PROJECT DESIGN DOCUMENT FORM
FOR CDM PROJECT ACTIVITIES (F-CDM-PDD)
Version 04.1

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	Golden Sugar 30MW High Energy Efficient Combined Heat and Power (CHP) System in Apapa, Lagos, Nigeria
Version number of the PDD	5
Completion date of the PDD	26/12/2012
Project participant(s)	Golden Sugar Company Limited Standard Bank Plc
Host Party(ies)	Federal Republic of Nigeria
Sectoral scope and selected methodology(ies)	1. Energy industries (renewable / non-renewable sources) AM0102 Version 01.0.0, "Greenfield cogeneration facility supplying electricity and steam to a Greenfield Industrial Consumer and exporting excess electricity to a grid and/or project customer(s)."
Estimated amount of annual average GHG emission reductions	59,421 t/yr

SECTION A. Description of project activity
A.1. Purpose and general description of project activity
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Golden Sugar Company Limited (the Greenfield industrial consumer) is in the process of establishing a Greenfield Sugar Refinery at the Apapa industrial park, located, in Lagos, Nigeria. The plan is to cogenerate power and steam at the site of the sugar refinery. In a first phase, two gas turbines will be installed, each with an installed capacity of 14.4MW_e (28.8MW_e total). The gas turbines will be fueled with natural gas. They will also be capable of firing diesel, as a stand-by fuel in periods when natural gas is not available. The energy requirement of the refinery includes process steam and power. Waste heat at the exhaust of each of the gas turbines will be recuperated by passing the waste gas stream of each of the two turbines, through each turbine's Heat Recovery Steam Generator (HRSG) to produce low pressure steam that will be utilized in the refinery. There are therefore 2 HRSGs, HRSG-1 and HRSG-2. The installed capacity of the HRSG-1, which is attached to the exhaust of the first turbine, is 30.55 Kg/sec (~110 tons/hr). HRSG-1 is designed to produce about 30 tonnes of steam/hour from heat recuperation from the exhaust of the first gas turbine, and the balance of the 80 tonnes of steam/hour through supplementary firing. HRSG-2, which is attached to the exhaust of the second gas turbine is designed to produce 30 tonnes of steam/hour mainly from heat recuperation from the exhaust of turbine 2.[1,2,3,4] The Greenfield industrial consumer will require 6.5MW of the power capacity of the cogeneration plant. The remaining power-generation capacity will be earmarked for the sale of electricity to Flour Mills of Nigeria PLC (the project customer), for its operations located adjacent to the sugar refinery site, comprising flour and rice milling as well as cement, fertilizer and port operations. Flour Mills of Nigeria PLC is a conglomerate operating in three distinct yet closely integrated categories: Food, Agro- Allied and Logistics Support and other subsidiaries. The electricity supplied from the project activity to the group will be distributed from a common main serving each of the Apapa divisions.

The project proponent anticipates a second phase of the project, at which time the refining capacity of the Greenfield industrial consumer will expand, warranting the installation of an additional ~30MW_e of cogeneration capacity, from which excess power will be sold to project customers that are yet to be identified.

Under baseline conditions, the Greenfield industrial consumer would have been supplied with power from a stand-alone Reference Power Plant implemented at about the same capacity as the project plant. Similarly, the Greenfield industrial consumer would have been supplied with steam from a stand-alone Reference Boiler implemented at about the same capacity as the steam generation capacity of the project plant. The project customer is currently operating its own captive power plant fired with natural gas, and utilizing captive diesel power as backup. Under baseline conditions the project customer would continue to be supplied with electricity from its own captive natural-gas-fired power plant.

The average annual CO_2 emission reduction over the first seven-year crediting period is 59,421 t/yr.

There is no specific document dedicated to spelling out the sustainable development goals that must be achieved by CDM Projects in Nigeria. The Vision 20:2020 document of the Federal Government of Nigeria has served as, and remains the basis for, sustainable development goals and targets for

[1] Booker Tate Technical review of Goden Sugar Company refinery project Nigeria Final eport.pdf
[2] 2010-10-22_Letter to Golden Sugar Company.pdf
[3] GSC Internal Memo 29 Oct 2010.pdf
[4] P100594S_tech_Specification_With HRSG and Fuel Duct Firing (1).pdf

development in Nigeria.[5] For CDM Projects in Nigeria, the Vision 20:2020 document provides frameworks for sectoral sustainable development. Specifically, a key requirement in the Nigerian Vision 20:20 Document for the Nigerian Manufacturing Sector is that investment in the sector must contribute to creating an enabling operating environment that allows for substantial improvement in efficiency, productivity and profitability of the sector (see pages 97-108). This project contributes to sustainable development in Nigeria by promoting the use of an advanced and energy-efficient technology for providing power and steam to enterprises in the industrial sector (food manufacturing). Given the high energy efficiency of the project activity (compared to the norm in the sector), the project satisfies a key thrust of the Vision 20:20, as well as the key target of significant improvement in productivity of the manufacturing activity, through the achievement of higher energy use efficiency. The project increases experience in the country with combined heat and power (CHP) technologies, reduces waste of natural gas as a national resource, and – by promoting the efficient use of natural gas – reduces emissions, thereby reducing both global and local environmental impacts.

A.2. Location of project activity

A.2.1. Host Party(ies)

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The Host Party is the Federal Republic of Nigeria

A.2.2. Region/State/Province etc.

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The project is located in Lagos State, South West Nigeria

A.2.3. City/Town/Community etc.

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The project will be located in Apapa, in Apapa Local Government Area in Lagos State

A.2.4. Physical/Geographical location

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The project is located in Apapa, Nigeria. The geo-coordinates of the project are:
Latitude: 06.4443° N Longitude: 03.3769° E

[5] FGN, Nigeria Vision 20:2020: The Final Implementation Plan (2010-2013), Volume II-Sectoral Plans and Programmes, May 2010.

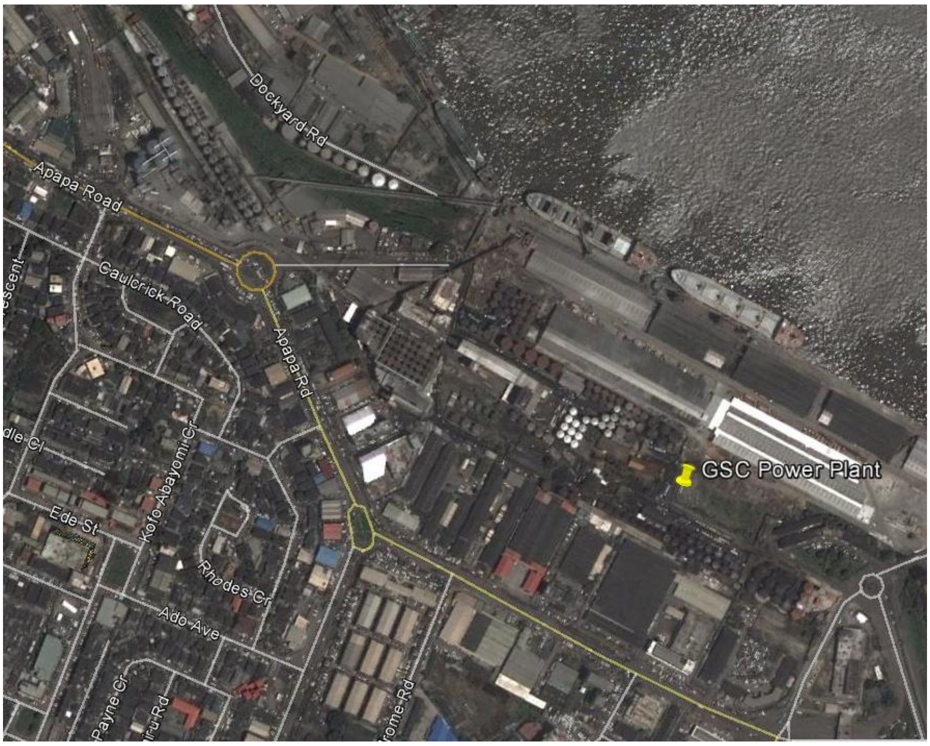

Figure 1. Golden Sugar Company Limited (GSC) Power Plant – local map of Apapa Industrial Park.

Figure 2. GSC Power Plant map indicating proximity of Apapa to Lagos, Nigeria

A.3. Technologies and/or measures

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The energy supply facility that will be implemented at the Greenfield Sugar Refinery will be a Gas-fired Combined Heat and Power (CHP) system. The CHP System will consist of: (a) 2 gas turbines each driving an electrical generator with an installed capacity of 14.4 MW each. The turbines will supply the 6.5 MW electricity demand of the Greenfield Sugar Refinery, while the excess electricity produced (~22.3 MW) will be exported to the adjacent Flour Mills of Nigeria; (b) Waste heat from the exhaust of

each of the 2 turbines will be passed through a Heat Recovery Steam Generator (HRSG) to produce low pressure steam needed for the sugar refining process. There are 2 HRSG (one each attached to each turbine). The installed capacity of the HRSG-1 (attached to the exhaust of the first turbine) is 110 tons/hr of steam. HRSG-1 is designed to produce 30 tonnes of steam/hour from recuperation of waste heat from the exhaust of turbine-1 and the balance 80 tonnes of steam/hour can be produced when needed by firing supplementary fuel at the HRSG. HRSG-2 is designed to produce about 30 tonnes of steam/hour only from heat recuperation from the exhaust of the turbine-2. This arrangement has been designed to ensure that the steam demand of the sugar refinery, is met at all times. A list of the pertinent parameters of the project production equipment is presented in the table below:

Project Facilities Parameters

S/N	Project Facility Parameters	Units	GS CHP Facilities
1.	*Power Generating-Gas Turbines Capacity*	*MW*	*2X14.4*[6]
2.	*Power Supply to the Refinery*	*MW*	*6.5*
3.	*Power Exported to FMN (Industrial Customer)*	*MW*	*22.3*
4a.	*Steam Capacity of HRSG-1*	*tonnes/hour*	*110*[7]
4b.	*Steam Capacity of HRSG-2*	*tonnes/hour*	*30*[8]
5.	*Steam Demand of the Greenfield Refinery*	*tonnes/hour*	*80*[9]
6.	*Natural Gas Consumption*	*MMCM/Year*	*57.2 (2013)*[10]
7.	*Heat to Power Ratio*	*Ratio*	*2.36*
8.	*Average Lifetime of Equipment*	*Years*	*25*[11]
9.	*Baseline Power Supply Facilities*	*MW*	*3 X 10 (Reference Power Plant)*
10.	*Baseline Steam Supply Facilities*	*tonnes/hour*	*6 X 16 (Reference Boiler)*

[6] See Footnote 1
[7] See Footnote 4
[8] See Footnote 1
[9] See Footnote 1
[10] See Spreadsheet <GS Financial Analysis_Rev 4 Final.xls>
[11] *C2. Technical Operational lifespan of project.pdf*

A.4. Parties and project participants

Party involved (host) indicates a host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Federal Republic of Nigeria (host)	Golden Sugar Company Limited (the Project Owner)	No
UK	Standard Bank Plc	No

A.5. Public funding of project activity

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No public funding will be used to finance the project activity.

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

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The selected methodology is AM0102 version 01.0.0, "Greenfield cogeneration facility supplying electricity and steam to a Greenfield Industrial Consumer and exporting excess electricity to a grid and/or project customer(s)."

In accordance with this methodology, the following tools are also applied:

- "Combined tool to identify the baseline scenario and demonstrate additionality"
- "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"

B.2. Applicability of methodology

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The methodology was designed for this particular project. The project meets all of the methodological applicability conditions, as follows:

Applicability Condition from AM0102 Ver. 01.0.0	Justification of Relevance to Proposed Project
This methodology applies to project activities that involve the installation of a Greenfield cogeneration facility (hereafter referred to as project facility) at the site of a Greenfield industrial consumer. The project facility supplies steam and electricity directly to the Greenfield industrial consumer for captive use and exports excess electricity to project customers and/or a grid.[12] The project facility is designed primarily to meet the heat/steam demand of the Greenfield industrial consumer.	The project involves installing a Greenfield cogeneration facility at the site of Golden Sugar Company Limited, which is the Greenfield industrial consumer. In its first phase, the project facility will supply heat/steam and electricity directly to the Greenfield industrial consumer for captive use and export excess electricity to a project customer. The project facility was designed primarily to meet the heat/steam demand of the Greenfield industrial consumer. These statements are verified in the project feasibility study and a technical review of the feasibility study, provided to the DOE for validation.
The methodology is not applicable to project activities involving the use of solid fuels. The fuel used at the	The primary fuel that will be used for the project is natural gas. Multiple fuels (diesel and natural gas) are

[12] Grid is defined as per the "Tool to calculate the emission factor for an electricity system".

