UPGRADE OF DOMINICAN POWER PARTNERS' LOS MINA POWER STATION FROM OPEN CYCLE TO COMBINED CYCLE POWER GENERATION

Logo (optional)

Document Prepared By Elysium Carbon Trade & Investment

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1 PROJECT DETAILS

1.1 Summary Description of the Project

The proposed project includes construction of a Heat Recovery Steam Generators (HRSGs) that will take advantage of the open cycle generation of the existing natural gas based power plant in Los Mina to produce steam, which will in turn be used to power a 108 MW steam turbine. Los Mina power plant currently includes two 105 MW units, with average historical production of 80MW each, due to grid system requirement. The total capacity of the plant will increase from 210 MW to an expected 318 MW.

The original site consisted of Plants I and II, which contained Units 1 through 4, and were owned and operated by the Government of the Dominican Republic. Plant I, Units 3 and 4, were sold to DESTEC. In late 1995 DESTEC sold them to AES (under the local name DOMINICAN POWER PARTNERS or DPP) who removed the units and installed the existing Units 5 and 6 in 1996. The units were converted to gas fired operations in 2003. The units are available year round and up until the last quarter of 2009 were operated primarily for emergency (peaking) power, at which time, the two units at this facility operated close to base load conditions, Monday through Friday with shut down on the weekends. Since 2010 operations again increased such that the units are running base loaded 24 hours per day, 7 days per week.

The natural gas used in Los Mina plant is purchased from AES Andres Plant which buys LNG from BP and re-gassify it on-shore. The gas is then transported through a 34 kilometers pipeline.

The potential GHG emissions reduction are based on the fact that electricity generated by the project activity using HRSGs will offset electricity from the national grid which is highly fuel oil and open-cycle based.

DPP's Combined Cycle Project is based on technology that enables recovery of exhaust heat to generate steam to operate a steam turbine for the purpose of power generation, and therefore enables a better utilization of non-renewable resources. Furthermore, the project enables a higher supply of energy to the local market using the same amount of fuel, and in turn enables further development of the country, which is currently limited by its energy supply

In early 2012 the project started the process to be validated and registered as a CDM project. As part of which an official validation started which included a global stakeholder process, a site visit, and several rounds of requests and amendments to the project documents. However, do to the fact that the project was not able to complete the registration before the end of 2012 it was decided to register the project as a VCS project. As a consequence all the information was converted to the VCS-PD version 3 format based on the VCS Standard version 3.3, VCS Program Guide version 3.4, & VCS Program Definitions version 3.4.

Currently, not all milestones that were clarified by DPP President on November 1st 2012 (provided to the VVB in a letter) as conditions to take the investment decision have been reached. Mainly, there are still negotiations regarding the EPC contract and due to the switch from CDM to VCS there is no clarity yet as to the probability of securing additional income from carbon credit. As a result, the investment decision had not been taken yet.

1.2 Sectoral Scope and Project Type

Sectoral scope 1, Energy industries. The project is not a grouped project.

1.3 Project Proponent

Organization name: DOMINICAN POWER PARTNERS, LDC

Address: Av. Winston Churchill No.01099, Acropolis Tower, 23rd Floor, Santo Domingo, 10127 Dominican Republic

Telephone: (809)955-2223

Fax: (809)955-8413

E-mail: Freddy.Obando@aes.com

Contact person: Freddy Obando

Title: Director

1.4 Other Entities Involved in the Project

Not relevant.

1.5 Project Start Date

1st January 2016.

1.6 Project Crediting Period

10 year crediting period. Project crediting period start dates is 1st January 2016 and project end of crediting period is 31st December 2025

1.7 Project Scale and Estimated GHG Emission Reductions or Removals

Project	
Large project	√

Years	Estimated GHG emission reductions or removals (tCO_2e)
2016	354,478
2017	346,852
2018	348,361

2019	342,789
2020	338,130
2021	347,015
2022	340,035
2023	345,768
2024	339,751
2025	331,993
Total estimated ERs	3,435,173
Total number of crediting years	10
Average annual ERs	343,517

1.8 Description of the Project Activity

The existing generating facility in Los Mina is a 210 MW plant, currently operating in open cycle configuration. It comprises two natural-gas fired Siemens W501D5 (Originally Westinghouse W501D5) combustion gas turbines with effective production of 105 MW each, and a WESTAC generator, as can be seen in the layout below. The turbines' expected lifetime is at least 40 years and the generators' expected lifetime is at least 30 years. Both were commissioned on 1996, and therefore have more than 13 years left.

The Combined Cycle Project consists of the design, manufacturing, installation, start up and commissioning of two Heat Recovery Steam Generators (HRSGs) and ancillary equipment that will take advantage of the hot exhaust gas (533-550 grades Celsius) from the two existing gas turbines to produce steam, which will drive a new steam turbine (ST) and generator to produce electricity, increasing the total power output by 108 MW in order to increase the total capacity without increasing the existing fuel consumption and gas turbines emissions. This will also reduce the existing unit heat rate from 12,000 BTU/Kwh to 8,000 BTU/Kwh. The final combined cycle configuration will be a 2x2x1(2 turbines, 2 HRSG, 1 steam turbine). It is estimated that the upgrade will increase the existing generating net capacity of about 210 MW to 318 MW that would be able to cater for the supply to the grid.

Expected operational lifetime of the project activity is at least 20 years until 2032.

The final design specifications of main components of the additional equipment are:

Equipment	**Technical Parameters**	
Two Heat Recovery Steam Generators (HRSG) designed to capture heat from the two gas turbine exhausts and produce steam	Possible Manufacturers:	Hitachi, ALSTOM, Backbock and Wilcox, Foster Wheeler
	2-Press HRSG, Non-Reheat, Incl.Integral Deaerator Incl. Spool for Future SCR and CO Catalyst. 45M,Steel Stack Incl., ASME code constructed. HP Section: 164,000 Kg/hr, 512 ˚C, 93 Barg LP Section: 32,817 Kg/hr, 221 ˚C, 10.8 Barg	
One steam turbine generator	Possible Manufacturers:	Siemens, Hitachi, ALSTOM, General Electric
	TC1F 851 mm LSB,Condensing Non-Reheat Steam Turbine with standard accessories; two case; single flow; 114,000kW @ 124.3kg/cm2 Horizontal exhaust; 3,600RPM	
One Steam Turbine GSU Transformer	Core Form;Type: TPAU-141000/13.8; 85/136MVA; 65°C rise; OA/FA-II; 13,800/138,000 Volts; BIL 650/150/150kV; Conservator60Hz	
One Generator	136,800-kVA; 13,800V; 5,650 amps; 3Ø; 60Hz; 2 pole; .8pF; Air cooled; field 1,815amps/250V. 18Mn-18Cr retaining rings.	
One cooling tower to cool the water from the cooling circuit	Wet Mechanical Draft Cooling Tower, Fiberglass Counterflow, 10-Cell @ Approximately 41,200 m3/hr flow	

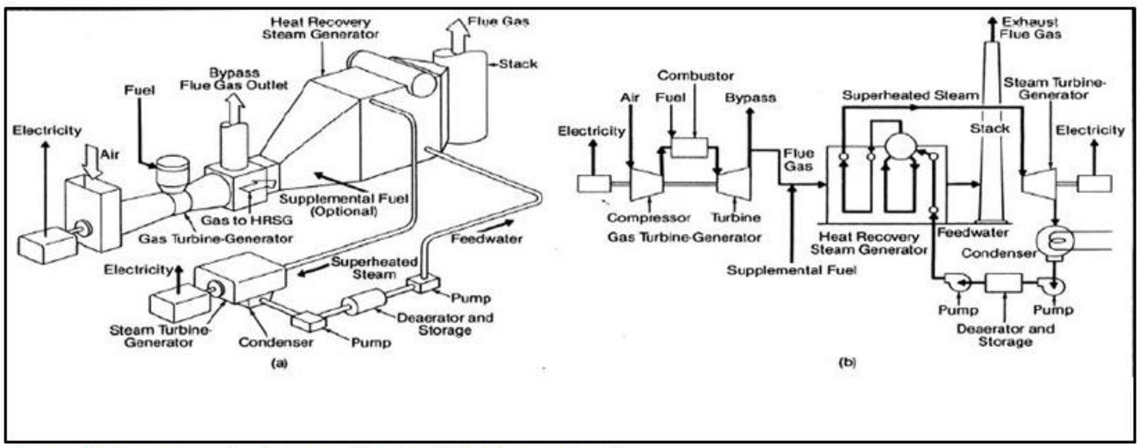


Figure 4: Plan of a typical conversion to CCGT for one turbine

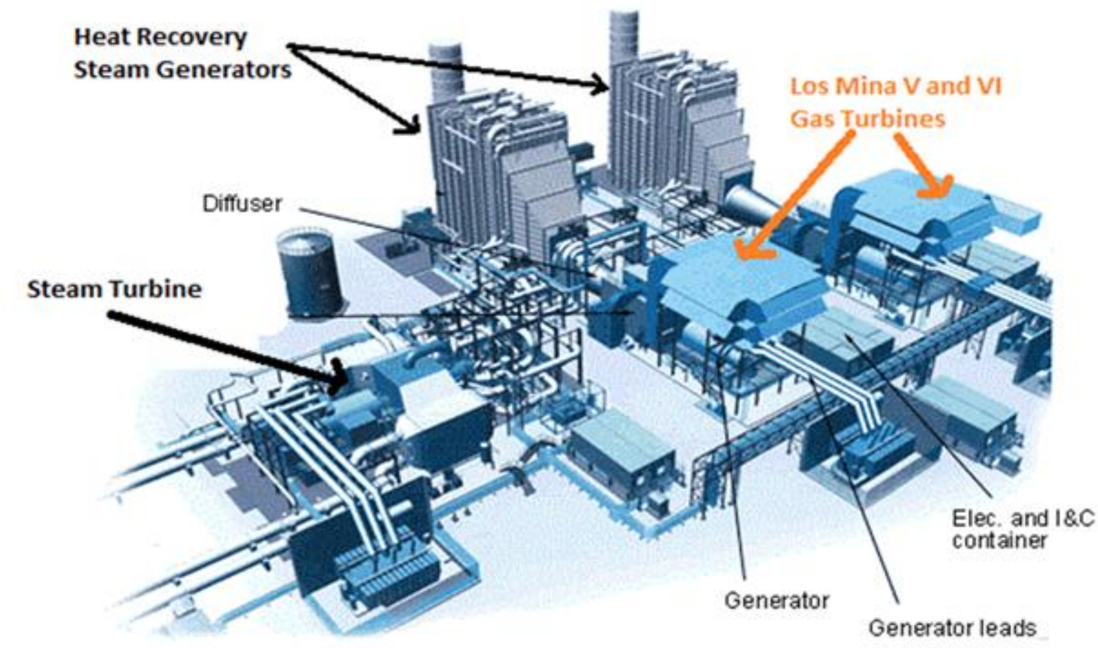


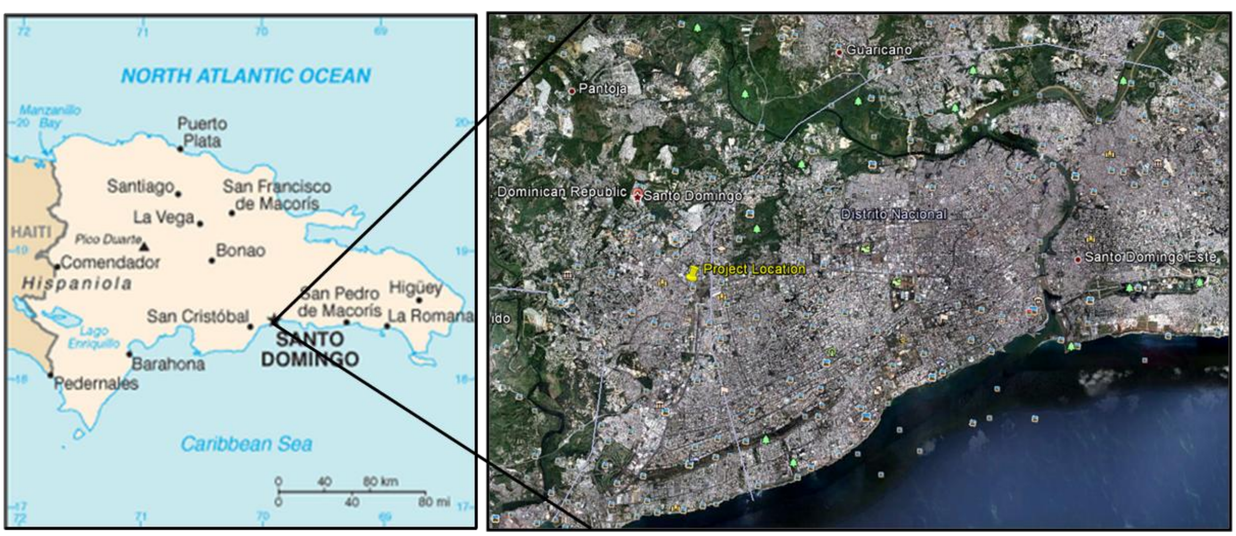
Figure 5: Laydown plan of Los Mina Plant with CCGT

