.7			-9.7	-9.7	-9.7	-9.7	-9.7				-9.7			
Maintenance Labour			n n	0.0 -1.1	-16						0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0	0.0					0.0		_	
Maintenance Labour Chemicals & consumables	(0.0	0.0	0.0 -1.1				0.0	0.01	11111	11 111							-19.9	-19.9										
Maintenance Labour Chemicals & consumables Waste disposal	(0.0 0.0	0.0	0.0 0.0	0.0	0.0	0.0	0.0 -7.1	0.0 -7.1	0.0 -7.1			-7 1	-19.9	-19.9		- 19 9			-19.91	-19.91	-19.9	-19	9 -199	-199	-199	1 -199	_14	· 91
Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	(0.0 0.0 0.0	0.0	0.0 0.0 0.0 -7.	0.0	0.0 -7.1	0.0 -7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1 -450.2	-19.9	-19.9 n.n			-18.8	-18.8	-19.9 n n	-19.9								
Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	(0.0 0.0 0.0 0.0 -16	0.0 0.0 6.0 -2	0.0 0.0 0.0 -7. 19.0 0.0	0.0 -7.1 0.0	0.0 -7.1 0.0	0.0 -7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 -300.1	-450.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0	0.1
Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	(0.0 0.0 0.0 0.0 -16	0.0	0.0 0.0 0.0 -7.	0.0 -7.1 0.0	0.0 -7.1 0.0	0.0 -7.1	-7.1	-7.1	-7.1	-7.1	-7.1			-19.9 0.0 0.0	0.0	0.0	0.0				0.0	0.1	0.0	0.0	0.0	0.0	0	
Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital		0.0 0.0 0.0 0.0 -16	0.0 0.0 6.0 -2-	0.0 0.0 0.0 -7. 19.0 0.0	0.0 -7.1 0.0 0.0	0.0 -7.1 0.0 0.0	0.0 -7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 0.0	-7.1 -300.1	-450.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0	1.0

																											Version 4	4.5	
IEA GREENHOUSE GAS R&D P	ROGRAMM	E						C	ost Evalu	ation - Disc	ount rate	5% CASE	3.1														Date :	: July 2004	4
30 jul 2004 11:04																													
REF	ERENRETRO	IT					REFEREN	RETROFIT					REFEREN	ETROFIT				B	REFERENR	FTROFIT		6	6						
Production	LIKENIKETIKO	T		Capital Co	\ct		Million \$			perating (`nete		/M \$/yearM			Economic	parameters		CI LIXLINIX					Results su	ımmanı				
	1404.6 2121.	2 MVV		Installed co			354.7	822.4		t 100% loa		T i	in viyean	iiii yiyeai		Discount ra	•		5.0		%			Emission a		net		95.270	\$/t (
Net power output		2 MVV		Contingend			10.0%	10.0%		uel	4 140001		132.9	100.3		Load factor			90.0	85.0	7.0						e' to calculati		W.E
CO2 output		6 t/h		Contingent	103		35.5	82.2		Maintenance			7.9	31.8		Fuel price			3.00	1.50							st that gives		21/1
Solid waste output		0 t/h		Owners co	nsts		7.0%	7.0%		hemicals +		iles	1.7	4.7		CO2 price	0 00		95.3	95.3				NPV	I IIIOOIOIT GIVOI	dance coo	it tildt gives	0.00	
CO2 emissions	373 130			OVVIICIS CC	,515		24.8	57.6		nsurance ar			7.1	23.5		Waste disp			0.0	184.5				IRR				5.00%	-
002 01113310113	313 130	g/KVVII		Retrofit es	ralation has	is vear	27.0	9		Vaste dispo		,3	0.0	2.7		Insurance a		29	2%		of installed	1 cost/v		II XI X				0.0070	
Reference plant data For	calculation of co	st of emissio					arly	0%		operating la			1.2	3.5		Number of			10	30	or motanec	a cooby							
CO2 emissions	373	g/kWh	Jir av oldanic		penditure es	-	urry	0.0%		por alling ia	boui		1.2	0.0		Cost per op			75.0	75.0	\$k/v								
	2.703	c/kWh	5	Total capi		, caiation	415.0	962.2	-	-						Administrat			56%		of operato	rs cost		Breakdow	n of c/kWh	cost			
2.00d long cool	2.100	GIRTIN		1000,000												Fuel storag			n		days	10 0001		Fuel				47.67%	
Retrofit year (n)	10			Working C	anital				г	ecommiss	ionina cos	+	0	n		Chemicals			30		days			Capital				35.28%	
Retrofit Expenditure year (n-2)	209			Chemicals	-		0.2	0.5			Torring 000	•	-			Start up tim			3		months			Other costs	2			17.05%	
Retrofit Expenditure year (n-1)	459			Fuel storag			0.0	9.7	10.							Retrofit dov	NAME OF TAXABLE PARTY.			1	months		6	Other cost	,			11.0070	
Retrofit Expenditure year (n)	359			Total work			0.2	10.2								Load factor		vear 1	90	60	%								
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%		85%	85%		85%	,
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	J
Expenditure Factor	09	6 40%	60%								20%	45%	35%																
Revenues																													
Electricity				125.4	167.2	167.2	167.2	167.2	167.2	167.2	167.2	167.2	153.3	80.0	151.2	101.2	151.2	151.2	151.2	151.2	151.2	151.2			151.2	151.2			
CO2 revenues(based on power output i	etrofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	129.7	
Operating Costs		J.																											
Fuel	0.						-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-45.2	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3		-85.3	-85.3			
Maintenance	0.						-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.3	-27.1		-27.1	-27.1	-27.1	-27.1	-27.1	-27.1			-27.1	-27.1			
Labour	0.						-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5			-3.5	-3.5	-3.5	-3.5	-3.5				-3.5			
Chemicals & consumables	0.						-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-2.1	-4.0			-4.0	-4.0	-4.0	-4.0	-4.0				-4.0			
Waste disposal	0.	0.0	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.2	-2.3			-2.3	-2.3	-2.3	-2.3	-2.3				-2.3			
Insurance and local taxes	0.		0.0				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-23.5	-23.5			-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5					
Fixed Capital Expenditures	0.					0.0	0.0	0.0	0.0	0.0	-192.4	-433.0	-336.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
	0.	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital Decommissioning Cost																													
	0.	0 -166.0	-249.0	20.8	30.7	30.7	30.7	30.7	30.7	30.7	-161.7	-402.3 -774.0	-309.3	48.7	135.2	135.2	135.2	135.2	135.2 -358.7	135.2 -223.5	135.2	135.2	135.2	135.2	135.2	135.2	135.2	135.2	F

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IEA GREENHOUSE GAS R&D F	PROGRAMI	ME								ost Evalu	ation - Disc	ount rate	5% CASE	3.2														Date	: July 200	J4
00:100011101																							8							+
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RE	FERENRETRO	OFIT						REFEREN	RETROFIT				F	REFEREN	RETROFIT				R	EFERENR	ETROFIT									+
Production					Capital Co	st		Million \$		0	perating (Costs	N	1M \$/yearN	IM \$/vear		Economic	parameter							Results su	ımmarv				
	1404.6 230	06.4 M	MVV		Installed co			354.7	1020.7		t 100% loa						Discount ra			5.0		%				voidance co	ist		123.88	1 \$/
Net power output		74.6 M			Contingend			10.0%	10.0%		uel			132.9	109.1		Load factor			90.0	85.0	%						e' to calculat		
CO2 output		08.5 t/l			Contingent	,100		35.5	102.1		daintenance			7.9	36.2		Fuel price			3.00	1.50							st that gives		PV
Solid waste output		1.84 t/l			Owners co	ete		7.0%	7.0%		hemicals +		iles	1.7	5.3		CO2 price			123.9	123.9				NPV	I IIIOOIOIT GIVOI	adrice co	it that gives	0.00	
CO2 emissions			a/kWh		Ovviici 3 CO	313		24.8	71.4		nsurance ar			7.1	27.5		Waste disp			0.0	184.5				IRR				5.00%	
002 (11113310113	010	70 g/	gerce viii		Retrofit esc	alation has	is vear	27.0	9		Vaste dispo		,3	0.0	3.0			and local tax	29	2%		of installed	1 cost/v		IIXIX				0.007	1
Reference plant data For	calculation of o	cost of	f amicciar					ark	0%		operating la			1.2	4.7		Number of		0.3	10	4n	or matanet	a cosby							+
CO2 emissions	373		g/kWh		Retrofit Ex		-	carry	0.0%		perating la	boai		1.2			Cost per or	-	10	75.0	75.0	\$ LA₁							S	+
	2.703		c/kWh		Total capit		scalation	415.0									Administrat			56%		of operato	re coet		Breakdow	n of c/kWh	cost			+
Electricity COSt	2.100		SULANI		i otai capi	iai CVSL		4 10.0	1134.2								Fuel storac			JU 70		days	is CUSL		Fuel	II OI GARVIII	vval		45.32%	1
Retrofit year (n)		10	_		Working C	anital				-	ecommiss	ionina cos		n	n		Chemicals			30		days			Capital				37.139	
		20%	-					0.2	0.5	L	/ecommiss	ioning cos		U	U					30		months							17.55%	-
Retrofit Expenditure year (n-2)		45%			Chemicals	_		0.2	10.5	0	9				0		Start up tim			3	3	months			Other cost:	S			17.00%	9
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)		45% 35%	-		Fuel storag			0.0									Retrofit dov	vvri urrie r, remainder		90	60	months						-		+
																														1
CASH FLOW ANALYSIS																														-
Million \$	2005	5 2	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000)	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor	500				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	6
Equivalent yearly hours					5913		7884	7884	7884	7884	7884	7884	7884	7227	3942	7446			7446	7446	7446	7446	7446			7446	7446			-
Expenditure Factor		Π%	40%	60%		1004	1001	1004	1004	1001	1004	20%	45%	35%	0072	1770	, 1770	1770	1440	1440	1770	1770	1770	1770	1 1 1 1 0	1770	1770	1440	1770	1
Revenues		0.70	4070	0070								2070	4370	3370																+
Electricity			-		125.4	167.2	167.2	167.2	167.2	167.2	167.2	167.2	167.2	153.3	82.5	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	155.9	0
CO2 revenues(based on power output	rotrofit acca)				120.4	107.2	107.2	107.2	107.2	0.0	0.0	107.2	107.2	100.0	88.2	166.6			166.6	166.6	166.6	166.6	166.6			166.6	166.6			
Operating Costs	renonicase)	-			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	00.2	100.0	0.000	0.001	100.0	100.0	0.001	0.001	100.0	100.0	0.001	0.001	0.001	0.001	100.0	4
Fuel Costs		0.0	0.0	nn	-89.7	-119.6	-119.6	-119.6	-119 6	-119.6	-119.6	-119.6	-119.6	-109.6	-49 1	-92.7	7 -92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.	7
Maintenance		0.0	0.0	0.0				-7.1	-7.1	-7.1	-119.6	-7.1	-7.1	-109.6	-49.1	-92.7			-92.7	-92.7	-92.7	-92.7	-92.7	-92.7		-92.7	-92.7		-92.	-
manucuature		0.0	0.0	0.0				-1.1	-1.1	-1.2	-1.1	-1.1	-1.1	-0.5	-10.3	-30.7			-30.7	-30.7	-30.7	-30.7	-30.7			-30.7	-30.7		-30.	-
		0.0	0.0	0.0					-1.6		-1.2	-1.2	-1.2	-1.2	-4.7	-4. <i>1</i>			-4.7	-4.1 -4.5	-4.7	-4.1 -4.5	-4.1 -4.5				-4. <i>1</i>		500000	
Labour		0.0	0.0	0.0			-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.4	-2.4	-4.5 -2.5			-4.5	-4.5 -2.5	-4.5 -2.5	-4.5 -2.5	-4.5 -2.5				-4.5 -2.5			_
Labour Chemicals & consumables		0.0	0.0					-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-1.3	-2.5 -27.5			-2.5	-2.5 -27.5	-2.5 -27.5	-2.5	-2.5 -27.5				-2.5 -27.5			
Labour Chemicals & consumables Waste disposal		0.0	0.0			-(.]	-1.1	-1.1	-1.1	-7.1	-1.1			-7.1 -418.0	-27.5	-27.5			-21.5	-27.5 0.0										-
Labour Chemicals & consumables Waste disposal Insurance and local taxes		0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	220.0			11 111	U.U	0.0	U.U	U.U	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	J
Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0			0.0	0.0	0.0	0.0	-238.8	-537.4			0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	
Labour Chemicals & consumables Waste disposal Insurance and local taxes		0.0			0.0			0.0	0.0	0.0	0.0	-238.8 0.0	-537.4	0.0	-11.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital		0.0	-166.0	-249.0	-0.2	0.0										159.8 -1097.1	3 159.8		159.8	159.8	159.8	159.8	159.8			159.8	0.0 159.8			

