CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 02 - in effect as of: 1 July 2004)

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:
Mondi Gas Turbine Co-generation in Richards Bay, South Africa

A.2. Description of the project activity:
The project activity encompasses the installation of a package cogeneration system whose input is (the equivalent of) natural gas from a pipeline, and whose outputs are electricity and heat supplied to an industry with demand for heat and electricity. The installation of the cogeneration system will take place at the Mondi Richards Bay operation premises. Mondi Business Paper will own and operate the cogeneration system and will utilise the electricity and heat generated by the cogeneration system in its operation at the Richards Bay mill. By introduction of the cogeneration system, the total amount of fossil fuels currently utilised through electricity imported from the national grid and coal used in the production of process heat and power to the mill, will be reduced, resulting in a reduction in an estimated 245 236 tonnes CO_{2e}/year.

A.3. Project participants:
Mondi Business Paper, Richards Bay (project developer), to be authorized by the South African DNA.

Official contact:
C Terblanche
Mondi Business Paper
PO Box 1551
Richards Bay
South Africa
3900

ciska.terblanche@mondibp.com

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:
The Richards Bay Mill

A.4.1.1. Host Party(ies):
The host country is South Africa

A.4.1.2. Region/State/Province etc.:
Kwa-Zulu Natal

A.4.1.3. City/Town/Community etc:
Richards Bay

A.4.1.4. Detail of physical location, including information allowing the unique identification of this project activity (maximum one page):

The cogeneration system will be located at the Richards Bay operation. This operation is located in Richards Bay, a harbour and industrial town that has developed since the early 1980's and is situated approximately 180 km north of Durban. The Mill site has a spacious layout with ample space for large-scale expansions. It has good road and rail connections, and is located only a few kilometres from the Richards Bay harbour. The Richards Bay mill is an integrated pulp and paper process producing bleached eucalyptus pulp and white top linerboard. The mill was commissioned during October 1984.

A.4.2. Category(ies) of project activity:

Co-generation and fuel switching. Sectoral scopes 1: Energy industries (renewable - / non-renewable sources) and Sectoral scope 4: Manufacturing industries

A.4.3. Technology to be employed by the project activity:

The project proposes the installation of a combined-cycle gas fired turbine for co-generation by Mondi Business Paper, Richards Bay. The gas-fired turbine will consume the equivalent of natural gas and produce heat and power required in the pulp and paper production process. Currently, the operation continually uses three power boilers, of which two are fired with coal to provide heat and electricity to the manufacturing plants. Mondi Richards Bay also imports electricity from the South African national grid.

Cogeneration involves the sequential use of energy to produce simultaneously, either electrical or mechanical power, in addition to usable process heat (in the form of steam). A gas turbine generator (GTG) with a heat recovery steam generator (HRSG) was identified as the most appropriate configuration for the Richards Bay mill.

The experience of pulp and paper industries in non-Annex 1 countries with cogeneration systems is limited. There are a number of technological barriers to the implementation of a cogeneration system with heat recovery in South Africa. The proposed project, which involves Combined Cycle Gas Turbine (CCGT) technology is the first of its kind in South Africa, and provides an opportunity for technology transfer from X[1] to South Africa. It is almost certain that implementation of this technology will encourage replication in other pulp and paper mills and other industry sectors within South Africa and the region.

Basic information for the cogeneration system:

Net electrical output under site conditions: 27.5 Megawatts (rated capacity) and
Net heat output under site conditions: 37 tonnes steam per hour

[1] Technology choice between two different technologies sourced from different countries to be determined.

A.4.4. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

1. Reduction of electricity imported from the national grid
   - The introduction of the gas turbine into the energy balance of the operation will result in a reduction of electricity imported from the national grid. Electricity produced from cogeneration with gas as energy source offsets electricity generated using coal fired power plants and reduces transmission and distribution losses associated with power plant generated electricity.
2. Reduction in CO_2, N_2O and CH_4 emissions from coal burnt on site
   - The introduction of a gas turbine into the energy balance at the operation will result in a total replacement of coal-fired boilers with a gas-fired turbine. The GHG emissions at the operation associated with the combustion of coal will reduce significantly.
3. Reduction in emissions associated with the transport of coal to the operational site
   - Coal is transported by rail to the operational site. Coal will be reduced significantly when the project is implemented, thereby eliminating the need for coal transport to the operation.

These reductions are a consequence of the project activity that would not have occurred because of the following barriers:

1. Technological Barrier and barrier due to prevailing practice.
   This technology is not currently implemented in the southern hemisphere. The project activity is the first in its kind in South Africa.

2. Investment analysis.

The alternative option:

1. Continuation of the current situation (Status Quo). Mondi Richards Bay will continue fuelling the existing Power Boilers with coal. The operation will continue to import electricity from the national grid.
2. The alternative project activity includes the introduction of a gas turbine to produce heat and power avoiding the cost of grid electricity outages. A conservative i.e. low cost high income/savings cash flow analysis reveals the results of the cash-flow models for additionality considerations, with the IRR expressed on a project basis and being compared to the Mondi internal hurdle/benchmark. These models illustrate that it would be unlikely that the project would go ahead given the required higher return needed because of the risks of the project and the sensitivity of the changes to assumptions impacting the project.

   The alternative will comply with all South African regulations. The proposed project activity is not the only alternative amongst the ones considered by Mondi that complies with all regulations. South Africa's Energy Policy aims to diversify the supply sources and primary energy carriers as a matter of dealing with security of energy.

A.4.4.1. Estimated amount of emission reductions over the chosen crediting period:

Crediting period: 10 years from October 2006 onwards

Total estimation of emission reductions over the crediting period: 245 236 tonnes CO_{2e}/year
Total annual estimate of emissions reductions over the crediting period: 2.45 million tonnes CO_{2e}

A.4.5. Public funding of the project activity:

No public funding is involved in the proposed project activity.

SECTION B. Application of a baseline methodology

B.1. Title and reference of the approved baseline methodology applied to the project activity:

The baseline under consideration has yet to be approved and is attached to this document as NM00XX. "Gas powered combined cycle cogeneration replacing coal based steam generation and grid electricity".

B.1.1. Justification of the choice of the methodology and why it is applicable to the project activity:

>>The methodology that is attached to this project design document is comprised of parts of a number of other approved methodologies including ACM0002 for the combined margin approach to emissions from grid electricity, the AM0008 and AM0014 that deal with fuel switching from coal and fossil fuels to natural gas and the use of natural gas "package" combined heat and power respectively.

B.2. Description of how the methodology is applied in the context of the project activity:

>>The project activity includes the provision of electricity and heat from natural gas. The baseline scenarios include an element dealing with heat from coal and another with electricity from the national grid in the quantities.

The heat baseline makes use of AM0008 and AM0014. It calculates the amount of coal that would be required to provide the same amount of heat (steam) as that provided in by project activity. The emissions from the coal can then be estimated from the coal emissions intensity data.

For the electricity part of the baseline, the methodology will be applied using Option b of ACM002 (the Consolidated Methodology for Grid Connected Projects), as this is the most complete of the options, with the exception of Option c. Option c (Dispatch Data Analysis) will not be used because data is not available and even if it were available, the costs of processing data would be beyond the amount affordable by the project developer. The data used for the calculation of the combined margin is shown in Annex 3 of this document. The main source of data for this project is the annual reports of NER (the National Electricity Regulator) and data supplied directly from this agency. The defaults used for the calculation of calorific values for fuel types and fuel oxidization, came from the IPCC GHG Gas Inventory Reference Manual (IPCC 1996). Fuel consumption of the plants in the national grid is not available for all plants, thus, this has been estimated in such cases where data is lacking in this draft CDM PDD using the Standard IPCC Guidelines for National Greenhouse Gas Inventories (1996).