1.9 Project Location

The geographic coordinates of the plant are:

Site Latitude: 18.499418º or in degrees 18º29'59.23 N

Site Longitude: -69.867831º or in degrees 69º52'06.91 W



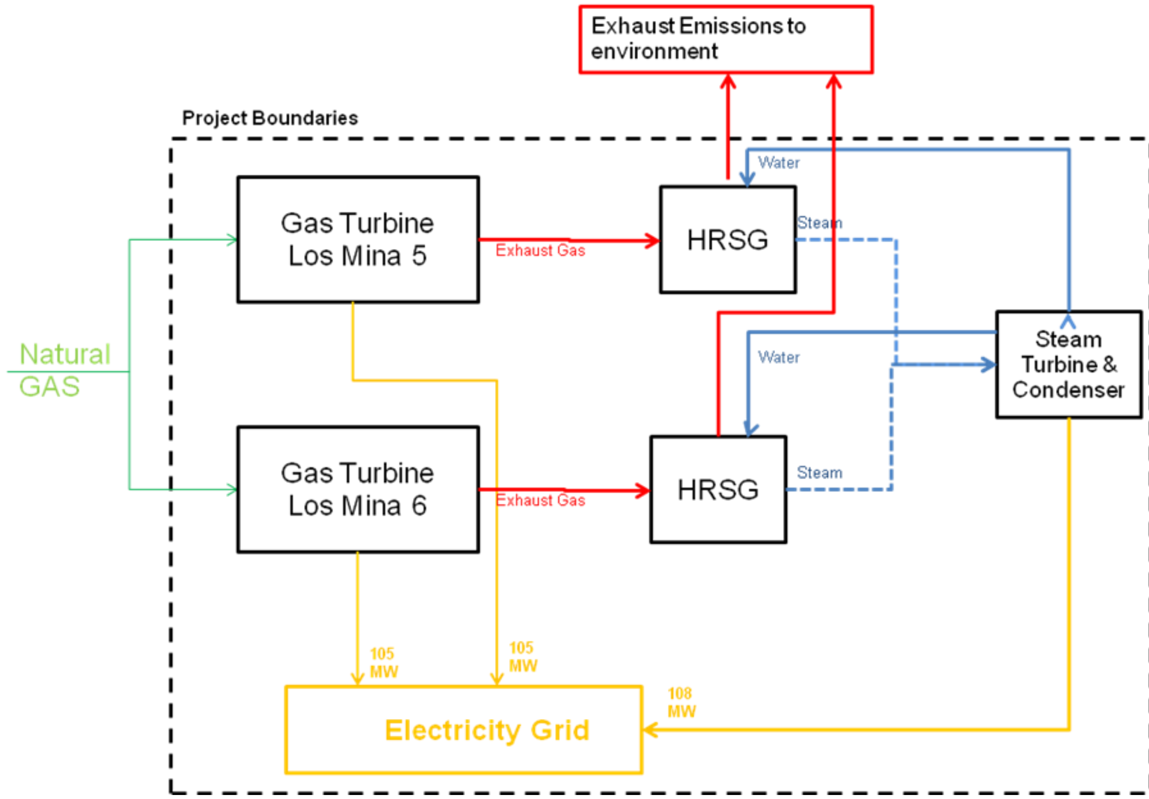
The power station is located at the eastern side of Santo Domingo (The Dominican Republic), in a mixed commercial, industrial, and residential area, densely inhabited low-income community of Los Minas Sur. The project activity is restricted to the site of the existing DPP power station. The site directly abuts neighbourhoods in all directions except to the south, where there is approximately 70 meter buffer of woodland, and to the west, where a small 1 ha industrial campus buffers additional communities.

The DPP facility is located at an elevation of 37 meters above sea level, in a humid tropical savanna climate, with mean monthly precipitation of 120.4mm. The prevailing winds are from the northeast, with mean wind speeds of 2.3 m/s. Sudden changes, caused by easterly winds, can cause violent disturbances.

On the northeast section of the site location, an electric substation owned by ETED has two of ten bays dedicated to Los Minas V and VI, while a third bay will be used by the combined cycle unit. There is an abandoned shoe factory on the site, which will be removed upon construction. Two fuel oil tanks from the decommissioned ITABOS unit 1 and 2 have already been removed. An additional two fuel oil storage tanks remain, which served Los Minas III and IV before the fuel switch to natural gas in 2003.

The spatial extent of the project boundaries encompasses the two gas turbines at the project site being converted to closed cycle (Los Mina 5 and Los Mina 6) and the associated HRSG and steam turbine (as shown in the diagram below) and all power plants physically connected to the electricity grid that the proposed VCS project is connected to, as defined in “Tool to calculate emission factor for an electricity system”.

In the calculation of project emissions, only CO2 emissions from fossil fuel combustion at the project plant are considered.



1.10 Conditions Prior to Project Initiation

The existing generating facility in Los Mina is a 210 MW plant, currently operating in open cycle configuration. It comprises two natural-gas fired Siemens W501D5 (Originally Westinghouse W501D5) combustion gas turbines with effective production of 105 MW each, and a WESTAC generator. The turbines' expected lifetime is at least 40 years and the generators' expected lifetime is at least 30 years. Both were commissioned on 1996, and therefore have more than 13 years left. Therefore the existing power plant was not implemented to generate GHG emissions but to generate electricity. The proposed project will only make the power plant more efficient and reduce the amount of GHG emissions per kWh generated.

1.11 Compliance with Laws, Statutes and Other Regulatory Frameworks

Please see sub-step 1b "Consistency with mandatory applicable laws and regulations" in the methodology application below

1.12 Ownership and Other Programs

1.12.1 Right of Use

DPP owns the power plant and has all relevant approvals and license to operate it. Supporting documents were presented to the VVB.

1.12.2 Emissions Trading Programs and Other Binding Limits

There are no GHG emission reduction requirements in the Dominican Republic and/or an emissions trading program. Any potential GHG reductions from this project will be voluntary.

1.12.3 Participation under Other GHG Programs

The project is not seeking registration under any other GHG programs

1.12.4 Other Forms of Environmental Credit

The project neither has nor intends to generate any other form of GHG-related environmental credit for GHG emission reductions or removals claimed under the VCS Program.

1.12.5 Projects Rejected by Other GHG Programs

The project was not rejected by any other GHG programs.

1.13 Additional Information Relevant to the Project

Eligibility Criteria

Not relevant.

Leakage Management

The only relevant leakage is calculated as part of the methodology requirements. Please see below in the methodology application.

Commercially Sensitive Information

Confidential agreements regarding the fuel costs were presented to the VVB but are excluded from the public version of the project description.

Further Information

Not relevant.

2 APPLICATION OF METHODOLOGY

2.1 Title and Reference of Methodology

CDM ACM0007: “Conversion from single cycle to combined cycle power generation” (Version 6.1.0)

Related Tools:

“Tool to calculate the emission factor for an electricity system” (Version 3)

"Combined tool to identify the baseline scenario and demonstrate additionality" (Version 05.0.0)

"Tool to determine the remaining lifetime of equipment" (Version 01)

"Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" (Version 02)

2.2 Applicability of Methodology

Applicability Condition – Methodology	Project Description
project activities that convert one or several grid connected power units at one site from single- cycle to combined-cycle mode	The project activity is to convert the existing single-cycle turbines into combined cycle by building Heat Recovery Steam Generators
The units have an operational history of at least one year with no major retrofit, and at least one unit has an operational history of more than three years with no major retrofit. There is no major retrofit in these time periods	The plant, with its two turbines, has started its commercial operation on May 19, 1996 and converted to NG in 2003. Only Los-Mina 5 had retrofit in the last three years. The retrofit cost was $1.5 M, which is less than 20% of a new turbine cost (14,252,557$), and is therefore not considered a major retrofit. (reference: Los-Mina Unit 5 Generator Rotor Exchange & Bearing Rebabbit)
In the case that a unit has less than three years operational history: all project power units were designed and commissioned for operation in single cycle mode only. This shall be demonstrated by the Project Proponents by providing relevant documents, such as original process diagrams and schemes from the construction of the plant, licenses and/or by an on-site check by the VVB prior to the implementation of the project activity.	All the units in Los-Mina plant have more than three years operational history. (Reference: Environmental License, "Permiso Ambiental DEA No.0481-06(Environmental Licenses to operate) 2008")
During the most recent three years prior to the implementation of the project activity and during the crediting period the project power units use(d) only the following fuel types: (a) Fossil fuels; and/or (b) Blends of fossil fuels and biofuels, where the biofuel is blended to the fossil fuel in a situation that is outside the control of the Project Proponents (such as regulatory requirements to blend biodiesel with diesel or biogas with natural gas).	The only fuel used by the plant is natural gas. The project activity is not planned to consume any other fuel. (Reference: Natural Gas invoices for example and discharge in Andreas, "SGS, Johnson&co., Liquified Natural Gas Discharge Report")
The type of fossil fuel used by the project power units during the crediting period were also used during the most recent three years prior to the implementation of the project activity, except, where applicable, any auxiliary fuel consumption (e.g. for start-ups) which shall not exceed 3% of the total fuel consumption in the units (measured on an energy basis).	The only fuel used by the plant is natural gas5. The project activity is not planned to consume any other fuel.