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IEA GREENHOUSE GAS R&D PR	OGRAMM	<u> </u>							ost Evalu	ation - Ret	rofit year -	5 year CA	SE 1														Date :	: July 2004	į
30 jul 2004 11:04																													
REFE	RENRETROF	IT		0			REFEREN	RETROFIT					REFEREN	RETROFIT				P	EFERENR	ETROFIT									
Production	REINETHOT			Capital Co	set		Million \$			Operating (Costs		/M \$/yearN			Economic	narameters		LI LIXLINIA					Results su	mmanı				
	04.6 1404.6	MVV		Installed co	2.000.00		354.7	337.7		t 100% loa			iliti wrye ai it	iiii wryeai		Discount rat			10.0		%				oidance cos	·+		69.016 \$	\$/t (
		MVV		Contingend			10.0%	10.0%		uel	u lactoi		132.9	132.9		Load factor	ic.		90.0	90.0	/-			(Note: Type			'to calculat		WIL C
) t/h		Contingent	LICS		35.5	33.8		/aintenance			7.9	15.4		Fuel price			3.00	3.00				the CO2 en					471
		t/h		Owners co	nete		7.0%	7.0%			consumal	nlec	1.7	2.4		CO2 price			69.0	69.0				NPV	nooion avoic	arice coo	. trial gives i	0.00	
		g/kWh		OWNIERS CO	3313		24.8	23.6			nd local tax		7.1	13.8		Waste dispo	neal cost		0.0	307.5				IRR				10.00%	
002 01113310113	.10 01	gritterii		Petrofit es	calation basis	e vear	27.0	5		Vaste dispo			0.0	0.1		Insurance a		00	2%		of installed	Lonetily		II XI X				10.0070	
Reference plant data For ca	alculation of cos	t of emissic					arly	0%		Operating la			1.2	1.8		Number of o		6.3	10	15	Of Illistance	COSDY							
	373	a/kWh			penditure esi penditure esi	-	arry	0.0%		zperaurig ia	boui		1.2	1.0		Cost per op			75.0	75.0	\$ ₽A₁		<u> </u>						
	997	c/kWh	+	Total capi		Caration	415.0	395.1								Administrati			56%		of operato	rs cost		Breakdow	of c/kWh c	ost			
_icotriony cost 2.3	701	CAMPAIL		i otai capi	tai CUSL		4 10.0	U3U. I								Fuel storage			00% N		days	15 CUSL		Fuel	O CONTROL	Val		53.12%	
Retrofit year (n)	E			Working C	`anital				-)ecommics	ioning cos		n	n		Chemicals			30		days			Capital			-	35.25%	
Retrofit Expenditure year (n-2)	0%			Chemicals			0.2	0.2		/ecommiss	norning cos			U		Start up timi		-	30		months			Other costs				11.63%	
Retrofit Expenditure year (n-1)	40%		_	Fuel storac			0.2	0.2	10.	- 4				- 6		Retrofit dow			Э	1	months		6	Other costs			-	11.0370	
Retrofit Expenditure year (n)	60%	-			king capital	-	0.2									Load factor,		voor 1	90	90	0/.						+		
CASH FLOW ANALYSIS																													
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Equivalent yearly hours		100	7	5913		7884	7884	7227	5913	7884	7884	7884	7884	7884	7884		7884	7884	7884	7884	7884	7884	7884		7884	7884	7884		
Expenditure Factor	Π%	40%	60%			0%	40%	60%		177.1	1.75.1		177	1.77.11	1.7.7.4	1			1771				1.7.7.1						
Revenues	- 0,0					370	1070	5576																					
Electricity	-			139.1	185.5	185.5	185.5	170.0	110.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	147.9	
CO2 revenues(based on power output ret	rofit case)			133.1		00.0	00.0	0.0	78.2	104.3	104.3	104.3	104.3	104.3	104.3	111.0	104.3	104.3	104.3	104.3	104.3	104.3		1.1.1.	104.3	104.3	104.3		
Operating Costs	5 0400,			0.0	0.0	0.0	0.0	0.0	10.2	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	10 1.0	101.0	107.0	101.0	101.0	101.0	101.0	
Fuel	0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-109.6	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	
Maintenance	0.0					-7.1	-7.1	-6.5	-10.4	-113.8	-113.8	-113.8	-113.8	-113.8	-113.8		-113.8	-113.8	-113.8	-113.8	-113.8	-113.8	-113.8		-13.8	-113.8	-113.8		
Labour	0.0	0.0				-1.2	-1.2	-1.2	-1.8	-13.8	-13.8	-13.8	-1.8	-13.8	-13.8		-13.8	-1.8	-13.8	-13.8	-13.8	-13.8			-13.8	-13.8	-1.8		
Chemicals & consumables	0.0	0.0				-1.5	-1.5	-1.4	-1.6	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1		-2.1	-2.1	-2.1	-2.1	-2.1	-2.1			-2.1	-2.1	-2.1		
Waste disposal	0.0					-1.3	0.0	-1.4	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1			-0.1	-0.1	-0.1	-0.1	
Insurance and local taxes	0.0	0.0	0.0		0.0	-7.1	-7.1	-7.1	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8		-13.8	-13.8	-13.8	-13.8	-13.8	-13.8			-13.8	-13.8	-13.8		
	0.0		0.0	200 100 1		-7.1	-158.0	-237.0	-13.0	-13.0	-13.6	-13.0	-13.0	-13.0	- 10.0 n n	10.0	- 10.0 n n	10.0	-13.0	-13.6	-13.0	-13.0	-13.0 n n	10.0	-13.0	-13.0	-13.0		
					- 1-	0.0	0.0	-237.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- 1-	
Fixed Capital Expenditures	0.0			-0.2	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Fixed Capital Expenditures Working Capital Decommissioning Cost	0.0	0.0																											-
Fixed Capital Expenditures Working Capital	0.0			34.5	49.0	49.0	-109.0	-192.8	71.6	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	100.9	

IEA GREENHOUSE GAS F	R&D PROGE	RAMME							C	ost Evalu	ation - Ret	rofit year -	5 year CA	SE 2.1				,										Date :	: July 2004	4
30 jul 2004 11:04																														-
	DEFENEL I	DETROE!	_					DEFEDEN I	ETROFIT					DEFEDEN I	DETROE!	-			_		ETRACIT									
Production	REFEREN	KETKUFI	1		Capital Co	-4		REFERENE Million \$			O	0 4 -		REFEREN F MM \$/yearN			F			REFEREN	KETKUFII				D l4			-		-
Fuel feedrate	1404.6	1672.4	1000						486.4		Operating		-	viivi əzyeariy	ılıvı əzyear		And the second second	parameter	5	10.0		%			Results su				89.531	A4.
			MVV		Installed co			354.7			at 100% loa	a ractor		100.0	158.2		Discount r				00.0	70			Emission a			-11		₽\L
Net power output	784.8 293.0				Contingend	ies		10.0% 35.5	10.0%		Fuel Maintenance			132.9 7.9	158.2		Load facto Fuel price			90.0	90.0	% \$/GJ						e' to calculat		21.72
CO2 output	0.00	50.1	t/h		0			7.0%	48.6 7.0%		viaintenance Chemicals :		blas	1.7	18.7		CO2 price			3.00 89.5	89.5				ine CO2 en NPV	nission avc	idance cos	st that gives	a zero NF 0.00	
Solid waste output	373		g/kWh		Owners co	SIS		24.8	34.0		nsurance a			7.1	16.8			and and		0.0	307.5				IRR				10.00%	
CO2 emissions	3/3	12	g/kvvn		Retrofit esc	alatian ban	inunas	24.8	34.U 5				es	0.0	0.0		Waste disp			2%			t/-		IRR				10.00%	
Reference plant data	For calculate	ion of oos	f of omicois					out :	0%		Maste dispo Operating la			1.2	2.3		Number of	and local tax	(es	10	2%	of installed	costry							-
		ion or cost						arry			Operating ia	ibour		1.2	2.3			-				Ф1.4.								-
CO2 emissions	373 2.997		g/kWh		Retrofit Exp		calation	415.0	0.0% 569.1								Cost per o			75.0 56%	75.0				Breakdowi	- F - 11-12-11-				
Electricity cost	2.997		c/kWh		Total capi	ai COST		410.0	269.1								Administra			56% N		of operator	S COST			I OT CIKWIN	COST		51.16%	
Potrofit year (n)		5			Marking C	anital					Docommics	lanina coo			0		Fuel storag			30		days days			Fuel				35.49%	
Retrofit year (n)		5 0%			Working C	-		0.0	1.0		Decommiss	sioning cos	5 L	U	U		Chemicals	-	100	30		months			Capital				13.35%	
Retrofit Expenditure year (n-2)		40%			Chemicals			0.2	0.0			- 4					Start up tin		3 0	3	3				Other costs				13.35%	-
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)		40% 60%			Fuel storag			0.0	1.0								Retrofit do	vn ume r, remainder		90	90	months								-
rections Experiatore year (ii)		0070	_		Total work	ing capital		V.Z	1.0								Load racto	, remainaci	year r	30	30	70								
CASH FLOW ANALYSIS																														
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor					68%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Equivalent yearly hours					5913	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expenditure Factor		0%	40%	60%			0%	40%	60%																					
Revenues																														
Electricity					139.1	185.5	185.5	185.5	170.0	122.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	1
CO2 revenues(based on power	output retrofit c	ase)			0.0	0.0	0.0	0.0	0.0	110.6	147.4	147.4	147.4	147.4	147.4	147.4		147.4	147.4	147.4	147.4	147.4	147.4		147.4	147.4	147.4		147.4	
Operating Costs																														
Fuel		0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-109.6	-106.8	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	
Maintenance		0.0		0.0			-7.1	-7.1	-6.5	-12.6	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8			-16.8	-16.8	-16.8	-16.8	-16.8		-16.8	-16.8	-16.8		-16.8	
Labour		0.0					-1.2	-1.2	-1.2	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3			-2.3	-2.3	-2.3	-2.3	-2.3		-2.3	-2.3	-2.3		-2.3	
Chemicals & consumables		0.0	0.0	0.0	-1.1	-1.5	-1.5	-1.5	-1.4	-7.5	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0	-10.0		-10.0	-10.0	-10.0	-10.0	-10.0	
Waste disposal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes		0.0	0.0	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Fixed Capital Expenditures		0.0	-166.0	-249.0	0.0	0.0	0.0	-227.6	-341.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital		0.0		0.0	-0.2	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Decommissioning Cost		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,													,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,						,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,		3,637.							
Total Cash Flow (vearly)		0.0	-166.0	-249.0		49.0	49.0	-178.6	-297.2	86.4	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	+
Total Cash Flow (cumulated)		0.0	-166.0	-415.0	-380.5	-331.5	-282.5	-461.1	-758.3	-671.9	-549.0	-426.0	-303.0	-180.1	-57.1	65.8	188.8	311.8	434.7	557.7	680.6	803.6	926.6	1049.5	1172.5	1295.5	1418.4	1541.4	1664.3	

				_																				-		-	Version	4.5	
IEA GREENHOUSE GAS R&D PRO)GRAMMF	Ξ						C	ost Evalua	tion - Retr	ofit year -	5 year CAS	SE 2.2														Date	: July 200	04
																													_
30 jul 2004 11:04																											_		_
REFER	RENRETROF	IT		+		F	EFEREN	RETROFIT		[2]		F	EFERENR	ETROFIT				R	EFERENR	ETROFIT			23						
Production		<u> </u>	_	Capital Co	st		Million \$		0	perating C	osts		M \$/yearM			Economic :	arameters							Results su	ummanı		+		-
Fuel feedrate 140	4.6 1671.0	0 MVV		Installed co			354.7	641.2		100% load			in viyeain	in try cui		Discount rat			10.0		%			Emission a		enst	+	116.761	31 \$/
		4 MVV	_	Contingend			10.0%	10.0%		uel	u luctoi		132.9	158.1		Load factor			90.0	90.0				(Note: Type			ve' to calcui		1 4
		9 t/h	+	Contingent	lica		35.5	64.1		aintenance			7.9	22.1		Fuel price			3.00	3.00							ost that give		IDV
		1 t/h	-	Owners co	ete		7.0%	7.0%			consumab	loc	1.7	10.7		CO2 price	-		116.8	116.8				NPV	mosion ave	Jiuanice co	JSI Irrai give	0.00	
	73 75		_	OWITEIS CO	1515		24.8	44.9			nd local taxe		7.1	19.9		Waste dispo	eal cost		0.0	307.5				IRR		-	+	10.00%	_
COZ EITIISSIOTIS 3	.3 10	y/KVVII	-	Retrofit esc	colotion boo	o voor	24.0	5		/aste dispo		:5	0.0	0.0		insurance a		00	2%		of installed	Loooth		IIXIX			-	10.007	/0
Reference plant data For call	culation of cos	of of oppion	nion avaidan				els a	0%		perating lat			1.2	3.5		Number of c		25	10	30	UI IIIStallet	COSDY		-		-	+		+
				-		-	Пу	0.0%	- 0	peraury rai	Juui		1.2	3.0					75.0		Φ1.6 ·		er e						+
	73	g/kWh	_	Retrofit Exp		caration	445.0	750.3								Cost per op			75.U 56%	75.0		re eact		Breakdow	m of all Will		+	-	+
Electricity cost 2.9	31	c/kWh	1 10	Total capit	tai COST		415.0	/50.3								Administrati			20%		of operato	IS COSE			n ot c/kWh	COST	-	47.88%	0/
D-161 (-)	-	-		W. dita	!4 . 1				-				п			Fuel storage			20		days			Fuel			-		
Retrofit year (n)	5	-	-	Working C					υ	ecommiss	ioning cos	t	U	0		Chemicals :			30		days			Capital		-	-	38.09%	
Retrofit Expenditure year (n-2)	0%		-	Chemicals			0.2	1.0								Start up timi			3	3	months		10	Other costs	ŝ	-		14.03%	%
Retrofit Expenditure year (n-1)	40%	-		Fuel storag			0.0	0.0								Retrofit dow				1	months					-			4
Retrofit Expenditure year (n)	60%	6 -		Total work	king capital		0.2	1.0		0	5		-			Load factor,	remainder	year 1	90	90	%							S	
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	\exists
'ear	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	1
Load Factor		-	-	68%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	% 90%	6 90%	%
																								7004				_	14
Equivalent yearly hours				5913	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	4 7884	1 7884	74
	0%	6 409	% 60%		7884	7884 0%	7884 40%	7227 60%	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	/884	7884	7884	4 /88	1 788	54
Equivalent yearly hours Expenditure Factor Revenues	0%	5 409	% 60%		7884				5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	1 /884	7884	788-	4 /88	788	54
Expenditure Factor Revenues	0%	6 40%	% 60%	6		0%	40%		5913 118.3					7884 157.7	7884 157.7							7884 157 7							
Expenditure Factor Revenues Electricity		6 409	% 60%		7884 185.5			60%		7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4			7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4	7884 157.7 183.4		157.7	7 157.7	157.7	157.7	7 157.7	7 157.3	.7
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retr		6 409	% 60%	6		0%	40%	60%	118.3	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7	7 157.7	157.7	157.7	7 157.7	7 157.3	.7
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retri			,, ,	139.1	185.5	0% 185.5 0.0	40% 185.5 0.0	170.0 0.0	118.3 137.6	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	157.7 183.4	7 157.7 1 183.4	157.7 183.4	157.7 183.4	7 157.7 4 183.4	7 157.1 1 183.4	1.7
Expenditure Factor Revenues Electricity Co2 revenues(based on power output retro Operating Costs Fuel	ofit case)	0 0.1	.0 0.0	6 139.1 0.0 0 -89.7	185.5 0.0 -119.6	0% 185.5 0.0 -119.6	40% 185.5 0.0 -119.6	170.0 0.0 -109.6	118.3 137.6	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	157.7 183.4 -142.3	7 157.7 4 183.4 3 -142.3	157.7 183.4 -142.3	157.7 183.4 1 -142.3	7 157.7 4 183.4 3 -142.3	7 157.5 4 183.4 3 -142.3	1.7
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance	ofit case)	0 0.1	.0 0.0 0.0 0.0	6 139.1 0.0 -89.7 0 -5.3	185.5 0.0 -119.6 -7.1	0% 185.5 0.0 -119.6 -7.1	40% 185.5 0.0 -119.6 -7.1	170.0 0.0 -109.6 -6.5	118.3 137.6 -106.7 -14.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3 -19.9	7 157.7 4 183.4 3 -142.3 3 -19.9	157.7 183.4 -142.3 -19.9	157.7 183.4 -142.3	7 157.7 4 183.4 3 -142.3 9 -19.9	7 157.3 1 183.4 3 -142.3 3 -19.8	1.7 1.4 1.3
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrict) Operating Costs Fuel Maintenance Labour	ofit case)	0 0.1 0 0.1 0 0.1	.0 0.0 0.0 0.0	6 139.1 0.0 -89.7 0 -5.3 0 -1.2	185.5 0.0 -119.6 -7.1 -1.2	0% 185.5 0.0 -119.6 -7.1 -1.2	40% 185.5 0.0 -119.6 -7.1 -1.2	170.0 0.0 -109.6 -6.5 -1.2	118.3 137.6 -106.7 -14.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	7 157.7 4 183.4 3 -142.3 3 -19.9 5 -3.5	157.7 183.4 -142.3 -19.9 -3.5	157.7 183.4 -142.3 -19.9 -3.5	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5	7 157.3 4 183.4 3 -142.3 3 -19.9 5 -3.6	1.7 1.4 1.3 1.9
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables	ofit case)	0 0.1 0 0.0 0 0.1 0 0.1	.0 0.0 0.0 0.0 0.0 0.0	6 139.1 0.0 -89.7 0 -5.3 0 -1.2 0 -1.1	185.5 0.0 -119.6 -7.1 -1.2 -1.5	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4	118.3 137.6 -106.7 -14.9 -3.5 -7.2	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -18.9 -3.5 -9.7	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5 7 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5 7 -9.7	7 157.7 183.4 1 183.4 3 -142.3 3 -19.9 5 -3.6 7 -9.7	1.7 1.4 1.9 1.5
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	ofit case) 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	.0 0.0 .0 0.0 .0 0.0 .0 0.0	6 139.1 0.0 0.0 0.0 -89.7 0.0 -5.3 0.0 -1.2 0.0 0.0 0.0	185.5 0.0 -119.6 -7.1 -1.2 -1.5	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	-109.6 -6.5 -1.2 -1.4	118.3 137.6 -106.7 -14.9 -3.5 -7.2 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5 7 -9.7 0 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.6 7 -9.7 0 0.0	7 157.7 183.4 183.4 183.6 19.9 19.9 19.9 19.0 19.0 19.0 19.0 19.0	1.7 1.4 1.9 1.5 1.7
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retriction Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	ofit case) 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	6 139.1 0.0 0 -89.7 0 -5.3 0 -1.2 0 0.0 0 0.0 0 0.0 0 0.0 0 0 -7.1	185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1	118.3 137.6 -106.7 -14.9 -3.5 -7.2 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	7 157.7 4 183.4 3 -142.3 3 -19.9 5 -3.5 7 -9.7 0 0.0 9 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.6 7 -9.7 0 0.0	7 157.7 4 183.4 3 -142.3 9 -19.8 5 -3.6 7 -9.7 0 0.0	1.7 1.4 1.9 1.5 1.7 1.0
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	ofit case) 0.0 0.0 0.0 0.0 0.0	0 0,1 0 0,1 0 0,1 0 0,1 0 0,1 0 0,1	.0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0	6 139.1 0.0 0 -99.7 0 -5.3 0 -1.2 0 0.0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0 0.0 0.	185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 -300.1	60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1 -450.2	118.3 137.6 -106.7 -14.9 -3.5 -7.2 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5 7 -9.7 0 0.0 9 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	7 157.7 4 183.4 3 -142.3 9 -19.8 5 -3.6 7 -9.7 0 0.0 9 -19.8	7 157.7 4 183.4 3 -142.3 5 -3.6 7 -9.7 0 0.0 8 -19.8	1.7 1.4 1.9 1.5 1.7 1.0
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retrict) Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	ofit case) 0.0 0.0 0.0 0.0 0.0	0 0,1 0 0,1 0 0,1 0 0,1 0 0,1 0 0,1	.0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0	6 139.1 0.0 0.0 -89.7 0 -5.3 0 -1.2 0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1	118.3 137.6 -106.7 -14.9 -3.5 -7.2 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.5 7 -9.7 0 0.0 9 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0	7 157.7 4 183.4 3 -142.3 9 -19.8 5 -3.6 7 -9.7 0 0.0 9 -19.8	7 157.7 4 183.4 3 -142.3 3 -19.8 5 -3.6 7 -9.7 0 0.0 3 -19.8	1.7 1.4 1.9 1.5 1.7 1.0
Expenditure Factor Revenues Electricity CO2 revenues(based on power output retnoperating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	ofit case) 0.0 0.0 0.0 0.0 0.0	0 0.1 0 0.1 0 0.1 0 0.1 0 0.1 0 -186.1	.0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0 .0 0.0	6 139.1 0.0 0 -89.7 0 -5.3 0 -1.2 0 0.0 0 -7.1 0 0.0 0 -7.1 0 0.0 0 -0.2	185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 -300.1	60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1 -450.2	118.3 137.6 -106.7 -14.9 -3.5 -7.2 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9	7 157.7 4 183.4 3 -142.3 3 -19.9 5 -3.5 7 -9.7 0 0.0 3 -19.9 0 0.0	157.7 183.4 -142.3 -19.9 -3.5 -9.7 0.0 -19.9 0.0	157.7 183.4 -142.3 -18.8 -3.5 -9.7 0.0 -19.9 0.0	7 157.7 4 183.4 3 -142.3 9 -19.9 5 -3.6 7 -9.7 0 0.0 9 -19.9 0 0.0	7 157.7 4 183.4 3 -142.3 3 -19.9 5 -3.6 7 -9.0 0 0.0 0 0.0	1.7 1.4 1.9 1.5 1.7 1.0 1.9