B.3. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity:

>>
Tool for the demonstration and assessment of additionality

1. This PDD follows the step-wise approach to demonstrate and assess additionality. These steps include:

- Identification of alternatives to the project activity;
- Investment analysis to determine that the proposed project activity is not the most economically or financially attractive;
- Barriers analysis;
- Common practice analysis; and
- Impact of registration of the proposed project activity as a CDM project activity.

Based on information about activities similar to the proposed project activity, the common practice analysis is to complement and reinforce the investment and barriers analysis. The steps are summarized in the flow-chart below.

STEP 0. PRELIMINARY SCREENING BASED ON THE STARTING DATE OF THE PROJECT ACTIVITY

Project commences in Fourth Quarter of 2006

STEP 1. IDENTIFICATION OF ALTERNATIVES TO THE PROJECT ACTIVITY CONSISTENT WITH CURRENT LAWS AND REGULATIONS

Define realistic and credible alternatives to the project activity(s) that can be (part of) the baseline scenario through the following sub-steps:

Sub-step 1a. Define alternatives to the project activity:

The alternatives to the project activity are:

1. The current situation of importing grid electricity and coal for power.
2. Heat and power from biomass.
3. Heat and power from other sources.
4. Plant closure.

Sub-step 1b. Enforcement of applicable laws and regulations:

1. The alternative(s) are all in compliance with all applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions, e.g. to mitigate local air pollution.

STEP 2. INVESTMENT ANALYSIS

The option 2 cannot be affected as biomass is already committed from bark, contaminated wood chips, and plantation waste for up to 50kilometres in radius of the plant.

Option 3 cannot be fulfilled as there are no other available sources of fuel other than coal and biomass that could readily compete with the project activity using gas.

Option 4 is not a viable option.

Sub-step 2a. Determine appropriate analysis method
The selected option is to undertake a IRR analysis of the proposed project activity and to compare that to Mondi's investment hurdle rate.

Sub-step 2b. – Option II. Apply investment comparison analysis
An investment analysis shows that the rate of return of the base case of the project activity is below the threshold for the project participant for a project of this nature.

Sub-step 2d. Sensitivity analysis (only applicable to options II and III):

The analysis used the most conservative figures for interest, escalations, inflation, tax, capital and operating costs. It also maximised the savings attributable to a more reliable source of electricity.

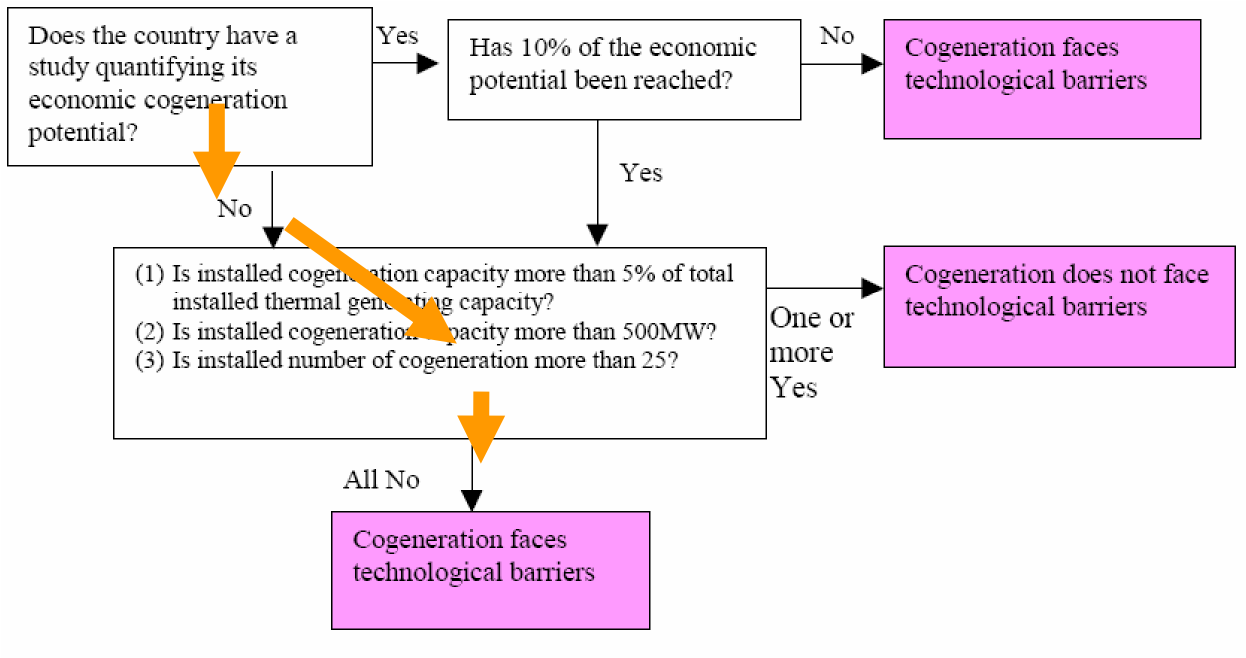
On stressing the cash flow to point of the lowest plausible alternative and highest positive proposed project activity, it was concluded that the project would not go ahead given the annual after tax including inflation effect since Mondi's hurdle rates would require a much higher return given the risks faced by the project and the potential range of assumptions that impact on a project such as this.

STEP 3. BARRIER ANALYSIS

Sub-step 3a. Identify barriers that would prevent the implementation of type of the proposed project activity:

The main barrier is technological. It is the first time that a CCGT is installed for heat and power production by an independent power producer. Using AM0014 barrier analysis method.

Technological barriers, *inter alia*:
Additionality test 1 is applied by following the flow chart below. A low market share of cogeneration means that there is insufficient infrastructure to support installation and maintenance of such systems, acting as a technological barrier to project participants.



Barriers due to prevailing practice, *inter alia*:

- The project activity is the “first of its kind”: No project activity of this type is currently operational in the host country or region.

The identified barriers are only sufficient grounds for demonstration of additionality if they would prevent potential project proponents from carrying out the proposed project activity if it was not expected to be registered as a CDM activity. In this case the proposed project activity is the first capacity of its class and is lower than 500MWs. So technological barriers do exist.

Sub-step 3 b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

The barrier does not affect the alternative/s.

STEP 4. COMMON PRACTICE ANALYSIS

The project activity is not common practice.

Step 5. Impact of CDM registration

The impact of CDM registration would conservatively allow for credits to accrue until 2012.

The increased rate of return would contribute to the project’s profitability and present a more feasible project, though still marginal with respect to Mondi’s expected rate of return threshold.

B.4. Description of how the definition of the project boundary related to the baseline methodology selected is applied to the project activity:

>>

The following emissions are considered:

a) **CO_2 from combustion.** CO_2 emissions corresponding to the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. CO_2 emissions corresponding to the combustion of gas in the project activity.

b) **CH_4 from combustion.** CH_4 emissions corresponding to the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. CH_4 emissions corresponding to the combustion of gas in the project activity.