project facility must be gaseous or liquid. If multiple fuels (excluding fuels used for start-up[13] only) are expected to be used by the project facility, each type of the multiple fuels must be identified ex ante in the PDD	not used in this project activity as diesel is only used for start-up and whenever gas is not available. These statements are verified in the project feasibility study.
The heat-to-power ratio of the project cogeneration facility shall be higher than 1.	The heat-to-power ratio of the project cogeneration facility is 2.37 The calculation of the heat-to-power ratio has been provided to the DOE for validation.
If the baseline scenario is to generate heat/steam by a reference boiler (i.e. H2) as identified through the procedures contained in Annex I, the methodology is applicable only: (1) if the relevant information required in Annex I to identify the reference boiler is available and (2) if the fuel of the reference boiler, as indentified through the procedures in Annex I, is the same as the project fuel or one of the multiple fuels used by the project facility.	The baseline scenario is to generate heat/steam by a reference boiler. The relevant information required in Annex 1 of the methodology to identify the reference boiler is available. The fuel used in the reference boiler, as identified through the procedures in Annex 1 of the applied methodology, is the same as the fuel used at the project facility (natural gas). The determination of the baseline scenario is presented in Sections B.4 and B.5. The identification of the reference boiler is presented in Section B.4.
If the baseline scenario is to generate electricity entirely or partly by a reference captive power plant (i.e. P2 or P3) as identified through the procedures in Annex I, The methodology is applicable only (1) if the relevant information required in Annex I to identify the reference captive power plant is available and (2) if the fuel of the reference captive power plant, as indentified through the procedures in Annex I, is the same as the project fuel or one of the multiple fuels used by the project facility	The baseline scenario is to generate electricity entirely by a reference captive power plant. The relevant information required in Annex 1 of the methodology to identify the reference captive power plant is available. The fuel of the reference captive power plant, as identified through the procedures in Annex 1, is the same as the project fuel (natural gas). The determination of the baseline scenario is presented in Section s B.4 and B.5. The identification of the reference captive power plant is presented in Section B.4.
The Greenfield industrial consumer shall satisfy all the following conditions: • The owner of the project facility is also the owner of the Greenfield industrial consumer; • The Greenfield industrial consumer will consume all the heat/steam and all/part of the electricity produced by the project facility; • The project facility must provide all of the electricity and heat/steam demand of the Greenfield industrial consumer	The following apply to the Greenfield industrial consumer: • The owner of the project facility (Golden Sugar Company Limited) is also the owner of the Greenfield industrial consumer; • The Greenfield industrial consumer will consume all of the heat/steam and part of the electricity produced by the project facility; • The project facility will provide all of the electricity and heat/steam demand of the Greenfield industrial consumer. These statements are verified in the project feasibility study and a technical review of the feasibility study, provided to the DOE for validation.
All of the following conditions apply to each of the project customers. If any of the condition is not met for project customer *i*, no emission reduction can be claimed for the power supplied to project customer *i*. • The captive power plant(s) of project customer *i* does not involve cogeneration; • Project customer *i* does not receive/purchase electricity from sources other than its own captive plants, the project facility or the grid; • The existing captive power plant(s) of project customer *i* shall have records on the fuel	There is only one project customer (Flour Mills Nigeria). The following apply: • The captive power plant of the project customer does not involve cogeneration; • The project customer will not receive/purchase electricity from sources other than its own captive plants or the project facility; • The existing captive power plants of the project customer have maintained records on the fuel consumption and electricity

[13] Start-up fuels shall not comprise more than 3% of total fuel used annually, on an energy basis;

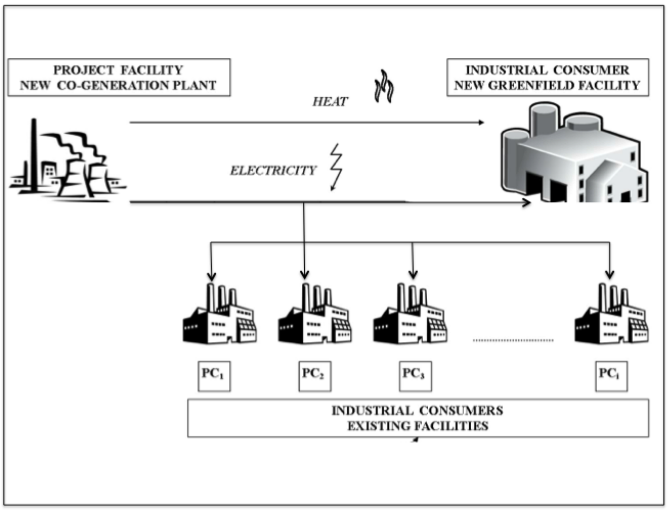
consumption and electricity production for one year prior to the implementation of the project activity; • All potential project customers shall be identified ex ante in the PDD. If power generated by the project facility is supplied to any customer not identified in the registered PDD, then the latest version of the "Procedures for notifying and requesting approval of changes from the project activity as described in the registered PDD" shall be followed.	production for one year prior to the implementation of the project activity. • The project customer is identified ex ante in the PDD. The existing captive power plant has been documented for validation by the DOE, including documentation demonstrating that the project customer is not physically connected to any other source of electricity and records of the project customer's fuel consumption and electricity production.
In addition, the applicability conditions included in the *Combined tool to identify the baseline scenario and demonstrate additionality* and the *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion* apply.	
From the *Combined tool to identify the baseline scenario and demonstrate additionality*: This tool contains an applicability condition for the methodology but no specific applicability conditions for projects.	No project-specific conditions apply.
From the *Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion*: "This tool provides procedures to calculate project and/or leakage CO_2 emissions from the combustion of fossil fuels. It can be used in cases where CO_2 emissions from fossil fuel combustion are calculated based on the quantity of fuel combusted and its properties."	This tool is used in the case of the proposed project to calculate emissions based on the quantity of fuel combusted and its properties. This can be verified in Section B.6.

B.3. Project boundary

<table>
<tr><th colspan="2">Source</th><th>GHGs</th><th>Included?</th><th>Justification/Explanation</th></tr>
<tr><td rowspan="12">Baseline scenario</td><td rowspan="3">Combustion of fossil fuels to produce heat/steam at the project facility</td><td>CO_2</td><td>Yes</td><td>Main emission source in the combustion of fossil fuels</td></tr>
<tr><td>CH_4</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td>N_2O</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td rowspan="3">Combustion of fossil fuels to produce electricity at the project facility</td><td>CO_2</td><td>Yes</td><td>Main emission source in the combustion of fossil fuels</td></tr>
<tr><td>CH_4</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td>N_2O</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td rowspan="3">Combustion of fossil fuels to produce electricity for Project Customers</td><td>CO_2</td><td>Yes</td><td>Main emission source in the combustion of fossil fuels</td></tr>
<tr><td>CH_4</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td>N_2O</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td rowspan="3">Combustion of fossil fuels to produce electricity for the grid</td><td>CO_2</td><td>Yes</td><td>Main emission source in the combustion of fossil fuels</td></tr>
<tr><td>CH_4</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td>N_2O</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td rowspan="7">Project scenario</td><td rowspan="3">Combustion of fossil fuels to produce heat/steam and electricity at the project facility</td><td>CO_2</td><td>Yes</td><td>Main emission source in the combustion of fossil fuels</td></tr>
<tr><td>CH_4</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td>N_2O</td><td>No</td><td>Excluded for simplification</td></tr>
<tr><td rowspan="4">Source 2
(Not applicable)</td><td>CO_2</td><td></td><td>Not applicable.</td></tr>
<tr><td>CH_4</td><td></td><td>Not applicable</td></tr>
<tr><td>N_2O</td><td></td><td></td></tr>
<tr><td>…</td><td></td><td></td></tr>
</table>

The spatial extent of the project boundary encompasses the site of the project facility and the site of the project customer. The project facility will not export power to a grid. The project boundary is presented graphically in Figure 1.

Figure 1: The Project Boundary



B.4. Establishment and description of baseline scenario

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As per AM0102 Version 01.0.0, the most plausible baseline scenario has been identified through the application of steps prescribed by the latest version (version 04.0.0) of the "Combined tool to identify the baseline scenario and demonstrate additionality." In accordance with AM0102 Version 01.0.0, the following requirements were satisfied in the application of the tool:

Step 1a: Define alternative scenarios to the proposed CDM project activity

The alternative scenarios considered included:

a. Alternatives for meeting the electricity demand of the Greenfield Sugar Refinery in the absence of the project activity;

b. Alternatives for meeting the heat/steam demand of the Greenfield Sugar Refinery in the absence of the project activity;

c. Alternatives for meeting the electricity demand of each of the project customer in the absence of the project activity.

a. Alternatives for meeting the electricity demand of the Greenfield industrial consumer in the absence of the project activity

In accordance with AM0102 version 01.0.0, and with the addition of alternatives specific to the project activity, the alternative scenarios for electricity supplied to the Greenfield industrial consumer include:

P1: The proposed project activity not undertaken as a CDM project activity;

P2: Electricity is supplied partly from a grid and partly from an off-grid captive power plant applying the fuel and technology identified for the reference captive power plant through the procedures in Annex 1;

P3: Electricity is supplied from an off-grid captive power plant applying the fuel and technology identified for the reference captive power plant through the procedures in Annex 1. This scenario has two options:

a) The reference plant is implemented at the minimum capacity (number of power units) required to meet the full power demand of the project activity (both the power demand of the Greenfield Industrial Customer and the Project Customer), and
b) The reference plant is implemented at the minimum capacity (number of power units) required to meet 50% of the power demand of the project activity (i.e. full power demand of the Greenfield Industrial Customer and any excess thereafter exported to the Project Customer);

P4: Electricity is imported from a grid;
P5: Electricity is supplied from a cogeneration plant fired with a different fossil fuel than the project activity; and
P6: Electricity is supplied from a biomass fired cogeneration plant.

Alternative P3 has been broken into P3 (a) and P3 (b) to reflect the fact that the project proponent could decide to implement only one of the two units of the project CHP plant. In this case, the relevant capacity of the Reference Power Plant (for P3 (b) will be 50% of the capacity of the plant in P3 (a)). The addition of an extra scenario to the list presented in AM0102 Ver.01.0.0 is acceptable since it is stated in the methodology that: "The alternative scenarios for electricity supplied to the Greenfield industrial consumer shall include *inter alia*:" meaning that the list following this statement in the methodology represent the minimum that must be considered.

The project facility will not use multiple fuels.

An important component of the determination of alternative scenarios for the supply of energy to the Greenfield industrial consumer in the absence of the CDM project activity is the identification of Reference Captive Energy Plant (Power and Heat/Steam). The procedure for the determining the characteristics of this plant, is included as Annex 1 of AM0102 Ver. 01.0.0. A quick survey of how electricity is supplied to industrial facilities (especially the food and allied manufacturing sub-sector) in Nigeria was carried out as part of the determination of the reference plant for this project. The coverage of the scoping survey was the greater Lagos Metropolitan industrial area. The following salient characteristics were discerned from the survey:

- In the food sector, energy needs consist mainly of electricity and heat/steam. In addition to this, a few food manufacturing concerns require chilling in their manufacturing operations;
- The common sources of electricity supplies to food sector manufacturing entities in the area covered include:
    - Onsite generation of electricity using diesel and/or natural gas as fuel. In many cases, especially for industries located in areas where there is access to the national grid, and where the industrial consumer is connected to the grid, the onsite generation has been conceptualized and implemented as a back-up to the grid. As a result of the low reliability of grid supply in Nigeria[14], many of these onsite generators have become the main source of electricity;
    - Grid electricity supply with or without onsite generation back-up.
- Although almost all the food industry enterprises covered in the scoping survey demand both electricity and steam, the most common type of these energy supply is via stand-alone power generators and boilers;
- Many of the food sector enterprises covered build onsite power plants and steam plants by installing multiple units of smaller capacity to arrive at their total demand capacity. For example,

[14] The typical Nigerian firm experiences power failures or voltage fluctuations about seven times per week, each lasting more than 2 hours (Adeola Adenikinju, "Analysis of the cost of infrastructure failures in a developing economy: The case of electricity sector in Nigeria, AERC Research Paper 148, AERC Nairobi, Feb. 2005)

at one of the companies covered by the survey the total capacity of onsite power generation of 5 MW was made up of 5 units each of capacity 1 MW.

The reference captive power plant for electricity supply has been identified following the procedures in Annex 1 of the applied methodology.[15] A key issue that was incorporated in the procedure utilized is that the technology and fuel of the plants accepted as candidates for the reference energy plants are demonstrated to be commonly installed to supply heat or power to a new industrial facility in the food industry sector in Nigeria. It was also ensured that the scale of the services provided are at comparable level of service to the one that will be encountered at the Golden Sugar project. The following is a summary of how the five steps listed out in Annex 1 of AM0102 were implemented:

Step I: Definition of similar plants to the project activity

The following issues specified in Annex 1 were considered in selecting the candidate reference plants:

- Only power plants that have been constructed in the past 5 years were included. The list of power plants constructed in the last 5 years is presented in Table 1.
- Only power plants that have capacities in the range 50% to 150% of the project plant were included. As shown in Table 1, the range of capacities of the power plants identified is from 14.528 to 18.6MW. The 50 – 150% range for the project power plant capacity is 14.4MW to 43.2MW. All of the power plants considered fall within this range.
- Only power plants that supplied at least 50% of their energy output in the food sector were included. All of the reference power plants presented in Table 1 are operating in the food sector and as such supplied 100% of their energy outputs to food sector industries.
- None of the power plants included have been registered as CDM Project Activities. Six CDM projects have been registered in n Nigeria[16]. None of these projects are in the food sector.

Step II: Definition of the geographical area

The entire geographical boundary of Nigeria was taken as the area covered in the identification of candidate Reference power plants. Fortunately, more than five candidates among the list of identified power plants were considered suitable.

Step III: Documentation of the design parameters of the energy plants in the peer group

The relevant parameters of the identified Reference Power Plant candidates are presented in Table 1:

[15] For details of the analysis performed following those procedures see: *GS Baseline Selection and Additionality Demonstration.docx*

[16] http://cdm.unfccc.int/Projects/projsearch.html Accessed 27/12/2012.

Table 1: Pertinent Data on Candidate Reference Power Plants[17]

Engine Type	Country	Design Capacity of a Single Unit (MW)	No. Of Units at Candidate Site	Year of Commissioning	Design Efficiency (%)	Fuel Type	CO2 Emission factor of Fuel (tCO2/TJ)
GEJ- 612 E12	Nigeria	1.816	8	2007	36	Natural Gas	52.02
GEJ-612 E12	Nigeria	1.816	10	2008	36	Natural Gas	52.02
PG 1000 6000 Series	Nigeria	1.0	15	2009	35	Natural Gas	52.02
Wartsila 12V25	Nigeria	2.0	8	2010	38	Diesel	74.3
GEJ 620	Nigeria	3.039	6	2010	38	Natural Gas	52.02

Step IV: Selection of the reference energy plant

The emissions ratios (in tCO_2/MWh) for each of the 5 alternatives presented in Table 1 are presented in Table 2:

Table 2: Estimates of Emission Factor for Each of the Baseline Scenarios

Engine Type	Design Efficiency (%)	Fuel Type	*Emissions Ratio (tCO_2/MWh)*
GEJ- 612 E12	36	Natural Gas	0.560
GEJ-612 E12	36	Natural Gas	0.560
PG 1000 6000 Series	35	Natural Gas	0.576
Wartsila 12V25	38	Diesel	0.739
GEJ 620	38	Natural Gas	0.531

According to Section IV of Annex 1 of AM0102, the alternative with the lowest emissions ratio should be selected as the Reference Captive Power Plant. In this case GEJ 620 has been selected.