																											Version •	4.5	
IEA GREENHOUSE GAS R&D	PROGRAMIV	E						C	ost Evalu	ation - Ret	rofit year -	5 year CA	SE 3.1														Date	: July 2004	4
30 jul 2004 11:04																													
Di	FERENRETRO	:IT	19	9			DEFEDEN	RETROFIT			8		REFEREN	PETPOFIT					REFERENR	ETPOFIT				8					
Production	I EKENKE I KO	11		Capital Co	ct		Million \$			perating (Coete		/M \$/yearN			Economic	parameters		LILKLIK	LIKOIII				Results su	ımmanı				-
Fuel feedrate	1404.6 2121	2 MVV		Installed co			354.7	822.4		t 100% loa			riivi wryeai i	nivi vryeai		Discount ra		10	10.0		%				voidance co	net		118.922	\$/t C
Net power output		2 MVV		Contingend			10.0%	10.0%		uel	u ractor		132.9	100.3		Load factor			90.0	85.0	7.0						e' to calculat		Ψ/Ε
CO2 output		6 t/h		Contingent	lics		35.5	82.2		dei Maintenance			7.9	31.8		Fuel price			3.00	1.50							st that gives		21/1
Solid waste output		0 t/h		Owners co	ete		7.0%	7.0%			+ consumat	les	1.7	4.6		CO2 price			118.9	118.9				NPV	rnooiori avoi	dance coa	n trial gives	0.00	
CO2 emissions	373 13			OVVIICIS CC	1313		24.8	57.6			nd local tax		7.1	23.5		Waste disp			0.0	184.5				IRR				10.00%	_
002 (11113310113	313 13	gritter		Retrofit es	calation basi	is vear	24.0	4		Vaste dispo		,3	0.0	2.7		Insurance a		29	2%		of installed	l cost/v		IIXIX				10.0070	
Reference plant data Fo	r calculation of co	st of emissi					arly	0%		operating la			1.2	3.5		Number of			10	30	or motanec	, coopy							+
CO2 emissions	373	g/kWh	On avoidance		penditure es penditure es		arry	0.0%		perating ia	ibodi		1.2	0.0		Cost per or			75.0	75.0	\$1/W								+
Electricity cost	2.997	c/kVVh		Total capi		Calation	415.0	962.2								Administrat			56%		of operato	rs cost		Breakdow	n of c/kWh	cost			+
Electricity cost	2.001	CART THE		i otai oapi	tai oost		410.0	JOZ.E								Fuel storag			n		days	13 0031		Fuel	II OI GIRIIII	3030		36.78%	
Retrofit year (n)				Working C	anital				г)acommics	sionina cos		0	n		Chemicals			30		days			Capital				47.10%	
Retrofit Expenditure year (n-2)	20			Chemicals			0.2	0.4		/ecommis	nonning cos	•	- 0	- 0		Start up tim	9		3		months			Other cost				16.12%	
Retrofit Expenditure year (n-1)	45			Fuel storag			0.0	9.7	-							Retrofit dov				1	months			Other cost				10.1270	
Retrofit Expenditure year (n)	35			Total work			0.2									Load factor		vear 1	90	60	%								+
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	3
Equivalent yearly hours				5913	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	744E	7446	7446	7446	7446	7446	j
Expenditure Factor	0	6 40%	60%			20%	45%	35%																					
Revenues		6																											
Electricity				139.1	185.5	185.5	185.5	170.0	88.8	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	1
CO2 revenues(based on power outpu	t retrofit case)			0.0	0.0	0.0	0.0	0.0	85.7	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	161.9	j
Operating Costs																													
Fuel	0	0.0	0.0		-119.6	-119.6	-119.6	-109.6	-45.2	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3		-85.3	-85.3	-85.3	-85.3	-85.3	-85.3			-85.3	-85.3			
Maintenance	0	0.0	0.0			-7.1	-7.1	-6.5	-14.3	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1		-27.1	-27.1	-27.1	-27.1	-27.1	-27.1			-27.1	-27.1			
Labour	0	0.0				-1.2	-1.2	-1.2	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5			-3.5	-3.5	-3.5	-3.5	-3.5				-3.5			
Chemicals & consumables	0					-1.5	-1.5	-1.4	-2.1	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9			-3.9	-3.9	-3.9	-3.9	-3.9				-3.9			
	0		0.0			0.0	0.0	0.0	-1.2	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3			-2.3	-2.3	-2.3	-2.3	-2.3				-2.3			
Waste disposal	0	0.0	0.0				-7.1	-7.1	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5	-23.5		-23.5			_
Waste disposal Insurance and local taxes			-249.0	0.0	0.0	-192.4	-433.0	-336.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Waste disposal Insurance and local taxes Fixed Capital Expenditures	0								-10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	J
Waste disposal			0.0	-0.2	0.0	0.0	0.0	0.0	-10.1	0.0	0.0	0.0																	
Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0		0.0				-384.0	-292.5	74.5	183.9	183.9	183.9 -525.2	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	183.9	

																											Version •	4.5	
IEA GREENHOUSE GAS R&D	PROGRAMI	ME							Cost Evalu	iation - Rei	trofit year -	5 year CA	SE 3.2														Date	: July 2004	4
30 jul 2004 11:04																													+
	REFERENRETRO)FIT					DEFEDI	NRETROFI	т				REFEREN	PETROFIT					REFERENR	ETDOFIT	-								
Production	XEI EIXEIIXE I IX	J111		Canit	tal Cost			Million \$		Operating	Costs		MM \$/yearN			Economic	parameter		LI LIXLIN	LIKOIII				Results su	ımmanı				+
Fuel feedrate	1404.6 230	6.4 MW	,		led costs		354			at 100% loa			illii yryearii	iiii wiyeai		Discount ra			10.0		%				voidance co	net		152.577	7 \$4
Net power output		4.6 MVV			naencies		10.0			Fuel	a ractor		132.9	109.1		Load factor			90.0	85.0	7.0						e' to calculat		Ψ
CO2 output		18.5 t/h	_	Conti	ngencies		35			Maintenanc			7.9	36.2		Fuel price			3.00	1.50							st that gives		Dν
Solid waste output		.84 t/h		Overne	ers costs		7.0				t consumat	loc	1.7	5.2		CO2 price			152.6	152.6				NPV	rnooiorr av oi	uance coa	n mai gives	0.00	
CO2 emissions		40 a/k\	Δ/h	OWITE	SIS CUSIS		24				nd local tax		7.1	27.5		Waste disp			0.0	184.5				IRR				10.00%	_
CO2 ettiissions	3/3 1	40 g/Ki	VVII	Petro	fit escalat	ion basis ve		4		Waste disp		3	0.0	3.0		100	and local tax	000	2%		of installed	d coetá,		IIXIX	9			10.0070	1
Reference plant data	or calculation of	onet of an	niccion a					0%		ovaste uisp Operating la			1.2	4.7		Number of		.55	10	270 4N	UI IIISLAIIEL	u cosuy							+
	373					liture escala		0.0%		Operating is	about		1.2	4.1			-		75.0	75.0	ΦLA		3						+
CO2 emissions Electricity cost	2.997	g/k\ c/k\			ini Expend I capital c		415			-						Cost per op Administrat			75.U 56%		of operato	re coet		Breakdow	n of c/kWh	cost			+
LIGORIUM COST	2.001	C/K\	A AUT	ı ota	Capital C	Vat	410	0 1194.2								Fuel storag			0070		days	ii S CUSE		Fuel	II OI CAKYVII	COSL		34.74%	
Retrofit year (n)		5 -	. 8	Manual and a selection of the selection	ing Capit	-al			S .	Dogomeio	sionina cos		п	n		Chemicals	_		30		days			Capital				34.74% 48.76%	
	-	-						0.5		Decommis	sioning cos	L	- 0	U					30	-				0.000					
Retrofit Expenditure year (n-2)		0% - 5% -		222	nicals stor	age	0									Start up tim		- 0	3	J	months			Other cost	S			16.51%)
Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)		5% - 5% -			storage I working			0 10.5 2 11.1								Retrofit dov	wn time r, remainder	4	90	60	months								+
																													+
CASH FLOW ANALYSIS	2005	200		2007 200	20	009 20	10 2011	2042	2013	2044	2045	2016	2017	2018	2019	2020	2024	2022	2022	2024	2025	2022	2027	2020	2020	2020	2024	2002	_
Million \$	2005	200	J6 2	2007 200	J8 2U	JU9 2U	10 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	0 1		2 3	3 4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	ļ
Load Factor					68%	90%	90% 90	6 83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	6
Equivalent yearly hours					5913	7884	7884 788	4 7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	744E	7446	7446	7446	7446	7446	ز
Expenditure Factor		0%	40%	60%			20% 45	6 35%																					Τ
Revenues																			1										
Electricity					139.1	185.5	185.5 185	5 170.0	91.5	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	3
CO2 revenues(based on power outp	out retrofit case)				0.0	0.0	0.0 0	0.0	108.6	205.2	205.2	205.2	205.2	205.2	205.2			205.2	205.2	205.2	205.2	205.2			205.2	205.2			
Operating Costs																													T
Fuel		0.0	0.0	0.0	-89.7	-119.6 -	119.6 -119	6 -109.6	-49.1	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	1
Maintenance		0.0	0.0	0.0	-5.3	-7.1	-7.1 -7		-16.3	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7			-30.7	-30.7	-30.7	-30.7	-30.7	-30.7		-30.7	-30.7		-30.7	
Labour		0.0	0.0	0.0	-1.2	-1.2	-1.2 -1			-4.7	-4.7	-4.7	-4.7	-4.7	-4.7			-4.7	-4.7	-4.7	-4.7	-4.7			-4.7	-4.7			
Chemicals & consumables		0.0	0.0	0.0	-1.1	-1.5	-1.5 -1	5 -1.4	-2.3	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	4
Waste disposal		0.0	0.0	0.0	0.0	0.0	0.0 0	0.0	-1.3	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	5
Insurance and local taxes		0.0	0.0	0.0	-7.1	-7.1	-7.1 -7	1 -7.1	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5	-27.5			-27.5	-27.5	-27.5	-27.5	-27.5				-27.5	-27.5		
		0.0 -1	166.0	-249.0	0.0		238.8 -537			0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-
Fixed Capital Expenditures			0.0	0.0	-0.2	0.0	0.0 0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		-
Fixed Capital Expenditures						0.0	0.0	0.0	555,434,44	0.0	0.0	0.0	0.0	0.0			0.0			0.0				0.0			0.0		+
		0.0																									-		+
Fixed Capital Expenditures Working Capital		0.0 -1	166.0 166.0		34.5 380.5		189.8 -488 521.3 -1009		87.9 -1295.6	215.5 -1080.1	215.5 -864.6	215.5 -649.1	215.5 -433.6	215.5 -218.2	215.5 -2.7			215.5 643.7	215.5 859.2	215.5 1074.7	215.5 1290.2	215.5 1505.6							_