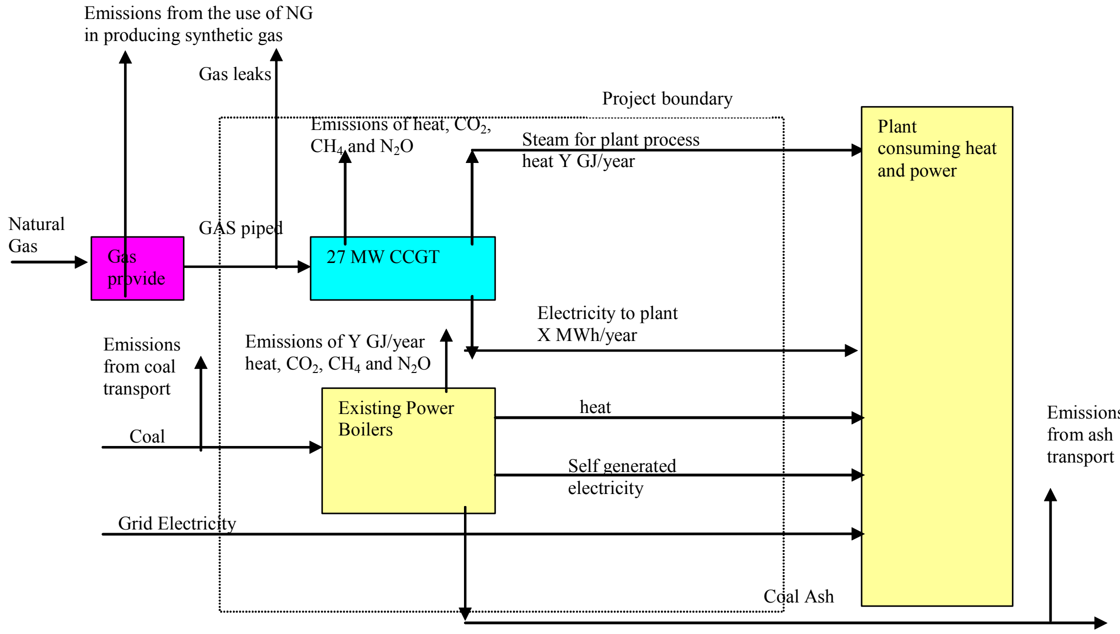
c) **N_2O from combustion.** N_2O emissions corresponding to the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. N_2O emissions corresponding to the combustion of gas in the project activity.

d) **CH_4 leaks.** CH_4 emissions from leaks in the transport and distribution pipeline supplying the operation and leaks in the gas distribution piping within the operation, associated with the gas consumption.

e) **CO_2 from electricity generation.** CO_2 emissions associated with the electricity that would have to be purchased from the power grid if the cogeneration system did not provide electricity to the operation. The emissions are corrected to take account of transmission and distribution losses.

f) **CO_{2eq} from transportation.** CO_2 emissions associated with the transportation of coal and ash are included as leakage.

The diagram below describes the project boundary.



B.5. Details of baseline information, including the date of completion of the baseline study and the name of person (s)/entity (ies) determining the baseline:

>>

ID no.	Data	Unit	When used	Sources
1	List of plausible scenarios		Baseline and additionality definition	To be elaborated by PP
2	Baseline IRR	%	Baseline and additionality definition	To be elaborated by PP
3	Project Activity IRR without CERs	%	Baseline and additionality definition	To be elaborated by PP
4	Discount rates	%	Baseline and additionality definition	National Statistics
4b	Escalation rates (coal, electricity, gas)	%	Baseline and additionality definition	To be elaborated by PP and suppliers
5	Threshold IRR	%	Baseline and additionality definition	To be elaborated by PP
6	Baseline power production	MWh/year	Baseline and additionality definition	To be elaborated by PP
7	Baseline heat production	GJ/year	Baseline and additionality definition	To be elaborated by PP
8	Emissions from NG	Tonnes CO2/GJ	Project activity	IPCC
9	Emissions from coal	Tonnes CO2/GJ	Baseline and additionality definition	IPCC
10	Emissions from Electricity Grid	Tonnes CO2/MWh	Baseline and additionality definition	Electricity suppliers
11	Quantity of Coal used in power boilers	Tonnes/year	Baseline and additionality definition Project activity and baseline	To be elaborated by PP
12	Quantity of NG used to produce MRG	GJ/Year	Leakage	To be elaborated by gas supplier
13	Quantity of electricity used	MWh/year	Project activity and project baseline	To be elaborated by PP
14	Emissions from transportation of Ash	Tonnes CO2/year	Leakage	To be elaborated by PP
15	Emissions from transportation of coal by rail	Tonnes CO2/year	Leakage	To be elaborated by rail transporters and PP
16	Emissions from the transmission of MRG	Tonnes CO2/year	Leakage	Gas supplier
17	Electricity and transmission and distribution losses	%	Project baseline	Transmission and distribution authortity
18	Price of coal	Rands/tonne	Baseline and additionality definition	To be elaborated by PP
19	Price of MRG	Rands/GJ	Baseline and additionality definition	To be elaborated by PP
20	Price of electricity from grid	Rands/MWh	Baseline and additionality definition	To be elaborated by PP
21	Operations manual for power production	-	Baseline and additionality definition	To be elaborated by PP
22	Electricity outages	-	Baseline and additionality definition	To be elaborate by PP
23	Others?			

Baseline completed 13th April

Defined by Ciska Terblanche

SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

The project activities can be initiated in September 2006

C.1.2. Expected operational lifetime of the project activity:

20 years

C.2 Choice of the crediting period and related information:

C.2.1. Renewable crediting period

Not selected

C.2.1.1. Starting date of the first crediting period:

>> not applicable

C.2.1.2. Length of the first crediting period:

>> not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

The project is expected to be operating by September 2006.

C.2.2.2. Length:

10years

SECTION D. Application of a monitoring methodology and plan

D.1. Name and reference of approved monitoring methodology applied to the project activity:

"Gas powered combined cycle cogeneration replacing coal based steam generation and grid electricity"

D.2. Justification of the choice of the methodology and why it is applicable to the project activity:

This methodology is comprised of methodologies employed in previously approved methodologies including ACM 0002, AM0008 and AM 0014, which deal with, an electricity baseline, natural gas for combined heat and power in the project activity and natural gas replacing a fossil fuel (coal) in the provision of process heat. Transport emissions are also calculated from an approved methodology. Additions to the monitoring include transmission losses for electricity and gas, and a mass balance used to estimate the up-stream leakage in the production of incremental synthetic gas from increments inputs of natural gas.

D.2. 1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:								
ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1. Q_NGy	Quantity of natural gas used by project activity	Measured and converted from metered volumes	joules	m	continuous	100%	electronic	Converted from physical quantity (e.g., m3), if needed, using conversion factor (e.g., kcal/m3) provided by local supplier. Confirmed by natural gas purchase record. Confirmed to be equal to ∑*n*, operation pattern *Qn*_NG*y*
1-n. Qn_NGy	Quantity of natural gas used at the process n	Measured and converted from metered volumes	joules	m	Monthly	100%	electronic	Converted from physical quantity, if needed, using conversion factor provided by local supplier (see above). This value is monitored by operation pattern (e.g., normal, start-up, holiday, etc.) at the process *n* (e.g., boiler).
2-n. η_n_NG	Fuel efficiency of natural gas used at the process n	Process n energy balance	%	measured; estimate ex ante to calculate total ER	once at the early stage of the project	100%	Electronic	Not a single value but a pattern (function) of "load factor" at the process *n*. Preferable to draw a graph as a function of load factor. The measurement should be repeated for each process *n* with several load factors in order to get the curve of η_n with statistical significance.
3. L_Factor $_n$	Load factor of operation pattern at the process n	Process n	%	m	once before fuel switch	100%	Electronic	Plural values of load factor are measured for "pre-set" operation patterns (such as normal operation, start-up, shut-down, holiday operation, etc.)
4. MCEO	Amount of electricity supplied to plant		MWh/year	M	Monthly	100%	Electronic and paper PI	
5. MCHO	Cogeneration heat supplied to plant		GJ/Year	M	Monthly	100%	Electronic and paper PI	