The result of the procedure for electricity supply is the following reference captive power plant:

- *Ten stand-alone gas-fired GEJ 620 engines, each with a capacity of 3.039MW and an energy efficiency of 38%. Ten units of the GEJ 620 engines has been chosen to ensure that the reference power plant will be able to deliver the quantity of electricity that will be produced by the project CHP.*

(b) Alternatives for meeting the steam demand of the Greenfield industrial consumer in the absence of the project activity

In accordance with AM0102 version 01.0.0, the alternative scenarios for heat/steam supplied to the Greenfield industrial consumer include:

H1: The proposed project activity not undertaken as a CDM project activity;

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[17] For more details see <G6. Reference Plant Data_Presentation.pdf>

H2: Steam is supplied by a stand-alone boiler applying the fuel and technology identified for the reference boiler through the procedures in Annex 1;

H3: Steam is supplied from a cogeneration plant fired with a different fossil fuel than the project activity; and

H4: Steam is supplied by a biomass fired cogeneration plant.

Similar activities described in Steps I – IV in the determination of the Reference Power Plant were carried out to determine the Reference Boiler scenario H2 that is one of the alternatives that could have been implemented to supply steam to the Sugar Refinery in the absence of the project activity. Key considerations and the outcome of the activities to determine the Reference Boiler are summarized below:

Step I: Definition of similar plants to the project activity

The following issues specified in Annex 1 of AM0102 were considered in selecting the candidate plants:

- Only boilers that have been constructed in the past 5 years were included. The list of boilers constructed in the last 5 years is presented in Table 3.
- Only boilers that have capacities in the range 50% to 150% of the project plant were included in the list of Reference plants. As shown in Table 3, the range of capacities of the boilers identified is from 45.5 to 80 tonnes/hour. The 50 – 150% range for the project boiler capacity is 40 to 120 tonnes/hour. All of the boilers considered fall within this range
- Only boilers that supplied at least 50% of its energy output in the food sector were included in the list of Reference plants. All of the reference boilers presented in Table 3 are operating in the food sector and supplies 100% of the energy generated to food sector consumers.
- None of the boilers included in the list of Reference plants have been registered as CDM Project Activities in Nigeria. Six CDM projects have been registered in n Nigeria[18]. None of these projects are in the food sector.

Step II: Definition of the geographical area

The entire geographical boundary of Nigeria was taken as the area covered in the identification of candidate Reference boilers. Given the fact that we were only able to identify three candidate boilers within Nigeria that fit the criteria spelt out in Step I, we extended the geographical boundary for the identification of the Reference Boiler to neighboring Non-Annex 1 country, Ghana. Two additional candidate boilers were identified.

Step III: Documentation of the design parameters of the energy plants in the peer group

The relevant parameters of the identified Reference Power Plant candidates are presented in Table 3:

[18] http://cdm.unfccc.int/Projects/projsearch.html Accessed 27/12/2012.

Table 3: Pertinent Data on Candidate Reference Boilers:[19]

Engine Type	Country	Design Capacity (Single Unit) (tonnes/hr)	No. Of Units at Candidate Site	Commissioning	Design Efficiency (%)	Fuel Type	CO2 Emission factor of Fuel (tCO2/TJ)
FKI BABKORK ROBEY	Nigeria	10	5	2008	80	N. Gas	52.02
Cochran	Nigeria	6.5	7	2008	80.5	N. Gas	52.02
UL-S 16000	Nigeria	16.0	4	2008	88	Natural Gas	52.02
John Thompson Africa TM1600	Ghana	16.0	5	2010	82	RFO	77.4
Babcock Wanson	Ghana	16.0	4	2010	82	RFO	77.4

Step IV: Selection of the reference Boiler

The emissions ratio (in tCO_2/TJ) of steam for each of the 5 alternatives presented in Table 3 are presented in Table 4:

Table 4: Estimates of Emission Factor for Each of the Baseline Scenarios

Engine Type	Design Efficiency (%)	Fuel Type	*Emissions Ratio (tCO2/TJ Steam)*
FKI BABKORK ROBEY	80	Natural Gas	70.00
Cochran	80.5	Natural Gas	69.57
UL-S 16000	88	Natural Gas	63.64
John Thompson Africa TM1600	82	RFO	95.12
Babcock Wanson	82	RFO	95.12

The reference captive boiler for steam supply to the Greenfield industrial consumer has been identified following the procedures in Annex 1 of the applied methodology, as summarized above. The result of the procedure for steam supply is the following reference captive power plant:

- *Six stand-alone gas-fired UL-S 16000 boilers, each with a steam-generation capacity of 16 t/hr and an energy efficiency of 88%.*

(c) Alternatives for meeting the electricity demand of the project customer in the absence of the project activity

In accordance with AM0102 version 01.0.0, and with the addition of alternatives specific to the project activity, the alternative scenarios for electricity supplied to the project customer include:

[19] For more information on Reference Boiler see <G6 . Reference Plant Data_Presentation.pdf>

B1: The project customer imports the electricity from the grid;
B2: The electricity is supplied from the existing off-grid captive fossil fuel fired power plant(s)[20];
B3: The electricity is supplied partly from the grid and partly from the existing off-grid captive fossil fuel fired power plant(s);
B4: The electricity is supplied from a new off-grid captive fossil fired power plant (with a capacity corresponding to the amount of electricity to be imported from the project activity)[21];
B5: The electricity is supplied from a new on-site renewable energy power plant;
B6: The electricity is supplied from a new on-site fossil-fuel fired cogeneration plant;
B7: The electricity is supplied from a new on-site biomass fired cogeneration plant;
B8: The proposed project activity not undertaken as a CDM project activity;

The Greenfield industrial consumer's cogeneration plant and the project customer's existing captive power plant are both fueled with natural gas. Any other fossil fuel would result in higher emissions in the baseline. Therefore, to be conservative, all of the scenarios involving the use of a different fossil fuel than natural gas were eliminated from further consideration as baseline scenarios.

Now that we have determined all the possible alternatives for the three supply scenarios, including the relevant Reference Power and Boiler plants, we can proceed to the next step of the Combined Tool:

Step 1b: Consistency with mandatory applicable laws and regulations

All of the remaining alternative scenarios among the ones listed above for the Greenfield industrial consumer and the project customer are consistent with applicable laws and regulations of Nigeria.

Step 2a: Identify barriers that would prevent the implementation of alternative scenarios

In accordance with the *Combined tool to identify the baseline scenario and demonstrate additionality* the following list of realistic and credible technology barriers that may prevent alternative scenarios to occur has been compiled and applied to the alternative scenarios listed above. Through this process, some of the alternative scenarios have been eliminated for consideration as a baseline scenario for the project.

Outcome of Step 2a:
Technology Barriers:

1. Use of biomass as an industrial energy generation fuel is not common practice in Nigerian industries[22]. Even in some small and medium scale industries where biomass residues are generated in abundance, it is not commonly used as an energy fuel. More often than not, these fuels are stockpiled and regularly burnt to reduce the volume of the stockpile. Examples can be found in Sawmill and Rice Mill Clusters in several parts of Nigeria (e.g. Okobaba Saw Mill Cluster in Lagos, and Rice Mill Cluster in Abakaliki). It is also important to stress that data on the availability of biomass residues and other potential biomass resources that can serve as fuel in the current project, in the absence of the project activity implemented as a CDM project, is at best scanty[23]. For these reasons, it is unlikely that the Greenfield industrial consumer or the

[20] We interpret this scenario to mean that power is provided *solely* from the existing captive plant.
[21] We interpret this scenario to mean that power is provided *solely* from the new captive plant.
[22] In a recent paper, J-F Akinbami wrote: "Renewable energy resources other than hydro (particularly large-scale) and traditional biomass are currently not given any consideration in the national energy supply mix and can even only account for a tiny contribution in the decades to come: J-F Akinbami, "Renewable Energy Sources and Technologies in Nigeria: See Pgs 174-177;
[23] This paper provides information on the fact that the stand alone option (boiler + power separate facilities) are the most common means of providing power and steam in Nigerian industries-see Page 19; Section 3.2 of the report also presents some good discussions of obstacles to investment in renewable energy in Nigeria: Felix Dayo, "Clean

project customer will have sufficiently reliable access to biomass fuel resources and the technical knowledge to implement, manage, operate and maintain a biomass-based facility.

2. Other renewable-energy options apart from biomass are also not likely to be considered for energy generation in this project. Small-scale hydropower systems are not feasible in the area where the project customer is located because there are no rivers near the project site where such facilities can be developed. Furthermore, wind speeds in the area surrounding the project site are known to be insufficient for sustainable wind power facility development[24]. Wheeling is not allowed in the current regulatory framework in Nigeria, so building a renewable plant outside the Lagos area is not an option. In addition, the unit costs of solar, geothermal, wave and tidal power facilities are still relatively high[25] and still far exceed the costs of fossil-fuel-based power facilities and these fuels are readily available.
3. Further, the project customer identified for this project does not require steam for its operations. It would not consider a cogeneration system due to the difficulty of getting offtakers for the steam.
4. Due to the vintage of the existing captive power plant currently used by the project customer to meet their power demand, it is implausible that the project customer would replace its existing power plant with a new off-grid captive fossil-fuel-fired power plant with a capacity corresponding to the amount of electricity to be imported from the project activity.
5. The very low reliability of power supply from the Nigerian grid is another crucial technology barrier[26], which precludes the use of all options involving dependence on power supply from the grid for maintaining normal operations[27]. Industrial facilities such as the Greenfield industrial consumer and the project customer require a high reliability of power supply. Although the grid exists in the area where these facilities are located, the grid supply is so unstable that it is not feasible to rely on grid-based power supplies for plant operations[28]. Therefore, both the Industrial project consumer and the project customer must either have sufficient captive capacity to generate all of their power requirements, and sufficient redundancy to secure this supply, or be able to purchase power from another captive power facility in the same industrial area. There are currently no such industrial facilities to purchase power from directly. Further, maintaining a purchase agreement with the grid operator (Power Holding Company of Nigeria, PHCN) requires paying a three million Naira monthly fee (36 million Naira per annum), regardless of whether or not any power is purchased. Therefore is not economically viable to maintain a grid connection for industrial facilities that has established self-reliance through captive power generation. For the project customer, this is evidenced by the fact that they have not purchased power from the

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Energy Investment in Nigeria – The domestic context", International Institute for Sustainable Development, Canada, 2008;

[24] World Bank, "Nigeria: Low Carbon Development Options for Power and Oil and Gas Sector", Final Draft Feb 12 2012. (See Section 3.6.6 especially Fig.13 where wind speed in the Southwest of Nigeria was characterized as being below 4 m/sec at 80m, considered as not optimal for economic windpower development

[25] Op cit footnote 13. The World Bank Study (Feb 12 2012) also looked at the potentials for other renewable energy and concluded their low penetration. For example, only Northeast Nigeria has a solar DNI above 4.1 KWh/m2/day considered as the economic threshold for CSP and most Photovoltaic power technologies. Even then these technologies have high upfront investment costs that will make them not comparable to most gas fired power plants.

[26] Adeola Adenikinju, "Efficiency of the Energy Sector and its Impact on the Competitiveness of the Nigerian Economy" International Association of Energy Economics, 2009, (See Page 29, where it is stated that consumers, especially firms connected to the grid spend additional investment funds to mitigate unreliable supply of electricity from the grid

[27] OP Cit Footnote 6, See Page 3 of the reference for evidence of the existence of the problem of power shortages in Nigeria

[28] Vivien Foster and Nataliya Pushak, "Nigeria's Infrastructure: A continental Perspective", Africa Infrastructure Country Diagnostic Report, The World Bank, February 2011. (See Page 26 where an enterprise survey carried out on Nigerian industries connected to the national grid reported power outage incidences of more than 320 days in a year as further evidence of high unreliability of grid power supplies)

grid since December 2009 and terminated their purchase agreement with PHCN in April 2010. In addition, they dismantled their physical connection to the grid. For these reasons, it is reasonable to conclude that neither the Greenfield industrial consumer nor the project customer would consider connecting to the grid for all or part of their power demand.

Step 2b: Eliminate alternative scenarios which are prevented by the identified barriers
Barrier 1 precludes all of the biomass-based scenarios from been considered as plausible baseline scenarios. Therefore, scenarios P6, H4, and B7 have been eliminated as plausible baseline scenarios.

Barrier 2 precludes renewable energy options other than biomass for electricity supply. Therefore, scenario B5 is not a plausible scenario for the project customer.

Barrier 3 precludes project customers from installing cogeneration facilities. Therefore, scenario B6 is not a plausible scenario for the project customer.

Barrier 4 precludes the project customer from replacing its existing power plant with a new off-grid captive fossil-fuel-fired power plant with a capacity corresponding to the amount of electricity to be imported from the project activity. Therefore, scenario B4 is not a plausible scenario for the project customer.

Barrier 5 precludes both the Greenfield industrial consumer and the project customer from connecting to the grid for all or part of their power demand. Therefore, scenarios P2, P4, B1 and B3 are not plausible for the supply of power in the absence of the CDM project activity.

In addition to these alternatives that have been eliminated through the barrier analysis alternative B8 can also be eliminated as the Project Customer will not implement the project CHP as a means of supplying its power needs.

In summary, as a result of the Barrier Analysis, all of the scenarios involving the use of biomass and other renewable energy resources (P6, H4, B5 and B7) have been determined to be implausible. Further, all of the scenarios involving reliance on the Nigerian grid for maintaining normal plant operations (P2, P4, B1 and B3) have been determined to be not viable. Scenario B4 has been deemed implausible due to the vintage of the generators at the project consumer’s existing captive power plant. Scenario B6 regards the supply of electricity to the project customer from an onsite cogeneration plant. The project customer has no steam demand. Hence, it is not plausible that the project customer would install a cogeneration plant to meet its electricity demand.

Scenario B8 has also been eliminated due to the fact that the Project Customer will not implement the project CHP in order to supply its electricity demand in the absence of the project activity.