The project activity does not increase the lifetime of the existing gas turbine or engine during the crediting period.	The expected lifetime of the existing gas turbines is 40 years. Since they were installed in 1996, and the crediting period ends in 2024, the project activity does not increase the lifetime of the existing gas turbine during the crediting period. In addition the project is an addition to the plant in the process and does not affect the lifetime of the units.
Baseline scenario is the continuation of the current practice	As demonstrated in B.4, based on the "Combined Tool to Identify the Baseline Scenario and Demonstrate Additionality", in the absence of the proposed project activity, in order to meet the demand in the grid system electricity will be generated by one or a combination of the following options: 1. The existing power plant in open-cycle mode 2. The existing grid-connected power plants 3. The addition of new generation sources to the grid
Applicability Condition – Tool to calculate the emission factor for an electricity system	
project activity that substitutes grid electricity, i.e. where a project activity supplies electricity to a grid or a project activity that results in savings of electricity that would have been provided by the grid	The project supplies electricity to the Dominican Republic grid. (Reference: Invoices of electricity sell to grid)
Not applicable if the project electricity system is located partially or totally in an Annex I country	The project activity is located in The Dominican Republic, which is as a Non Annex I country
Applicability Condition – Combined tool to identify the baseline scenario and demonstrate additionality	
This tool is only applicable to methodologies for which the potential alternative scenarios to the proposed project activity available to Project Proponents cannot be implemented in parallel to the proposed project activity	The proposed project activity is a retrofit project so the continuation of current practice cannot exist in parallel to the proposed project activity
Applicability Condition – Tool to determine the remaining lifetime of equipment	
No applicability condition	
Applicability Condition – Tool to calculate	

project or leakage CO2 emissions from fossil fuel combustion	
CO2 emissions from fossil fuel combustion are calculated based on the quantity of fuel combusted and its properties	CO2 emissions from fossil fuel combustion are calculated as instructed by the selected methodology ACM0007

2.3 Project Boundary

The project boundary and identified relevant GHG sources based on the selected methodology.

Source		GHGs	Included?	Justification/Explanation
Baseline scenario	Dominican Republic Grid electricity generation	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative
	On-Site Natural Gas consumption to operate the project power units in single cycle mode	CO_2	Yes	An important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
Project scenario	On-Site Natural Gas consumption to operate the project power units in combined cycle mode	CO_2	Yes	An important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
	On-Site Natural Gas consumption to supplement the exhaust heat in operating the steam turbine	CO_2	No	No onsite NG consumption to supplement the heat
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small

2.4 Baseline Scenario

According to the methodology ACM0007, the baseline scenario is identified by using the latest approved version of the “Combined Tool to Identify the Baseline Scenario and Demonstrate Additionality”, adopted by the CDM Executive Board and available at the UNFCCC CDM. In applying the tool, realistic and credible alternatives should be separately determined regarding how power would be generated in the absence of the VCS project activity.

The following four steps were applied, as prescribed by the tool:

STEP 0. Demonstration that a proposed project activity is the First-of-its-kind

STEP 1. Identification of alternative scenarios;

STEP 2. Barrier analysis;

STEP 3. Investment analysis (if applicable);

STEP 4. Common practice analysis.

STEP 0: Demonstration whether the proposed project activity is the First-of-its-kind

This step is optional and was not applied as the proposed project activity is not the First-of-its-kind.

STEP 1. Identification of alternative scenarios

This step serves to identify all alternative scenarios to the proposed VCS project activities that can be the baseline scenario through the following sub-steps:

Sub-step 1a. Define alternative scenarios to the proposed VCS project activity:

According to the tool, the alternative scenarios that are available to the project developer should include:

S1 The proposed project activity undertaken without being registered as a VCS project activity;

S2 Where applicable, no investment is undertaken by the Project Proponents but third party(ies) undertake(s) investments or actions which provide the same output to users of the project activity, for example:

- In the case of a Greenfield power project, an alternative scenario may be that the Project Proponents would not invest in another power plant but that power would be generated in existing and/or new power plants in the electricity grid.

S3 Where applicable, the continuation of the current situation, not requiring any investment or expenses to maintain the current situation, such as, inter alia:

- The continued venting of methane from a landfill;
- The continued release of N_2O from adipic or nitric acid production.

S4 The continuation of the current practice requiring an investment or expenses to maintain the current situation, i.e. in the absence of the proposed project activity the electricity, to meet the demand in the grid system, will be generated:

(1) By the operation of the project power units in single cycle mode;

(2) By the operation of existing grid-connected power plants; and

(3) By the addition of new generation sources to the grid

S5 Other plausible and credible alternative scenarios to the project activity scenario, including the common practices in the relevant sector, which deliver the same output, taking into account, where relevant, examples of scenarios identified in the underlying methodology;

S6 The proposed project activity undertaken without being registered as a VCS project activity to be implemented at a later point in time (e.g. due to existing regulations, end-of-life of existing equipment, financing aspects).

The project activity is not a Greenfield power project, but an upgrade of an existing power plant; Only DPP is liable for the Los Mina Plant, and the waste heat generated in the plant cannot be used anywhere else. Therefore, there is no third party that can undertake investments or actions which use the exhaust heat and provide the same output to users of the project activity. Hence scenario 2 is not an applicable alternative.

Scenario 3 is not an applicable alternative since the operation of the plant requires expenses.

Considering that the project activity is an upgrade of a specific technology and only the owner of the facility can initiate such an upgrade, no other alternatives provide outputs comparable to, or compatible with, the proposed VCS project activity. Furthermore, the alternative of construction a third open cycle unit instead of upgrading the existing units to close cycle is not realistic as this will require the Project Proponent to negotiate and secure a new fuel supply contract for the additional fuel required and request and amendment to its environmental emissions permits which will be very problematic considering the close proximity to a residential area. Hence scenario 5 is not an applicable alternative.

Since the current operation of the project power plant holds all necessary environmental and operation permits (DPP's concession permit, Letter from Organismo Coordinater Del Sistema Electrico Nacional Interconectado De La Republica Dominicana, and, DPP's environmental permit, "Permiso Ambiental DEA No.0481-06", 2008), and end-of-life of existing equipment is in more than 20 years, there are no identified conditions that could be changed or resolved in the future and affect the circumstances for the project activity. The proposed project activity undertaken without being registered as a VCS project activity, to be implemented at a later point in time, as defined by scenario 6, is therefore not an applicable alternative.

In the absence of the project, electricity would have continued to be produced by the existing gas turbines in open-cycle mode and the hot exhaust gases would be vented to the atmosphere. There is no other use for the waste heat at the Los Mina' plant due to the fact that no one in the neighborhood can efficiently utilize the heat and this resource cannot be transported over long distances nor stored. There are no other technologies currently available that could use the waste heat. Therefore, in the absence of the project activity, the heat would be exhausted to the atmosphere. Electricity requirements that would have been met by the project activity would be met from existing power plants on the grid and by the addition of new generating sources on the grid, to meet growing demand (The Dominican Republic Long-Term Electricity Plan, "PROGRAMACIÓN DE LA OPERACIÓN DE LARGO PLAZO ENERO 2012 – DICIEMBRE

2015”). Continuation of the current situation, as defined by scenario 4 is, therefore, very likely as an alternative scenario to the Project.

No other alternatives are deemed realistic and credible, nor provide outputs comparable to, or compatible with, the proposed VCS project activity. Hydropower solar or wind energy is not an alternative for the proposed Project Activity because it is not comparable in terms of the available location and facility.

Consequently, the alternative scenarios available to the Project Developer are:

S1 The proposed project activity undertaken without being registered as a VCS project activity;

S4 The continuation of the current practice, i.e. in the absence of the proposed project activity the electricity, to meet the demand in the grid system, will be generated:

(1) By the operation of the project power units in single cycle mode;

(2) By the operation of existing grid-connected power plants; and

(3) By the addition of new generation sources to the grid

Sub-step 1b. Consistency with mandatory applicable laws and regulations:

The identified alternatives are in compliance with all applicable legal and regulatory requirements including the set of laws that compose the legal framework of the energy sector in the Dominican Republic (The Legal Framework of the Energy Sector, Comisión Nacional de Energía de la República Dominicana, http://www.cne.gov.do/app/do/marco_leyes.aspx):

Laws and Regulations	Description	Implications on Project Activity	Implications on Alternative Scenarios
Law No.125-01	Electricity Law. Defines that electricity companies which intend to operate an electricity generation business must request a definitive concession for the operation of electricity works. The law also sets conditions for environmental impact studies	DPP are in the process of obtaining the concession permit, including its project activity	S4: 1) DPP holds the required concession permit . 2) All grid-connected power plants hold the concession permit 3) New generation sources to the grid should obtain the concession permit in

			order to supply electricity to the grid
			S1: Same as project activity
Law No. 57-07	Development Incentive Act of Renewable Sources of Energy	No implications on project activity	S4: No implication on all operating plants. May implicate on new plants.
			S1: Same as project activity
Law No. 112-00	Hydrocarbons Law. Establishes a tax on consumption of fossil fuels and oils shipped through the Dominican oil refinery or imported into the country. Natural gas is exempted	Since only natural gas will be used in Los Mina, and since DPP will not be the importer of its fuel, there are no implications on project activity	S4: 1) There are no implications on DPP, since it is not the importer of the fuel, and only natural gas, which is exempted, is used in Los Mina 2) All grid-connected power plants pay the tax, if required by the law 3) New generation sources to the grid should pay the tax in case they import fossil fuel to the country
			S1: Same as project activity

Law No. 4532-56	Regulates the exploitation of oil fields and other fuels in the Dominican Republic.	Since DPP will not perform exploitation of oils and its derivatives, hydrocarbon fuels and other minerals, there are no implications on project activity	S4: 1) There are no implications on DPP, since it does not perform any exploitation of oils and its derivatives, hydrocarbon fuels and other minerals. 2) All grid-connected power have the permission for exploitation, in case it is required 3) New generation sources to the grid will obtain the permission to exploit sites, prior to their operation, if required by the law
			S1: Same as project activity
Law No. 64-00	Law of Environment and Natural Resource. Legislates and regulates all aspects related to the environment, and establishes standards for the conservation, protection, enhancement and restoration of the environment and natural resources, and ensures their sustainable use. Defines the environmental	DPP holds the environmental permit for the project activity, which ensures all environmental requirements, as defined by this law, are performed.	S4: 1) DPP holds the required environmental permit for its current operation. 2) All grid-connected power plants hold the environmental permit, as required by the law 3) New generation sources to the grid should obtain the environmental permit prior to their start of

	permission. More related to the energy sector: chapter II - water pollution, Chapter III - soil contamination, Chapter IV - air pollution, Chapter V- hazardous substances and products; Chapter VI - wastes and domestic and municipal waste. Chapter VII deals with human settlements and noise pollution.		operation S1: Same as project activity

None of the identified alternatives contradicts any legal or regulatory requirements, or poses a risk to do so in the future. Therefore, they are all deemed to be realistic and credible alternatives available to the Project Developer.

STEP 2. Barrier analysis

This step serves to identify barriers and to assess which alternatives are prevented by these barriers by applying the following sub-steps:

Sub-step 2a. Identify barriers that would prevent the implementation of alternative scenarios:

There are no technological barriers that may prevent alternative scenarios to occur. Furthermore, open-cycle thermal power plants have been operating in the Dominican Republic for decades. Natural gas is widely available and closed-cycle power plants operate in the country. The continuation of current practice by definition does not include the use of a new practice. Therefore there are no technical barriers that are relevant to the identified alternatives.

Investment barriers:

The financial barrier is analyzed in Step 3. There are no other investment barriers.

Sub-step 2b. Eliminate alternative scenarios which are prevented by the identified barriers:

Since there are no identified barriers faced by the project and by the identified alternatives, the list of remaining alternatives at the end of step 2 is the same: S1 and S4.

STEP 3. Investment analysis

This step determines, through an investment analysis comparison, which of the alternatives remaining after Step 2 is the most economically or financially attractive. If the investment analysis is conclusive, the economically or financially most attractive alternative scenario is considered to be the baseline scenario. If the sensitivity analysis is not conclusive, then the alternative to the project activity with the least emissions among all the alternatives is considered to be the baseline scenario.