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>> The project emissions PE_y (measured in ton of CO_2 equivalents (tCO_2e/yr)) during a year (y) is expressed as:

$PE_y = (\sum_i Q_i\_NG_y) * (EF\_NG + FC\_NG\_CH_4 * GWP\_CH_4 + FC\_NG\_N_2O * GWP\_N_2O)$ Equation 1

where:

$Q_i\_NG_y$	Are quantity of natural gas used in the project scenario for replacing $Q\_F_{i,y}$ quantity of fuel i used in the baseline scenario, measured in energy units (e.g., Joule).
$Q\_NG_y = (\sum_i Q_i\_NG_y)$	Are the total quantity of natural gas in the project scenario for replacing all quantity of fuel i used in some element processes in the baseline scenario.
EF_NG	Are the IPCC default CO_2 emission factor per unit of natural gas associated with fuel combustion (e.g., tCO_2/Joule).
$FC\_NG\_CH_4$	Are the IPCC default CH_4 emission factor of natural gas associated with fuel combustion, measured in tCH_4/Joule.
$FC\_F_i\_N_2O$	Are the IPCC default N_2O emission factor of natural gas associated with fuel combustion, measured in tN_2O/Joule.

The variables in the baseline emissions ($Q_n\_F_{i,y}$) and the project emissions ($Q_n\_NG_y$) are linked with the constraint relation:

$Q_n\_F_{i,y} * \eta_n\_F_i = Q_n\_NG_y * \eta_n\_NG$ Equation 2

For each element process n which uses the fuel i in the baseline scenario. Here $\eta_n\_F_i$ and η_n_NG are fuel efficiency for use of fuel i (baseline scenario) and natural gas (project scenario) respectively, measured either in unit of output per unit of energy (e.g., ton of output/Joule) or ratio of the output energy to the input energy, or the percentage, as appropriate $\eta_n\_F_i$ and η_n_NG are regarded as functions of the load factor measured *ex-ante* before fuel switching[3] (for $\eta_n\_F_i$) and at the early stage of each crediting period[2] (for η_n_NG). This relation should be kept at each operating pattern,[3] in which a single load factor can represent.

Total project activity emissions

Total project emissions per year = emissions intensity of natural gas * quantity of natural gas used in the production of heat and electricity = emissions intensity of project electricity * quantity of electricity produced by project activity (MCEO MWh/year) + emissions intensity of project activity heat * quantity of process heat produced by the project activity (MCHO GJ/year).

[2] The measurement should be repeated for each process n with several load factors in order to get the curve of η_n with statistical significance.

[3] The operating pattern may include normal operation, start-up, shut-down, holiday operation, etc. during which the load factor can be represented by a certain fixed value.

Total project activity emissions (tonnes CO_2 per year) = (MCEO MWh/year * 3600 Joules/MWh + MCHO GJ heat * 10 E9) * *EF*_NG Tonnes CO_{2e}/Joule Natural Gas

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :								
ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
6. EG_y (EG_h if dipatch data OM is used)	Electricity exported from the Grid	Electricity generation of each power source / plant j, k or n	MWh	Directly measured	yearly	100%	electronic	
7. EFy	CO2 emission factor of the grid	Identification of power source/plant for OM	tCO2 / MWh	C	yearly	100%	electronic	Calculated as a weighted sum of the OM and BM emission factors
8. EFOM,y	CO2 Operating Margin emission factor of the grid	Identification of power source/plant for BM	tCO2 / MWh	C	yearly	100%	electronic	Calculated as indicated in the relevant OM baseline method above
9. EFBM,y	CO2 Build Margin emission factor of the grid	Fraction of time during which low cost/must run-sources are on the margin	tCO2 / MWh	C	yearly	100%	electronic	Calculated as [∑i Fi,y*COEFi] / [∑m GENm,y] over recently built power plants defined in the baseline methodology
10. Fi,y	Amount of each fossil fuel consumed by each power source / plant	The merit order in which power plants are dispatched by documented evidence	Mass or volume	M	yearly	100%	electronic	Obtained from the power producers, dispatch centers or latest local statistics.

11. COEFi	CO2 emission coefficient of each fuel type i	The proportion of electricity lost compared to the electricity dispatched as a result of technical losses in transmission and distribution	tCO2 / mass or volume unit	M	yearly	100%	electronic	Plant or country-specific values to calculate COEF are preferred to IPCC default values.
12. GENj/k/n,,y	Electricity generation of each power source / plant j, k or n	Grid operator data	MWh/a	M	yearly	100%	electronic	Obtained from the power producers, dispatch centers or latest local statistics.
13.	Identification of power source/plant for OM	Grid operator data	Text	e	yearly	100%	electronic	Identification of plants (j, k or n) to calculate operating margin emission factor
14.	Identification of power source/plant for BM	Grid operator data	Text	e	yearly	100%	electronic	Identification of plants (j, k or n) to calculate operating margin emission factor
15. λ_y	Fraction of time during which low cost/must run-sources are on the margin	Grid operator data	number	c	yearly	100%	electronic	Factor accounting for number of hours per year during which lowcost/must-run sources are on the margin
16.	The merit order in which power plants are dispatched by documented evidence	Grid operator data	Text	m	yearly	100%	paper for original documents, else electronic	Required to stack the plants in the dispatch data analysis.

17. T&D	The proportion of electricity lost compared to the electricity dispatched as a result of technical losses in transmission and distribution	Frid operator data	%	c	yearly	100%	Electronic	Technical losses of electricity from the transmission and distribution of electricity across the entire selected electricity grid.
18. Q_Fi	The quantity of fuel i used in the baseline scenario,	Project proponent	Joules/ year	c	yearly	100%	electronic	

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>> **Electricity baseline calculations**

BEy = EGby x EFy Equation 3

Where:

EGby: Quantity of baseline grid electricity in year y (MWh)
EFy: Grid electricity emissions factor in year y (tCO2e/MWh)- as per ACM0002, see below
$EF_y = \omega_{om} * EF\_OM_y + \omega_{bm} * EF\_BM_y$ Equation 4

Where:

EF_y(offsite): Emission factor (tCO_2e / MWh)
ω_{OM}: Operating Margin weight, which is 0.5 by default
EF_OM: Operating Margin emission factor (tCO_2e / MWh)
ω_{BM}: Build Margin weight, which is 0.5 by default
EF_BM: Build Margin emission factor (tCO_2e / MWh)
y: A given year

and

$$EF\_OM_y = (1-\lambda_y)\frac{\sum_{i,j} F_{i,j,y} * COEF_{i,j}}{\sum_j GEN_{j,y}} + \lambda_y \frac{\sum_{i,j} F_{i,k,y} * COEF_{i,k}}{\sum_j GEN_{k,y}}$$ Equation 5

Where:
EF_OM: Operating Margin emission factor (tCO_2e / MWh)
***F*:** Amount of fuel *i* consumed by relevant power sources *j*
***COEF*:** CO_2 emission coefficient of fuel (t CO_2/ t)
***GEN*:** Electricity supplied by the plant to the grid (MWh)
***i*:** Refers to each fuel type
***j*:** Refers to operation power sources delivering electricity to the grid, not including low-operating cost and must-run power plants.
***k*:** Refers to power sources delivering to the grid from low cost/must run sources.
***y*:** Refers to a given year

$$\lambda_y(\%) = \frac{\text{Number of hours per year for which low - cost/must - run sources are on the margin}}{\text{8760 hours per year}}$$ Equation 6

$$EF\_BM_y = \frac{\sum_{i,m} F_{i,m,y} * COEF_{i,m}}{\sum_m GEN_{j,y}}$$ Equation 7

Where:
***EF_BM*:** Build Margin emission factor (tCO_2e / MWh) and
***m*:** Refers to last additions power sources delivering electricity to the grid.

$$EFy_{T\&D} = \left[\frac{EFy \times 100}{100 - T\&D}\right] - EFy$$ (Equation 8)

Where,

EFy **T&D** - Baseline emission factor of transmission and distribution losses for imported electricity to plant. The units are in tCO_2e/MWh
T&D – Transmission & Distribution loss % (These losses include technical electrical energy losses that incur during transmission & distribution). [The value used should be supported by documentary evidence]

Formulae used in the estimation of emissions from heat in the baseline scenario
The second part of the baseline includes the emissions from the fossil fuels used to produce the steam that provides process heat to the operation.