Implementing a cogeneration system as the source of electricity and heat/steam for the Greenfield industrial consumer may be considered a plausible baseline option, given the higher energy efficiency of cogeneration compared to stand-alone power and heat production. Lack of knowledge and experience required for the operation and maintenance of cogeneration technology in Nigeria would constitute a barrier to its adoption in a Nigerian industrial setting, unless the benefit arising from the system’s higher energy efficiency provides adequate financial incentives to overcome this barrier. Until we are able to show that the economic benefit of the technology is unable to overcome the technical barrier, the combination of scenarios P1 and H1 will be considered a plausible baseline for the Greenfield industrial consumer.

The remaining scenarios to be considered are as follows:

For power supply to the Greenfield industrial consumer:

P1: The proposed project activity not undertaken as a CDM project activity;

P3: Electricity is supplied from an off-grid captive power plant applying the fuel and technology identified for the reference captive power plant through the procedures in Annex 1. This scenario has two options:

a) The reference plant is implemented at the full design capacity of the power component of the project activity, and

b) The reference plant is implemented at 50% of the design capacity of the power component of the project activity.

For heat supply to the Greenfield industrial consumer:

H1: The proposed project activity not undertaken as a CDM project activity;

H2: Heat/steam is supplied by a stand-alone boiler applying the fuel and technology identified for the reference boiler through the procedures in Annex 1.

For power supply to the project consumer:

B2: The electricity is supplied from the existing off-grid captive fossil-fuel-fired power plant(s).[29]

These scenarios can be combined to result in applicable combined baseline alternatives for consideration in the financial analysis.

Note that scenarios P1 andH1 correspond to the project activity not implemented as a CDM project. Therefore we can only combine each of the components of this alternative with each other and NOT with any other components of the other scenarios.

The cost of power production for the project customer using their existing captive power plant is Naira 24/kWh[30]. The agreed price for power to be purchased by the project customer from the Greenfield industrial consumer is Naira 22/kWh.

Outcome of Step 2b:

Given the barriers identified and elimination of inapplicable combinations presented above, the plausible Combined Baseline Scenarios for the Greenfield Industrial Consumer are presented in Table 5**.**

Table 5: Applicable Combined Baseline Alternatives for the Greenfield Industrial Consumer

Combined Baseline Alternatives	Power supply to the Greenfield industrial consumer	Heat supply to the Greenfield industrial consumer
The Project without CDM	P1	H1
Scenario A	P3a	H2
Scenario B	P3b	H2

For the Project Customer, B2 is the Baseline Alternative.

B.5. Demonstration of additionality

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The outcome of Section B.4 resulted in the identification of three plausible Combined Baseline Alternatives for the supply of power and steam to the Greenfield industrial consumer and one Baseline Alternative for the supply of power to the project customer. In accordance with version 04.0.0 of the

[29] We interpret this scenario to mean that power is provided *solely* from the existing captive plant.

[30] See <Cost of electrical energy_from Onsite Power Gen at FMN_2012.pdf>

"Combined tool to identify the baseline scenario and demonstrate additionality" Step 3, an investment analysis has been performed to compare the economic attractiveness of the Combined Baseline Alternatives remaining after applying Step 2 of the Tool for the Greenfield Industrial consumer.

Step 3. Investment analysis
The additionality of the project has been assessed by comparing the economic performance index (the project IRR) of the three Combined Baseline Alternatives listed in Table 2. Since energy plant (power and steam) must be put in place to supply energy to the Greenfield Sugar Refinery, then it is imperative that one of the alternatives identified must be built. Each of these alternatives will involve investment. According to Para. 19 Section V of EB62 Report, Annex 5[31], it is stated that: "In cases where the alternative requires investment anyhow and baseline emissions are based on that alternative, the only means of determining that the project activity is less financially attractive than at least one alternative is to conduct an investment comparison analysis". This is the approach that has been utilized in this section. This assessment was performed in accordance with the "Guidelines on the Assessment of Investment Analysis, version 5: Section 3, of this guideline, which also covers specific guidance on the calculation of project IRR and equity IRR" (EB 62 report, Annex 5) was also followed. In implementing the investment analysis three basic starting assumptions were made:

(a) The plant load factor (PLF) achievable in the first year of operations is 70%. This assumption is based on experiences of Golden Sugar in start-up of such energy equipment. It has been assumed that this PLF will subsist until the second year of operations, increasing to 80% for the third year, and stabilizing at a level of 90% thereafter[32];
(b) The project facilities will be operated for an average of 8200 hours per year, with the remaining operational hours in a year utilized for scheduled and forced maintenance of the system.[33]
(c) No investment is required for the baseline scenario of the supply electricity to the project customer as there is adequate capacity in place at the site to supply electricity to the consumer in the absence of the project activity.[34]

The alternative in Table 2 with the highest IRR is the alternative that would have been implemented in the absence of the implementation of the CDM project and, hence, the baseline. The project is additional if the project implemented without the CDM is not the option with the highest project IRR.

The project IRRs calculated for each of the three Combined Baseline Alternatives are:

Project implemented without CDM:	43.64%
Scenario A:	50.95%
Scenario B:	38.99%

Scenario A is the most economically attractive and is therefore the baseline scenario for this project.

Sensitivity analysis
A sensitivity analysis has been carried out in compliance with paragraphs 20 and 21 of the *Guidelines on the Assessment of Investment Analysis* (Version 05, EB 62, Annex 5). Three variables, including the initial investment cost constitute more than 20% of total project costs or total project revenues: CAPEX, Gas Price and Power Tariff. These three variables were analyzed, applying a sensitivity range of ±10%. The results of the sensitivity analysis are presented in Table 6.

[31] See <Guideline on the Assessment of Investment Analysis.pdf >
[32] Based on operational experiences of Golden Sugar on industrial energy facilities
[33] Based on operational experiences of Golden Sugar on industrial energy facilities
[34] Details of the onsite power generators at the site of the project customer is available

Table 6: Sensitivity Analysis

IRR ESTIMATES							
BASELINE ALTERNATIVES	**BASE IRR**	**CAPEX (+10%)**	**CAPEX (-10%)**	**GAS PRICE (+10%)**	**GAS PRICE (-10%)**	**POWER TARIFF (+10%)**	**POWER TARIFF (+10%)**
PROJECT W/O CDM CER	*43.64%*	*40.67%*	*48.75%*	*43.49%*	*46.93%*	*47.55%*	*39.64%*
SCENARIO A	*50.95%*	*47.67%*	*54.95%*	*48.30%*	*53.64%*	*58.83%*	*42.82%*
SCENARIO B	*38.99%*	*36.66%*	*41.80%*	*32.77%*	*45.51%*	*45.08%*	*32.86%*

Even with the perturbation of these three parameters, Scenario A still remain the most economically-attractive for all the three parameters perturbed. Therefore, it can be concluded that Scenario A is the baseline scenario. Table 7 was prepared to further test the robustness of the conclusion on Scenario A as the baseline scenario, especially to evaluate the magnitude that the sensitivity parameters must reach to invalidate the conclusions reached that Scenario A is the baseline scenario. The numbers reported in Table 7 showed at what points in the perturbation of the CHP project CAPEX, the price of the natural gas, and the tariffs at which electricity is sold to the various consumers will the Project Scenario become the baseline scenario:

Table 7: Level Parameters Must Reach for the Project to become the Baseline Scenario

Parameters	Base Value Used in Investment Analysis	Value Above or Below which Project Scenario Becomes the Baseline Scenario	Comment
CAPEX of the Project	US$ 59.12 Million	Value must be ≤US$52 Million (or less than 88% of the Base Value of the CAPEX)	The base value used in the cash flow analysis was obtained from firm quotation. Since the transaction has been completed and invoiced it is inconceivable that the CAPEX can be below the base value.
Price of Natural Gas Supplied as Fuel to the Project Activity	US$4.880/MMBTU in 2013	The perturbation showed that the price of gas must be below about US$3.2?MMBTU for the baseline scenario conclusion to be invalidated	This scenario It is unlikely, given the evolution of the Nigerian Gas market to have such a price range,
Electricity Tariff to Consumers Supplied with Electricity from the Project Facility	US$ 0.099/KWh – for Electricity Supplied to the Refinery US$ 0.138/KWh – for Electricity Supplied to Industrial Consumers	Tariff to Refinery ≥US$0.117/KWh (~1.9 times the base price) Tariff to Industrial Consumer: ≥US$0.163/KWh (~1.186times the base price)	Given the current tariff for recommended electricity tariff in the Nigerian MYTO (the NERC recommended Tariff) and expected growth into the future such a jump in base tariff is unreasonable

Given the comments in Table 7, it can be concluded that the values of the CAPEX, the price of natural gas and the electricity tariffs utilized for the consumers and utilized in the analysis is robust and are unlikely to reach the levels that will negate the conclusion of the investment analysis. We therefore conclude that Scenario A is the Baseline Scenario for this project. Scenario A can be described as follows:

- The Greenfield industrial consumer would have been supplied with power from a stand-alone Reference Power Plant implemented at about the same capacity as the project plant.

- The Greenfield industrial consumer would have been supplied with steam from a stand-alone Reference Boiler implemented at about the same capacity as the steam generation capacity of the project plant.

  The project customer would have been supplied with electricity from the existing off-grid captive fossil fuel fired power plant(s) available at its site.

Step 4: Common practice analysis
According to a report recently completed under funding by the World Alliance of Decentralized Energy (WADE), the total CHP potential in Nigeria may be as high as 1,000 MW.[35] However, CHP technologies are not widely utilized in the Nigerian economy. In March 2012 a project team visited Nigeria and performed a scoping survey of energy facilities in the food industry. At that time, only two industrial operators with heat and power demand were identified to have installed cogeneration facilities. The first, at Dangote Foods Limited, cannot strictly be said to be a CHP as a substantial portion of excess steam produced by the facility is dumped (wasted), as there are no markets for the steam from nearby facilities. Coca Cola Nigeria recently (2011) also installed a CHP. However, the capacity of this plant is only 4MW. In accordance with the *Guidelines on Common Practice* (EB69 Annex), the applicable capacity or output range for evaluating common practice in the use of CHP technology for this project is +/-50% of the total design capacity or output of the proposed project activity (28.8MW). Hence the range of CHP capacities relevant for this common practice analysis is 14.4 – 43.2MW. There are no CHP plants within this capacity range installed in the food sector in Nigeria. To consolidate this fact further, we applied Section 2 of the Guideline on Common Practice (Stepwise approach for common practice) as follows:

<u>Step 1: Calculate applicable capacity or output range as +/-50% of the total design capacity or output of the proposed project activity.</u>

The design capacity of the Underlying Project in terms of the electricity producing capacity is 28.8 MW
The applicable range of the project within the +/-50% range is :

Applicable Output Range of the Project = 14.4 – 43.2 MW

<u>Step 2: In the applicable geographical area, identify all plants that:</u>

(a) Applies the same measure as the proposed project activity;
(b) Utilizes the same energy source/fuel and feedstock as the project activity;
(c) Produces the same products with comparable quality, properties and application areas as the project activity;
(d) Delivers output or capacity, within the applicable output range calculated in Step 1, and
(e) Have started commercial operation before the start date of the project (N_{All})

[35] "More for Less: How Decentralized Energy Can Deliver Cleaner, Cheaper and More Efficient Energy in Nigeria." A Report by World Alliance for Decentralized Energy (WADE), Christian AID and the International Center for Environment and Energy Development (ICEED), August 2009.

As stated earlier there are no CHP facility with power production in the range described above and that complies with the applicable criteria listed in (a) – (e) above, in the food sector of Nigeria as at the time of preparing this PDD.

Step 3: Within the projects identified in Step 2, identify those that are neither registered CDM project activities, project activities submitted for registration, nor project activities undergoing validation. Note their number *Nall.*

Since there are no such plants operating in Nigeria:

$\boldsymbol{N_{All} = 0}$

Step 4: Within similar projects identified in Step 3, identify those that apply technologies that is different to the technology applied in the proposed project activity. Note their number $\boldsymbol{N_{diff}}$.

Since $N_{All} = 0$, *then,*

$N_{diff.} = 0$.

Step 5: Calculate factor F=1-*Ndiff/Nall* representing the share of similar projects (penetration rate of the measure/technology) using a measure/technology similar to the measure/technology used in the proposed project activity that deliver the same output or capacity as the proposed project activity.

Since $\boldsymbol{N_{diff.} = N_{All} = 0}$

Then:

We can conclude that $F \leq 0$

Also,
$\boldsymbol{N_{All} - N_{diff.} = 0}$

According to Para. 10 of the "Common Practice Guideline",

The proposed project activity is a "common practice" within a sector in the applicable geographical area if both the following conditions are fulfilled:

- The factor F is greater than 0.2, and
- Nall-Ndiff is greater than 3.

Since neither of these two conditions is satisfied, it can be concluded that the proposed project activity is NOT a common practice in Nigeria.

As a result of this analysis we conclude that the Golden Sugar CHP facility is first-of-its-kind (*i.e.* not common practice) in the food sector in Nigeria.[36]

[36] First of its kind here refers to the Guidelines definition (EB69 Annex 7) that: "The project is the first in the applicable geographical area that applies a technology that is different from technologies that are implemented by any other project, which are able to deliver the same output and have started commercial operation in the applicable geographical area before the project design document (CDM-PDD) is published for global stakeholder consultation

Prior Consideration
The idea of installing an energy efficient combined heat and power plant to provide the steam and electricity needs of the greenfield Golden Sugar refinery was born out of discussions in early 2010 with Standard Bank regarding the financing of the underlying project. It was brought to the attention of Golden Sugar management at this time that doing so – instead of designing the refinery power plant using traditional stand-alone boilers and generators – would improve the environmental performance of the refinery and could be made financially viable through the generation of carbon credits (CERs) and their sale to Standard Bank. The chronology of key events in the development of this CDM project and leading up to the project start date are summarized below:

(a) March 2010: The Carbon Unit of Standard Bank introduced CDM Concepts to top Managers of Golden Sugar and proposed an approach for the design of a green energy supply system for the proposed sugar refinery. The approach proposed by Standard Bank to design the new sugar refinery's energy system using an energy-efficient combined-heat-and-power (CHP) plant was approved by the Managing Director of Golden Sugar.