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IEA GREENHOUSE GAS R&D P	ROGRAMI	ΛE							Cost Evalu	ation - Ret	ofit year +	5 year CA	ASE 1														Date	: July 2004	1
30 jul 2004 11:04																													
REF	ERENRETRO	FIT					REFEREN	RETROFIT					REFEREN	ETROFIT					REFERENR	FTROFIT									
Production	LIKE III			Capital C	ost		Million \$			perating (osts		/M \$/yearN			Economic	narameters		C. CICCIO					Results su	mmanı				
	404.6 140	4.6 MW		Installed of			354.7	337.7		t 100% loa			in viyean	iiii qiyedi		Discount ra	•		10.0		%			Emission a		et		82,770	\$/+ (
		5.9 MVV		Continger			10.0%	10.0%		uel	u luotoi		132.9	132.9		Load factor			90.0	90.0	/0			(Note: Type			e' to calcula		W.F
		1.9 t/h		Continger	icics		35.5	33.8		Maintenance			7.9	15.4		Fuel price			3.00	3.00				the CO2 en					21/1
Solid waste output		.04 t/h		Owners o	nsts	-	7.0%	7.0%		hemicals +	-	les	1.7	2.4		CO2 price	0 00		82.8	82.8				NPV	IIIOOIOII GEOI	Juliec Coo	indi giveo	0.00	
CO2 emissions		37 a/kV\	'h	Ovviici3 c	.03:3		24.8	23.6		nsurance ar			7.1	13.8		Waste disp			0.0	307.5				IRR				10.00%	-
002 01113310113	010	or gritti	110	Retrofit e	scalation bas	sis vear	27.0	15		Vaste dispo		,3	0.0	0.1		Insurance a		29	2%		of installed	l cost/v		II XI X	- 2			10.0070	
Reference plant data For a	alculation of a	nst of emi	ssion avoir	danc Retrofit E			arly	0%		operating la			1.2	1.8		Number of			10	15	Of Installed	, cooby							
CO2 emissions	373	g/kV\			xpenditure e	-	July	0.0%		por alling ia	oodi			1.0		Cost per op			75.0	75.0	\$k/v								
	.997	c/kV\		Total cap		oculation.	415.0	395.1	-	-						Administrati			56%		of operator	rs cost		Breakdow	n of c/kWh	cost			
2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2. 2		OHA!														Fuel storage	10000		n		days	.0 0001		Fuel				59.92%	
Retrofit year (n)		15 -		Working	Capital				г	ecommiss	ionina cos	+	п	0		Chemicals			30		days			Capital				30.27%	
Retrofit Expenditure year (n-2)		0% -		Chemical			0.2	0.2			ioning out	•		-		Start up tim			3		months			Other costs				9.81%	
Retrofit Expenditure year (n-1)		0% -		Fuel stora			0.0	0.0	10.		10					Retrofit dow	NAME OF TAXABLE PARTY.		-	1	months		6	Other costs				0.0170	
Retrofit Expenditure year (n)		3% -			rking capita	ı	0.2									Load factor		vear 1	90	90	%								
Million \$	2005	2006	200	7 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%		90%	100.000.00	90%	90%	90%	90%	90%	90%	90%	90%		90%	83%	68%	90%	90%	90%	90%	90%	90%	90%		90%	_
Equivalent yearly hours				5910	3 7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expenditure Factor		3% 4	0% 1	30%												0%	40%	60%											
Revenues																													
Electricity				139.1	1 185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	110.9	147.9	147.9	147.9	111.0	7. 7. 7. 7.	147.9	147.9			
CO2 revenues(based on power output r	etrofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.8	125.1	125.1	125.1	125.1	125.1	125.1	125.1	125.1	125.1	
Operating Costs					S.																								
Fuel		0.0	0.0	0.0 -89.			-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6		-119.6	-109.6	-89.7	-119.6	-119.6	-119.6	-119.6		-119.6	-119.6			
Maintenance		0.0	0.0	0.0 -5.3				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1		-7.1	-6.5	-10.4	-13.8	-13.8	-13.8	-13.8		-13.8	-13.8			
Labour		0.0	0.0	0.0 -1.3				-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2			-1.2	-1.8	-1.8	-1.8	-1.8			-1.8	-1.8			
Chemicals & consumables		0.0	0.0	0.0 -1.				-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5			-1.4	-1.6	-2.1	-2.1	-2.1			-2.1	-2.1			
Waste disposal		0.0	0.0	0.0		0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1		-0.1	-0.1			
Insurance and local taxes		0.0	0.0	0.0 -7.				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1			-7.1	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8	-13.8			_
Fixed Capital Expenditures				49.0 0.0				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-237.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
		0.0	0.0	0.0 -0.1	2 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital Decommissioning Cost									-	-	-																		1
		D.O -16	6.0 -2	49.0 34.6 15.0 -380.6			49.0	49.0	49.0	49.0 -86.5	49.0 -37.5	49.0	49.0	49.0	49.0	49.0	-109.0	-192.8	87.2	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	

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IEA GREENHOUSE GAS R&D P	ROGRAM	ME			-			C	ost Evalu	ation - Ret	ofit year +	5 year CA	ASE 2.1														Date	: July 200	4
30 jul 2004 11:04																													
REF	ERENRETR	OFIT					REFEREN	RETROFIT					REFEREN	ETROFIT				B	REFERENR	FTRAFIT									
Production	LIKEIKEIK	J111		Capital	Cost		Million \$		-	operating (nete		/M \$/yearN			Economic	narameter		CI EKENIN	LIKOIII				Results su	ımmarı		+		-
	1404.6 167	2.4 MW	S 9	Installed			354.7	486.4		t 100% loa			iller wrye ar it	iiii wrycai		Discount ra			10.0		%			Emission a		net	_	107.494	1 ¢/t (
Net power output		3.7 MVV		Continue			10.0%	10.0%		uel	u lactoi		132.9	158.2		Load factor			90.0	90.0	70						e' to calculat		ΨVL
CO2 output		0.1 t/h		Continge	ilicies		35.5	48.6		dei Maintenance			7.9	18.7		Fuel price			3.00	3.00							st that gives		51/1
Solid waste output		1.01 t/h		Owners	cnete		7.0%	7.0%		hemicals +	-	loc	1.7	11.1		CO2 price			107.5	107.5				NPV	mooion avo	radrice co	St triat gives	0.00	
CO2 emissions		72 g/kV	N/h	Ovviicis	C0313		24.8	34.0		nsurance ar			7.1	16.8		Waste disp			0.0	307.5				IRR				10.00%	_
CO2 emissions	010	rz g/K	VIII	Petrofit s	scalation ba	eie vear	24.0	15		Vaste dispo		3	0.0	0.0		Insurance a		00	2%		of installed	Lonetily		IIXIX			-	10.0070	
Reference plant data For	calculation of	onst of em	ission av	oidanc Retrofit B			Parly	0%		operating la			1.2	2.3		Number of		6.3	10	20	Of Illistance	COSDY							+
CO2 emissions	373	g/kV			Expenditure e	-	Jany	0.0%		zperaurig la	Jour		1.2	2.0		Cost per op			75.0	75.0	\$LA.		<u> </u>					S	+
	2.997	c/k\			pital cost	Scalation	415.0	569.1			-					Administrat			56%		of operato	re coet		Breakdow	n of c/kWh	cost	_		+
Electricity Cost	2.001	C/KV	*11	i otal ca	picai cost	100	710.0	000.1								Fuel storag			0070 N		days	15 CUSL		Fuel	VI GENTYII	.vat	122	58.55%	
Retrofit year (n)	13	15 -		Working	Canital				г	ecommiss	ionina cos		n	n		Chemicals			30		days			Capital			-	31.04%	
Retrofit Expenditure year (n-2)		0% -	-		als storage		0.2	1.0		/ecommiss	ioning cos			- 0		Start up tim	9		30		months			Other cost:				10.41%	
Retrofit Expenditure year (n-1)		0% -		Fuel stor			0.2	0.0			- 6					Retrofit dov			J	1	months			Other Cost	5			10.4170	+
Retrofit Expenditure year (n)		0% -			orking capita	-l	0.2									Load factor		vear 1	90	90	0/4								+
Million \$	2005	200	6 20	007 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Ī
Year	000	00)	0 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68	% 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	0
Equivalent yearly hours				591	13 7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	1 7884	7884	4
Expenditure Factor		0%	40%	60%												0%	40%	60%											Т
Revenues											-													8					
Electricity				139	.1 185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	122.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	163.9	3
CO2 revenues(based on power output	etrofit case)			0	.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.7	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	J
Operating Costs	5																												
Fuel		0.0	0.0	0.0 -89	.7 -119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-106.8	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	-142.4	1 -142.4	-142.4	ŧ
Maintenance		0.0	0.0	0.0 -5	.3 -7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-12.6	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	3
Labour		0.0	0.0	0.0 -1				-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2			-1.2	-2.3	-2.3	-2.3	-2.3			-2.3	-2.3			
Chemicals & consumables		0.0	0.0	0.0 -1	.1 -1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-7.5	-10.0	-10.0	-10.0				-10.0			
Waste disposal		0.0	0.0		.0 0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0			
Insurance and local taxes		0.0	0.0	0.0 -7				-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8		
Fixed Capital Expenditures			66.0		.0 0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-341.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
		0.0	0.0	0.0 -0	.2 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital Decommissioning Cost		10										10																	
		0.0 -1	66.0	-249.0 34 -415.0 -380			49.0	49.0	49.0	49.0 -86.5	49.0 -37.5	49.0	49.0	49.0	49.0) 49.0	-178.6	-297.2	108.6	152.5	152.5	152.5	152.5	152.5	152.5	152.5	5 152.5	152.5	E

								_																			Version •	4.5	
IEA GREENHOUSE GAS R&D P	ROGRAMI	ΛE						9	Cost Evalu	ation - Ret	rofit year +	5 year C	SE 2.2														Date	: July 2004	4
30 jul 2004 11:04																													
REF	ERENRETRO	DEIT					REFEREN	RETROFIT					REFEREN	ETROFIT					REFEREN	ETROFIT			6						
Production	LIXLING	7111		Capita	Cost		Million \$			Operating (`nete		1M \$/yearN			Economic	parameter		ALI LIALIVI	CIROIII				Results su	ımmanı				-
	404.6 167	1.0 MW		Installe		12	354.7	641.2		t 100% loa			iiii wryeaiii	iiii wrycai		Discount ra			10.0		%			Emission a		net		141.415	⊈/t i
		7.4 MW		Contino			10.0%	10.0%		uel	u ractor		132.9	158.1		Load factor			90.0	90.0	70						e' to calculat		Ψ
		9.9 t/h		Conting	jencies		35.5	64.1		/aintenance			7.9	22.1		Fuel price			3.00	3.00							st that gives		2(7)
Solid waste output		1.01 t/h		Owner	coete		7.0%	7.0%		Chemicals +		lec	1.7	10.7		CO2 price			141.4	141.4				NPV	rnoonorr avoi	dance coa	n trial gives	0.00	
CO2 emissions		75 g/kV	A/h	Ovviici	5 00313		24.8	44.9		nsurance ar			7.1	19.9		Waste disp			0.0	307.5				IRR				10.00%	-
CO2 EITHSSIGHS	313	J grite	VII	Petrofit	escalation b	acic vear	24.0	15		Vaste dispo			0.0	0.0			and local tax	90	2%		of installed	l coetA/		IIXIX				10.0070	
Reference plant data For a	ealculation of c	cost of em	nission au	oidanc Retrofit			vearly.	0%		Operating la			1.2	3.5		Number of		.03	10	30	or mistance	a cosby							-
CO2 emissions	373	g/kV			Expenditure		carry	0.0%		aperating ia	boui		1.2	0.0		Cost per op			75.0	75.0	\$LA.		<u> </u>						-
	1.997	c/kV			apital cost	escalation	415.0		-							Administrat			56%		of operato	re coet		Breakdow	n of c/kWh	cost			-
Electricity Cost		CANA	*11	i ocai c	apital cost		710.0	700.0								Fuel storag			J070		days	15 6031	0	Fuel	OI GERTYII	50 JL		56.85%	+
Retrofit year (n)		15 -		Markin	g Capital	15			-	Decommiss	ionina cos		п	n		Chemicals			30		days			Capital				32.51%	
Retrofit Expenditure year (n-2)		0% -			als storage		0.2	1.0		/ecommiss	ioning cos			- 0		Start up tim			30		months			Other cost:			-	10.64%	
Retrofit Expenditure year (n-1)		0% -		Fuel st			0.0									Retrofit dov				1	months			Other cost	2			10.0470	-
Retrofit Expenditure year (n)		0% -			orking capi	4 -1	0.0									_	r, remainder	voor 1	90	90	0/.				-				+
CASH FLOW ANALYSIS Million \$	2005	2006	6 2	007 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	F
Year	000	00)	0 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
	524																												Γ
Load Factor		_			8% 90			90%	90%	90%	90%	90%	90%	90%	90%		90%	83%	68%	90%	90%	90%	90%		90%	90%		90%	_
Equivalent yearly hours					313 788	14 7884	1 7884	7884	7884	7884	7884	7884	7884	7884	7884		7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	-
Expenditure Factor	(0% 4	40%	60%												0%	40%	60%											1
Revenues																													
Electricity				13	9.1 185	.5 185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	118.3	157.7	157.7	157.7	157.7		157.7	157.7		157.7	
CO2 revenues(based on power output r	etrofit case)				0.0	.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.6	222.1	222.1	222.1	222.1	222.1	222.1	222.1	222.1	222.1	_
Operating Costs																													
Fuel		0.0	0.0		9.7 -119			-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6			-109.6	-106.7	-142.3	-142.3	-142.3	-142.3		-142.3	-142.3			
Maintenance		0.0	0.0		5.3 -7			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1			-6.5	-14.9	-19.9	-19.9	-19.9				-19.9			
Labour		0.0	0.0		1.2 -1			-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2			-1.2	-3.5	-3.5	-3.5	-3.5				-3.5			
Chemicals & consumables		0.0	0.0		1.1 -1	_		-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5		118	-1.4	-7.2	-9.7 n.n	-9.7	-9.7	-9.7			-9.7			
Waste disposal		0.0	0.0		0.0	.0 0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0			
		0.0	0.0		7.1 -7			-7.1	-7.1	-7.1	-7.1	-7.1 n.n	-7.1	-7.1	-7.1			-7.1 -450.2	-19.9	-19.9	-19.9	-19.9	-19.9	-19.9		-19.9			-
Insurance and local taxes			0.08					0.0	0.0	0.0	0.0		0.0	0.0	0.0				0.0	0.0	0.0	0.0	U.L	0.0	0.0	0.0			
Fixed Capital Expenditures				0.0	0.2 0	.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	U.U	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes Fixed Capital Expenditures Working Capital Decommissioning Cost		0.0	0.0																										+
Fixed Capital Expenditures Working Capital				-249.0 3	4.5 49	.0 49.0	0 49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0) 49.0	-251.1	-405.9	131.6	184.5	184.5	184.5	184.5	184.5	184.5	184.5	184.5	184.5	F