The baseline scenario for the project activity, which is eligible to use in this methodology, is that the current fuels (coal and/or petroleum fuels; denoted by *i* in the formula below) are continued to be used in the existing facility at least up to the end of the crediting period without any retrofit, which extends its capacity or lifetime, or improves its fuel efficiency.

The fuels that are replaced by the project activity *i* are identified using operating protocols of the plant concerned and correct by monitoring operating records.

The baseline emissions BE_y (measured in ton of CO_2 equivalents (tCO_2e/yr)) during a year (y)[4] is expressed as:

$$BE_y = \sum_i Q\_F_{i,y} * (EF\_F_{i,}\_CO_{2y} + FC\_F_i\_CH_4 * GWP\_CH_4 + FC\_F_i\_N_2O * GWP\_N_2O) \quad \text{(Equation 9)}$$

where:
$Q\_F_{i,}$ Are quantity of fuel *i* used in the baseline scenario, measured in energy units (e.g., Joule).
EF_F_i Are CO_2 equivalent emission factor per unit of energy of fuel *i* (e.g., $tCO_2e/Joule$).
FC_F_i CH_4 Are the IPCC default CH_4 emission factor of fuel *i* associated with fuel combustion, measured in $tCH_4/Joule$.
FC_F_i N_2O Are the IPCC default N_2O emission factor of fuel *i* associated with fuel combustion, measured in $tN_2O/Joule$.
GWP_CH_4 Is the global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period.
GWP_N_2O Is the global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period.

The parameters (variable) $Q\_F_{i,y}$ in the baseline emissions formula are calculated as specified in the "project scenario" section by using monitored parameters and default values.

[4] Throughout this document, suffix "*y*" denotes that such a variable parameter is the annual amount during a given year (*y*).

*FC*_NG_CH_4, *FC*_F*i*_CH_4, *FC*_NG_N_2O, *FC*_F*i*_N_2O, *FE*_NG_CH_4, *FE*_F*i*_CH_4, and *EF*_$TF_{(j \text{ or } k)}$ are obtained as the default values specified in the IPCC Guidelines on GHG Inventories or Good Practice Guidance Report.

Total baseline emissions
Total baseline emissions per year = emissions intensity of baseline electricity * quantity of electricity produced by project activity (MCEO MWh/year) + emissions intensity of baseline heat * quantity of process heat produced by the project activity (MCHO GJ/year)

Total baseline emissions = MCEO *(MWh/year) ** $EF_{y\ T\&D}$ *(tonnes* CO_2*e/MWh) + MCHO GJ/year * BEy/Y* (tonnes CO_2e/GJ) Equation 10

D. 2.2. Option 2: Direct monitoring of emission reductions from the project activity (values should be consistent with those in section E).

Not applicable.

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:								
ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Not applicable.

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

>> Not applicable.

D.2.3. Treatment of leakage in the monitoring plan

D.2.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project activity

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
15. MEC GS	*Quantity of synthetic gas dispatched down pipeline*	*From gas supplier*	*GJ/year*	*m*	*yearly*	*All data*	*Electronic and paper*	
16. Q_TFj,y	*Quantity of transport energy for mode "j" in yea r"y" for project activity*	*From transport records*	*GJ/year*	*m*	*Yearly*	*All data*	*Electronic and paper*	
17. Q_TFk,y	*Quantity of transport energy for mode "k" in year "y" for the baseline scenario*	*From transport records*	*GJ/year*	*m*	*Historic data*	*All data*	*Electronic and paper*	
18 GWP SG	*Global warming potential of synthetic gas*	*From analysis of contents*	*tCO2e/GJ*	*m*	*yearly*	*sample*	*Electronic and paper*	
19. Sasol mass balance factors								

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>> LE_y = [MEC $GS_{j,y}$ * FE_NG_CH_4 – MEC $GS_{k,y}$ * FE_NG_CH_4)] * GWP_CH_4
+ [$\sum_j$ (Q_$TF_{j,y}$ * EF_TF_j) – $\sum_k$ (Q_$TF_{k,y}$ * EF_TF_k)] + (MEC GS - Q_NGy *10^9) * GWP SG - (Natural gas used a SASOL to produce MRG) Equation 11

Where FE_NG_CH_4 and FE_F_i_CH_4 are the IPCC default CH_4 emission factor of natural gas and fuel i associated with fugitive emissions (tonnes CH_4/joules/year). In case that the effect of methane leaked from pipeline cannot be neglected, it should be included in this term (although it is not a function of Q_NG_y in the IPCC Guidelines).

For the transportation related part, Q_$TE_{j,y}$ and EF_TE_j are transportation energy quantity used and its CO_{2e} emission factor concerning the transportation mode j for project scenario and for mode k for baseline scenario (such as marine, railroad or truck). In case those information and data are not available due to uncertainties and diversities in energy market, the IPCC default value could apply. Otherwise, it could be estimated qualitatively in view of it being a relatively small part of the total emissions.

The natural gas used in the incremental synthetic gas production is considered upstream leakage. This source of leakage can be calculated using mass balances around the synthetic gas producer's plant. An example of the mass balance for the East and West plants at Secunda is available upon request which includes:

1. Process description and mass balance story line (Word document)
2. Excel document describing and numbering the streams in the mass balance
3. A worked example of a mass balance for a specific day. A spreadsheet is available providing the "PI tag numbers" i.e. the memory location in the Process Information system database that the figure is recorded. The PI system allows cumulative figures (monthly, annually etc.) to be captured as well.

The mass balance will be subject to independent validation and verification on application.

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

>> **Emissions reductions from the project activity**

Emissions reductions from the project activity = MCEO *(MWh/year)* * $EF_{y\ T\&D}$ *(tonnes CO_2e/MWh)* + *MCHO GJ/year* * *BEy/MCHO* (tonnes CO_2e/GJ) - (MCEO MWh/year * 3600 Joules/MWh + MCHO GJ heat * 10^9) * EF_NG Tonnes CO_2/Joule Natural Gas – LE_y Equation 12

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored

Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
1-5	*Low*	*These data are used to calculate the project activity emissions*
6-17	*Medium*	*These data are used to calculate the electricity baseline emissions*
18	*Low*	*These data are used to calculate the heat baseline emissions*
15-19	*Medium*	*These data used to calculate the leakage*

D.4 Please describe the operational and management structure that the project operator will implement in order to monitor emission reductions and any leakage effects, generated by the project activity

All parameters to be monitored will be included in the existing ISO 14001 system which describes the method of data collection and reporting, as well as the length of time for which data must be kept.