(b) September 2010: Booker Tate delivered the initial feasibility study for the design of the refinery energy plant utilizing CHP technology.

(c) October 2010: IPRO submitted its peer review of the Booker Tate feasibility study, proposing what became the final design of the CHP plant.

(d) January 2011: Golden Sugar entered into an Emission Reduction Purchase Agreement with Standard Bank. As part of this agreement, Standard Bank agreed to finance the development of the CDM component of the project. Standard Bank immediately brought in its CDM consultants to develop the CDM project documentation.

(e) February 2011: Golden Sugar submitted the prior consideration form for the project to the UNFCCC and the Nigerian DNA. The UNFCCC posted confirmation of the receipt of the Golden Sugar prior consideration form on its website-

(f) April 2011: The Nigerian DNA released a Letter of No Objection for the project.

(g) July 2011: Golden Sugar Management made firm financial commitment for the purchase of the project equipment on July 19 2011. This date is the Start Date of the CDM Project[37];

(h) June 2012: PDD uploaded for global stakeholder consultation.

The start date of the project activity is prior to the date of publication of the PDD for global stakeholder consultation. Prior consideration of the CDM was demonstrated through the submission of the Prior Consideration form and cover letter to the UNFCCC Secretariat on February 10th, 2011. These documents were also submitted to the Nigerian DNA office in Abuja.

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or before the start date of the proposed project activity, whichever is earlier. The project will not claim first-of-its-kind as an additionality criterion because the selected project crediting period is renewable.

[37] Between April 2011 and February 2012, the CDM Consultant after determining that no existing approved methodology within the UNFCCC approved methodology stable is applicable to the project circumstances of the Golden Sugar CDM project, developed a New Methodology (NM0352) and submitted it through a DOE appointed by Standard Bank to the UNFCCC Secretariat; In February 2012: After two rounds of reviews by the Methodology Panel, the UNFCCC CDM EB approved the NM 0352 as AM0102. It was only after then that the Consultant commenced the developed of the PDD;

B.6. Emission reductions
B.6.1. Explanation of methodological choices
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Baseline Emissions:

In accordance with AM0102 version 01.0.0, baseline emissions include emissions from consumption of fossil fuels for the electricity and steam that would be generated at the site of the Greenfield industrial consumer, from consumption of fossil fuels at the sites of the project consumers for the electricity imported from the project activity, and from consumption of fossil fuels to supply the electricity to the grid. Baseline emissions are calculated by the following equations:

$$BE_y = BE_{GIC,p,y} + BE_{GIC,ST,y} + \sum_i BE_{PC,i,y} + BE_{grid,y} \quad \textbf{(1)}$$

Where:

BE_y = Baseline emissions in year *y* (t CO_2/yr)
$BE_{GIC,p,y}$ = Baseline emissions from the production of electricity supplied to the Greenfield industrial consumer in year *y* (t CO_2/yr)
$BE_{GIC,ST,y}$ = Baseline emissions from the production of heat/steam supplied to the Greenfield industrial consumer in year *y* (t CO_2/yr)
$BE_{PC,i,y}$ = Baseline emissions from the production of electricity supplied to project customer *i* in year *y* (t CO_2/yr)
$BE_{grid,y}$ = Baseline emissions from the production of electricity supplied to the grid in year *y* (t CO_2/yr)

The Greenfield Industrial Consumer will not be connected to the grid. Therefore, $BE_{grid,y} = 0$.

There is one single project customer. The project customer is not connected to the grid.

For the *ex ante* estimate of baseline emissions, the following values have been applied (based on calculations below):

		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
BE_y	**tCO_2/yr**	**161,795**	**161,795**	**181,970**	**196,549**	**196,549**	**196,549**	**196,549**
$BE_{GIC,p,y}$	tCO_2/yr	19,123	19,123	21,854	24,586	24,586	24,586	24,586
$BE_{GIC,ST,y}$	tCO_2/yr	82,926	82,926	94,771	106,619	106,619	106,619	106,619
$BE_{PC,i,y}$	tCO_2/yr	59,746	59,746	59,746	65,344	65,344	65,344	65,344
$BE_{grid,y}$	tCO_2/yr	-	-	-	-	-	-	-

1. Baseline emissions for electricity supplied to the Greenfield industrial consumer, $BE_{GIC,p,y}$

a. Electricity supplied by a Greenfield captive power plant

In the absence of the project activity, the electricity demand of the Greenfield industrial consumer can be met entirely by a Greenfield natural-gas-fired captive power plant implemented at the project site. The baseline emissions for the generation of the electricity provided to the Greenfield industrial consumer are calculated with the equation below.

$$BE_{GIC,p,y} = EG_{GIC,y} \times 0.0036 \left(TJ / MWh \right) \times \frac{\min(EF_{CO2,RPF}, EF_{CO2,PJ,y})}{\eta_{RP}} \qquad \textbf{(2)}$$

Where:

$BE_{GIC,p,y}$ = Baseline emissions from the production of electricity supplied to the Greenfield industrial consumer in year *y* (t CO_2/yr)

$EG_{GIC,y}$ = Quantity of electricity generated by the project facility that is supplied to the Greenfield industrial consumer in year *y* (MWh/yr)

$EF_{CO2,RPF}$ = CO_2 emission factor of the natural gas used by the reference captive power plant (t CO_2/TJ)

$EF_{CO2,PJ,y}$ = CO_2 emission factor of the natural gas used by the project facility in year *y* (t CO_2/TJ)

η_{RP} = Design energy efficiency of the reference captive power plant (fraction)

For the *ex ante* estimate of baseline emissions, the following values have been applied[38]:

		2013	2014	2015	2016	2017	2018	2019
BEgic,p,y	tCO2/yr	19,123	19,123	21,854	24,586	24,586	24,586	24,586
EGgic,y	MWh/yr	38,802	38,802	44,346	49,889	49,889	49,889	49,889
EFco2,rpf	tCO2/TJ	52.02	52.02	52.02	52.02	52.02	52.02	52.02
EFco2,pj,y	tCO2/TJ	52.02	52.02	52.02	52.02	52.02	52.02	52.02
h_{RP}	fraction	0.38	0.38	0.38	0.38	0.38	0.38	0.38

The emission factor of the fossil fuels used by the project facility in year *y* is calculated according to the equation below.

$$EF_{CO2,PJ,y} = \frac{\sum_i (EF_{CO2,i,y} \times NCV_{i,y} \times FC_{i,y})}{\sum_i (NCV_{i,y} \times FC_{i,y})} \qquad \textbf{(3)}$$

Where:

$EF_{CO2,PJ,y}$ = CO_2 emission factor of the natural gas used by the project facility in year *y* (t CO_2/TJ)

$EF_{CO2,i,y}$ = Weighted average CO_2 emission factor of fuel type *i* (natural gas) in year *y* (t CO_2/GJ), monitored as per “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”

$NCV_{i,y}$ = Weighted average net calorific value of the fuel type *i* (natural gas) in year *y* (GJ/mass or volume unit), monitored as per “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”

$FC_{i,y}$ = Quantity of fuel type *i* (natural gas) combusted in process *j* during the year *y* (mass or volume unit/yr), monitored as per “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”

For the *ex ante* estimate of baseline emissions, the following values have been applied[39]:

[38] For calculation and input data details see: *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ2 – GS baseline emissions”

		2013	2014	2015	2016	2017	2018	2019
EFco2,i,y	**tCO2/GJ**	0.05202	0.05202	0.05202	0.05202	0.05202	0.05202	0.05202
NCV,i,y	GJ/Nm3	0.036	0.036	0.036	0.036	0.036	0.036	0.036
FCi,y	Nm3	53,757,727	53,757,727	61,437,403	69,117,078	69,117,078	69,117,078	69,117,078

Baseline Emissions for heat/steam supplied to the Greenfield industrial consumer, $BE_{GIC,ST,y}$

In the absence of the project activity, the steam demand of the Greenfield industrial consumer is met through a Greenfield captive fossil-fuel-fired boiler installed at the project site or at the consumer site. The steam generated by the project facility is only supplied to the Greenfield industrial consumer and must meet its total heat demand. The maximum heat generation capacity of the project facility in any year *y* of the crediting period is limited by the maximum heat demand of the Greenfield industrial consumer in this respective year *y*. The baseline emissions from the production of heat that is generated in the reference boiler for the supply of heat to the Greenfield industrial consumer in the absence of the project activity can be calculated as follows:

$$BE_{GIC,ST,y} = HG_{GIC,y} \times EF_{RB} \qquad \textbf{(4)}$$

Where:

$BE_{GIC,ST,y}$	=	Baseline emissions from the production of steam supplied to the Greenfield industrial consumer in year *y* (t CO_2/yr)
$HG_{GIC,y}$	=	Quantity of steam generated by the project facility that is supplied to the Greenfield industrial consumer in year *y* (TJ/yr)
EF_{RB}	=	Emission factor of the reference boiler, which would have supplied steam to the Greenfield industrial consumer in the absence of the project activity in year *y* (t CO_2/TJ)

For the *ex ante* estimate of baseline emissions, the following values have been applied[40]:

		2013	2014	2015	2016	2017	2018	2019
$BE_{GIC,ST,y}$	**tCO_2/yr**	82,926	82,926	94,771	106,619	106,619	106,619	106,619
$HG_{GIC,y}$	TJ/yr	1,403	1,403	1,603	1,804	1,804	1,804	1,804
EF_{RB}	tCO_2/TJ	59.11	59.11	59.11	59.11	59.11	59.11	59.11

The emission factor for the baseline steam generation is based on the design parameters of the reference boiler identified through the procedures in Annex 1. The emission factor of the reference boiler EF_{RB} is calculated as follows:

$$EF_{RB} = \frac{\min(EF_{CO2,RBF}, EF_{CO2,PJ,y})}{\eta_{RB}} \qquad \textbf{(5)}$$

[39] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ3 – GS baseline emissions”

[40] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ4 – GS baseline E steam”

Where:

EF_{RB}	=	Emission factor of the reference boiler, which would have supplied steam to the Greenfield industrial consumer in the absence of the project activity in year *y* (tCO_2/TJ)
$EF_{CO2,RBF}$	=	CO_2 emission factor of the fuel used by the reference boiler (t CO_2/TJ)
$EF_{CO2,PJ,y}$	=	CO_2 emission factor of the fuel(s) used by the project facility in year *y* (t CO_2/TJ)
η_{RB}	=	Design energy efficiency of the reference boiler (fraction)

For the *ex ante* estimate of baseline emissions, the following values have been applied[41]:

$EF_{CO2,RBF}$	tCO_2/TJ	59.11
$EF_{CO2,PJ,y}$	tCO_2/TJ	52.02
η_{RB}	fraction	0.88

2. Baseline Emissions for electricity supplied to project customer *i*, $BE_{PC,i,y}$

In the absence of the project activity, the electricity supplied by the project facility to the project customer would be met by an existing captive power plant(s) at the site of the project customer.

a. Electricity supplied by an existing captive power plant(s)

In the absence of the project activity, the electricity demand of project customer *i* can be met entirely by an existing fossil fuel fired captive power plant(s) installed at the customer site. The baseline emissions for the generation of the electricity provided to project customer *i* are calculated with the equation below. There are two on-site captive power plants that could supply to project customer *i*. The power plant with the least carbon intensive power generation unit has been conservatively applied to determine the emission factor of the captive power plant used in the baseline emission calculations.

$$BE_{PC,i,y} = \min\left\{EG_{PC,i,y}, \sum_j EG_{cap,i,j}\right\} \times \min\left\{EF_{i,j}\right\} \quad \textbf{(6)}$$

Where:

$BE_{PC,i,y}$	=	Baseline emissions from the production of electricity supplied to project customer *i* in year *y* (t CO_2/yr)
$EG_{PC,i,y}$	=	Quantity of electricity generated by the project facility that is supplied to project customer *i* in year *y* (MWh/yr)
$EG_{cap,i,j}$	=	Historical maximum electricity generation of existing fossil fuel fired captive power plant *j* at the site of project customer *i* (MWh/yr)
$EF_{i,j}$	=	Emission factor of existing fossil fuel fired captive power plant *j* at the site of project customer *i* (t CO_2/MWh)

[41] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ5 – EF ref boiler”

For the *ex ante* estimate of baseline emissions, the following values have been applied[42]:

		2013	2014	2015	2016	2017	2018	2019
$BE_{PC,i,y}$	**tCO2/yr**	59,746	59,746	65,344	65,344	65,344	65,344	65,344
$EG_{PC,i,y}$	MWh/yr	121,390	121,390	138,731	156,072	156,072	156,072	156,072
$EG_{cap,i,j}$	MWh/yr	132,763	132,763	132,763	132,763	132,763	132,763	132,763
$EF_{i,j}$	tCO_2/MWh	0.49	0.49	0.49	0.49	0.49	0.49	0.49

The emission factor for the baseline electricity generation is based on the fuel consumption and the electricity generation information of the latest year available. The emission factor of existing captive fossil fuel fired power plant *j* at the site of project customer *i*, $EF_{i,j}$, is calculated according to the equation below.

$$EF_{i,j} = \frac{\sum_k (FC_{i,j,k} \times NCV_{i,j,k} \times EF_{CO2,k})}{EG_{i,j}} \quad \textbf{(7)}$$

Where:

$EF_{i,j}$ = Emission factor of existing fossil fuel fired captive power plant *j* at the site of project customer *i* (t CO_2/MWh)
$FC_{i,j,k}$ = Quantity of natural gas fired in captive power plant *j* in the year prior to the implementation of the project activity (2011, mass or volume unit)
$NCV_{i,j,k}$ = Net calorific value of natural gas fired in captive power plant *j* (GJ/mass or volume unit)
$EF_{CO2,k}$ = CO_2 emission factor of natural gas (tCO_2/GJ)
$EG_{i,j}$ = Quantity of electricity generated in captive power plant *j* at the site of project customer *i* in the year prior to the implementation of the project activity (2011, in MWh)

For the *ex ante* estimate of baseline emissions, the following values have been applied[43]:

		2009	2010	2011
$EF_{i,j}$	tCO_2/MWh	0.49	0.50	0.50
$FC_{i,j,k}$	Nm^3	29,356,570	36,059,959	35,314,235
$NCV_{i,j,k}$	GJ/Nm^3	0.036	0.036	0.036
$EF_{CO2,k}$	tCO_2/GJ	0.0520	0.0520	0.0520
$EG_{i,j}$	MWh	110,241	132,563	130,446

[42] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ6 – BE Project Customer”

[43] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “EQ7 – EF FMN captive plant”

The lowest baseline emission factor for the existing fossil fuel fired captive power plant (2009) has been selected, for conservativeness.