Here, the project NPV is selected as the most suitable financial indicator to compare between S1 and S4 since the continuation of current situation, as defined by scenario 4, does not require investment in new equipment but do requires expenses and since the decision of investment in Los Mina generation is based on the comparison between the NPVs of the two options. Therefore, this analysis compares the NPV of current practice, and the NPV of the project activity without VCUs.

Detailed analysis of the project investment and electricity tariff was submitted to the VVB during validation.

<u>**The effect of the electricity market in the Dominican Republic on the financial risk of the project**</u>

In order to provide further information about the risks taken by a power generator in the DR market, it’s necessary to clarify the business model in which the Project will be developed.

Market Power Purchase Agreement (M-PPA) Vs Independent Power Producer (IPP) Model:

- The Project primary revenues will come through a M-PPA. A Market PPA is considered a natural tool for sector participants such as distributors, generators and unregulated users to secure their supply with a specific price and commodity structure. In an MPPA the parties agree to specific energy and capacity transactions. Negotiated terms include the term, price, payment schedules, guarantees and default provisions. The contracts between generators and distributors and/or large unregulated users are normally in the form of M-PPAs and any differences between the volumes sold or purchased through the M-PPAs are settled in the spot market.

- The financial settlement of M-PPAs is completely disconnected from the actual dispatch of any particular power generator. As the M-PPAs are financial contracts rather than being tied up to the physical production of the generator, there is no obligation to produce the electricity necessary to fulfil the PPA commitments. Consequently, if a power generator, which entered into a PPA and committed to sell electricity to a customer, does not generate the total amount of electricity needed to satisfy its contractual obligation during a particular month, the power market clearance mechanisms will cover such deficit in the M-PPA through allocating purchases in the spot market at the spot price to be delivered to the buyer under the M-PPA and paid for by the generator. The financial nature of a M-PPA implies that a power generator, even with a high level of contracted capacity is always facing commodity and volume exposure related to its sales.

- An Independent Power Producer Model is a power company which owns and or operates facilities to generate electric power for sale to a utility, central government buyer or any end user. Their usual contract structure is design to provide a full recovery of the investment since the only source of revenues comes from the supply contract where is common to see full pass-through of the generator costs (including O&M costs) and in this model the off-taker take the dispatch risk, fuel supply risk, collections risk, etc; but at the same time ensuring to the entity a reasonable return on their investment paid through the capacity payment. This type of model usually is referred as a physical IPP model, which have less risk from a Market-PPA model but at the same time, lower returns, since they are guaranteed and low probability of having any upsides on the business cases during the term of the contract.

The model implemented in the DR for the Project is a Market-PPA scheme which has additional exposure in terms of risk taking that cannot be fully reflected in the financial model. The following points should also be considered therefore as an indication of how conservative the financial analysis is:

- EPC risk: since the EPC has not yet been closed, any extra cost, or delay in the operation start date will be fully burden by the Project, not being possible to get from the market or the M-PPA additional compensation for such effects.

- Regulatory risk: The Project revenues come from the energy sales, capacity sales and ancillary services. The DR regulatory office could take measures to update the methodologies, prices and rules for such markets assumed for the compensation or payment of certain services such as capacity, frequency regulation, among others.

- Government Financial Health: Most of the energy of the project will be contracted with the DISCO (distribution companies own by the government). Historically the DISCOS financial deficit has been a key risk element to new investment. DISCO financial deficit will continue, extending the need for government subsidy to the upcoming years.

- Capacity Payment: The DR capacity pricing is based on the capital cost of installing a peaking unit in the system and it describes this unit as a gas turbine fuelled by diesel. The regulatory framework in the Dominican electricity market establishes a methodology for allocating firm capacity to each power generation unit. The OC allocates firm capacity to a power generation unit based on many factors, including yearly peak demand, the number of power generation units installed in the Dominican Republic, the capacity of each power generation unit, the level of reliability required by the system and the availability rate of each power generation unit. In addition, the availability rate takes into account the ability to generate without relief for force majeure, lack of fuel or other similar events. Under the regulatory framework, firm capacity is defined as the power that a generation unit is allowed to provide during the peak demand hours, taking into account each power generation unit's availability and the reliability of such unit. The aggregate firm capacity of all power generation units for the entire year should equal the aggregate demand estimated for that year. The financial model does not contemplate the potential risk of a price change or a capacity payment mechanism change in the regulation; instead, the financial model contemplates this capacity payment as and constant cash flow, something that is not guaranteed.

- Un-hedged energy: The project has un-hedged energy sales (or spot sales); gross margin depends on the cost of the three commodities used in DR affecting the price at which spot energy is valued and the production costs of our units. Variation of the spread between commodities may reduce the dispatch of the units.

- Ancillary Services Exposure: The DR regulation related to the operational safety and stability of the system demands from the OC to program between 6% to 10% of the total demand as rotating or operative reserve. Andres and DPP are the larger players in this service due to their technology capability to do so. This service is a mandatory service representing an un-hedged position in the ancillary services.

- Unit dispatch risk:

    - All power companies in the Dominican electricity system with units available for dispatch are put in order of merit for dispatch. The order of merit determines the price to be paid for the electricity and the order in which each participant is dispatched. Generators are dispatched in order beginning with the generator with the lowest declared variable cost until the demand for electricity by the system is satisfied. The variable cost of the last generator dispatched determines the marginal price of electricity in the market for that hour "the spot price". The Operator and Coordinator Body "OC", publishes a weekly order of merit list that it uses to coordinate the dispatch of the generation units. The order of merit is effective for one week and is the same for the whole week. Dispatched variable cost is based on the price of fuel, the units' efficiency (heat rate), and the nodal factor (or transmission losses due to transportation from the generator to the principal connection point in the grid).

    - The dispatch of each unit in every hour of each week is limited to their order in the merit list of the OC of the DR market. It is important to recall that any contract does not impact or influence in any way the unit dispatch.

    - Another important risk is be the transmission system reliability. For example during the years 2010-2012, the generation park from the east were limited due to flow gate restriction in several main transmission lines of the DR transmission system. This situation limited DPP for a period of time during that period, impacting its availability to supplying its contract with its own generation, and instead buying from the spot (at a higher price) to supply their contracts portfolio (as a total).

Further information on the financial model

Since the Los Minas Combined Cycle plant is a project that modifies two current open cycle gas turbines plant, the analysis performed was a comparative analysis of the financial situation without the project vs the financial situation with the project. For the years 2013 to 2015 the same values were used for the analysis in both situations as the upgrade will only take place in 2016. only the Investment and a 2 month outage for the Combined Cycle were added to the project scenario. The model is taking into consideration the current regulatory laws that applied in the Dominican Republic Electricity Sector. Also the model values the energy and capacity first and then deducts the energy and capacity contracts, just like the Economics Transactions made by the “Organismo Coordinador” the Market Operator.

The data for the future consumption and generation as it appears in the model comes from a separate model called “MOPERD”. MOPERD is the standard model used in the DR for the projection and long term planning of the system (official reference to this model was provided to the VVB). MOPERD is an economic dispatch model. The model dispatch the duration curve taking into account: availability, efficiency, maintenances, the entre of new players, old player that leave the market, fuel prices, demand growth, etc, guarantying the supply of the demand at minimum cost. The generation and the fuel consumption related to the generation used in the financial model come from the MOPERD model and due to the above the values are not constant year to year.

Sources of the main variables:

- Commodities: All the commodities values taken into consideration are the same as used in the 2013 DPP Budget process.

- NYMEX Natural Gas (Henry Hub) ($/mmBtu), Source: Kiodex as of 12/14/2012 through 2022; actual price calculated using prompt month average.

- API#4 fob Richard's Bay, SA b. 6000 kcal nar ($/mt), Source: 2012 to 2017 based on ICE as of 12/14/2012. 2017 to 2022 escalated at inflation.

- CPI source The Economist Intelligence Unit.

- Brent Crude Oil, Source: Kiodex as of 12/14/2012 through 2019; then escalated at CPI; actual price calculated using prompt month average.

- Energy Price: Coal price is used in the model because electricity costs in the Dominical Republic are tied to coal prices and therefore so do the project income. Energy price for the long term is calculated taking into consideration that in the Long Term the Energy price will be highly correlated to Coal prices, as it is expected that even more Coal plants will be constructed. DPP obtain the info through Bloomberg but reference can also be found on www.theice.com or www.globalcoal.com.

- Sales Contract: The Sales Contracts are calculated using as guidelines our current contracts with the Distribution Companies.

- Fixed Cost and Operative Expenses: DPP history costs are used as guideline for these costs.

Additional explanations on financials

AES Andres have a long term fuel supply contract for Natural Gas with BP. The price of fuel for this contract is at NYMEX prices. Annually DPP receive 33.6 TBTU of Natural Gas. DPP purchase contract price is Andres purchase price (which is NYMEX +0.2) plus 0.2. So the model has NYMEX +0.4 which is the same. The contract with BP expires in 2023. After that year, DPP takes the assumption that a new LNG supply contract will be referenced to Brent. The actual Henry Hub related LNG contract is expected to be on the 2-7 US$/MMBTU range on the evaluated period, while a 13% Brent LNG contract is expected to be between 11-15 US$/MMBTU. For the model DPP assumes that only 16 TBTU of the NYMEX BP contract are for the Los Minas Plant, in case the plant uses more gas, it will be Brent related.

With respect to DPP model using Brent related LNG instead to NYMEX HH, this comes from the fact that NYMEX HH has break it relation to the LNG market and just represent the US Natural Gas market. Suppliers are not providing long term price related to NYMEX but to Brent. For example all of DPP LNG purchase outside of 2001 BP contract has been at a percentage of Brent (contracts cannot be shown due to confidential agrrement), but a clear evidence can be find in Platts quotation when the US NG market is below 4$/MMBTu(NYMEX HH), the rest of the LNG Market is related to Brent of NBP:

Platts daily LNG markers ($/MMBtu)

Mar 19		Change	
DES Japan/Korea Marker (JKM)			
JKM (May)	15.950	0.000	—
H2 Apr	16.150	0.000	—
H1 May	16.000	0.000	—
H2 May	15.900	0.000	—
H1 Jun	15.800	0.000	—
DES Japan/Korea (JKM) Swaps			
Jun	15.750	[illegible]	
Jul	15.850	0.000	—
Aug	15.950	0.000	—
DES Southwest Europe Marker (SWE)			
SWE (May)	12.500	0.120	▲
H2 Apr	12.700	0.120	▲
H1 May	12.550	0.120	▲
H2 May	12.450	0.120	▲
DES Northwest Europe Marker (NWE)			
NWE (May)	12.000	0.120	▲
H2 Apr	12.200	0.120	▲
H1 May	12.050	0.120	▲
H2 May	11.950	0.120	▲
FOB Middle East			
FOB Middle East (May)	14.300	0.000	—
DES West India			
DES West India (May)	14.850	0.000	—
FOB Australia (netback)			
FOB Australia (May)	14.520	0.000	—

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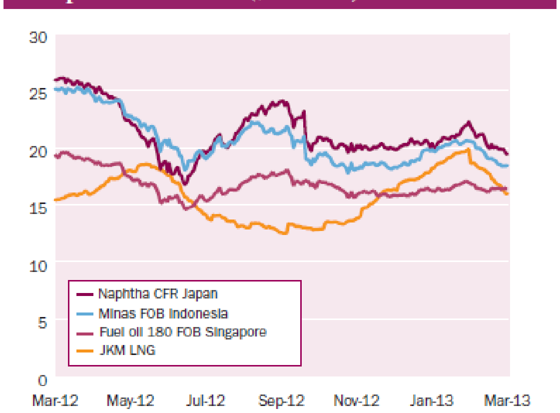
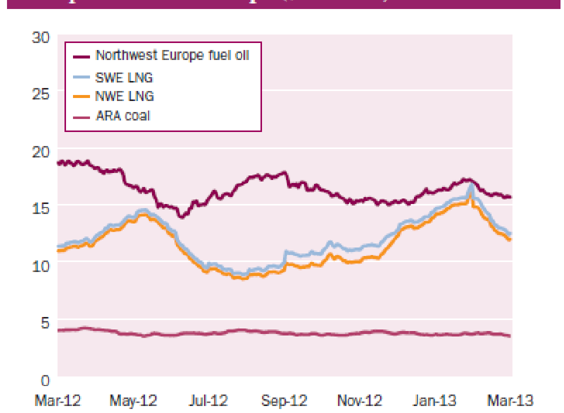
Data?mvr=L

Competitive fuels Asia ($/MMBtu)



Source: Platts

Competitive fuels Europe ($/MMBtu)



Source: Platts

DPP long term price (Brent x 12.7%) comes from an average of informal quotation to supplier for the long term price. After 2023 the Terminal Fee is updated as per a 0.85 US$/MMBTU of today using the CPI, obtaining the 1.23 US$/MMBTU value.