																											Version	4.5	1
IEA GREENHOUSE GAS R&D P	ROGRAMM	<u> </u>						C	ost Evalu	ation - Reti	rofit year +	5 year C	SE 3.1														Date	: July 2004	1
30 jul 2004 11:04																													
DEF	ERENRETRO	TT T					REFEREN	PETPOFIT	0				REFEREN	ETPOFIT			[4.		EFEREN R	ETPOFIT		4							
Production	LKLIKLIKOI	1		Capital Co	·et		Million \$			perating C	`oete		1M \$/yearN			Economic	narameters		LILKLIK	LIKOIII				Results su	ımmanı				
	404.6 2121.	2 MVV		Installed co			354.7	822.4		t 100% loa			iivi qiyeariv	iivi oryeai		Discount ra			10.0		%			Emission a		not		159.710	Φ# C
		2 MVV		Contingend			10.0%	10.0%		uel	u ractor		132.9	100.3		Load factor	ie .		90.0	85.0	7.0						e' to calculai		ΦIL
Net power output CO2 output		2 IVIVV 3 t/h		Conungent	iles		35.5	82.2		uei laintenance			7.9	31.8		Fuel price			3.00	1.50							e เบ calcula st that gives		11.71
Solid waste output		o t/h		Owners or	oto		7.0%	7.0%		hemicals +	100	doo	1.7	4.6		CO2 price			159.7	159.7				NPV	nission avo	iluance co	si iriai gives	0.00	
The state of the s				Owners co	ISIS		24.8	57.6					7.1	23.5			!4		0.0	184.5				IRR				10.00%	-
CO2 emissions	373 130	g/kVVh		Dotrofit oo	salation basi		24.8	14		isurance ar		es	0.0	23.5		Waste disp		-				d a a a t t .		IRR				10.00%	
Reference plant data For	alculation of co	-6 -6	a a calabana		calation basi		mult r	0%		Vaste dispo			1.2	3.5		Insurance a		es .	2% 10	30	of installed	a costry							
•			n avoidand			-	arry	100000		perating lal	bour		1.2	3.0		Number of o		<u> </u>	2000		Φ1.4.		5	<u> </u>				8	
CO2 emissions	373	g/kVVh			penditure es	calation	145.0	0.0% 962.2								Cost per op			75.0 56%	75.0				D l. d	n of c/kWh				
Electricity cost	.997	c/kVVh		Total capi	tai cost		415.0	962.2				-				Administrati			50%		of operato	rs cost			n ot cikuun	COST		50.000/	
D - 6	4.5															Fuel storage	-	8	U		days	8	8	Fuel		8		52.69%	
Retrofit year (n)	16			Working C					L	ecommiss	ioning cos	t	0	0		Chemicals		100	30		days			Capital				36.13%	
Retrofit Expenditure year (n-2)	209			Chemicals			0.2	0.4								Start up tim			3		months			Other cost	S			11.18%	
Retrofit Expenditure year (n-1)	459			Fuel storag			0.0	9.7								Retrofit dow					months								-
Retrofit Expenditure year (n)	359	6 -	5	Total work	king capital		0.2	10.1	-							Load factor	, remainder	year 1	90	60	%								
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure Factor	09	6 40%	60%													20%	45%	35%											
Revenues																													
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	88.8	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	167.7	
CO2 revenues(based on power output i	etrofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.1	217.4	217.4	217.4	217.4	217.4	217.4	217.4	217.4	217.4	
CO2 revenues(based on power output i																								l j					
		10		00.7	1100	440.0	440.0	440.0	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-45.2	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	-85.3	
	0.	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.0	-115.0	-110.0					-7.1	-7.1	-6.5	-14.3	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	-27.1	
Operating Costs	0.					-119.6	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1						-27.1	-27.1						-3.5	
Operating Costs Fuel		0.0	0.0	-5.3	-7.1									-7.1 -1.2	-7.1 -1.2		-1.2	-1.2	-3.5	-3.5	-3.5	-3.5			-3.5	-3.5	-3.5	-3.0	
Operating Costs Fuel Maintenance	0.	0.0	0.0	-5.3 -1.2	-7.1 -1.2	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1			-1.2	-1.2 -1.5	-1.2 -1.4	-3.5 -2.1				-3.5	-3.5		-3.5 -3.9			
Operating Costs Fuel Maintenance Labour	0.	0.0	0.0 0.0 0.0	-5.3 -1.2 -1.1	-7.1 -1.2 -1.5	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-7.1 -1.2	-1.2	-1.2	-1.2 -1.5			-2.1 -1.2	-3.5	-3.5	-3.5	-3.5 -3.9	-3.5 -3.9	-3.9		-3.9	-3.9	ı
Operating Costs Fuel Maintenance Labour Chemicals & consumables	0.	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0	-5.3 -1.2 -1.1 0.0	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-1.2 -1.5	-1.2 -1.5	-1.2 -1.5 0.0	-1.5	-1.4	-2.1	-3.5 -3.9	-3.5 -3.9	-3.5 -3.9	-3.5 -3.9 -2.3	-3.5 -3.9 -2.3	-3.9 -2.3	-3.9 -2.3	-3.9 -2.3	-3.9 -2.3	
Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0.	0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5	-7.1 -1.2 -1.5 0.0	-7.1 -1.2 -1.5 0.0	-7.1 -1.2 -1.5 0.0	-7.1 -1.2 -1.5 0.0	-1.2 -1.5 0.0	-1.2 -1.5 0.0	-1.2 -1.5 0.0	-1.5 0.0	-1.4 0.0	-2.1 -1.2	-3.5 -3.9 -2.3	-3.5 -3.9 -2.3	-3.5 -3.9 -2.3	-3.5 -3.9 -2.3	-3.5 -3.9 -2.3	-3.9 -2.3	-3.9 -2.3	-3.9 -2.3 -23.5	-3.9 -2.3 -23.5	
Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	0. 0. 0.	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 -249.0	-5.3 -1.2 -1.1 0.0 -7.1 0.0	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0	-1.2 -1.5 0.0 -7.1 -192.4	-1.5 0.0 -7.1	-1.4 0.0 -7.1	-2.1 -1.2 -23.5	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.9 -2.3 -23.5	-3.9 -2.3 -23.5	-3.9 -2.3 -23.5 0.0	-3.9 -2.3 -23.5 0.0	
Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	0. 0. 0. 0.	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0	-5.3 -1.2 -1.1 0.0 -7.1 0.0	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1 0.0	-7.1 -1.2 -1.5 -0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1 -192.4	-1.5 0.0 -7.1 -433.0	-1.4 0.0 -7.1 -336.8	-2.1 -1.2 -23.5 0.0	-3.5 -3.9 -2.3 -23.5 0.0	-3.5 -3.9 -2.3 -23.5 0.0	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5	-3.9 -2.3 -23.5	-3.9 -2.3 -23.5	-3.9 -2.3 -23.5 0.0	-3.9 -2.3 -23.5 0.0	
Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0. 0. 0. 0.	0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 -249.0	-5.3 -1.2 -1.1 0.0 -7.1 0.0 -0.0	-7.1 -1.2 -1.5 0.0 -7.1 0.0	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1 0.0	-7.1 -1.2 -1.5 -0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-7.1 -1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1	-1.2 -1.5 0.0 -7.1 -192.4 0.0	-1.5 0.0 -7.1 -433.0	-1.4 0.0 -7.1 -336.8	-2.1 -1.2 -23.5 0.0	-3.5 -3.9 -2.3 -23.5 0.0	-3.5 -3.9 -2.3 -23.5 0.0	-3.5 -3.9 -2.3 -23.5	-3.5 -3.9 -2.3 -23.5 0.0	3.5 3.9 3.2.3 3.23.5 0.0 0.0	-3.9 -2.3 -23.5 0.0	-3.9 -2.3 -23.5 0.0	-3.9 -2.3 -23.5 0.0 0.0	-3.9 -2.3 -23.5 0.0	

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Retrofit year (n)	20%			Working (0.0	0.5		ecommiss	ioning cos	· ·	U	U				10	30								-	11.39%	
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Retrofit Expenditure year (n-1) Retrofit Expenditure year (n)	35%			Fuel stora	ge king capital		0.0									Retrofit dov			90	60	months								+
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CASH FLOW ANALYSIS																													_
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	_
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	6 90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	ó
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	1 7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	3
Expenditure Factor	0%	% 41	960	%												20%	45%	35%											İ
Revenues								5 5								2070									5				t
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	91.5	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	172.9	a
CO2 revenues(based on power output re	trofit case)			0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1 0.0	0.0	0.0	144.9	273.8	273.8	273.8	273.8		273.8	273.8			
Operating Costs				-								0.0								2.0.0	210.0	210.0	2.0.0	2.0.0	210.0	2.0.0		210.0	1
Fuel	n.c	n	n n	.0 -89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-49.1	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	-92.7	7
Maintenance	0.0	1.40		.0 -5.3		-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1		-7.1	-6.5	-16.3	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7	-30.7		-30.7	
Labour	0.0			D -1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2			-1.2	-47	-4.7	-47	-4.7	-4.7		-4.7	-4.7		-4.7	
	0.0			.0 -1.1		-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5			-1.4	-2.3	-4.4	-4.4	-4.4	-4.4		-44	-4.4	5000,000,00		
				0 00		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n n	1 00	0.0	0.0	-1.3	-2.5	-2.5	-2.5	-2.5		-2.5	-2.5			
Chemicals & consumables	3115			.0 -7.1	0.0	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	0.0	-7.1	-7.1	-27.5	-27.5	-27.5	-27.5	-27.5			-27.5			
Chemicals & consumables Waste disposal	0.0					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	n n	-238.8	-537.4	-418.0	0.0	0.0	-21.0	21.0 n n	21.0 η η	0.0	-21.0	-21.0			-
Chemicals & consumables Waste disposal Insurance and local taxes	0.0		.749			0.0	0.0	0.0				- 1-	0.0	0.0	0.0		0.0	0.0	-11.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0			-
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures	0.0	.0 -16			0.0	0.0	0.0	0.0	0.0	0.0	0.0					0.0	0.0	0.0	(5 to to to to)										
Chemicals & consumables Waste disposal Insurance and local taxes	0.0	.0 -16		.0 -0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							0.0	0.0		0.0					I
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0.0	.0 -16	0.0	.0 -0.2			49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	0 -189.8	-488.4	-373.7	124.2	284.0	284.0	284.0	284.0		284.0	284.0	284.0	284.0	

Appendix 8

Task 1 – Same Output Retrofit

Task 1 – Same Output Retrofit

Introduction

The common basis for the study is the capture of 85% of carbon in the feedstock. This results in a reduced and widely variable net output of electricity across the cases, as compared to the reference plant, from less than 2% to more than 25%.

Some operators might be interested in an option to capture 85% of the carbon and at the same time retain the original plant output. This may be required to maintain installed nameplate capacity at specific parts of the network for regulatory compliance, or it could be to comply with an existing off-take agreement.

In order to achieve this it is necessary in most cases to install supplementary combined cycle power plants. These would operate, in the same mode as the refuelled CCPP with 85% of the carbon in the fuel captured as CO_2 . The closest fit gas turbine is chosen for each case to generate a total plant output as close as possible to the reference plant.

Process Description and Performances

A breakdown of the additional power generation required to bring each of the capture cases back to the reference case output is given in table 1 below. A summary of the revised plant performances and costs are given in tables 2, 3 and 4 below with further details at the end of this appendix.

Table 1 Additional Power Requirements

Additional Power Requirements	Ref.	1	2-1	2-2	3-1	3-2	
Combined Cycle Power Plant Net Electrical Output	784.8	664.3	809.6	764.3	806.0	774.3	MWe
CO ₂ Capture Plant Auxiliary Power Consumption	0.0	-38.5	-158.9	-168.0	-244.9	-269.1	MWe
CO ₂ Capture Plant Power Production	0.0	0.0	43.0	71.1	190.1	269.4	MWe
Total Overall Plant Net Power Output	784.8	625.9	693.7	667.4	751.2	774.6	MWe
Additional Power Required	0	158.9	91.1	117.4	33.6	10.2	MWe

Case 1

For Case 1 an additional 159 MWe is required to bring the total output up to that of the Reference Case. The best fit for this additional output is to add a GE 9EA in combined cycle. This operates on natural gas in parallel to the original CCPP. The flue gases are routed to additional Acid Gas Removal trains and the CO2 is combined with that from the original CCPP and sent to an increased capacity CO2 Compression and Drying section. The throughput increase required in the Acid Gas Removal and CO_2 Compression and Drying units is 27%.

Case 2-1

In Case 2-1 an additional 91 MWe is required to bring the output to that of the reference plant. CO₂ free fuel gas feeds a supplementary GE 6FA, operating in combined cycle to generate this extra power. The GE 6 FA is well proven operating in syngas. The entire fuel generation part of the flowsheet (encompassing everything apart from the CCPP) is increased to generate the extra 16% fuel gas.

Case 2-2

Case 2-2 requires extra output of 117 MWe. The best fit turbine is a GE 9EA operating again in combined cycle. The GE 9 EA is well proven operating in syngas. Similar areas of the flowsheet to Case 2-1 increase in throughput to generate the CO_2 free fuel gas required. The required increased output of CO_2 free fuel gas is 27%.

Case 3-1

Case 3-1 has a shortfall of 34 MWe against the reference case. In this case the extra power is generated by an additional GE 6B gas turbine in combined cycle. This is added to the existing GE 6B gas turbines used in the Power Block for this case. The additional gas turbine also superheats the additional steam, generated by the increased fuel flow in the enlarged capture plant.

The fuel throughput increase required in this case is 10% over the original flowscheme. The entire flowscheme is increased to create this higher fuel requirement, with the exception of the original Power Block, which has an additional gas turbine added, and the CCPP, which remains the same as it, does in all the cases.

Case 3-2

The additional power required for Case 3-2 is only 10 MW. This is generated by 'stretching' the original flowscheme by increased supplementary firing in the HRSG of the Power Block. This extra duct burning actually reduces the surface required in the Power Block HRSG by improving the temperature driving force in the coils. The fuel generation part of the plant is increased in throughput by 1%.