D.5 Name of person/entity determining the monitoring methodology:

>> Ciska Terblanche of Mondi Ltd
Mondi Business Paper
PO Box 1551
Richards Bay
South Africa
3900 ciska.terblanche@mondibp.com

For the Sasol Leakage
Gerrit Kornelius
Air Quality and GHG Advisor, Sasol SHE Centre
Box 5486
2000 JOHANNESBURG
+27 11 344 0141
+27 82 906 3196 gerrit.kornelius@sasol.com]

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

>> $PE_y = (\sum_i Q_i\_NG_y) * (EF\_NG + FC\_NG\_CH_4 * GWP\_CH_4 + FC\_NG\_N_2O * GWP\_N_2O)$
where:

$Q_i\_NG_y$	Are quantity of natural gas used in the project scenario for replacing $Q\_F_{i,y}$ quantity of fuel *i* used in the baseline scenario, measured in energy units (e.g., Joule).
$Q\_NG_y = (\sum_i Q_i\_NG_y)$	Are the total quantity of natural gas in the project scenario for replacing all quantity of fuel *i* used in some element processes in the baseline scenario.
EF_NG	Are the IPCC default CO_2 emission factor per unit of natural gas associated with fuel combustion (e.g., tCO_2/Joule).
$FC\_NG\_CH_4$	Are the IPCC default CH_4 emission factor of natural gas associated with fuel combustion, measured in tCH_4/Joule.
$FC\_F_i\_N_2O$	Are the IPCC default N_2O emission factor of natural gas associated with fuel combustion, measured in tN_2O/Joule.

The quantity of gas is estimated for the plant based on specifications is 2355 million GJ/year. The actual quantity of gas utilised will have to measured ex-post.

In GHG terms this will be
= 2355 million GJ/year/1000 GJ/TJ * tonnes NG/55GJ * (2.83 tonnes CO_2/tonne NG/55GJ/tonne NG + 1.4 kgs CH_4/TJ * 1tonne/1000kgs * 1TJ/GJ NG * 21 + 2.4kgN_2O/TJ NG * 1tonne/1000kgs * 1TJ/GJ NG * 310)

= 123 000 tonnes CO_{2e}/year

E.2. Estimated leakage:

>> LE_y = [MEC $GS_{j,y}$ * $FE\_NG\_CH_4$ – MEC $GS_{k,y}$ * $FE\_NG\_CH_4$)] * GWP_CH_4 + [$\sum_j (Q\_TF_{j,y} * EF\_TF_j) - \sum_k (Q\_TF_{k,y} * EF\_TF_k)$] + (MEC GS - Q_NGy *10^9) * GWP SG - (Natural gas used a SASOL to produce MRG) Equation 1

Where $FE\_NG\_CH_4$ and $FE\_F_i\_CH_4$ are the IPCC default CH_4 emission factors of natural gas and fuel *i* associated with fugitive emissions (tonnes CH_4/joules/year). In case that the effect of methane leaked from pipeline cannot be neglected, it should be included in this term (although it is not a function of Q_NG_y in the IPCC Guidelines).

For the transportation related part, $Q\_TE_{j,y}$ and EF_TE_j are transportation energy quantity used and its CO_{2e} emission factor concerning the transportation mode *j* for project scenario and for mode *k* for baseline scenario (such as marine, railroad or truck). In case those information and data are not available due to uncertainties and diversities in energy market, the IPCC default value could apply. Otherwise, it could be estimated qualitatively in view of it being a relatively small part of the total emissions.

Upstream leakage in the manufacture of synthetic gas
The estimated leakage from the Secunda plant will be estimated ex-post using the mass balance methodology. As natural gas has not been introduced to Secunda, there is no empirical data on which to

estimate the leakage. Sasol representative (Gerrit Kornelius) refers to modelling undertaken by the "Gas Circuit group in Sastech using ASPEN and came out to close to 1:1 on an energy basis." Evidence to substantiate this claim can be provided on request.

Physical leakage
The gas transmission leakage will also be physical leakage will be calculated using the difference between what Secunda dispatches and what Mondi receives. As Mondi is already receiving synthetic gas from use in their Lime kilns, the fraction of the total gas going to the turbine will be utilised in this leakage calculation.

For the purposes of the calculation there are no figures specific to South Africa or from the project as yet. Thus international revised estimates from the IPCC Guidelines for GHG inventories Volume 3 Reference manual Table 1-64, p. 1.131 are used indicates a values of 116 000 to 340 000 kg Methane per PJ. Taking an average of 230 000 kgs/PJ or 0.23kgs/GJ. The 2355 million GJ/year used in the power plant therefore results in leakage of:

2355 million GJ/year * 0.23kgs CH_4/GJ * 21
= 11374 tonnes CO_{2e}/year

Transport Leakage
As the leakage associated with transport is all positive. The reduction of emissions from transportation of coal and coal ash can be ignored on the grounds of conservatism.

E.3. The sum of E.1 and E.2 representing the project activity emissions:

>> 123 000 + 11374 tonnes CO_{2e}/year
= 134 372 tonnes CO_{2e}/year

E.4. Estimated anthropogenic emissions by sources of greenhouse gases of the baseline:

>>
Electricity baseline emissions (borr owed in part from Manganese Feralloys PDD currently under validation)

This analysis will quantify emissions arising as a result of electricity consumption in the baseline scenario. The estimation of the associated emissions will be quantified in the monitoring process as set out in section D2.1.2 and D.2.1.4

The following equations are used to quantify emissions in the project scenario.
BEy = EGby x EFy Equation 3

Where:

EGby: Quantity of baseline grid electricity in year y (MWh)
EFy: Grid electricity emissions factor in year y (tCO2e/MWh)- as per ACM0002, see below
$EF_y = \omega_{om} * EF\_OM_y + \omega_{bm} * EF\_BM_y$ Equation 4

Where:

$EF_{y(offsite)}$: Emission factor (tCO_2e / MWh)
ω_{OM}: Operating Margin weight, which is 0.5 by default
EF_OM: Operating Margin emission factor (tCO_2e / MWh)
ω_{BM}: Build Margin weight, which is 0.5 by default

EF_BM: Build Margin emission factor (tCO_2e / MWh)
y: A given year

and

$$EF\_OM_y = (1-\lambda_y)\frac{\sum_{i,j} F_{i,j,y} * COEF_{i,j}}{\sum_j GEN_{j,y}} + \lambda_y \frac{\sum_{i,j} F_{i,k,y} * COEF_{i,k}}{\sum_j GEN_{k,y}}$$ Equation 5

Where:
EF_OM: Operating Margin emission factor (tCO_2e / MWh)
F: Amount of fuel *i* consumed by relevant power sources *j*
COEF: CO_2 emission coefficient of fuel (t CO_2/ t)
GEN: Electricity supplied by the plant to the grid (MWh)
i: Refers to each fuel type
j: Refers to operation power sources delivering electricity to the grid, not including low-operating cost and must-run power plants.
k: Refers to power sources delivering to the grid from low cost/must run sources.
y: Refers to a given year

$$\lambda_y(\%) = \frac{\text{Number of hours per year for which low - cost/must - run sources are on the margin}}{\text{8760 hours per year}}$$ Equation 6

$$EF\_BM_y = \frac{\sum_{i,m} F_{i,m,y} * COEF_{i,m}}{\sum_m GEN_{j,y}}$$ Equation 7

Where:
EF_BM: Build Margin emission factor (tCO_2e / MWh) and
m: Refers to last additions power sources delivering electricity to the grid.