Project Emissions

Project emissions include emissions from fossil fuel consumption at the project site for the generation of electric power and heat and for auxiliary loads related to the generation of electric power and heat. All of the natural gas consumed at the project facility is included in the project emission calculations.

Project emissions PE_y are calculated using the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion." The combustion process *j* as referred to in the tool is the process of producing steam and power in the project facility CHP plant, and includes the following:

- On-site fossil fuel consumption for the generation of electric power and heat. This includes all fossil fuels used at the project site in heat generators (e.g. boilers) for the generation of electric power and heat; and all on-site fossil fuel consumption of auxiliary equipment and systems related to the generation of electric power and heat.[44]

As per this tool project emissions $PE_y = PE_{FC,j,y}$. Project emissions for the production processes at the project facility (process *j*) have been calculated as follows:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y} \qquad (1)$$

Where:

$PE_{FC,j,y}$ = Are the CO_2 emissions from fossil fuel combustion in process j during the year *y* (tCO_2/yr);

$FC_{i,j,y}$ = Is the quantity of fuel type *i* combusted in process *j* during the year *y* (mass or volume unit/yr);

$COEF_{i,y}$ = Is the CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2/mass or volume unit)

i = Are the fuel types combusted in process *j* during the year *y*

The CO_2 emission coefficient $COEF_{i,y}$ can be calculated using one of the following two Options, depending on the availability of data on the fossil fuel type *i*, as follows:

For the *ex ante* estimate of project emissions, the following values has been applied for natural gas (i) combusted at the project facility (process *j*)[45]:

		2013	2014	2015	2016	2017	2018	2019
$\mathbf{PE_{FC,j,y}}$	tCO_2/yr	105,701	105,701	120,801	135,901	135,901	135,901	135,901
$FC_{i,j,y}$	Nm^3/yr	57,189,086	57,189,086	65,358,955	73,528,825	73,528,825	73,528,825	73,528,825
$COEF_{i,y}$	tCO_2/Nm^3	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018

[44] Note that for the *ex ante* estimate of project emissions natural gas has been used as the sole fuel combusted at the project facility. For monitoring periods when diesel has been used as a start-up fuel and/or due to lack of natural gas, project emissions from diesel consumption must be calculated separately, using the same calculation procedures applied here.

[45] For fuel consumption see *GS Financial Analysis - Baseline and Additionality - Final.xlsx*, sheet "Financial Analysis_CHP".

Option A: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the chemical composition of the fossil fuel type *i*, using the following approach:

If $FC_{i,j,y}$ is measured in a mass unit: $$COEF_{i,y} = w_{C,i,y} \times 44/12 \quad (2)$$

If $FC_{i,j,y}$ is measured in a volume unit: $$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 44/12 \quad (3)$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type i (tCO_2/mass or volume unit);
$w_{C,i,y}$	=	Is the weighted average mass fraction of carbon in fuel type i in year y (tC/mass unit of the fuel);
$\rho_{i,y}$	=	Is the weighted average density of fuel type i in year y (mass unit/volume unit of the fuel)
i	=	Are the fuel types combusted in process j during the year y

Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i,y} \quad (4)$$

Where:

$COEF_{i,y}$	=	Is the CO_2 emission coefficient of fuel type i in year *y* (tCO_2/mass or volume unit)
$NCV_{i,y}$	=	Is the weighted average net calorific value of the fuel type *i* in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	=	Is the weighted average CO_2 emission factor of fuel type *i* in year *y* (tCO_2/GJ)
i	=	Are the fuel types combusted in process *j* during the year *y*

Option A should be the preferred approach, if the necessary data is available.

For the *ex ante* estimate of project emissions, Option B using the following values has been applied for natural gas (i) combusted at the project facility:[46]

$COEF_{i,y}$	tCO_2/Nm^3	0.0018
$NCV_{i,y}$	GJ/Nm^3	0.036
$EF_{CO2,i,y}$	tCO_2/GJ	0.0520

Leakage

Both the project activity and the baseline utilize natural gas. Natural gas consumption for the project activity is less than natural gas consumption in the baseline: this is the source of emission reductions for this project activity. Hence, fugitive methane emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas are less for the project activity than in the baseline case. Therefore, we have assumed that leakage is zero. This is a conservative assumption.

$LE_y = 0$

[46] For calculation and input data details see *GS Project Baseline Emission Calculations final.xlxs*, sheet “Input data”

Emission reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad (1)$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO_2e/yr)
PE_y	=	Project emissions in year *y* (t CO_2/yr)
LE_y	=	Leakage emissions in year *y* (t CO_2/yr)

For the *ex ante* calculations of emission reductions, the following values have been applied/calculated:

		2013	2014	2015	2016	2017	2018	2019
$\boldsymbol{ER_y}$	**tCO_2e/yr**	56,094	56,094	61,169	60,647	60,647	60,647	60,647
BE_y	tCO_2/yr	161,795	161,795	181,970	196,549	196,549	196,549	196,549
PE_y	tCO_2/yr	105,701	105,701	120,801	135,901	135,901	135,901	135,901
LE_y	tCO_2e/yr	-	-	-	-	-	-	-

B.6.2. Data and parameters fixed ex ante

(Copy this table for each piece of data and parameter.)

Data / Parameter	$EG_{cap,m}$, $HG_{cap,m}$
Unit	MW and tonnes/hr
Description	Design capacity of energy plant *m* in the peer group
Source of data	Nameplate information on the installed capacity of energy plant *m* in the peer group. See: *GS Baseline Selection and Additionality Demonstration.docx*
Value(s) applied	For power: 3.039 x 10 MW For steam: 16 tonnes/hr x 6
Choice of data or Measurement methods and procedures	Not applicable. As per AM0102
Purpose of data	Calculation of baseline emissions.
Additional comment	

Data / Parameter	Y_m
Unit	year
Description	Year of commissioning of energy plant *m* in the peer group
Source of data	Information supplied from plant owners. See: *GS Baseline Selection and Additionality Demonstration.docx*
Value(s) applied	For power: 2010, For steam: 2006
Choice of data or Measurement methods and procedures	Not applicable. As per AM0102
Purpose of data	Calculation of baseline emissions.
Additional comment	

Data / Parameter	$EF_{CO2,m}$
Unit	tCO_2/TJ
Description	CO_2 emission factor of the fuel(s) used in energy plant *m* in the peer group
Source of data	Calculated based on fuel characteristics data provided by the fuel supplier. See: *NGC Gas Analysis Result.jpg* and *Calculation - Specific CO2 Content Natural Gas.xls*
Value(s) applied	52.02
Choice of data or Measurement methods and procedures	As per AM0102. Measurements were carried out by a reputable laboratory and in accordance with international standards.
Purpose of data	Calculation of baseline emissions.
Additional comment	The fuel supplier periodically performs tests of the characteristics of the natural gas. The results of the latest such test are from January 2011, supplied by the fuel supplier to Golden Sugar in March 2012.

Data / Parameter	η_m
Unit	fraction
Description	Design efficiency of energy plant m in the peer group
Source of data	Information supplied from plant owners. See: *GS Baseline Selection and Additionality Demonstration.docx*
Value(s) applied	0.38
Choice of data or Measurement methods and procedures	Not applicable. As per AM0102
Purpose of data	Calculation of baseline emissions.
Additional comment	

Data / Parameter	$EG_{cap.i.j}$
Unit	MWh/yr
Description	Historical maximum of electricity generation of existing fossil fuel fired captive power plant *j* at the site of project customer *i* (2010)
Source of data	Plant records. See: *GS Emission Reduction Calculations Final.xlsx* sheet "Input data"
Value(s) applied	$EG_{cap.i.j}$
Choice of data or Measurement methods and procedures	Not applicable. As per AM0102
Purpose of data	Calculation of baseline emissions.
Additional comment	

Data / Parameter	$FC_{i.j,k}$
Unit	Nm^3
Description	Quantity of natural gas fired in captive power plant *j* in the year prior to the implementation of the project activity (2011)
Source of data	Plant records. See: *GS Emission Reduction Calculations Final.xlsx* sheet "Input data"
Value(s) applied	35,314,235
Choice of data or Measurement methods and procedures	Not applicable. As per AM0102
Purpose of data	Calculation of baseline emissions.
Additional comment	

Data / Parameter	$NCV_{i,j,k}$
Unit	GJ/Nm^3
Description	Net calorific value of natural gas fired in captive power plant *j*
Source of data	Calculated based on data provided by the fuel supplier. See: *NGC Gas Analysis Result.jpg* and *Calculation - Specific CO2 Content Natural Gas.xls*
Value(s) applied	0.036
Choice of data or Measurement methods and procedures	As per AM0102. Measurements were carried out by a reputable laboratory and in accordance with international standards.
Purpose of data	Calculation of baseline emissions.
Additional comment	The fuel supplier periodically performs tests of the characteristics of the natural gas. The results of the latest such test are from January 2011, supplied by the fuel supplier to Golden Sugar in March 2012.

Data / Parameter	$EF_{CO2,k}$
Unit	tCO_2/TJ
Description	CO_2 emission factor of fossil fuel type *k* (natural gas)
Source of data	Calculated based on fuel characteristics data provided by the fuel supplier. See: *NGC Gas Analysis Result.jpg* and *Calculation - Specific CO2 Content Natural Gas.xls*
Value(s) applied	52.02
Choice of data or Measurement methods and procedures	As per AM0102. Measurements were carried out by a reputable laboratory and in accordance with international standards.
Purpose of data	Calculation of baseline emissions.
Additional comment	The fuel supplier periodically performs tests of the characteristics of the natural gas. The results of the latest such test are from January 2011, supplied by the fuel supplier to Golden Sugar in March 2012.

Data / Parameter	$EG_{i,j}$
Unit	MWh/yr
Description	Quantity of electricity generated in captive power plant *j* at the site of project customer *i* in the year prior to the implementation of the project activity (2011)
Source of data	Plant records. See: *GS Emission Reduction Calculations Final.xlsx* sheet "Input data"
Value(s) applied	131,371.54
Choice of data or Measurement methods and procedures	As per AM0102. Measurements carried out using calibrated meters.
Purpose of data	Calculation of baseline emissions.
Additional comment	

B.6.3. Ex ante calculation of emission reductions
>> See Annex 3: Excel Spreadsheet on Emission Reduction Calculations

Examples of how the Emission Reduction Calculations have been applied for the ex ante estimates for January through December 2013

Baseline Emissions

Total baseline emissions:

$$BE_y = BE_{GIC,p,y} + BE_{GIC,ST,y} + \sum_i BE_{PC,i,y} + BE_{grid,y} \qquad \textbf{(1)}$$

161,795 = 19,123 + 82,926 + 59,746 + 0

Baseline emissions for the generation of the electricity provided to the Greenfield industrial consumer:

$$BE_{GIC,p,y} = EG_{GIC,y} \times 0.0036 (TJ / MWh) \times \frac{\min(EF_{CO2,RPF}, EF_{CO2,PJ,y})}{\eta_{RP}} \qquad \textbf{(2)}$$

19,123 = 38,802 x 0.0036 x min(52.02, 52.02)/0.38

The emission factor of the fossil fuels used by the project facility in year *y*:

$$EF_{CO2,PJ,y} = \frac{\sum_i (EF_{CO2,i,y} \times NCV_{i,y} \times FC_{i,y})}{\sum_i (NCV_{i,y} \times FC_{i,y})} \qquad \textbf{(3)}$$

52.02 = (0.05202 x 0.036 x 59,991,132)/(0.036x59,991,132)

Baseline emissions from the production of heat that is generated in the reference boiler for the supply of heat to the Greenfield industrial consumer:

$$BE_{GIC,ST,y} = HG_{GIC,y} \times EF_{RB} \quad \textbf{(4)}$$

82,926 = 1,403 x 57.74

The emission factor of the reference boiler EF_{RB}:

$$EF_{RB} = \frac{\min(EF_{CO2,RBF}, EF_{CO2,PJ,y})}{\eta_{RB}} \quad \textbf{(5)}$$

59.11 = min(52.02, 52.02)/0.88

The baseline emissions for the generation of the electricity provided to project customer *i*:

$$BE_{PC,i,y} = \min\left\{EG_{PC,i,y}, \sum_j EG_{cap,i,j}\right\} \times \min\left\{EF_{i,j}\right\} \quad \textbf{(6)}$$

59,746 = min(121,390 , 132,763) x 0.49

The emission factor of existing captive fossil fuel fired power plant *j* at the site of project customer *i*:

$$EF_{i,j} = \frac{\sum_k (FC_{i,j,k} \times NCV_{i,j,k} \times EF_{CO2,k})}{EG_{i,j}} \quad \textbf{(7)}$$

0.49 = (29,356,570 x 0.036 x 0.0520)/(110,241)

Project Emissions

Total project emissions:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y} \quad \textbf{(1)}$$

105,701 = 57,189,986 x 0.0018

Using Option B to calculate $COEF_{i,y}$:

$COEF_{i,y} = NCV_{i,y}\ x\ EF_{CO2,i,y}$

0.0018 = 0.036 x 0.0520

Leakage

We have assumed that leakage is zero. This is a conservative assumption.

$LE_y = 0$

Emission Reductions

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(1)}$$

56,094 = 161,795 – 105,701 – 0

B.6.4. Summary of ex ante estimates of emission reductions

Year	**Baseline emissions (t CO_2e)**	**Project emissions (t CO_2e)**	**Leakage (t CO_2e)**	**Emission reductions (t CO_2e)**
2013	161,795	105,701	0	56,094
2014	161,795	105,701	0	56,094
2015	181,970	120,801	0	61,169
2016	196,549	135,901	0	60,647
2017	196,549	135,901	0	60,647
2018	196,549	135,901	0	60,647
2019	196,549	135,901	0	60,647
Total	1,291754	875,808	0	415,947
Total number of crediting years	7			
Annual average over the crediting period	184,536	125,115	0	59,421

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

(Copy this table for each piece of data and parameter.)