Table 2 – Plant Power Output (Reference Case Output)

Plant Power Output	Ref.	1	2-1	2-2	3-1	3-2	
Combined Cycle Power Plant Net Electrical Output	784.8	664.3	809.6	764.3	806.0	774.3	MWe
Revised Capture Plant Auxiliary Power Consumption	0.0	-48.8	-177.5	-194.2	-268.4	-272.0	MWe
Revised Capture Plant Power Production	0.0	164.7	154.8	235.3	256.3	281.7	MWe
Revised Overall Plant Net Power Output	784.8	780.2	786.9	805.4	793.9	784.0	MWe
Difference from Reference Plant	0	-0.6	0.3	2.6	1.2	-0.1	%

Table 3 - Plant Performance (Reference Case Output)

Plant Performance	Ref.	1	2-1	2-2	3-1	3-2	
Revised Overall Plant Fuel Consumption (LHV)	1404.6	1780.1	1940.7	2123.1	2324.6	2331.6	MWth
Fuel Gas to Combined Cycle Power Plant	1404.6	1404.6	1672.4	1671.0	2121.2	2306.4	MWth
Revised Overall Plant CO ₂ emissions	2.31	0.42	0.46	0.5	0.8	0.82	Mt/y
Revised Overall Plant Net Electrical Efficiency	55.9	43.8	40.6	37.9	34.2	33.6	%

Economic Analysis

Table 4 – Additional Capital Expenditures (Reference Case Output)

Additional Capital Expenditures	Ref.	1	2-1	2-2	3-1	3-2	
Additional Capital Costs ¹	-	584	712	978	1045	1210	Million US \$
Specific Total Investment	529	1280	1432	1729	1839	2073	US \$/MWe
CO ₂ Emission	0.373	0.068	0.074	0.078	0.135	0.140	t/MWh
Avoided CO ₂ Emission (% of ref.)	-	81.8	80.2	78.9	63.9	62.5	%
Costs of Avoided CO ₂	-	74.3	98.2	128.9	136.9	167.5	US \$/ton

Notes

- 1. On top of capital expenditure for reference plant of 415 million US \$
- 2. Calculated with electricity at 30.0 US \$/MWh

Conclusions

The study demonstrates that the reference case output can be generated with CO_2 capture using additional gas turbines all of which are commercially proven on syngas. In all cases the overall efficiency is reduced. This is because the additional gas turbines are all less efficient than the GE 9FA used in the CCPP. In case 3-2, the reduction in efficiency is very small, because the additional power generation is achieved by a small, 1%, increase in capture plant capacity. No additional gas turbines are added and the plant configuration is not changed.

The reduced efficiency means that in all cases the CO₂ emitted per MWh increases and the increased throughput means that the avoided CO₂ when compared with the reference plant is also reduced.

The specific investment costs differ marginally (within 1%) for all cases compared to the original calculations.

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Fuel feedrate 140				Installed co			354.7	499.2		t 100% load	Tactor		400.0	100.1		Discount ra	te		10.0	00.0	%			Emission a				74.307	⊅\£ (
Net power output 78-		MVV		Contingend	cies		10.0%	10.0%		uel			132.9	168.4		Load factor			90.0	90.0							ve' to calcula		1.25
CO2 output 29		t/h		A			35.5	49.9	1111	laintenance	1000		7.9	19.0		Fuel price			3.00	3.00					mission avc	olaance co	ost that gives		
		t/h		Owners co	OSIS		7.0%	7.0%		hemicals +			1.7	2.4		CO2 price		-	74.3	74.3				NPV IRR		-	+	0.00	
CO2 emissions 3	73 68	g/kVVh	9	D . 0	1.7		24.8	34.9	-	surance an		S	7.1	17.1		Waste disp			0.0	307.5		1 12		IRR			-	10.00%	
5.6	100				calation bas			10		Vaste dispo			0.0	0.2		Insurance a		es	2%		of installed	costry					+		
	culation of cos		n avoldand				ariy	0%	0	perating lab	our		1.2	1.8		Number of o			10	15	AL I								
	73	g/kVVh			penditure es	calation	145.0	0.0%								Cost per op			75.0	75.0				Daniel			+		
Electricity cost 2.99	37	c/kVVh	-	Total capi	tai cost		415.0	584.0					100			Administrati			56%		of operato	rs cost			n of c/kWh	cost	- 22	E0 4001	
D 1 - G 1 (-)			8											0		Fuel storage		3	0		days		8	Fuel	15			56.40%	
Retrofit year (n)	10			Working C					D	ecommissi	oning cost		0	0		Chemicals:		-	30	-	days			Capital	33		_	33.09%	
Retrofit Expenditure year (n-2)	0%	_		Chemicals			0.2	0.2								Start up tim			3	3	months			Other costs	S			10.51%	
Retrofit Expenditure year (n-1)	40%			Fuel storag	-		0.0	0.0								Retrofit dow				1	months								
Retrofit Expenditure year (n)	60%	-	8	Total work	king capital		0.2	0.2				5				Load factor,	remainder	year 1	90	90	%					S.			
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18			21	22	23	24	25	
							-	3		-		9		- 11					10	17	10	19	20	21		1			
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%		90%	
100000000000000000000000000000000000000				68% 5913		90% 7884		-									90% 7884	90% 7884						90%	90%	90% 7884			
Equivalent yearly hours	0%	40%	60%	5913			90%	90%	90%	90%	90%	90%	83%	68%	90%				90%	90%	90%	90%	90%	90%	90%				
Load Factor Equivalent yearly hours Expenditure Factor Revenues	0%	40%	60%	5913			90%	90%	90%	90%	90% 7884	90% 7884	83% 7227	68%	90%				90%	90%	90%	90%	90%	90%	90%				
Equivalent yearly hours Expenditure Factor	0%	40%	60%	5913	7884		90%	90%	90%	90%	90% 7884	90% 7884	83% 7227	68%	90%				90%	90%	90%	90%	90%	90%	90% 7884		4 7884	7884	
Equivalent yearly hours Expenditure Factor Revenues		40%	60%	5913	7884	7884	90% 7884	90% 7884	90% 7884	90%	90% 7884 0%	90% 7884 40%	83% 7227 60%	68% 5913	90% 7884	7884 184.4	7884	7884	90% 7884	90% 7884	90% 7884	90% 7884	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	7884 184.4	4 7884 4 184.4	7884 184.4	
Equivalent yearly hours Expenditure Factor Revenues Electricity		40%	60%	5913	7884	7884	90% 7884	90% 7884	90% 7884 185.5	90% 7884 185.5	90% 7884 0%	90% 7884 40%	83% 7227 60%	68% 5913	90% 7884 184.4	7884 184.4	7884 184.4	7884	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	7884 184.4	4 7884 4 184.4	7884 184.4	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retri			3070	5913 139.1 0.0	7884 185.5 0.0	7884	90% 7884	90% 7884	90% 7884 185.5	90% 7884 185.5	90% 7884 0%	90% 7884 40%	83% 7227 60%	68% 5913 138.3 104.6	90% 7884 184.4	7884 184.4	7884 184.4	7884	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4	90% 7884 184.4 139.5	90% 7884 184.4 139.5	7884 184.4 139.5	4 7884 4 184.4 5 139.5	7884 184.4 139.5	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retri Operating Costs	ofit case)	0.0	0.0	5913 139.1 0.0 -89.7 -5.3	7884 185.5 0.0 -119.6 -7.1	7884 185.5 0.0 -119.6 -7.1	90% 7884 185.5	90% 7884 185.5 0.0 -119.6 -7.1	90% 7884 185.5 0.0 -119.6 -7.1	90% 7884 185.5 0.0 -119.6 -7.1	90% 7884 0% 185.5 0.0	90% 7884 40% 185.5 0.0	83% 7227 60% 170.0 0.0 -109.6 -6.5	68% 5913 138.3 104.6	90% 7884 184.4 139.5	7884 184.4 139.5	7884 184.4 139.5	7884 184.4 139.5	90% 7884 184.4 139.5	90% 7884 184.4 139.5 -151.6 -17.1	90% 7884 184.4 139.5 -151.6 -17.1	90% 7884 184.4 139.5	90% 7884 184.4 139.5	90% 7884 184.4 139.5 -151.6	90% 7884 184.4 139.5 -151.6 -17.1	7884 184.4 139.5	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1	7884 184.4 139.5 -151.6 -17.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel	ofit case)	0.0	0.0	5913 139.1 0.0 -89.7 -5.3 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2	68% 5913 138.3 104.6 -113.7 -12.8 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	7884 184.4 139.5 -151.6 -17.1 -1.8	7884 184.4 139.5 -151.8 -17.1 -1.8	7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	90% 7884 184.4 139.5 -151.6 -17.1 -1.8	7884 184.4 139.5 -151.6 -17.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8	7884 184.4 139.5 -151.6 -17.1 -1.8	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables	ofit case) 0.0 0.0 0.0	0.0	0.0	139.1 0.0 1-89.7 0 -5.3 0 -1.2	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4	68% 5813 138.3 104.6 -113.7 -12.8 -1.8 -1.6	90% 7884 184.4 139.5 -151.8 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	ofit case) 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	5913 139.1 0.0 189.7 0.0 1-89.7 0.0 1-1.2 0.0 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4	68% 5913 138.3 104.6 -113.7 -12.8 -1.8 -1.6 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1 1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	ofit case) 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	139.1 0.0 139.1 0.0 -89.7 0 -5.3 0 -1.2 0 -1.1 0.0 0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1	68% 5913 138.3 104.6 -113.7 -12.8 -1.8 -0.1 -17.1	90% 7884 184.4 139.5 -151.8 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1 1 -0.1 1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal	ofit case) 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	139.1 0.0 139.1 0.0 -89.7 0 -5.3 0 -1.2 0 -1.1 0.0 0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4	68% 5913 138.3 104.6 -113.7 -12.8 -1.8 -1.6 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1 1 -0.1 1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	ofit case) 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0	139.1 0.0 -89.7 0 -5.3 0 -1.2 0 -1.1 0 0.0 0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1	68% 5913 138.3 104.6 -113.7 -12.8 -1.8 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1 1 -0.1 1 -17.1 0 0.0	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	
Equivalent yearly hours Expenditure Factor Revenues Electricity CO2 revenues(based on power output retro Operating Costs Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0.0 0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0 0.0 0.0 0.0 -166.0	0.0 0.0 0.0 0.0 0.0 0.0 -249.0	5913 139.1 0.0 1-89.7 0.5.3 0.1 1.2 0.1 0.0 1.7.1 0.0 0.0 1.7.1 0.0 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1 0.0	7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 0% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0	90% 7884 40% 185.5 0.0 -119.6 -7.1 -1.2 -1.5 0.0 -7.1	83% 7227 60% 170.0 0.0 -109.6 -6.5 -1.2 -1.4 0.0 -7.1	68% 5913 138.3 104.6 -113.7 -12.8 -1.8 -0.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1 0.0	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1 0.0	90% 7884 184.4 139.5 -151.8 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1 0.0	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1 0.0	90% 7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1 0.0	7884 184.4 139.5 -151.6 -17.1 -1.8 -2.1 -0.1 -17.1	4 7884 4 184.4 5 139.5 6 -151.6 1 -17.1 8 -1.8 1 -2.1 1 -0.1 1 -17.1 0 0.0	7884 184.4 139.5 -151.6 -17.1 -2.1 -0.1 -17.1 0.0	

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REFE	RENRETRO	FIT				-	REFEREN	RETROFIT		F-0	- E		REFEREN	RETROFIT			0. 0.	R	EFERENR	FTROFIT	•								
Production	,	1		Capital Co	ost		Million \$			perating (osts		/IM \$/yearN			Economic	parameters							Results su	ımmanı				
0.0000 0.0000000000	4.6 1940	.7 MVV		Installed co	7.000		354.7	608.6		t 100% loa		Ī	,	,		Discount ra			10.0		%				voidance co	nst		98.189	\$/t
		.9 MVV		Contingen			10.0%	10.0%		uel			132.9	183.6		Load factor			90.0	90.0	%						e' to calculati		W. C
		.1 t/h		Contingen	0.00		35.5	60.9		daintenance			7.9	21.4		Fuel price			3.00	3.00							st that gives		VI
	.00 0.0			Owners co	nsts		7.0%	7.0%		hemicals +		nles	1.7	11.1		CO2 price			98.2	98.2				NPV			t trial gives	0.00	
The state of the s		4 g/kWh					24.8	42.6		surance ar			7.1	19.3		Waste disp			0.0	307.5				IRR				10.00%	
			2	Retrofit es	calation basi	s vear		10		Vaste dispo			0.0	0.0		Insurance a		es	2%		of installed	cost/v	2						
Reference plant data For car	culation of co	st of emis	sion avoidar		penditure es		arly	0%		perating la			1.2	2.3		Number of			10	20									
	73	a/kVVh			penditure es	-		0.0%		1						Cost per op			75.0	75.0	\$k/v								
Electricity cost 2.9		c/kWh		Total capi			415.0	712.1								Administrati			56%		of operator	rs cost		Breakdow	n of c/kWh	cost			
																Fuel storag	10000		0		days			Fuel				54.87%	,
Retrofit year (n)	11	D -		Working (Capital					ecommiss	ionina cos	t	0	0		Chemicals			30		days			Capital				33.54%	
Retrofit Expenditure year (n-2)	0'	% -		Chemicals			0.2	1.0								Start up tim			3		months			Other cost:	S			11.59%	
Retrofit Expenditure year (n-1)	40			Fuel stora			0.0	0.0	-							Retrofit dov	NAME OF TAXABLE PARTY.		-	1	months		4						
Retrofit Expenditure year (n)	60'	% -			king capital		0.2									Load factor		vear 1	90	90	%								
Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	t
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	L
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	7884	
Expenditure Factor	0'	% 40	% 60%	6							0%	40%	60%																
Revenues	100																												
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	139.5	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	
CO2 revenues(based on power output retr	ofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.8	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	182.4	
Operating Costs																													
Fuel	0	.0 0	.0 0.		-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-123.9	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	-165.2	
Maintenance	0	.0 0	.0 0.			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-14.4	-19.3			-19.3	-19.3	-19.3	-19.3	-19.3				-19.3			
Labour	0	.0	.0 0.			-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-2.3	-2.3			-2.3	-2.3	-2.3	-2.3	-2.3				-2.3			
Chemicals & consumables	0		.0 0.			-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-7.5	-10.0			-10.0	-10.0	-10.0	-10.0	-10.0				-10.0			
Waste disposal	0		.0 0.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0			0.0	0.0			
	0	.0	.0 0.			-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3		-19.3			-
Insurance and local taxes		.0 -166				0.0	0.0	0.0	0.0	0.0	0.0	-284.8	-427.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Fixed Capital Expenditures	0			0 -0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
	0	.0 0.	.0 0.	-0.2							-						- 10	-	-										+
Fixed Capital Expenditures Working Capital	0	.0 -166			49.0	49.0	49.0	49.0	49.0	49.0	49.0	-235.8	-383.0	107.8	152.3	152.3	152.3	152.3	152.3	152.3	152.3	152.3	152.3	3 152.3	152.3	152.3	152.3	152.3	