Utilising grid related data (as set out in Annex 3) an emissions factor (CEF) for the South African grid can be calculated through application of ACM0002 of 0.977 t CO_2/MWh.

$$EFy_{T\&D} = \left[\frac{EFy \times 100}{100 - T\&D}\right]$$ (Equation 8)

Where,
EFy **T&D** - Baseline emission factor of transmission and distribution losses for imported electricity to plant. The units are in tCO_2e/MWh
T&D – Transmission & Distribution loss % (These losses include technical electrical energy losses that incur during transmission & distribution).

Using 10% technical losses as a result of transmission and distribution (T&D = 10%) the following can be calculated.

$$EFy_{T\&D} = \left[\frac{0.977 \times 100}{100 - 10}\right]$$

EFy $_{\mathbf{T\&D}}$ **= 1.086 $\mathbf{tCO_2e/MWh}$**

Total electricity used per year 27.5MW * 365 days/year * 24 * 0.96

Where: 0.96 is estimated availability to be confirmed ex-post

Total emissions: 231264 MWh/year * 1.086 tCO_2e/MWh = 251153 tonnes CO_{2e}/year

Heat baseline emissions:
The second part of the baseline includes the emissions from the fossil fuels used to produce the steam that provides process heat to the operation.

Coal was used to supply steam at 37 tonnes/hour. The steam rate is 6 tonnes per tonne of coal.

The baseline scenario for the project activity, which is eligible to use in this methodology, is that the current fuels (coal and/or petroleum fuels; denoted by *i* in the formula below) are continued to be used in the existing facility at least up to the end of the crediting period without any retrofit, which extends its capacity or lifetime, or improves its fuel efficiency.

The fuels that are replaced by the project activity *i* are identified using operating protocols of the plant concerned and correct by monitoring operating records.

The baseline emissions BE_y (measured in ton of CO_2 equivalents (tCO_2e/yr)) during a year (*y*)[5] is expressed as:

$$BE_y = \sum_i Q\_F_{i,y} * (EF\_F_{i,}\_CO_{2y} + FC\_F_i\_CH_4 * GWP\_CH_4 + FC\_F_i\_N_2O * GWP\_N_2O) \quad \text{(Equation 9)}$$

where:
$Q\_F_{i,}$ Are quantity of fuel *i* used in the baseline scenario, measured in energy units (e.g., Joule).
EF_F_i Are CO_2 equivalent emission factor per unit of energy of fuel *i* (e.g., tCO_2e/Joule).
FC_F_i CH_4 Are the IPCC default CH_4 emission factor of fuel *i* associated with fuel combustion, measured in tCH_4/Joule.
FC_F_i N_2O Are the IPCC default N_2O emission factor of fuel *i* associated with fuel combustion, measured in tN_2O/Joule.
GWP_CH_4 Is the global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period.
GWP_N_2O Is the global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period.

[5] Throughout this document, suffix "*y*" denotes that such a variable parameter is the annual amount during a given year (*y*).

$BE_y = \sum$ 37 tonnes steam/hour / 6 tonnes steam/tonne coal * 24 * 365 * 0.96 * (2.465 tonnes CO_{2e}/tonne coal + 0.000058 tonnes CH_4/tonne coal * 21 + 0.000036 tonnes N_2O/tonne coal * 310)

BE_y = 128 455 tonnes CO_2/year

Total baseline emissions

251153 + 128 455 tonnes CO_{2e}/year
= 379608 tonnes CO_{2e}/year

E.5. Difference between E.4 and E.3 representing the emission reductions of the project activity:

>> 379608 - 134 372 tonnes CO_{2e}/year
245 236 tonnes CO_{2e}/year

E.6. Table providing values obtained when applying formulae above:

>>**Project activity**	**Amount tonnes CO_2/year**
Emissions from natural gas	123 000
Leakage	
Upstream leakage in synthetic gas production	-
Gas pipe physical leakage	11 374
Transport leakage	0
Baseline	
Emissions from heat	128 455
Emissions from electricity	251 153

SECTION F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

The Environment Conservation Act requires a project developer to conduct an environmental impact assessment for a proposed project prior to implementation. An independent environmental consultant (SRK) conducted an initial assessment to determine the impacts of the proposed project and the report with findings from the assessment was submitted to the Department of Agriculture and Environment Affairs (DAEA). DAEA has granted Mondi Business Paper an Exemption from doing a full EIA in terms of Section 28A of the Environment Conservation Act. This is due to the fact that the assessment of the proposed project indicates that only environmental benefits will flow from the project implementation. Mondi Richards Bay conducted a public consultation process whereby comments were invited from stakeholders.

Environmental impacts identified during the Environmental Impact Assessment:

1. Reduction in SO_2 emissions from the operation
    a. The amount of SO_2 emissions emitted from the operation due to the combustion of coal will be eliminated. This is a positive impact on the local air quality in the Richards Bay area.

2. Reduction in particulate emissions from the operation
    a. A reduction in particulate emissions during start-up phases of the coal-fired boilers will be eliminated. This will reduce visible emissions from the operation during start-up and impact positively on the local air quality in Richards Bay.
3. No significant impact on water consumption or wastewater generation in terms of volume or quality is expected.
4. No biotic impacts are anticipated, as the proposed activity will be in an industrial site.
5. The need for transport via rail (coal to the facility) and road (ash to landfill) will be reduced Hence transport emissions will be reduced as a result of the project activity.
6. The amount of solid waste (ash) generated by the coal fired boilers will be reduced significantly as result of this project activity.
7. No impact on land use is associated with the project activity except the reduction of landfill space required for the dumping of ash.
8. Socio-economic aspects – there will not be a reduction in the number of employees at Mondi as a result of this project activity.
9. The project activity will reduce cumulative negative impacts arising from emissions from the surrounding industries thereby furthering the extent of the positive impact associated with health in the area.

A positive decision was received from the Department of Agriculture and Environment Affairs for the implementation of the project.

F.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

- No impacts were considered to have a significant negative impact on the environment.
- The Department of Agriculture and Environmental Affairs issued a positive Record of Decision in February 2005 to authorise the project.

SECTION G. Stakeholders' comments

Only the Richards Bay Clean Air Association (RBCAA) submitted comments that support the project in principle.

G.1. Brief description how comments by local stakeholders have been invited and compiled:

Mondi Business Paper, Richards Bay commissioned an independent environmental consultant (SRK) to manage the stakeholder participation process. This consisted of the placement of an advertisement in the local newspapers, distribution of personalised letters to stakeholders, and electronically distributing the Background Information Document. The Department of Agriculture and Environmental Affairs therefore confirmed that the public were well informed and that all concerns were addressed adequately

G.2. Summary of the comments received:

The EIA consultants for the project participant identified interested and affected parties, advertised the project in a local newspaper calling for comments and received comments. The process and the comments are documented.

G.3. Report on how due account was taken of any comments received:

No concerns were raised and hence no account was necessary.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Mondi Business Paper
Street/P.O.Box:	P.O. Box 1551
Building:	
City:	Richards Bay
State/Region:	Kwa-Zulu Natal
Postfix/ZIP:	3900
Country:	South Africa
Telephone:	
FAX:	
E-Mail:	Ciska.Terblanche@mondibp.com
URL:	
Represented by:	Ciska Terblanche
Title:	Environmental Manager
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	Technical
Mobile:	+27828985750
Direct FAX:	
Direct tel:	+27359022322
Personal E-Mail:	Ciska.Terblanche@mondibp.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding was involved.