Additional explanation on how do fuel prices translates into PPA prices, and how a Fuel price affects a Generator net margin

As with any generator, DPP current and future Power Purchase Agreements are its natural hedging mechanism for fuel prices change over the life of the asset. In the DR, the typical PPA structure includes a full pass trough of the commodity that reflects the power generator fuel price plus a fixed margin to recover its investment and provide reasonable returns on equity (please see above explanation on the electricity market in the DR). That structure provides a more robust business case since it reduces volatility in the forecasted results on a variable commodity markets. Usually, as in DPP´s case, the plant is not contracted up to its 100% and a minor % is left for spot sales and that provide potential upsides and at the same time are left un-contracted in order to cover any operational situation, such as an increase in the expected forced outage ratio.

On a financial evaluation of such project, it is important to consider that any fuel increase or decrease will be passed to the client in proportion of their PPA size versus the plant's production, that means that if the power plant production is contracted on 80% contract – 20% spot level, then only 20% of the spot sales are to be affected by the fuel price increase, since the 80% contracted will also see a change in the revenue line as a result of the pass through structure.

In addition, it is important to understand that if the fuel prices change over the life of the plant not just the cost will be affected but also it is likely to see a correlation between the spot prices (electricity market prices) since those are set by the production cost of the marginal unit, which in turn is a direct result of its efficiency and it´s fuel price. That means that both revenues and costs move when a fuel price change is registered.

Additional explanations on the LNG-Oil price linkage (based on "2013 Summit Working Papers " of the Energy Pacific Energy Summit and other sources).

Global LNG demand has grown by leaps and bounds since the first commercial cargo was shipped from Algeria to the United Kingdom in 1964. LNG trade that year was a mere 0.2 million tons (mmt), but 46 years later that figure swelled to nearly 220 mmt. Since the mid-1970s, Asia has overtaken Europe as the largest consuming region in the world. The Americas occupy third place, followed by the Middle East, which started LNG imports in 2009.

Asia's dominance of worldwide LNG trade is expected to remain steady through 2020, even as Atlantic Basin and Middle Eastern demand rises.

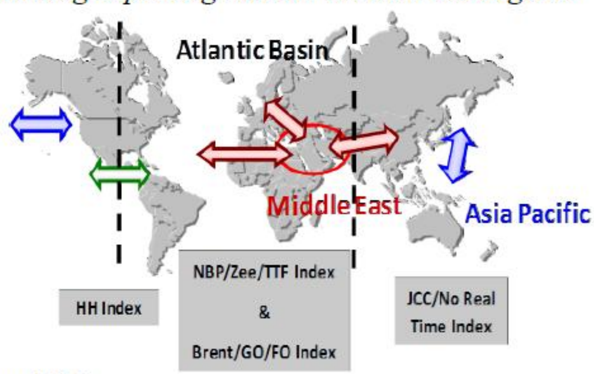
In terms of supply, as of 1997, there were only nine LNG exporters worldwide: Abu Dhabi, Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, Qatar, and the United States (Alaska). Since then, nine additional exporters have entered the market—Trinidad and Tobago and Nigeria in 1999, Oman in 2000, Egypt in 2005, Equatorial Guinea and Norway in 2007, Yemen and Russia in 2009, and Peru in 2010—thereby increasing the total number of LNG exporters to eighteen. During 2015–20, global LNG supply capacity may grow by 12% annually with the start of new LNG export projects and greater production capacity from existing projects.

A key factor affecting the outlook for LNG supply going forward will be the global balance of demand and supply.

Although natural gas is traded internationally, access to gas imports is far more restricted than access to oil imports. Almost every seaport in the world can import at least some volume of oil products; oil transport and storage use relatively simple and cheap infrastructure unlike LNG, which requires specialized and expensive infrastructure due to its cryogenic nature.

The basis on which natural gas is sold and priced varies dramatically between global markets, and unfortunately, there is not true of International LNG Market. In early 2012, gas was sold into Japan for as high as $18 per million British thermal unit (mmBtu) at the same time that wholesale prices were $9 per mmBtu in the United Kingdom, less than $2 per mmBtu in the United States, and $0.75 per mmBtu in Saudi Arabia.

Different gas pricing indices used across regions



Source: FGE.

Most analyst and independent consultant has similar conclusion on how the market can be divided. Natgas.info mentions on their web page that natural gas market could be divide into four groups:

1. Gas to Gas Market: Liberal market with volatile prices generally not linked with other market (North America, United Kindom). This market is characterized by large numbers of buyer and sellers largely competing without governmental intervention.

2. Price Indexed to substitute energy price: In this market the gas price moves in proportion with other fuels, usually crude oil or oil products quoted by a formula which ‘indexes’ or is derived from oil prices, trying to match their substitute fuel sold at a discount – on an equivalent energy basis – to oil and oil products (Europe, and to a lesser extent, in south-east Asia).

3. Oil-Linked price Market: Gas price linked directly to oil price. This group is characterized by the traditional LNG markets (Japan, Korea, Taiwan, China and others). Because oil price have gone through wide swings over time, "S Curves" (Sometimes Caps and/or Floors) were introduced at one point in Asian Contracts. S curves reduced the slop at the upper and lower "Pivot Points"; protecting the buyer at high oil prices and the seller at low oil price. But as oil prices began to move to much higher levels, S curves increasingly put the seller at a disadvantage implemented a direct oil-linked formula as a percentage of Brent.

4. Regulated Market: Controlled markets with government mandated price. Regulated markets dominate much of the other regions of the world. In these regions, the gas

markets are relatively immature and largely controlled by the State. The gas prices may be nationally set (by decree in many cases) and all supply in entered into a gas 'pool'. The state manages the differences in supply prices, and may choose to sell gas at prices less than the average 'pool' price for political reasons. There is no transparency in prices, no markets, and very little incentive – unless they receive special license from the government – for private sector investment in supply or infrastructure. If the mandated gas prices are artificially low, such as in the Middle East, inefficient consumption of energy often occurs.

Even though there is no such as and international LNG index, the LNG market is driven by an Oil-Linked price market:

- Virtually all Canadian LNG-export consortia have resolved to index LNG sales to crude oil.

- In much of continental Europe LNG contract prices continue to be set by linkages to Brent or to the spot prices of gas oil and fuel oil.

- Asian LNG prices are generally linked to crude oil prices—in particular to the Japan Custom Cleared price (JCC), also referred to as the "Japan crude cocktail" price. The JCC is the average price of crudes imported into Japan every month and is published by the Ministry of Finance on a monthly basis. Japan is the largest importer of LNG in the world and accounts for over half of all the LNG imports in Asia.

- High project costs, coupled with long-term LNG contracts that are currently in force, ensure that Asian LNG pricing will remain predominantly linked to oil for the foreseeable future, and over the next few years, oil-linked volumes will grow as Australian projects come online.

- Finally, the higher cost structure of projects in Canada and new frontiers such as East Africa ensure that oil-linked pricing will remain a mainstay, given that these projects need this type of linkage to justify multi-billion dollar investments.

Although many expected a gradual convergence of prices in the main regional gas markets, the last few years have seen a great divergence. In 2012, Japanese prices have continued to increase, U.S. prices have continued to fall, and NBP prices have remained generally steady. The three distinct regional markets for gas have thus been restored, and the expected increase in shale gas output in the United States in coming years will ensure that they will maintain very different pricing regimes. This massive disconnect between Hub prices in the United States and Canada versus oil-linked prices in Asia is what is driving the LNG-export proposals in North America. The possible Hub indexation will still be relatively small, and there is no guarantee that all U.S. exports will be sold on a Hub basis. A large portion of U.S. LNG exports will be lifted by aggregators such as BG Group who will sell on an oil-linked basis

In conclusion, as explained above and as was shown to the validator in the latest LNG purchase agreements for the Dominican Republic, the crude oil linkage are the representative LNG prices market of today's long and mid-term LNG purchase for this country.

Sensitivity Analysis for the NPV

A sensitivity analysis and a turning point analysis has been conducted in order to assess whether the conclusions regarding financial attractiveness are robust to reasonable variations in the critical assumptions. The variables selected for the sensitivity analysis are the energy spot price fuel costs and the unexpected initial costs. The fuel cost variable was chosen because it is the biggest ongoing cost item, and the contingency was chosen as it represents the sensitivity of the economic analysis to changes in the initial investment costs. The range analyzed for the fuel costs were ±10% and for the contingency 10% as the base and 5% and 15% as the range. It is important to note that both LNG and Coal future prices affect the financial model, on both the O&M costs as well as the anticipated income (see above explanation on the electricity market in the DR). Therefore the fuel cost sensitivity was conducted separately for the affect of a ±10% change in the price of LNG and Coal. See below the 9 scenarios that were analyzed with scenario 5 as the base case.

Scenario	1	2	3	4	5	6	7	8	9
Contingency	5.00%	10.00%	15.00%	5.00%	10.00%	15.00%	5.00%	10.00%	15.00%
Fuel Price	10%	10%	10%	0%	0%	0%	-10%	-10%	-10%

The Tables below shows a summary of the financial analysis including the sensitivity analysis and the turning point analysis. The base case is represented by case number 5 with no change in fuel prices and contingency at 10%.

Results for Coal price sensitivity:

Valuation Summary	Scenario								
	1	2	3	4	5	6	7	8	9
NPV with Project ($M)	$152	$145	$137	$127	$120	$112	$102	$95	$88
NPV without Project ($M)	$141	$141	$141	$131	$131	$131	$122	$122	$122
ΔNPV ($M)	$11	$4	($3)	($5)	($12)	($19)	($20)	($27)	($34)
Fuel price change NPV 0 (%)	-2%	-5%	-7%	-7%	-10%	-13%	-12%	-15%	-18%

Results for LNG price sensitivity:

Valuation Summary	Scenario								
	1	2	3	4	5	6	7	8	9
NPV with Project ($M)	$172	$165	$158	$127	$120	$112	$87	$80	$73
NPV without Project ($M)	$149	$149	$149	$131	$131	$131	$113	$113	$113
ΔNPV ($M)	$23	$16	$9	($5)	($12)	($19)	($26)	($33)	($40)
Fuel price change NPV 0 (%)	3%	0%	-3%	-7%	-10%	-13%	-16%	-18%	-20%

Conclusion of the Sensitivity Analysis:

As explained above, the proposed project is an upgrade of the existing power plant, and this upgrade requires a large investment. The relevant financial indicator therefore is the comparison between the NPV of the continuation of the current practice and the NPV of the proposed project. The average ΔNPV of all 9 scenarios for the Coal sensitivity analysis is $US -12 million and for the LNG sensitivity analysis $US -10 million, which shows how unprofitable and risky this project is. Although it may look like some of the cases return a positive result for the proposed project, it is important to remember that the ΔNPV represents the value the project generates over 19 years, compared to the current situation, based on an initial investment of about $US 260 million and additional market risks that can't be reflected in the financial model (see above explanation on the electricity market in the DR). From this perspective it is clear that even the best results in the sensitivity analysis are negligible and not sufficient to consider the proposed project as economically attractive compared to the fact that the current operation is profitable with minimal associated risk.