																			-								Version	4.5	-
IEA GREENHOUSE GAS R&D PF	OGRAMM	E						9	ost Evalu	ation - CAS	E 2.2																Date	: July 200	J4
29 jul 2004 12:40		_																											
REF	RENRETRO	IT					REFEREN	RETROFIT					REFEREN	ETROFIT				5	EFERENR	ETROFII									
Production	KENKETKO	1		Capital Co	\ct		Million \$		-	operating C	`nete		/M \$/yearN			Economic	parameter		LILKLINK	LIKOIII				Results s	Imman/				+
	04.6 2123	1 MVV		Installed co			354.7	835.7		t 100% loa			inii yryeani	iiii wrycai		Discount ra			10.0		%				avoidance c	roet		128.93	5 \$4
		4 MVV		Contingen			10.0%	10.0%		uel	u lactoi		132.9	200.9		Load factor			90.0	90.0							re' to calcula		2 4/1
		4 t/h		Contingent	JICS		35.5	83.6		dei Maintenance			7.9	26.5		Fuel price			3.00	3.00			5				st that give		IDV1
the state of the s		1 t/h		Owners co	nete		7.0%	7.0%		hemicals +		nlec	1.7	10.7		CO2 price			128.9	128.9			i i	NPV	rriiooiorr avi	Diuanice cc	oi mai yive	0.0	
	373 7			Ovviici3 co	1313		24.8	58.5		nsurance ar			7.1	23.8		Waste disp			0.0	307.5				IRR				10.00%	
COZ EITIISSIOTIS	010 1	y/KVVII		Retrofit es	ralation has	ic vear	24.0	10		Vaste dispo		-3	0.0	0.0		-	and local tax	90	2%		of installed	d costA/		IIXIX				10.007	U
Reference plant data For c	alculation of co	et of amicei	nn avoidan				ark	0%		perating lal			1.2	3.5		Number of		53	10	30	OI IIIStalict	u cosby							+
	373	g/kWh	or avoidan		penditure es	-	arry	0.0%		zperating rai	boui		1.2	0.0		Cost per or	-		75.0	75.0	¢LA.		5			<u> </u>	0		+
	997	c/kWh		Total capi		scalation	415.0									Administra			56%		of operato	re coet		Breakdow	n of c/kWh	cost			+
Electricity cost 2	001	C/KVVII		i otai capi	tai cost		410.0	377.0								Fuel storac			0070		days	JIS CUSE		Fuel	III OI CIKVVI	i cost		52.539	1/4
Retrofit year (n)	11			Working C	`anital				г	ecommiss	ionina cos		0	n		Chemicals			30		days			Capital				35.549	
Retrofit Expenditure year (n-2)	יח			Chemicals	•		0.2	1.0		ecommiss	ioning cos		U	U		Start up tin			20	30	months			Other cost				11.939	
Retrofit Expenditure year (n-1)	40'	-		Fuel storag			0.2	0.0	- 6		0			- 6		Retrofit do			J	1	months		4	Other cos	.5	9		11.007	0
Retrofit Expenditure year (n)	60'	-		Total worl	-	1	0.2										r, remainder	voor 1	90	90	0/.								+
CASH FLOW ANALYSIS Million \$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	1
MIIIION \$	2005	2006	2007	2006	2009	2010	2011	2012	2013	2014	2015	2010	2017	2010	2019	2020	2021	2022	2023	2024	2025	2026	2021	2020	2029	2030	2031	2032	
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	+
Load Factor				68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	% 90%	90%	90%	6 90%	90%	/6
Equivalent yearly hours				5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	5913	7884	7884	7884	7884	7884	7884	7884	7884	788	4 7884	7884	7884	4 7884	788-	.4
Expenditure Factor	0'	6 40%	60%								0%	40%	60%																
Revenues									2					2															
Electricity				139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	142.7	190.3	190.3	190.3	190.3	190.3	190.3	190.3	190.3	190.	3 190.3	190.3	190.3	3 190.3	190.	.3
CO2 revenues(based on power output re	trofit case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.9	241.2	241.2	241.2	241.2	241.2	241.2	241.2	241.2	241.	2 241.2	241.2	241.2	2 241.2	241.	2
Operating Costs		0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-135.6	-180.8	-180.8	-180.8	-180.8	-180.8	-180.8	-180.8	-180.8	-180.	8 -180.8	-180.8	-180.8	-180.8	-180.	8
Fuel	0		0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-17.9	-23.8	-23.8	-23.8	-23.8	-23.8	-23.8	-23.8	-23.8	-23.	8 -23.8	-23.8	-23.8	-23.8	-23.	8
50 - 10 - 10 - 10 - 10 - 10 - 10 - 10 -	0	0.0	0.0				4.0	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.	.5 -3.5	-3.5	-3.5	5 -3.5	-3.	5
Fuel				-1.2	-1.2	-1.2	-1.2	-1.4			20 00 00	4.5	-1.4	-7.2	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.7	-9.	.7 -9.7	-9.7	-9.7	7 -9.7	-9.	.7
Fuel Maintenance	0	0.0	0.0				-1.2 -1.5	-1.5	-1.5	-1.5	-1.5	-1.5				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.	0 00	0.0	0.0	0.0	0.	.0
Fuel Maintenance Labour	0	0.0 0.0	0.0	-1.1	-1.5 0.0	-1.5 0.0	-1.5 0.0	-1.5 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0														
Fuel Maintenance Labour Chemicals & consumables	0	0 0.0 0 0.0 0 0.0	0.0	-1.1 0.0	-1.5 0.0	-1.5 0.0	-1.5	-1.5					0.0 -7.1	0.0 -23.8	0.0 -23.8			-23.8	-23.8	-23.8	-23.8								8
Fuel Maintenance Labour Chemicals & consumables Waste disposal	0 0	0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0	-1.1 0.0 -7.1	-1.5 0.0 -7.1	-1.5 0.0 -7.1	-1.5 0.0	-1.5 0.0	0.0	0.0	0.0	0.0	0.0										-23.	8 -23.8		-23.8	-23.8	-23.	
Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes	0 0 0	0 0.0 0 0.0 0 0.0 0 0.0 0 -166.0	0.0 0.0 0.0 0.0 -249.0	-1.1 0.0 -7.1 0.0	-1.5 0.0 -7.1 0.0	-1.5 0.0 -7.1 0.0	-1.5 0.0 -7.1	-1.5 0.0 -7.1	0.0 -7.1	0.0 -7.1	0.0 -7.1	0.0 -7.1	0.0 -7.1	-23.8		3 -23.8 0.0	-23.8 0.0		-23.8	-23.8	-23.8	-23.8 0.0	3 -23.	8 -23.8 0 0.0	-23.8 0.0	-23.8 0.0	3 -23.8 0.0	-23. 0.	.0
Fuel Maintenance Labour Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0 0 0 0 0	0 0.0 0 0.0 0 0.0 0 0.0 0 -166.0 0 0.0	0.0 0.0 0.0 0.0 -249.0	-1.1 0.0 1 -7.1 0 0.0 1 -0.2	-1.5 0.0 -7.1 0.0 0.0	-1.5 0.0 -7.1 0.0	-1.5 0.0 -7.1 0.0	-1.5 0.0 -7.1 0.0	0.0 -7.1 0.0	0.0 -7.1 0.0	0.0 -7.1 0.0	-7.1 -391.1	0.0 -7.1 -586.7	-23.8 0.0	- 23.8 0.0	3 -23.8 0 0.0 0 0.0	-23.8 0.0 0.0	-23.8 0.0	-23.8 0.0	-23.8 0.0	-23.8 0.0	-23.8 0.0	3 -23. 0 0. 0 0.	8 -23.8 0 0.0 0 0.0	-23.8 0.0 0.0	-23.8 0.0 0.0	3 -23.8 0 0.0 0 0.0	-23. 0. 0.	.0

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EA GREENHOUSE GAS	R&D PROG	RAMME					-		9	ost Evalu	ation - CAS	E 3.1																Date :	July 2004	4
00: 10004 40 40																,														-
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	REFEREN	RETROFI	Т					REFEREN	RETROFIT					REFEREN	ETROFIT				F	REFEREN	RETROFI	Т						9		
Production	TILL LITE				Capital Co	ost		Million \$		c	Operating (osts		/M \$/yearM			Economic	parameters				•			Results su	ımmanı				
uel feedrate	1404.6	2324.6	MW		Installed co			354.7	893.4		t 100% loa			,	,		Discount ra		10	10.0		%		9	Emission a		nst		136.861	\$/t (
Net power output	784.8				Contingen			10.0%	10.0%		uel			132.9	110.0		Load factor			90.0	85.0	%			_			' to calculate		***
CO2 output	293.0				Contingen	0.00		35.5	89.3		/aintenance			7.9	33.4		Fuel price			3.00		\$/GJ						st that gives a		21/1
Solid waste output	0.00				Owners co	osts		7.0%	7.0%		Chemicals +		les	1.7	4.6		CO2 price			136.9	136.9				NPV				0.00	-
CO2 emissions	373	134	a/kWh					24.8	62.5		nsurance ar			7.1	25.0		Waste disp			0.0	184.5				IRR				10.00%	
			3		Retrofit es	calation bas	sis vear		9		Vaste dispo			0.0	3.0		1	and local tax	es	2%		of installe	d cost/v							
Reference plant data	For calcula	ation of cost	of emissio	n avoidan	c Retrofit Ex			early	0%	(Operating la	oour		1.2	3.5		Number of	operators		10	30									
CO2 emissions	373		a/kWh			penditure e:			0.0%								Cost per op			75.0		\$k/v								
Electricity cost	2.997		c/kWh		Total capi			415.0									Administrat			56%		of operato	rs cost		Breakdow	n of c/kWh	cost			
									-								Fuel storag			0		davs			Fuel				45.48%	
Retrofit year (n)		10	-		Working (Capital					Decommiss	ioning cos	t	0	0		Chemicals			30		days			Capital				41.23%	
Retrofit Expenditure year (n-2)		20%	-		Chemicals			0.2	0.4			•					Start up tim			3	3				Other costs	s			13.29%	
Retrofit Expenditure year (n-1)	9	45%	-		Fuel stora		4	0.0	10.6	14					- 4		Retrofit dov		14		1	months		8						9
Retrofit Expenditure year (n)		35%				king capita	ı	0.2	11.1								Load factor	r, remainder	vear 1	90	60	%								
'ear		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				9	68%	90%	90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours					5913	7884	7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	744E	7446	7446	7446	7446	7446	
Expenditure Factor		0%	40%	60%	6							20%	45%	35%																
Revenues																														
Electricity					139.1	185.5	185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	93.8	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	
CO2 revenues(based on power	er output retrofit	case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.3	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	
Operating Costs																														
Fuel		0.0	0.0	0.0	-89.7	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-49.5	-93.5		-93.5	-93.5	-93.5	-93.5	-93.5	-93.5	-93.5		-93.5	-93.5	-93.5	-93.5	
Maintenance		0.0	0.0	0.0	-5.3	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-15.0	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	-28.4	
Labour		0.0	0.0	0.0	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-3.5	-3.5			-3.5	-3.5	-3.5		-3.5					-3.5	-3.5	
Chemicals & consumables		0.0	0.0						-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-2.1	-3.9			-3.9	-3.9	-3.9		-3.9						-3.9	
Waste disposal		0.0		0.0				17.17	0.0	0.0	0.0	0.0	0.0	0.0	-1.4	-2.6			-2.6	-2.6	-2.6		-2.6						-2.6	
Insurance and local taxes		0.0							-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0	-25.0		-25.0					-25.0	-25.0	-
Fixed Capital Expenditures		0.0							0.0	0.0	0.0	-209.1	-470.4	-365.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0			0.0	0.0	0.0	0.0	
		0.0	0.0	0.0	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-11.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Working Capital																														
Working Capital Decommissioning Cost																														
		0.0	-166.0	-249.0	0 34.5 0 -380.5		49.0 -282.5		49.0	49.0 -135.5	49.0	-160.1 -246.6	-421.4 -667.9	-321.6 -989.6	88.6 -901.0	213.6 -687.3		213.6	213.6	213.6	213.6	213.6 594.5	213.6	213.6	213.6	213.6	213.6 1662.6	213.6	213.6	3

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REF	RENRETRO	FIT					REFEREN	RETROFIT					REFEREN	RETROFIT				B	EFERENR	ETROFIT									
Production	IKLIKLIKO			Capital	Cost		Million \$			Operating (Costs		/M \$/yearN			Economic	parameter		LILKLINK	LIKOIII				Results su	ımmanı				+
	404.6 2331	.6 MVV		Installed			354.7	1034.1		at 100% loa			iliti wrye ai it	iiii wiyeai		Discount ra			10.0		%			Emission a		net		167.527	7 ¢/t
Net power output		.0 MVV	3	Contino			10.0%	10.0%		Tuel	d lactor		132.9	110.3		Load factor			90.0	85.0							e' to calculat		Ψ
The state of the s		1.9 t/h	-	Conting	encies		35.5	103.4		Maintenance			7.9	36.5		Fuel price			3.00	1.50							e to carcarat st that gives		DVI
Solid waste output		36 t/h		Owners	costs		7.0%	7.0%		Chemicals +		nlec	1.7	5.2		CO2 price			167.5	167.5				NPV	rnooiorr avo	ruarree eo	Ji triat giveo	0.00	
CO2 emissions	373 14		i/h	Owners	CUSIS		24.8	72.4		nsurance ar			7.1	27.8		Waste disp			0.0	184.5				IRR				10.00%	_
CO2 emissions	373 14	o g/K/	VII	Retrofit	escalation b	acie vear	24.0	9		Naste dispo		-3	0.0	3.0			and local tax	00	2%		of installed	d coet/y		IIXIX				10.0070	-
Reference plant data For	alculation of c	net of am	iceinn av				parky	0%		Operating la			1.2	4.7		Number of		C3	10	4N	UI IIISLAIICI	acosby							+
CO2 emissions	373	g/kV			Expenditure		carry	0.0%		operating ia	boui		1.2	7.1		Cost per or	-		75.0	75.0	ΦLA.		<u> </u>		0 0			S	+
	.997	c/kV			apital cost	cocalation	415.0									Administrat			56%		of operato	re coet		Breakdow	n of c/kWh	cost			+
Electricity COSE .	100.	C/KV	711	i otal c	apital COSL		4 10.0	1203.0								Fuel storag			JU 70		days	is CUSL		Fuel	II OI O/KYYII	UVSL		43.65%	4
Retrofit year (n)	1	0 -		Morkin	g Capital				г	Decommiss	ionina cos		n	n		Chemicals			30		days			Capital				43.65%	-
Retrofit Expenditure year (n-2)	20	-			als storage		0.2	0.5		>=comm155	nonning cos		U	U		Start up tim			20		months			Other cost:				13.67%	
Retrofit Expenditure year (n-1)	45			Fuel sto			0.2			- 4						Retrofit dov				1	months			Other cost	2			13.0770	-
Retrofit Expenditure year (n)	35				orking capi	tal	0.2									_	r, remainder	vear 1	90	60	0/4								+
Million \$	2005	200	5 20	07 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Į
Year	000	00		0 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
Load Factor				6	3% 90	% 90%	90%	90%	90%	90%	90%	90%	83%	45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	6
Equivalent yearly hours				59	13 788	4 7884	7884	7884	7884	7884	7884	7884	7227	3942	7446	7446	7446	7446	7446	7446	7446	7446	7448	7446	7446	7446	7446	7448	3
Expenditure Factor	0	% 4	40%	60%	1000				100000000000000000000000000000000000000	2006.00.00	20%	45%	35%					10000000	1.0000000	100000000									Т
Revenues							8																						t
Electricity				13	9.1 185	5 185.5	185.5	185.5	185.5	185.5	185.5	185.5	170.0	92.6	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	J
CO2 revenues(based on power output r	etrofit case)				0.0	0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.7	228.0			228.0	228.0	228.0	228.0	228.0	228.0	228.0	228.0	228.0	228.0	228.0	j
Operating Costs																													
Fuel		1.0	0.0	0.0 -8	9.7 -119	6 -119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-119.6	-109.6	-49.6	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	-93.8	3
Maintenance		1.0	0.0	0.0	5.3 -7	.1 -7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-6.5	-16.4	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	-31.0	J
		1.0	0.0	0.0 -	1.2 -1	.2 -1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	7
Labour		1.0	0.0	0.0 -	1.1 -1	.5 -1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.4	-2.3	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	-4.4	4
Labour Chemicals & consumables	_	. 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.4	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.8	-2.6	-2.6	-2.6	-2.6	-2.8	ŝ
		1.0	0.0	0.0	7.1 -7	.1 -7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-7.1	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	-27.8	3
Chemicals & consumables		1.0	0.0						0.0	0.0	-242.0	-544 4	-423.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	١
Chemicals & consumables Waste disposal	0	1.0			0.0	0.0	0.0	0.0	0.0	U.U	-242.0	-044.4																	_
Chemicals & consumables Waste disposal Insurance and local taxes Fixed Capital Expenditures Working Capital	0	1.0		249.0	-	0 0.0		- 1-	0.0	0.0	0.0	0.0	0.0	-11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7
Chemicals & consumables Waste disposal Insurance and local taxes	0 0	i.0 i.0 -1i	66.0 0.0	249.0 0.0 -	-	0 0.0	0.0	- 1-						-11.2 100.0	238.8			238.8	238.8	238.8	238.8	238.8	238.8		238.8	238.8			8

Appendix 9

Task 3 – Pre-Implementation Retrofit

Task 3 - Pre-Implementation Retrofit

Introduction

A major problem facing an intended new power plant investor is the choice between a plant design that cannot capture CO_2 and one that can only operate with CO_2 capture. With the former, he will face penalties under any carbon tax levy for which his only recourse is to pay. The latter choice will give him an uncompetitive plant for today that produces by-product CO_2 to no benefit.