Data / Parameter	$EG_{GIC,y}$
Unit	MWh/yr
Description	Quantity of electricity generated by the project facility that is supplied to the Greenfield industrial consumer in year *y*
Source of data	Measurements at the consumer side
Value(s) applied	2013: 37,310 2014: 37,310 2015: 42,640 2016: 47,970 2017: 47,970 2018: 47,970 2019: 47,970
Measurement methods and procedures	An electricity meter will be installed on the line taking electricity generated from the project CHP. The electricity meters will be operated continuously and data recorded monthly. The accuracy of the electricity meters will be at 0.2S level. The measurement will be taken online and the data will be recorded in the control system. All the measurement instruments and procedure adopted will be as per the industry practice.
Monitoring frequency	Data monitored continuously and aggregated as appropriate, to calculate emission reductions
QA/QC procedures	The energy metering equipment are calibrated and checked for accuracy by qualified third party in accordance with national standard, The energy meter will be calibrated once annually in accordance with EN50160 International Standard following the procedures of ANSI 12.20 and IEC62053-22 specifications. The monthly electricity supplied to the Greenfield Sugar Refinery will be approved and signed off by the CDM Manager. With normal care in installation and instrumentation, the accuracy of the electricity metering will be consistently better than ±0.5%.
Purpose of data	Calculation of baseline emissions.
Additional comment	Data will be archived by electronic/paper as available.

Data / Parameter	$HC_{GIC,y}$
Unit	TJ/yr
Description	Quantity of steam generated by the project facility that is supplied to the Greenfield industrial consumer in year *y*
Source of data	Measurements on the consumer side
Value(s) applied	2013: 1,403 2014: 1,403 2015: 1,603 2016: 1,804 2017: 1,804 2018: 1,804 2019: 1,804
Measurement methods and procedures	This parameter will be determined as the difference of the enthalpy of the process heat (steam or hot water) supplied to process heat loads in the project activity minus the enthalpy of the feed-water and the boiler blow-down. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations will be used to calculate the enthalpy as a function of temperature and pressure. Data will be monitored continuously and aggregated as appropriate. Temperature, pressure and mass flow of steam will be continuously measured with online meters. Steam flow meter that automatically measures temperature and pressure of the steam will be installed on line and used for data acquisition. Accuracy of temperature measurement has to be 0.25% of the measured value or better. Accuracy of pressure measurement has to be 0.3% of the measurement range of the meter or better. Read outs shall occur with the frequency of the plant control system but the frequency should not be lower than once per minute
Monitoring frequency	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions
QA/QC procedures	Steam flow meters should be calibrated once every year as per international QA/QC procedures, e.g. according to the IAPWS-IF 97international standard.
Purpose of data	Calculation of baseline emissions.
Additional comment	The DOE shall ensure the compliance of the applicability condition on heat-to-power ratio for each monitoring period, by comparing $HG_{GIC,y}$ (converted to MWh/yr) to the sum of $EG_{GIC,y}$ and $EG_{PC,i,y}$.

Data / Parameter	$EG_{PC,i,y}$
Unit	MWh/yr
Description	Quantity of electricity generated by the project facility that is supplied to the project customer in year *y*
Source of data	Measurements at the customer site
Value(s) applied	2013: 121,390 2014: 121,390 2015: 138,731 2016: 156,072 2017: 156,072 2018: 156,072 2019: 156,0724
Measurement methods and procedures	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions
Monitoring frequency	The online energy meters (main + crosscheck meters) will measure continuously. The data will be logged monthly and archived.
QA/QC procedures	The energy metering equipment will be calibrated and checked for accuracy once annually in accordance with EN50160 International Standard following the procedures of ANSI 12.20 and IEC62053-22 specifications. The monthly electricity imported from the project power plant will be approved and signed off by the CDM Manager. With normal care in installation and instrumentation, the accuracy of the electricity metering will be consistently better than ±0.5%. The consistency of metered electricity generation should be cross-checked with receipts from electricity purchases
Purpose of data	Calculation of baseline emissions.
Additional comment	The DOE shall also confirm that electricity is only supplied to the project customers as identified ex ante in the PDD. If ex post power is supplied to any customer not identified in the registered PDD, then the latest version of the “Procedures for notifying and requesting approval of change from the project activity as described in the registered PDD” shall be followed.

Data / Parameter	FCi,j,y
Unit	(m3/year)
Description	Volume of fuel utilized by the Cogen (project activity) in year y (m3)
Source of data	Fuel Meter installed in the fuel input line to the cogeneration facility
Value(s) applied	2013: 57,189,086 2014: 57,189,086 2015: 65,358,955 2016: 73,528,825 2017: 73,528,825 2018: 73,528,825 2019: 73,528,825
Measurement methods and procedures	Online gas meter installed on the fuel line before supply to the burners. The hourly data from the meter will be archived electronically
Monitoring frequency	Continuously, aggregated at least annually
QA/QC procedures	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance, calibration and testing to ensure acceptable monitoring accuracy. The readings should be verified by comparing gas bills received from the gas supply company. Meters used will be of international standard and will be maintained according to the monitoring plan and ISO 5167-1:2003. With normal care in installation and instrumentation, the accuracy of the flow measurement is consistently better than ±0.5%. Primary and secondary instrumentation to be calibrated annually. Flow rate and density calculations and flow totalization to be checked annually. Composition QA/QC for density calculations included in the analyzer QA/QC. Records of calibration will be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data and corrective action will be managed by the CDM Manager.
Purpose of data	Calculation of project emissions.
Additional comment	

B.7.2. Sampling plan
>> Not applicable.

B.7.3. Other elements of monitoring plan
>>

Management structure and responsibility

Overall responsibility for daily operating and reporting lies with the project proponent. A staff will be defined within the company to carry out the monitoring work (data recording and archiving, quality assurance and quality control of the data, equipment´s calibration, scheduled and unscheduled maintenances and adoption of corrective actions, if needed).

Management structure

The manager of the proposed project activity will hold the overall responsibility for the monitoring process, including the follow up of daily operations, definition of personnel involved with the monitoring work, revision of the monitored results/data, and quality assurance of measurements and the process of training new staff.

Responsibility of the personnel directly involved

The personnel involved with monitoring will be responsible for carrying out the following tasks:

- Supervise and verify metering and recording: the staff will coordinate internally with other departments to ensure and verify adequate metering and recording of data, including power delivered to the various consumers including the grid;

- Collection of additional data, sales/invoices: the staff will collect sales receipts and relevant data for monitoring of the proposed project activity;

- Calibration: the staff will coordinate internally to ensure that calibration of the metering instruments is carried out in accordance with national standards

- Data archives: the staff will be responsible for keeping all monitoring data and making it available to the DOE for the verification of emission reductions

Support and third parties participation

The staff will receive support from the CDM experts (internal and/or external) in its responsibilities through the following actions:

- Provide the staff with a calculation template in electronic form for calculation of annual emission reductions;

- Provide specific CDM monitoring instructions to the personnel involved in the project activity´s operation;

- Follow-up of the monitoring plan and continuous on demand advice to the staff;

- Compilation of the monitored data and preparation of the monitoring report;

- Coordination with DOEs for the preparation of periodic verifications.

Monitoring equipment and installation

All equipment will be in compliance with national standards.

Data monitoring and management

All monitoring data and records will be archived in electronic format as well as on paper, for a minimum of 2 years, following the end of the crediting period to which it applies.. The electronic documents will be backed up on compact disc or hard disc. The project proponent will also keep copies of sales receipts and prepare a periodic monitoring report, the monitoring data summary, the calibration records and the emission reductions calculation.

Quality control

The metering equipment will be properly calibrated according to the relevant national calibration standard.

SECTION C. Duration and crediting period

C.1. Duration of project activity

C.1.1. Start date of project activity

>>

19/07/2011

The start date is based on date of first purchase of equipment for the project facility. See bank accounting statement, provided to the DOE for validation (proprietary information supplied to DOE for validation *Golden Sugar account statement.xlsx*).

C.1.2. Expected operational lifetime of project activity

>>

Twenty-five years[47]

C.2. Crediting period of project activity

C.2.1. Type of crediting period

>>

Renewable. The calculations in this document refer to the first crediting period.

C.2.2. Start date of crediting period

>>

01/01/2013 or the effective date of registration of the project activity, whichever occurs later.

C.2.3. Length of crediting period

7 years

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>

Table A provides a summary of the ratings of the severity of the impacts of the various phases of the project activities as reported in the approved EIA report:

Table A: Summary of Impact Severity Ratings

Activity	Type of Impact	Impact Significance	Severity of Impact	Duration of Impact
Site Preparation	Demolition of Existing Sheds Disturbance to Wild Life around de-vegetated areas	Low	Medium	Short term
	Macro- and Micro-Economy	Low	Low	Short term
Construction	Movement of Construction Materials	Low	Low	Medium Term
	Vibration, Noise and Air	Low	Low	Short Term
	Macro- and Micro-Economy	Low	Low	Short Term
All Phases	Accidents	Moderate	Medium	Medium Term

[47] *C2. Technical_Operational lifespan of project.pdf*

An in-depth analysis of the negative impacts associated with the project (including the implementation of the energy facility enabled the EIA Consultant to come up with implementable mitigation actions which can reduce the severity and in some cases clearly eliminate some of the impacts. Table B provides a summary of the more in-depth impacts and the corresponding mitigation actions that were recommended by the EIA study.

Table B: Summary of Impacts, Mitigation Actions and Residual Impacts

Activity/Phase	*Component*	*Type of Impact*	*Mitigation Measures*	*Residual Impacts*
Pre-Construction/Site Preparation	(a) Air Quality	Dust emissions from excavation of structures leading to high suspended particulates in the atmosphere	GOLDEN SUGAR REFINERY shall ensure: • Low-emission/high efficiency engines shall be used • Movement of men and materials shall be properly coordinated to optimize vehicle use and resultant emissions • Dust and particulate barriers shall be used during operation	Low
	(b) Noise and Vibration	Noise emissions generated by construction activities and resultant hearing impairment on site workers.	GOLDEN SUGAR REFINERY shall ensure • Noise attenuation measures such as installation of acoustic mufflers, on large engines and equipment; • Hearing protection shall be provided for workers on site.	Low
	(c) Solid Waste	• Waste runoff flowing toward the Solid waste constituting aesthetic nuisance • Sewage Nuisance	GOLDEN SUGAR REFINERY shall ensure • Waste are contained and removed regularly by LAWMA • Provision of mobile toilet and prompt removal by L/S MOE accredited sewage service operator.	Low
Construction	(a) Air Quality, Noise and Vibration	• Noise emissions generated by construction activities and resultant hearing impairment on site workers. • Dust emissions from excavation of structures leading to high suspended particulates in the atmosphere	GOLDEN SUGAR REFINERY shall ensure • Noise attenuation measures such as installation of acoustic mufflers, on large engines and equipment; • Hearing protection shall be provided for workers on site. • Low-emission/high efficiency engines shall be used • Movement of men and materials will be properly coordinated to optimize vehicle use and resultant emissions	Low
	(b) Surface Water Quality and Hydrology	• Increased turbidity of the Lagoon water from the discharge of surface runoff from construction operations. • Degradation of surface water quality and its resultant effects on aquatic receptors and artisanal fishing activities	GOLDEN SUGAR REFINERY shall • Stack excavated materials properly to reduce turbidity effect on surface runoffs; • Contain surface runoffs within the existing storm water drainage system of the site; • Backfill and compact trenches to minimize the mobilization of highly turbid surface runoffs frown the site to receiving waters, • Adequate contingency measures shall be put in place to contain accidental spills ensure Spill	Low

	(c) Transportation	Disturbance to Traffic Flow along and within NPA facility and Apapa expressway by Heavy Duty Trucks conveying construction materials to site	containment equipment shall be available at the construction site GOLDEN SUGAR REFINERY shall ensure • Traffic Management plan is instituted; • Transportation of equipment and material to coincide with low traffic period in Apapa area	Low
	(d) Income, Health and Safety	• Hearing impairment due to exposure to noise of heavy machineries • Marine accidental collision due to increased transportation activities on the Lagoon and over-speeding on the part of navigators; • Deaths and injuries from local paddle driven boats capsized by waves generated front project vessels sailing around the Lagoon area.	GOLDEN SUGAR REFINERY shall ensure the following: • Navigational protocol shall be maintained and complied with. • Protocols include maintaining a safe speed and staying within the delineated navigation lanes both onshore and offshore. • Wearing of ear protection. • Compliance with maximum exposure hours to loud noise by site workers.	Low
	(e) Waste Management	• Wastes constitute aesthetic issues for the, project area. • Accumulated wastes could lead to contamination of soil/ groundwater as well as the Lagoon,	GOLDEN SUGAR REFINERY shall ensure the following: • Waste generation shall be properly contained to avoid contamination of ground water. • Runoff from the stockpile of waste must be prevented from flowing into the Lagoon • LAWMA shall be contracted to handle waste generated on site. • Accredited sewage operator to provide mobile toilet throughout the construction period	Low
Operations	(a) Air Quality	• Fugitive emissions from tanks and pipes used to transport or store fuel, products; • Combustion exhausts from machines e. g. pumps, power generating sets, vessels and road truck	Golden Sugar Refinery shall ensure the following: • All flanges and vents shall be properly tightened to reduce fugitive emissions. • All systems shall be regularly checked to ensure there are no leakages or losses. • All machinery and vehicles for the project shall have high efficiency burner to reduce emission of noxious gases.	Low
	(b) Noise and Vibrations	Noise emissions generated by plant machinery and resultant hearing impairment on factory workers.	GOLDEN SUGAR REFINERY shall ensure • Noise attenuation measures such as installation of acoustic mufflers, on large engines and equipment; • Hearing protection shall be provided for workers on site.	Low
	(c) Surface Water Quality and Hydrology	• Frequent movement of vessels along the waters resulting in perturbation of sediment and release of such sediment causing turbidification • Accidental release of oil and grease into the waters from moving vessels • Degradation of surface water quality and its resultant effects on aquatic receptors and artisan fishing activities	GOLDEN SUGAR REFINERY shall ensure that: • All vessel captains shall be compelled to sail within	Low