In addition to the sensitivity analysis, a turning point analysis was conducted to identify the change in fuel price that would start making the project less risky. As no official benchmark for the ΔNPV is available, the value "zero" was chosen as a VERY conservative benchmark to indicate the "turning point" from which the project will at least not be worse-off than the current situation and NOT the business feasibility which obviously will require a much higher ΔNPV to justify the risk. The results of the turning point analysis appear on the bottom line of the two sensitivity analysis tables above. The values present the change needed in the fuel price to make the ΔNPV "zero". As can be seen in the base case for both Coal and LNG (scenario 5), a drop of 10% in fuel price is needed just to make the ΔNPV "zero".

The proposed project therefore is not financially attractive and only one alternative remains as the most likely scenario: Alternative S4, the continuation of the current situation. This is the baseline scenario.

STEP 4. Common practice analysis

If the proposed project activity is the First-of-its-kind then this step is not applicable. Otherwise, the previous Steps shall be complemented with an analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and applicable geographical area.

This test is a credibility check to demonstrate additionality and complements the barrier analysis (Step 2) and, where applicable, the investment analysis (Step 3).

Since the project is not the First-of-its-kind in the Dominican Republic, the proposed VCS project activity applies measures that are listed in the definitions section above, and therefore Step 4 (a) is applied:

Step 4a: The proposed VCS project activity applies measures that are listed in the definitions section above

Sub-step 4a(1): Calculate the applicable output range as +/-50% of the design output or capacity of the proposed project activity.

The design output capacity of the proposed project activity is 318 MW. The applicable output range is therefore 318 +/-50% of 318=318+/-159.5=477.5/158.5 MW.

Sub-step 4a(2): In the applicable geographical area, identify all plants that deliver the same output or capacity within the applicable output range, calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number Nall. Registered CDM project activities and projects activities undergoing validation shall not be included in this step.

The following plants are in the Dominican Republic and with capacity in the range calculated (i.e. 158.5-477.5) (see DR Power Plants Data 2007-2011, Grid Calculation electronic spreadsheet): AES Andres, CESPM, San Felipe, Haina, and Itabo.

Hence: Nall=5.

Sub-step 4a(3): Within the plants identified in Step 2, identify those that apply technologies different to the technology applied in the proposed project activity. Note their number Ndiff.

The technology of each of the identified plants:

Plant	**Technology**	**Installed Capacity (MW)**
AES Andres	Combined Cycle	319
CESPM	Combined Cycle	300 (3 units of 100)
SAN FELIPE (also called SMITH & ENRON)	Combined Cycle	175
HAINA	Steam Turbine and Gas Turbine	238.9 (54+84.9+100)
ITABO	Steam Turbine	260 (128+132)

Hence: Ndiff=2.

Sub-step 4a(4): Calculate factor F=1-Ndiff/Nall, representing the share of plants using a technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

The calculated factor: F=1-2/5=0.6

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

(a) The factor F is greater than 0.2; and

(b) Nall-Ndiff is greater than 3.

The conditions for common practice were examined:

(a) The factor F, equals 0.6, hence is greater than 0.2.

(b) Nall-Ndiff=3, hence is not greater than 3.

Since not both conditions are fulfilled, the proposed project activity is not regarded as “common practice”. Since the proposed project activity is not regarded as “common practice”, the proposed project activity is additional.

2.5 Additionality

The "Combined tool to identify the baseline scenario and demonstrate additionality" was used. See section 2.4 for the detailed demonstration of additionality.

2.6 Methodology Deviations

The equations in the methodology assume that the fuel used is measured in mass or weight units and so include conversion to energy units. When using NG it is common to measure energy content as well as refer to energy content in the supply contracts. In such cases mass and/or weight is often not measured or recorded, as in the case of DPP. To follow the methodology, we used energy data instead of mass or weight and cancelled the conversion to energy. The deviation does not affect the meaning of the equation or the result of the calculations.

3 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

3.1 Baseline Emissions

ACM0007 specifies that the project mainly reduces CO2 emissions through the substitution of power generation supplied by the existing sources connected to the grid and likely future additions. The project emission reductions in any year is the difference between the baseline emissions displaced, the project emissions during the year and any emissions due to leakage during the year.

Emission Reduction

The emission reductions (ERy) are calculated according to the procedures prescribed in the UNFCCC Clean Developed Mechanism (CDM) approved methodology ACM0007 methodology. ACM0007 requires that the emission reductions by the project activity to be calculated as the difference between the baseline emissions (BE_y), project emissions (PE_y) and emissions due to leakage (LE_y).

$$ER_y = BE_y - PE_y - LE_y$$

Baseline Emissions

The baseline emissions (BE_y) are calculated, as prescribed by ACM0007, by following three steps:

Step 1: Determination of the baseline emissions for different scenarios of project electricity generation

Step 2: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

Step 3: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

Step 1: Determination of the baseline emissions for different scenarios of project electricity generation

In the case of Los Mina's project the quantity of electricity generated in the project power units, adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the maximum annual quantity of electricity that the project power units could have produced prior to the implementation of the project activity (EG_{MAX}), and therefore baseline emissions are calculated based on case (c) as follows:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + \left(EG_{MAX} - EG_{BL,AVR}\right) \cdot \min\left(EF_{CO2,BL,y}; EF_{grid,y}\right) + \left(EG_{PJ,adj,y} - EG_{MAX}\right) \cdot EF_{grid,y}$$

Where:

BE_y = Baseline emissions in year y (tCO2/yr)

$EG_{PJ,adj,y}$ = Quantity of electricity supplied by all project power units to the electricity grid in year y, adjusted for changes to efficiency (MWh/yr)

$EG_{BL,AVR}$ = Average annual quantity of electricity supplied by all project power units to the electricity grid during the defined operational history (MWh/yr)

$EF_{CO2,BL}$ = Baseline emission factor of all project power units operated in single cycle mode (tCO2/MWh)

$EF_{grid,y}$ = Emission factor of the electricity grid to which the project power unit is connected (tCO2/MWh)

The maximum annual quantity of electricity that could be generated by the project power units in the baseline scenario (EG_{MAX}) is calculated as:

$$EG_{MAX} = CAP_{MAX} \cdot T_{MAX}$$

Where:

EG_{MAX} = Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr)

CAP_{MAX} = Maximum gross power generation capacity of the project power units prior to the implementation of the project activity (MW)

T_{MAX} = Maximum amount of time during a year in which the project power units could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)

Since all project power units have three years operational history, and since there was no major retrofit during this period in any of the units, then the maximum annual amount of time that the project power units could have operated at full load prior to the validation of the project activity is calculated as follows:

$$T_{MAX} = 8{,}760 - \frac{\sum_{x=1}^{3} HMR_x}{3}$$

Where:

T_{MAX}= Maximum amount of time during a year in which the project power units could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)

HMR_x= Average number of hours during which the plant did not operate due to maintenance or repair in year x (hours/yr)

x = Each year during the three years operational history

The average annual amount of electricity supplied to the electricity grid by the project power units in the three years historical period is calculated according to the equation below. Since both units in Los Mina have at least a three years operational history and no major retrofit during this period, this calculation is based on data from both units:

$$EG_{BL,AVR} = \frac{\sum_{x=1}^{3} EG_x}{3}$$

Where:

$EG_{BL,AVR}$ = Average annual quantity of electricity supplied by all project power units to the electricity grid during the three year operational history (MWh/yr)

EG_x = Quantity of electricity supplied by the project power units with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr)

x = Each year of the three years operational history

The total amount of electricity supplied to the electricity grid by all project power units in year y of the crediting period has to be adjusted for the calculation of baseline emissions so that future energy efficiency improvement measures shall not result in emissions reductions. Therefore, the total amount of electricity supplied to the grid ($EG_{PJ,y}$) is conservatively adjusted by applying a discount factor based on the minimum of the monitored efficiencies after the implementation of the project activity, as described in the equations below:

$$EG_{PJ.adj} = EG_{PJ,y} \cdot \frac{\eta_{PJ,min,y}}{\eta_{PJ,y}}$$

With

$$\eta_{PJ,min,y} = \min\left(\eta_{PJ1} \ldots \eta_{PJ,y}\right)$$

Where:

$EG_{PJ.adj}$ = Quantity of electricity supplied by all project power units to the electricity grid in year y, adjusted for changes to project power plant efficiency (MWh/yr)

$EG_{PJ,y}$ = Total amount of electricity supplied to the electricity grid by the project power units in year y (MWh/yr)

$\eta_{PJ,min,y}$ = Minimum of the yearly average energy efficiency of the project power units monitored during the previous years (1 to y) after the implementation of the project activity for year y

η P_{J1}…$\eta_{PJ,y}$ = Average energy efficiency of the project power units in years 1 to y of the crediting period

Step 2: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

Since all project power units have a three years operational history and since there was no major retrofit in these unit during this period, the baseline CO2 emissions factor for the project power units operated in single cycle mode ($EF_{CO2,BL}$) is determined based on the historical performance of the units and calculated as follows:

$$EF_{CO2,BL} = \frac{\sum_{x=1}^{3} \sum_i FC_{i,x} \times NCV_{i,x}}{\sum_{x=1}^{3} EG_x} \times EF_{CO2,min}$$

Where:

$EF_{CO2,BL}$ = CO2 emission factor for electricity generated in single cycle mode in the baseline

(tCO2/MWh)

$FC_{i,x}$ = Quantity of fuel type i used by the project power units in year x (mass or volume

unit/yr)

$NCV_{i,x}$ = Net calorific value of the fuel type i used by the project power units in year x (GJ/mass or volume unit)

$EF_{CO2,min}$ = CO2 emission factor of the least carbon intensive fuel type used by the project power units during the three years operational history (tCO2/GJ)

EG_x = Quantity of electricity supplied by the project power units with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr)

x = Each year of the three years operational history

Step 3: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

The baseline emission factor ($EF_{grid,y}$) is calculated as a combined margin (CM), following the six steps in the “Tool to calculate the emission factor for an electricity system” (Version 3):

Step 1. Identify the relevant electricity systems;

Step 2. Choose whether to include off-grid power plants in the project electricity system (optional);

Step 3. Select a method to determine the operating margin (OM);

Step 4. Calculate the operating margin emission factor according to the selected method;

Step 5. Calculate the build margin (BM) emission factor;

Step 6. Calculate the combined margin (CM) emission factor.

Step1: Identify the relevant electricity systems

The Dominican Republic grid is connected through the National Interconnected Electric System (SENI, Sistema Eléctrico Nacional Interconectado); for this, the relevant electric power system is the entire SENI grid16, moreover the public information of the SENI is classified for fuel type consumption and for plant production instead of regional production.