Annex 3

BASELINE INFORMATION

BUILD MARGIN DATA

Plant Name	Technology	Fuel Type	MWh	MW	Fuel Consumption	Year On-Line
Majuba	steam	coal	4,600,976	3,843	6,511,374	1996
Kendal	steam	coal	26,006,905	3,840	39,229,687	1993
Lethabo	steam	coal	22,019,627	3,558	29,504,941	1990
Tutuka	steam	coal	11,185,646	3,510	17,129,229	1990
Matimba	steam	coal	25,145,393	3,690	37,042,898	1988

Operating Margin Data 2002

Plant Name	Technology	Fuel Type	MWh	MW	Fuel Consumption Unit	Fuel Consumption per year	Year Plant Online	State or Private
Majuba	Steam	Coal	4,600,976	3,843	tonnes	6,961,108	1996	Private
Kendal	Steam	Coal	26,006,905	3,840	tonnes	39,347,494	1993	Private
Lethabo	Steam	Coal	22,019,627	3,558	tonnes	33,314,889	1990	Private
Tutuka	Steam	Coal	11,185,646	3,510	tonnes	16,923,472	1990	Private
Matimba	Steam	Coal	25,145,393	3,690	tonnes	38,044,058	1988	Private
Duvha	Steam	Coal	23,320,444	3450	tonnes	35,282,977	1984	Private
Matla	Steam	Coal	25,577,292	3450	tonnes	38,697,505	1983	Private
Kriel	Steam	Coal	19,165,265	2850	tonnes	28,996,343	1979	Private
Hendrina	Steam	Coal	12,752,987	1895	tonnes	19,294,802	1976	Private
Acacia	Steam	Kerosene	197	171	tonnes	298	1976	Private
Port Rex	Steam	Kerosene	28	171	tonnes	42	1976	Private
Arnot	Steam	Coal	11,974,764	1980	tonnes	18,117,379	1975	Private
Athlone	Steam	Coal	76,596	180	tonnes	115,887	N/A	State
Bloemfontein	Steam	Coal	8,233	103	tonnes	12,456	N/A	State
Orlando	Steam	Coal	8,233	300	tonnes	12,456	N/A	State
Pretoria West	Steam	Coal	167,099	170	tonnes	252,815	N/A	State
Rooiwal	Steam	Coal	949,078	300	tonnes	1,435,920	N/A	State
Athlone	Steam	Kerosene	867	180	tonnes	1,311	N/A	State
Johannesburg	Steam	Kerosene	4,048	176	tonnes	6,124	N/A	State
Roggebaai	Steam	Kerosene	2,787	50	tonnes	4,216	N/A	State
Kelvin	Steam	Coal	1,721,353	540	tonnes	2,604,344	N/A	State
Sasol Synth Fuels	Steam	Coal	4,421,074	600	tonnes	6,688,923	N/A	Private
Sasol Chem Ind	Steam	Coal	808,079	139	tonnes	1,222,594	N/A	Private

Operating Margin Data 2001

Plant Name	Technology	Fuel Type	MWh	MW	Fuel Consumption Unit	Fuel Consumption per year	Year Plant Online	State or Private
Majuba	Steam	Coal	5,616,086	3,843	tonnes	8,496,932	1996	Private
Kendal	Steam	Coal	24,326,123	3,840	tonnes	36,804,532	1993	Private
Lethabo	Steam	Coal	21,907,040	3,558	tonnes	33,144,549	1990	Private
Tutuka	Steam	Coal	8,398,787	3,510	tonnes	12,707,057	1990	Private
Matimba	Steam	Coal	23,822,748	3,690	tonnes	36,042,945	1988	Private
Duvha	Steam	Coal	22,616,252	3450	tonnes	34,217,560	1984	Private
Matla	Steam	Coal	25,256,641	3450	tonnes	38,212,372	1983	Private
Kriel	Steam	Coal	19,428,746	2850	tonnes	29,394,981	1979	Private
Hendrina	Steam	Coal	12,460,428	1895	tonnes	18,852,171	1976	Private
Acacia	Steam	Kerosene	197	171	tonnes	298	1976	Private
Port Rex	Steam	Kerosene	28	171	tonnes	42	1976	Private
Arnot	Steam	Coal	11,390,033	1980	tonnes	17,232,702	1975	Private
Athlone	Steam	Coal	79,273	180	tonnes	119,937	N/A	State
Bloemfontein	Steam	Coal	21,437	103	tonnes	32,433	N/A	State
Orlando	Steam	Coal	0	300	tonnes	0	N/A	State
Pretoria West	Steam	Coal	74,983	170	tonnes	113,447	N/A	State

Rooiwal	Steam	Coal	433,983	300	tonnes	656,600	N/A	State
Athlone	Steam	Kerosene	685	180	tonnes	1,036	N/A	State
Johannesburg	Steam	Kerosene	4,048	176	tonnes	6,124	N/A	State
Roggebaai	Steam	Kerosene	1,707	50	tonnes	2,583	N/A	State
Kelvin	Steam	Coal	1,626,933	540	tonnes	2,461,490	N/A	State
Sasol Synth Fuels	Steam	Coal	5,107,703	600	tonnes	7,727,767	N/A	Private
Sasol Chem Ind	Steam	Coal	705,439	139	tonnes	1,067,303	N/A	Private

Operating Margin Data 2000

Plant Name	Technology	Fuel Type	MWh	MW	Fuel Consumption Unit	Fuel Consumption per year	Year Plant Online	State or Private
Majuba	Steam	Coal	4,278,340	3,843	tonnes	6,472,972	1996	Private
Kendal	Steam	Coal	25,279,546	3,840	tonnes	38,247,026	1993	Private
Lethabo	Steam	Coal	22,319,026	3,558	tonnes	33,767,868	1990	Private
Tutuka	Steam	Coal	10,089,338	3,510	tonnes	15,264,799	1990	Private
Matimba	Steam	Coal	23,085,200	3,690	tonnes	34,927,061	1988	Private
Duvha	Steam	Coal	23,530,675	3450	tonnes	35,601,049	1984	Private
Matla	Steam	Coal	25,085,200	3450	tonnes	37,952,988	1983	Private
Kriel	Steam	Coal	16,392,855	2850	tonnes	24,801,789	1979	Private
Hendrina	Steam	Coal	12,530,513	1895	tonnes	18,958,207	1976	Private
Acacia	Steam	Kerosene	36	171	tonnes	54	1976	Private
Port Rex	Steam	Kerosene	1,399	171	tonnes	2,117	1976	Private
Arnot	Steam	Coal	9,135,768	1980	tonnes	13,822,082	1975	Private
Athlone	Steam	Coal	65,753	180	tonnes	99,482	N/A	State
Bloemfontein	Steam	Coal	21,266	103	tonnes	32,175	N/A	State
Orlando	Steam	Coal	0	300	tonnes	0	N/A	State
Pretoria West	Steam	Coal	37,028	170	tonnes	56,022	N/A	State
Rooiwal	Steam	Coal	533,000	300	tonnes	806,409	N/A	State
Athlone	Steam	Kerosene	618	180	tonnes	#REF!	N/A	State
Johannesburg	Steam	Kerosene	4,048	176	tonnes	935	N/A	State
Roggebaai	Steam	Kerosene	0	50	tonnes	6,124	N/A	State
Kelvin	Steam	Coal	1,654,015	540	tonnes	0	N/A	State
Sasol Synth Fuels	Steam	Coal	5,107,703	600	tonnes	2,502,464	N/A	Private
Sasol Chem Ind	Steam	Coal	705,439	139	tonnes	7,727,767	N/A	Private

Annex 4

MONITORING PLAN
As in part D of this PDD