	(d) Income, Health and Safety	• Hearing impairment due to exposure to noise of heavy machineries • Marine accidental collision due to increased transportation activities on the Lagoon and over-speeding on the part of navigators; • Deaths and injuries from local paddle driven boats capsized by waves generated from vessels delivering molasses sailing around the Lagoon area.	regulatory safety speed limits; • Adequate care shall be taken to prevent accidental release of oil land oily wastes into the Lagoon waters; • Surface runoffs are contained within the existing storm water drainage system of the site. • Adequate contingency measures shall be put in place to contain accidental spills ; • Spill containment equipment shall be available at the construction site • Navigational protocols shall be maintained and complied with. • Protocols include maintaining a safe speed, and staying within delineated navigation lanes both onshore and offshore. • Wearing of ear protection. • Compliance with maximum number of hours of exposure to loud noise by site workers.	Low
	(e)Fires and explosions	• Mechanical or electrical failure; • accidental ruptures of tanks; • leakages of chemical and petroleum products, operators carelessness and static electricity or lightening discharges • sabotage or terrorist attacks	• Lighting conductors shall be installed in the facility • Fire extinguisher and fire hydrant shall be provided on site with sufficient capacity for sustaining the firewater spray. • Applicable Warning poster shall be used in all chemical storage, fuel storage areas and other strategic location and processes within the refinery. • A contingency plan that will have an alert mechanism and shall be incorporated into the environmental management plan of the project.	Low
	(f) Transportation	Disturbance to Traffic Flow around Apapa and within NPA by Heavy Duty Trucks	• Traffic Management plans shall be instituted • Speed limit must be observed	Low

Tables A and B were summarized from the EIA report that was prepared by the consultant engaged by Golden Sugar Company Limited and the report is available for review. The report also contained an environmental monitoring plan (EMP) that the company has agreed to implement during project implementation and operations of the plant, in accordance with Nigerian environmental laws. Furthermore, the Federal Ministry of Environment issued an environmental certificate to Golden Sugar Company Limited after a successful EIA process.[48]

[48] See the following files, which have been submitted to the DOE for validation: *GSC COVER PAGE.pdf*, *Pager divider for golden sugar.pdf*, *GOLDEN SUGAR EIA Report TOC & EXEC. SUM Mar 2010.pdf*, *GOLDEN SUGAR EIA Report 1-8 FINAL EDITION MARCH 2010.pdf*

D.2. Environmental impact assessment

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Environmental Impacts Assessment Act No 86 of 1992, section 64, No 13 of Mandatory Study Activities stipulated that manufacturing companies, industry etc planning to construct a power plant with installed capacity of over 10MW must carry out an Environmental Impact Assessment (EIA) before the commencement of the project. The installed power generating capacity of the CHP plant under consideration in this PDD is 30 MW and as such the project by law requires the preparation of an EIA. Therefore the management of Golden Sugar Company Limited in its commitment to best environmental practices and standards and as required by the Nigerian environmental law, commissioned an environmental impact assessment study of the plan to implement a sugar refinery facility (including the implementation of its energy facilities) in the first quarter of 2009.

In line with the company's corporate policy on Environmental Sustainability, an Environmental Impact Assessment (EIA) was conducted with the following objectives:

- To provide a reference database for the environment existing around the project location.
- To identify adverse environmental problems that may be encountered in the construction and operation of the various components of the sugar refinery project (including the generation and distribution of energy---power and steam), which may cause negative environmental, social, health and economic effects on the immediate environment.
- To incorporate mitigation measures and environmental management program into the project development process.
- To meet the requirements for the issuance of an Environmental Impact Assessment (EIA) Permit by the Federal Ministry of Environment.

The terms of reference of given to the EIA Consultant at the beginning of the study can be summarized as follows:

- Characterization (qualitative and quantitative) of the baseline environmental conditions of the study area prior to the commencement of project activities;
- Identification and assessment of potential impacts of the proposed Sugar refinery facility project;
- Identification of cost-effective mitigation plans to palliate or completely eliminate negative impacts;
- Identification and development of appropriate post-development environmental monitoring program;
- Define the frame work for interaction and the integration of views of a multi-disciplinary project team with regulators, host communities and other stakeholders.

The study and the other relevant processes mandated by the Nigerian environmental impact assessment protocol (baseline studies, preparation of EIA report, technical review by the Federal Ministry of Environment, public hearing etc.) took a period of about 12 months and was successfully completed with the mandatory public hearing and eventual issuance of an interim environmental permit, which mandated the commencement of the project implementation by January 15th 2010. A final certificate was issued by the Federal Ministry of Environment in August 2010.

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

>>

(a) Identification of Stakeholders

The area where the project site is located is an industrial area. As a result, the primary impact stakeholders are those companies and corporate entities within the immediate environment of the proposed project, this include: Nigerian Ports Authority (the statutory host or Landlord), ENL Consortium Limited, Nosak Group of Companies, Mettle Energy and Gas Limited, Real Oil Mills Limited, Flour Mills of Nigeria Limited and Apapa Bulk Terminal Limited. The secondary impact stakeholders are the local Government and the State Government responsible for the welfare and administration of the proposed project site, the naturalists and conservationists and the environmental NGO groups all over Nigeria. These stakeholders were identified from a list that was compiled by the Public Relations Department of the company. The identification of stakeholders who attended the event was based on criteria including: those stakeholders working or living close to the site of the sugar refinery; those in direct daily/regular business interactions with the proponent company; local and state government officials with responsibility for various issues e.g. industrial environmental regulatory oversight, area governance etc; and relevant NGOs.

(b) Media Used for Inviting Stakeholders

The mode utilized for inviting the stakeholders to the forum was basically through invitation letters and telephone calls by the Public Relation Department of Golden Sugar Company Limited.

(c) The Agenda for the Forum

An interactive stakeholder session took place at the Rockview Hotel, FESTAC, Lagos Nigeria, on the 12th December 2009. Present at the forum were representatives of Lagos State Government Environmental Regulatory Agencies, Non Governmental Organizations as well as staff and students of Higher Institutions of Learning in the Lagos area. Focal agenda of the meeting included:

- ***Opening Addresses by a top official of Golden Sugar, and Introduction of participants***
- ***Presentations***

The key presentation was made by the Project Manager from Golden Sugar. The presentation centered on:

  - A description of the energy-efficient CHP plant that is the basis of this CDM project;
  - Salient issues of the implementation program for the Greenfield Sugar Refinery, with a focus on the energy generation concept of the project;
  - The contribution of the project to economic development of the country and especially its contribution to the mitigative response of the nation to global climate change;
  - General discussion on challenges of power generation in Nigeria, the Impacts of Climate Change and International Community's Response to Climate Change, Nigeria's Response to Climate Change, and the contribution of the project to Nigeria's climate change Agenda.

- ***Discussion Session***

During this discussion session some few participants were given the opportunity to discuss the issues raised in the lead presentation and also contribute to the general theme of the meeting, which is the stakeholders evaluation of the proposed project. During the discussion session more emphasis was placed on an elucidation of the technical parameters of the Sugar Refinery and the CHP Plant and Benefits of the Project.[49]

- ***Question and answer sessions***

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[49] Further details regarding stakeholder consultations can be found in the Environmental Impact Assessment report: *GOLDEN SUGAR EIA Report 1-8 FINAL EDITION MARCH 2010.pdf* This document has been provided to the DOE for validation.

A question and answer session was then held. Questions were taken from participating stakeholders and answers to the questions were provided by professionals from Golden Sugar. The question and answer session was recorded and summarized in a report.

(d) How the Comments were Compiled and treated

The comments, questions and contributions of the stakeholders were recorded and became an integral part of the stakeholders' responses in the report that was prepared and also became a component of the environmental assessment report of the project. The question and answer sessions were recorded and summarized in a report of the stakeholder's meeting that was held on December 12 2009. The evidences of the stakeholder's forum are listed in the footnote[50,51,52].

E.2. Summary of comments received

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The views of the stakeholders concerning the CHP plant, and responses/actions provided, were documented and later collated.[53] No specific comments or questions were raised regarding concerns over the CHP plant *per se*. The complete list of stakeholder questions and comments and how they were addressed are provided in section E.3., below.

E.3. Report on consideration of comments received

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Comment/question received	**Response/action**
What social impacts will there be on health and employment?	The company does not foresee any particular negative social impacts on health and employment but will design and implement an appropriate health, safety and environment plan at all stages of the project implementation. The company expects jobs to be created, thereby increasing local incomes and economic activity.
Will this increase the amount of pollution in the area?	Golden Sugar assured attendees that there would be no significant additional air or water pollution. The project will include an effluent treatment plant.
You should source equipment and labour locally. Will you be doing this?	To the extent that it is economic and possible to do so, Golden Sugar agreed to use local resources.
There may be water pollution through increased nutrients in the ecosystem and/or change in PH of water and soil	Appropriate water treatment and spillage containment will be part of the project.

50 For the presentations made during the stakeholder's forum see <GOLDEN SUGAR REFINERY PRESENTATION.ppt>

51 The summary of the activities can be found in <Golden sugar Consultation Forum.doc>

52 For Pictures taken during the Stakeholders forum refer to <Stakeholders Meeting Pictures- Folder>

53 A list of stakeholders who were present at the meeting can be found in: *Stakeholders meeting attendance.jpg*. Pictures of the participants during the interactions can be found in the folder: Stakeholders meeting attendance.

Possibility of fire?	Comprehensive fire protection and fighting facilities will be provided.
Possibility of product spillage?	Appropriate water treatment and spillage containment will be part of the project.
We would support the project because it will bring extra income and jobs to the area.	No response required but Golden Sugar agreed with the respondent.
Will this cause more traffic problems?	Golden Sugar assured attendees that a Truck holding Bay is being built in Gbagada which would serve as a holding bay for trucks coming to the facility, no vehicle would leave the park unless it has been issued a permit to come to the factory for loading/off loading. Also the proponent envisaged the use of rail lines to convey the bulk of the consignment out of the factory when completed.
Will there be good safety on the site?	Golden Sugar committed to have and implement an appropriate environmental safety, health and security management plan at all stages of the project.
Will the project prevent the free flow of existing drains?	Golden Sugar assured the meeting that existing underground pipelines will not be damaged during the construction of the proposed project however, we would be most grateful if stakeholders could come up with their 'As built drawings' of such pipelines.
There may be increased noise from traffic.	Golden Sugar assured attendees that the additional traffic will be small in relation to existing traffic levels. In addition, there will be use of truck marshalling and vehicle staging areas where vehicles will be parked until they are called to the refinery to deliver or collect goods, and use of a rail link for finished products.

SECTION F. Approval and authorization

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The Letter of Approval from the Host Party DNA was not available at the time of submitting the PDD to the validating DOE.

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Appendix 1: Contact information of project participants

Organization name	Golden Sugar Company Limited
Street/P.O. Box	2 Old Dock Road, P.O. Box 341
Building	n/a
City	Apapa
State/Region	Lagos State
Postcode	n/a
Country	Nigeria
Telephone	+234 1 5803370
Fax	+234 1 587 0395
E-mail	Ctheodorakopoulos@fmnplc.com
Website	not available
Contact person	Costas Theodorakopoulos
Title	Managing Director
Salutation	Mr.
Last name	Theodorakopoulos
Middle name	n/a
First name	Costas
Department	n/a
Mobile	+234 803 960 0191
Direct fax	n/a
Direct tel.	+234 1 761 2023
Personal e-mail	Ctheodorakopoulos@fmnplc.com

Organization name	Standard Bank Plc.
Street/P.O. Box	20 Gresham Street
Building	n/a
City	London
State/Region	n/a
Postcode	EC2V 7JE
Country	United Kingdom of Great Britain and Northern Ireland
Telephone	+44 20 3145 6890
Fax	+44 20 3189 6930
E-mail	co2@standardbank.com
Website	www.standardbank.com
Contact person	Geoff Sinclair
Title	Head of Carbon Sales & Trading
Salutation	Mr.
Last name	Sinclair
Middle name	n/a
First name	Geoff
Department	Energy Trading and Marketing
Mobile	+44 7769 648 695
Direct fax	+44 20 3189 6930
Direct tel.	+44 20 3156 6893
Personal e-mail	geoff.sinclair@standardbank.com

Appendix 2: Affirmation regarding public funding

No public funding will be utilized for the financing of this project activity.

Appendix 3: Applicability of selected methodology

The calculation of the heat-to-power ratio of the project cogeneration facility is available in the Excel file *GS Financial Analysis* - *Baseline and Additionality* - *Final_C.xlsx* which has been provided to the DOE for validation.

Appendix 4: Further background information on ex ante calculation of emission reductions

For full details of the baseline calculation see file:
GS Emission Reduction Calculations Final 30052012 rev 291012.xlsx

Appendix 5: Further background information on monitoring plan

Not applicable. The monitoring plan is fully elaborated in section B.7.

Appendix 6: Summary of post registration changes

Changes required for methodology implementation in 2nd and 3rd crediting periods

As per AM0102, the required changes should be assessed using the tool for "Assessment of the validity of the current/original baseline and update of the baseline at the renewable of the crediting period."

Post-registration additions of project customers

As per AM0102, if power generated by the project facility is supplied to any customer not identified in the registered PDD, then the latest version of the "Procedures for notifying and requesting approval of changes from the project activity as described in the registered PDD" shall be followed.

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History of the document

Version	Date	Nature of revision
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	EB 66 13 March 2012	Revision required to ensure consistency with the "Guidelines for completing the project design document form for CDM project activities" (EB 66, Annex 8).
03	EB 25, Annex 15 26 July 2006	
02	EB 14, Annex 06b 14 June 2004	
01	EB 05, Paragraph 12 03 August 2002	Initial adoption.
Decision Class: Regulatory **Document Type:** Form **Business Function:** Registration		