For determining the Operating Margin (OM) emission factor, it is necessary to determine the net electricity imports. In this case, there are no imports or exports from other systems inside the country. All the electricity generated is managed through the Interconnected Grid System. Therefore, there is no "Connected Electricity System" in this case as defined in the "Tool to calculate the emission factor for an electricity system".

The information on the grid characteristics is given in the Annual Memories (Memorias Anuales), prepared by the Coordination Body of the Interconnected National Electric System (Organismo Coordinador del Sistema Eléctrico Nacional Interconectado, OC SENI). These boundaries include all the geographic areas and infrastructures within the entire Dominican Republic territory, as well as energy transmission and distribution variables inside the Dominican Republic system.

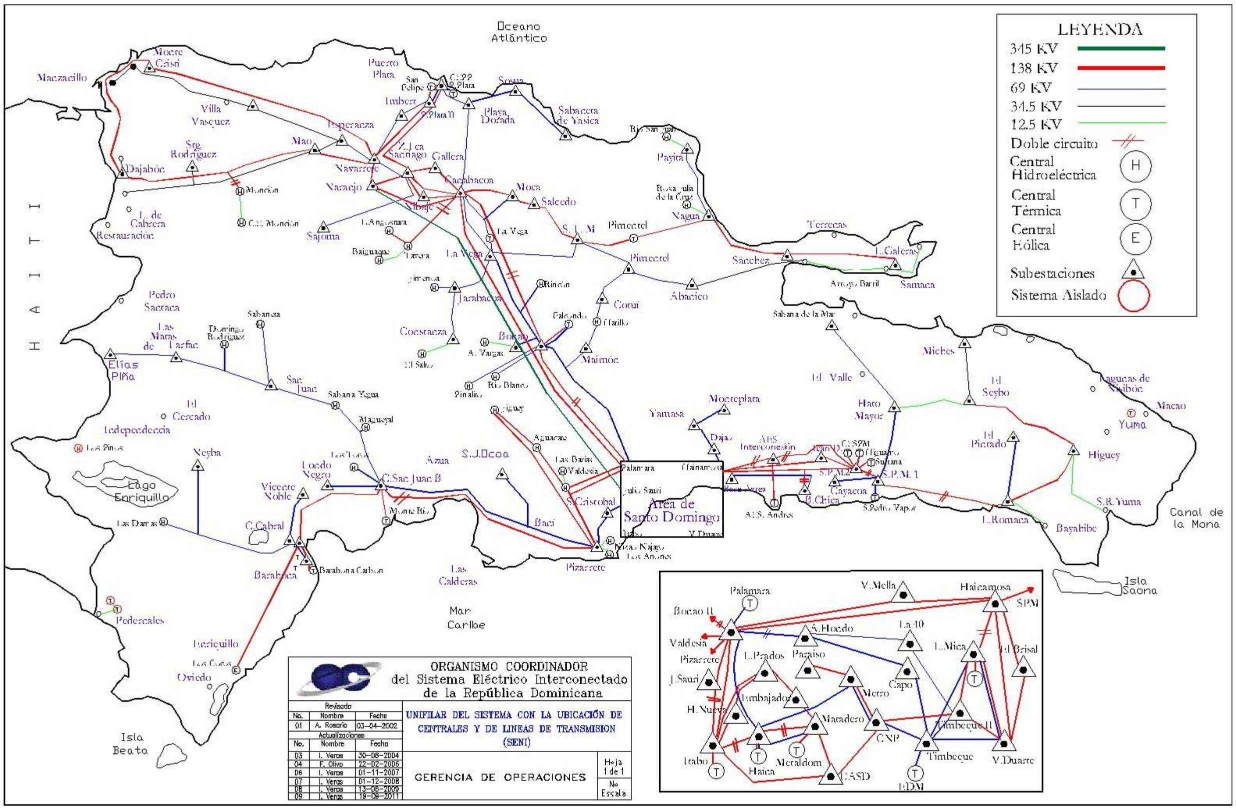


Figure: Schematic map of SENI. Source: Coordination body of SENI (http://www.oc.org.do)

Step2: Choose whether to include off-grid power plants in the project electricity system (optional)

Project Proponents may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Dominican Power Partners has chosen Option I, and only grid power plants are included in the calculation.

Step 3: Select a method to determine the operating margin (OM)

The calculation of the operating margin emission factor ($EF_{grid,OM,y}$) is based on one of the following methods:

a. Simple OM; or

b. Simple adjusted OM; or

c. Dispatch data analysis OM; or

d. Average OM.

The below analysis uses the Simple OM method with an ex ante $EF_{grid,CM,y}$ calculation.

Option (a) can only be used if low-cost/must-run resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

In The Dominican Republic, low-cost/must-run resources represent well below 50% of total grid generation in the average of the five most recent years:

Technology	2007	2008	2009	2010	2011
Hydro Turbine	1729503.29	1348953.257	1422848.514	1392280.469	1484620.166
Combined Cycle	2797049.552	3471787.765	2976522.525	3031642.64	3446520.48
Open Cycle Gas Turbine (OCGT)	364176.7369	338223.0251	465517.9144	1223528.992	1363551.35
Steam Turbine	2393374.261	2341721.6	2507674.548	2471058.298	2242801.027
Gas Turbine	27763.59822	44530.44872	50184.27096	84393.83304	132378.5559
Diesel Engine	3941546.518	3941072.487	3924966.952	4023545.633	3993442.602
Eolic Turbine	0	0	0	0	13745.41869
Low Cost/Must Run Percentage	**15.37%**	**11.74%**	**12.54%**	**11.39%**	**11.82%**

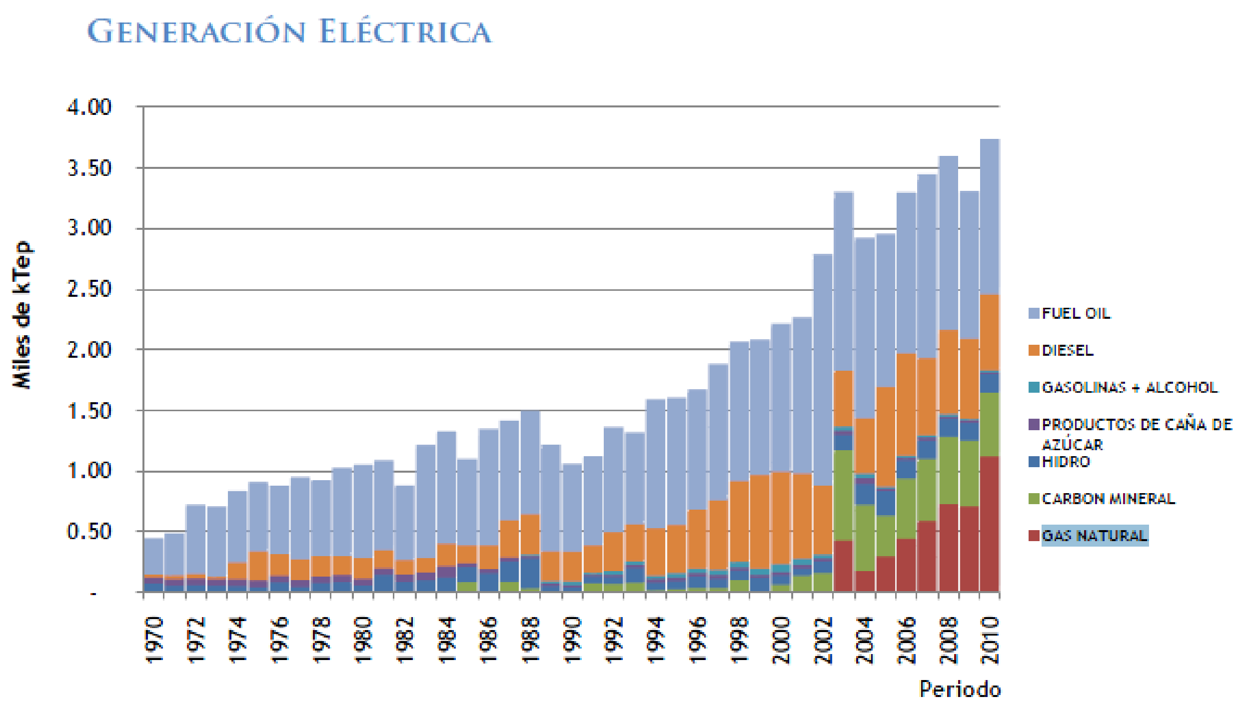


Figure: Energy Generation by Resource (1970-2010), (reference: Balances de Energía, 1970 – 2010, Comisión Nacional de Energía de la República Dominicana
http://www.cne.gov.do/app/do/sien_archivo.aspx

For the simple OM, the simple adjusted OM and the average OM, the emissions factor can be calculated using either of the two following data vintages:

- Ex ante option
- Ex post option

DPP has chosen to use the ex ante option to calculate the emissions factor, and data from years 2007-2011 was used.

Step 4: Calculate the operating margin emission factor according to the selected method

The simple OM emission factor is calculated as the generation-weighted average CO2 emissions per unit net electricity generation ($t_{CO2/MWh}$) of all generating power plants serving the system, not including low-cost/must-run power plants/units.

The simple OM may be calculated by one of the following two options:

Option A: Based on the net electricity generation and a CO2 emission factor of each power unit; or

Option B: Based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system.

Option B can only be used if the necessary data for Option A is not available. Since all data was available, option A was selected for the calculation.

Option A: Calculation based on average efficiency and electricity generation of each plant

Under this option, the simple OM emission factor is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,y}$ = Simple operating margin CO2 emission factor in year y ($t_{CO2/MWh}$)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y

(MWh)

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y ($t_{CO2/MWh}$)

m = All power units serving the grid in year y except low-cost/must-run power units

y = The relevant year as per the data vintage chosen in Step 3

The emission factor of each power unit m is determined as follows:

Option A1. If for a power unit m data on fuel consumption and electricity generation is available, the emission factor ($EF_{EL,m,y}$) should be determined as follows:

$$EF_{EL,m,y} = \frac{\sum_i \mathrm{FC}_{\mathrm{i,m,y}} \times \mathrm{NCV}_{\mathrm{i,y}} \times \mathrm{EF}_{\mathrm{CO2,i,y}}}{EG_{m,y}}$$

Where:

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y ($t_{CO2/MWh}$)

$FC_{i,m,y}$ = Amount of fossil fuel type i consumed by power unit m in year y (Mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type i in year y (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO2 emission factor of fossil fuel type i in year y ($t_{CO2/GJ}$)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

m = All power units serving the grid in year y except low-cost/must-run power units

i = All fossil fuel types combusted in power unit m in year y

y = The relevant year as per the data vintage chosen in Step 3

Option A2. If for a power unit m only data on electricity generation and the fuel types used is available, the emission factor should be determined based on the CO2 emission factor of the fuel type used and the efficiency of the power unit, as follows:

$$EF_{EL,m,y} = \frac{\mathrm{EF}_{\mathrm{CO2,m,i,y}} \times 3.6}{\eta_{m,y}}$$

Where:

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y ($t_{CO2/MWh}$)

$EF_{CO2,m,i,y}$ = Average CO2 emission factor of fuel type i used in power unit m in year y ($t_{CO2/GJ}$)

$\eta_{m,y}$= Average net energy conversion efficiency of power unit m in year y (ratio)

m = All power units serving the grid in year y except low-cost/must-run power units

y = The relevant year as per the data vintage chosen in Step 3

Option A3. If for a power unit m only data on electricity generation is available, an emission factor of 0 $t_{CO2/MWh}$ can be assumed as a simple and conservative approach.