The ideal option would be a plant designed to be capable of operating efficiently with or without CO_2 capture, dependant on the prevailing commercial conditions. However, it is generally perceived that a plant capable of capturing CO_2 cannot be operated efficiently when operating without CO_2 capture and existing IGCC plant design require major and costly changes to allow them to capture CO_2 . Previous work by Jacobs demonstrates that a plant with pre-investment for future CO_2 capture could be commercially competitive if full advantage is taken of the non-captured CO_2 in increasing capture plant internal power output and reducing the parasitic power load by removing the requirement to inject nitrogen.

This option can be made available using the designs for Cases 3-1 and 3-2, renamed Cases 3-3 and 3-4 respectively. These designs could be operated to advantage without CO_2 capture. The fuel gas diluent of nitrogen and water vapour, both of which are energy intensive to use, could be replaced simply by leaving the CO_2 in the fuel gas. Here it acts as the diluent and is eventually discharged up the stacks of the CCPP and Power Block.

Process Description and Performances

Case 3-3

The flowscheme of the fuel production plant (rather than a capture plant) is very similar to the flowscheme for the capture plant. The three differences are that the Acid Gas Removal unit does not remove CO_2 from the fuel gas, the CO_2 Compression and Drying section is omitted as are the large nitrogen compressors from the Fuel Gas Conditioning section.

The equipment to remove CO₂ from the fuel gas can easily be added to the Acid Gas Removal unit as can the equipment for CO₂ Compression and Drying and the nitrogen compressors required for the Fuel Gas Conditioning section.

The gas leaving the Acid Gas Removal section is therefore sulphur free, but rich in CO_2 . The Gas Conditioning section simply heats the gas using heat recovered from the Cooling section. There is no need for any nitrogen addition as this gas is in fact ideal for feeding to the CCPP, having a flame temperature coincident with 25ppm NO_x .

The hot syngas passes to the Power Block and the CCPP as in the CO₂ removal case.

One difference to the CO₂ removal case is that the Power Block in this case requires two GE 6B gas turbines to make best use of the stream generated from waste heat recovered in the Cooling section. The power generation in this case is therefore significantly larger than the CO₂ removal case reported, due to the existence of the additional gas turbine together with the additional fuel gas mass flow achieved using CO₂ as a diluent rather than nitrogen. Therefore the output from the gas turbines in

both the Power Block and the CCPP are increased. There is also lower internal power consumption as there is no need to compress CO₂ or large quantities of nitrogen.

A summary of the plant performance and costs is given in tables 1 and 2 below and at the end of this appendix.

Case 3-4

This case is essentially the same as case 3-3 although with the remote turbine there is no preheating of the fuel to the CCPP. Instead this is achieved using steam from the HRSG of the CCPP. The steam is condensed and returned to the HRSG as there is no need for additional diluent for the gas turbine as there was in the CO₂ removal case.

The Gas Conditioning block in this case only preheats the Power Block fuel as these are local to the fuel gas generation plant.

The Power Block in this case has the same number of gas turbines as the CO₂ removal case, so there is no increased output due to this although all the other factors mentioned above for case 3-3 also apply to this case as well.

A summary of the plant performance and costs is given in tables 1 and 2 below and at the end of this appendix.

Table 1 – Plant Performance Output (No CO₂ Capture)

Plant Performance Output	Ref.	3-3	3-4	
Combined Cycle Power Plant Net Electrical Output	784.8	846.6	820.8	MWe
Fuel Plant Auxiliary Power Consumption	-	-154.3	-158.9	MWe
Fuel Plant Power Production	-	281.3	270.7	MWe
Overall Plant Net Power Output	784.8	973.6	932.6	MWe
Total Plant Fuel Consumption (LHV)	1404.6	2388.7	2390.7	MWth
Fuel Gas to Combined Cycle Power Plant	1404.6	1478.8	1406.3	MWth
Overall Plant Net Electrical Efficiency	55.9	40.8	39.1	%

The heat rate of the gas turbine when operating on fuel gas diluted primarily with CO₂ is higher than operating on syngas diluted primarily with nitrogen. This is because the higher mass flow of fuel gas requires a reduced firing temperature to avoid overloading the gas turbine shaft.

Economic Analysis

Table 2 – Additional Capital Expenditure (No CO₂ Capture)

Additional Capital Expenditu	re	•	Ref.	3-3	3-4	
Additional Capital Costs ¹			-	949	1102	Million US \$
Specific Total Investment			529	1401	1627	US \$/MWe
Costs of Electricity			30.3	44.4	49.8	US \$/MWh

Notes

1. On top of capital expenditure for reference plant of 415 million USD

Conclusions

A fuel plant can be built which is CO₂ capture ready and used to refuel an existing gas turbine at similar efficiencies and costs to a traditional IGCC without the ability to capture CO₂. The prices for natural gas and coal as used in the study means that the cost of electricity produced by such a plant is not competitive with electricity produced from natural gas in a combined cycle. However, there are some parts of the world, most notably North America where the price differential between coal (or petroleum coke) and natural gas would mean that refuelling a natural gas combined cycle with syngas are now commercially attractive.

Despite the lower heat rate of the gas turbine when operating on CO₂ contain syngas, the power output of the CCPP is increased and overall efficiency is in line with commercial IGCC's operating on solid feedstock.

Just as in the CO₂ capture cases 3-1 and 3-2, the remote fuel plant, case 3-4 is less efficient than the local fuel plant. This is because power cannot be recovered from the expander, as the fuel gas is piped at high pressure and also heat from the fuel plant cannot be used to preheat the fuel gas to the CCPP. This function is carried out by using steam taken from the HRSG of the CCPP, which reduces the overall output of the CCPP when compared with the local case.

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	REFERENCE	RETRO	-IT					REFEREN	RETROF	IT				REFERENCE	RETROI	IT				REFERE	RETROF	IT								
Production					Capital C	Cost		Million \$ 1	/lillion \$		Operating	Costs		MM \$/year	/M \$/yea	•	Economi	c paramet	ers						Results	summary				
Fuel feedrate	2388.7	0.0	MVV		Installed	costs		1165.5	0.0		at 100% l	ad facto	r	1	- 5		Discount	rate		10.0		%			Emission	avoidand	e cost		167.527	/t CO2
Net power output	973.6	0.0	MVV		Continge	ncies		10.0%	10.0%		Fuel			113.0	0.0		Load fact	or		85.0	0.1	%			(Note: Ty	pe Tools	'Solver' 'S	Solve' to c	calculate	
CO2 output	0.0	0.0	t/h					116.6	0.0		Maintenan	ce		31.6	0.0		Fuel price			1.50	1.50	\$/GJ			the CO2	emission	avoidance	e cost the	at gives a z	ero NF
Solid waste output	1.70	1.70	t/h		Owners of	costs		7.0%	7.0%		Chemicals	+ consu	umables	4.2	0.0		CO2 price	9		167.5	167.5	\$/t			NPV				0.00	M\$
CO2 emissions	_	828	g/kVVh					81.6	0.0		Insurance	and loca	Itaxes	23.3	0.0		Waste dis	sposal cos		184.5	184.5	\$/t			IRR				10.00%	
					Retrofit e	scalation	basis year	r	9		Waste dis	posal		2.7	0.0		Insurance	and local	taxes	2%	2%	of install	ed cost/v	,						
Reference plant data	For calculation	of cost of	emission						0%		Operating			3.5	0.0		Number o			30	30									
CO2 emissions	_		g/kVVh			xpenditur			0.0%		Ĭ						Cost per	perator		75.0	75.0	\$k/y								
Electricity cost	4.442		c/kWh			pital cost		1363.6	0.0								Administr			56%		of operat	tors cost		Breakdo	wn of c/k	Wh cost			
,																	Fuel stora	age		30		davs			Fuel				29.82%	
Retrofit year (n)		100	-		Working	Capital					Decommi	ssionina	cost	0	0		Chemical	_		30		days			Capital				51.25%	
Retrofit Expenditure year (n-2)		20%	_			ls storage		0.4	0.0								Start up ti			3		months			Other cos	sts			18.92%	
Retrofit Expenditure year (n-1)		45%			Fuel stor			10.9	0.0	10							Retrofit do					months			02.70, 00	7.0			10.0270	
Retrofit Expenditure year (n)		35%				rking cap	ital	11.3	0.0	-								or, remaind	ler vear	60	60	%								
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
'ear		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor					45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours					3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure Factor		0%	40%	60%																										
Revenues										- 30																				
Electricity					170.5	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	322.0	
CO2 revenues(based on por	wer output retrofit	case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs		0.																												
Fuel		0.0	0.0	0.0	-50.8	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	-96.0	
Maintenance		0.0	0.0	0.0	-14.2	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	-26.9	
Labour		0.0		0.0			-3.5	-3.5	-3.5	-3.5		-3.5	-3.5					-3.5	-3.5	-3.5	-3.5	-3.5	-3.5							
Chemicals & consumables		0.0		0.0			-3.6	-3.6	-3.6	-3.6		-3.6	-3.6					-3.6	-3.6	-3.6		-3.6	-3.6							
Waste disposal		0.0		0.0			-2.3	-2.3	-2.3	-2.3	100000000000000000000000000000000000000	-2.3	-2.3					-2.3	-2.3	-2.3	-2.3	-2.3	-2.3							
Insurance and local taxes		0.0		0.0			-23.3	-23.3	-23.3	-23.3		-23.3			/			-23.3	-23.3	-23.3		-23.3	-23.3							
ixed Capital Expenditures		0.0		-818.2			0.0	0.0	0.0	0.0		0.0	0.0			0.0		0.0	0.0	0.0	0.0	0.0	0.0					0.0		0.0
Norking Capital		0.0	0.0	0.0	-11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.3
Decommissioning Cost																														0.
otal Cash Flow (yearly)		0.0	-545.5	-818.2	64.1	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	166.4	11.3

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	REFERENCE	RETROF	-IT					REFEREN	RETROFI	Т				REFERENCE	RETROF	iT.				REFERE	RETRO	FIT								
Production				(Capital C	ost		Million \$	Million \$		Operatir	ng Costs		MM \$/year /	IM \$/yea	r	Economi	ic parame	eters						Results	summary				
Fuel feedrate	2390.7	0.0	MVV	li li	nstalled c	costs		1296.8	0.0		at 100%	load fact	or	-			Discount	rate		10.0		%			Emission	avoidanc	ce cost		167.527	\$/t (
Net power output	932.6	0.0	MVV	(Continger	ncies		10.0%	10.0%		Fuel			113.1	0.0		Load fact	or		85.0	0.1	%			(Note: Ty	pe Tools	'Solver'	'Solve' to d	calculate	
CO2 output	0.0	0.0	t/h					129.7	0.0		Maintena	nce		34.6	0.0		Fuel price	9		1.50	1.50	\$/GJ						ce cost tha		
Solid waste output	1.84	1.70	t/h	(Owners c	costs		7.0%	7.0%		Chemica	ıls + cons	umables	4.3	0.0		CO2 pric	е		167.5	167.5	\$/t			NPV				0.00	M
CO2 emissions	-	828	g/kVVh					90.8	0.0		Insuranc	e and loca	al taxes	25.9	0.0		Waste di:	sposal co	st	184.5	184.5	\$/t			IRR				10.00%	,
				F	Retrofit es	scalation b	oasis yea	r	9		Waste di	sposal		3.0	0.0		Insurance	e and loca	l taxes	2%	2%	of insta	lled cost/	/						
Reference plant data	For calculation	of cost of	emission						0%		Operatin	-		3.5	0.0		Number o	of operato	rs	30	30									
CO2 emissions	_		g/kWh			xpenditure			0.0%								Cost per			75.0	75.0	\$k/v								
Electricity cost	4.984		c/kWh			ital cost		1517.2	0.0								Administr			56%			ators cos		Breakdo	wn of c/k	Wh cost			
7.5					1												Fuel stora			30		days			Fuel				27.78%	
Retrofit year (n)		100	-	ì	Norking	Capital				12	Decomn	nissioning	g cost	0	0		Chemica			30		days			Capital				53.03%	
Retrofit Expenditure year (n-2)		20%	-			s storage		0.4	0.0								Start up t			3		months			Other co:	sts			19.20%	-
Retrofit Expenditure year (n-1)		45%	-		uel stora			10.9	0.0								Retrofit d			_	1	months								
Retrofit Expenditure year (n)		35%	-			rking cap	ital	11.3	0.0								Load fact		100	60	60	%								
Million \$		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2
Year		000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	2
Load Factor					45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	,
Equivalent yearly hours			100		3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7448	7446	7446	7446	7446	7446	7446	,
Expenditure Factor		0%	40%	60%																										
Revenues										- 1													2		1					
Electricity					183.2	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	346.1	
CO2 revenues(based on pov	wer output retrofit	case)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs		- 6																												
Fuel		0.0	0.0	0.0	-50.9	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	-96.1	
Maintenance		0.0	0.0	0.0	-15.6	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	-29.4				-29.4	-29.4	-29.4	-29.4	-29.4	-29.4	
Labour		0.0	0.0	0.0	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	-3.5	,
Chemicals & consumables		0.0	0.0	0.0	-1.9		-3.6			-3.6	-3.6				-3.6															
Waste disposal		0.0	0.0	0.0	-1.3		-2.5	-2.5		-2.5	-2.5				-2.5	-2.5														_
Insurance and local taxes		0.0	0.0	0.0	-25.9		-25.9			-25.9					-25.9				-											-
Fixed Capital Expenditures		0.0	-606.9	-910.3	0.0	0.0	0.0			0.0	0.0	0.0			0.0	0.0	0.0			-										-
Working Capital Decommissioning Cost		0.0	0.0	0.0	-11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
T. 10 151 7 10		0.0	-606.9	-910.3	72.7	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	\vdash
Total Cash Flow (yearly)																														