The operating margin emission factor, calculated based on option A1, as can be seen in the electronic spreadsheet:

$$EF_{grid,OMsimple,y} = 0.812$$

Step 5: Calculate the build margin (BM) emission factor

To calculate the BM, Option 1 from the tool has been chosen; hence the BM emission factor will be calculated ex ante, based on the most recent information available on units already built for sample group m at the time of PD submission to the VVB for validation. This option does not require monitoring the emission factor during the crediting period.

The sample group of power units m used to calculate the build margin should be determined as per the following procedure, consistent with the data vintage selected above:

a) Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently (SET5-units) and determine their annual electricity generation (AEGSET-5-units, in MWh);

The set of five power units that started to supply electricity to the grid most recently, and their annual electricity generation (calculated based on years 2007-2011):

SET 5-unit		
Plant	Comission Year	Average Electricity Generation
MONTE RIO	2003	515,068.68
PIMENTEL II	2009	165,957.15
PINALITO 1	2009	47,398.45
PINALITO 2	2009	45,926.72
PIMENTEL III	2010	262,613.37
AEGSET-5-units		1,036,964.37

b) Determine the annual electricity generation of the project electricity system, excluding power units registered as CDM project activities (AEG_{total}, in MWh). Identify the set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total} (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) (SET≥20%) and determine their annual electricity generation (AEG_{SET}-≥20%, in MWh);

The average annual electricity generation of the project electricity system, excluding power units registered as CDM project activities is: AEG_{total}= 11,795,436 MWh, and therefore 20% of AEG_{total}= 2359087 MWh.

The set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total}:

SET>20%		
AES ANDRES	2003	1,957,604.54
MONTE RIO	2003	515,068.68
PIMENTEL II	2009	165,957.15
PINALITO 1	2009	47,398.45
PINALITO 2	2009	45,926.72
PIMENTEL III	2010	262,613.37
AEGSET>20%		2,994,568.92

c) From SET5-units and SET≥20% select the set of power units that comprises the larger annual electricity generation (SET_{sample});

The larger annual electricity generation is of SET>20%. SET_{sample} is therefore the following list of units: AES ANDRES, MONTE RIO, PIMENTEL II, PINALITO 1, PINALITO 2 & PIMENTEL III.

As no power plant in SET_{sample} started to supply electricity to the grid more than 10 years ago, step (d) was not followed:

The build margin emissions factor is the generation-weighted average emission factor ($t_{CO2/MWh}$) of all power unit m calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO2 emission factor in year y ($t_{CO2/MWh}$)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y

(MWh)

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y ($t_{CO2/MWh}$)

m = Power units included in the build margin

y = Most recent historical year for which electricity generation data is available

Where the CO2 emission factor of each power unit m ($EF_{EL,m,y}$) was given in Step 4, following the option A1 from the tool.

The calculated operating margin emission factor, as can be seen in the electronic spreadsheet:

$$EF_{grid,BM,y} = 0.541$$

Step 6: Calculate the combined margin emissions factor

The calculation of the combined margin (CM) emission factor ($EF_{grid,CM,y}$) is based on the preferred option given by the tool to calculate the EF: Weighted average CM.

The combined margin emissions factor is therefore calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times W_{OM} + EF_{grid,BM,y} \times W_{BM}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO2 emission factor in year y ($t_{CO2/MWh}$)

$EF_{grid,OM,y}$ = Operating margin CO2 emission factor in year y ($t_{CO2/MWh}$)

W_{OM} = Weighting of operating margin emissions factor (%)

W_{BM} = Weighting of build margin emissions factor (%)

Since the project activity is not a wind and solar power generation, the following default values were used for W_{OM} and W_{BM}:

W_{OM} = 0.5 and W_{BM} = 0.5 for the first crediting period, and W_{OM} = 0.25 and W_{BM} = 0.75 for the second and third crediting period.

The calculated combined margin emissions factor, as can be seen in the electronic spreadsheet:

$$EF_{EL,m,y} = 0.6765$$

3.2 Project Emissions

The project emissions (PEy), are defined in "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion", and are calculated based on the quantity of fuels combusted and the CO2 emission coefficient of those fuels, as follows:

$$PE_{FC,j,y} = \sum_{i} FC_{i,j,y} \cdot COEF_{i,y}$$

Where:

$PE_{FC,j,y}$ =Are the CO2 emissions from fossil fuel combustion in process j during the year y ($t_{CO2/yr}$);

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

$CO_{EFi,y}$ = Is the CO2 emission coefficient of fuel type i in year y (tCO2/mass or volume unit)

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

The CO2 emission coefficient $CO_{EFi,y}$ is calculated based on net calorific value and CO2 emission factor of the fuel type i, as follows:

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

Where:

$CO_{EFi,y}$ = Is the CO2 emission coefficient of fuel type i in year y (tCO2/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 CO2 emission factor of fuel type i in year y ($t_{CO2/GJ}$)

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

3.3 Leakage

The leakage emissions are associated with the upstream emissions on an increase in fossil fuel use and are determined in the case of Los Mina's project as follows:

$$LE_y = LE_{upstream,y} + LE_{HR,y}$$

Where:

LE_y = Leakage emissions in year y ($t_{CO2e/yr}$)

$LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in year y ($t_{CO2e/yr}$)

$LE_{HR,y}$ = Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year y ($t_{CO2e/yr}$)

Determination of $LE_{HR,y}$

Since the quantity of heat recovered from the exhaust heat during the most recent year prior to the implementation of the project activity (QHR,x) was zero and therefore was less than 3% of the fossil fuels consumed by the project power units in an energy basis, then emissions from this leakage source are equal to zero and there is no need to calculate LEHR,y.

Determination of $LE_{upstream,y}$

In cases where the fuel consumption in the project activity is lower than the historical fuel consumption in the three historical years x, leakage emissions from this source are equal to zero. Fuel consumption in the project activity is not lower than the historical fuel consumption, therefore, leakage emissions associated with the upstream emissions from an increase in fossil fuel use in the project activity shall be considered. The leakage emissions are calculated as follows:

$$LE_{upstream,y} = MAX\left[0, \left(\left(\sum_i FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,upstream,CH4}\right) \cdot GWP_{CH4} + LE_{LNG,CO2,y}\right) \times \left(1 - \frac{\frac{1}{3} \cdot \sum_{x=1}^{3} FC_{i,x} \cdot NCV_{i,x}}{\sum_i FC_{i,y} \cdot NCV_{i,y}}\right)\right]$$

Where:

$LE_{upstream,y}$ = Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in the year y ($t_{CO2e/yr}$)

$FC_{i,y}$ = Quantity of fuel type i used by the project power unit(s) in year y (mass or volume unit/yr)

$NCV_{i,y}$ = Average net calorific value of the fuel type i used by the project power unit(s) in year y (GJ/mass or volume unit)

$EF_{i,upstream,CH4}$ = Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel i used by the project power unit(s) in year y ($t_{CH4/GJ}$)

GWP_{CH4} = Global warming potential of methane valid for the relevant commitment period (tCO2e/tCH4)

$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year y ($t_{CO2e/yr}$)

$FC_{i,x}$ = Quantity of fuel type i used by the project power unit(s) in year x (mass or volume unit/yr)

$NCV_{i,x}$ = Net calorific value of fuel type i used by the project power unit(s) in year x (GJ/mass or volume unit)

x = Each year of the three years operational history

Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) are calculated, where applicable, as follows:

$$LE_{LNG,CO2,y} = FC_{LNG,y} \cdot NCV_{LNG,y} \cdot EF_{CO2,upstream,LNG}$$

Where:

$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year y ($t_{CO2e/yr}$)

$FC_{LNG,y}$ = Quantity of natural gas produced from LNG used by the project power unit(s) in year y

(mass or volume unit/yr)

$NCV_{LNG,y}$ = Net calorific value of natural gas produced from LNG used by the project power unit(s) in year y (GJ/mass or volume unit)

$EF_{CO2,upstream,LNG}$ = Emission factor for upstream CO2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($t_{CO2e/GJ}$).

3.4 Summary of GHG Emission Reductions and Removals

The emission reductions (ERy) are calculated according to the procedures prescribed in the UNFCCC Clean Developed Mechanism (CDM) approved methodology ACM0007 methodology. ACM0007 requires that the emission reductions by the project activity to be calculated as the difference between the baseline emissions (BEy), project emissions (PEy) and emissions due to leakage (LEy).

$$ER_y = BE_y - PE_y - LE_y$$

Years	Estimated baseline emissions or removals (tCO_2e)	Estimated project emissions or removals (tCO_2e)	Estimated leakage emissions (tCO_2e)	Estimated net GHG emission reductions or removals (tCO_2e)
2016	1,522,521.74	1,096,445.14	71,598.18	354,478
2017	1,469,754.74	1,059,124.32	63,778.09	346,852
2018	1,492,755.74	1,076,893.21	67,501.33	348,361
2019	1,458,254.24	1,052,975.92	62,489.77	342,789
2020	1,425,782.24	1,029,980.88	57,671.46	338,130
2021	1,513,050.74	1,094,785.07	71,250.33	347,015
2022	1,465,019.24	1,060,845.88	64,138.82	340,035
2023	1,528,610.24	1,108,680.47	74,161.93	345,768
2024	1,487,343.74	1,079,537.03	68,055.31	339,751
2025	1,429,164.74	1,037,850.84	59,320.51	331,993
Total	**14,792,257.37**	**10,697,118.77**	**659,965.74**	**3,435,173**

4 MONITORING

4.1 Data and Parameters Available at Validation

Data / Parameter	EG_x
Unit	MWh/yr
Description	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year *x*
Source of data	Generation records. Historical data of electricity supplied by the project to the grid in the defined operational history.
Value(s) applied	2009: 465,518 2010: 1,223,529 2011: 1,363,551
Choice of data or Measurement methods and procedures	Data reported by the grid coordinator was used (official confirmation as to the validity of the data from the OC was provided to the DOE)
Purpose of data	Calculation of baseline emissions
Additional comment	The consistency of metered net electricity generation should be cross-checked with receipts from sales (if available). Meters should be subject to regular maintenance and calibration. Year *x* refers to each year of the unit,s three years operational history. This parameter is only required if any of the project power unit(s) does not have three years operational history with no major retrofit in this period

Data / Parameter	$FC_{NG,x}$
Unit	MMBTU/yr
Description	Quantity of natural gas used by the project power units in year x
Source of data	Historical data of annual fuel consumption by the project operating in single cycle mode, taken from invoices from supplier
Value(s) applied	2009:5,595,895 2010:14,672,476 2011:16,558,146
Choice of data or Measurement methods and procedures	The data available for the three most recent years is in MMBTU, and not in volume or mass units. These values were converted to GJ, using standard conversions.
Purpose of data	Calculation of baseline emissions
Additional comment	The data for any direct measurements with mass or volume meters at the plant site should be cross-checked with an annual energy balance that is based on purchased quantities and stock changes. Meters should be subject to regular maintenance and calibration Year x refers to each year of the unit's operational history

Data / Parameter	$NCV_{NG,x}$
Unit	GJ/Kg
Description	Net calorific value of natural gas used by the project power units in year x
Source of data	Values provided by the fuel supplier in invoices
Value(s) applied	N/A
Choice of data or Measurement methods and procedures	In line with national or international fuel standards
Purpose of data	Since fuel consumption data that is available for the three most recent years is in MMBTU, and not in volume or mass units, NCV for the historical years is not used
Additional comment	

Data / Parameter	$EF_{C02,min}$
Unit	$tC0_2/GJ$
Description	$C0_2$ emission factor of the least carbon intensive fuel type used by the project power units during the three years operational history (NG)
Source of data	IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	0.0543
Choice of data or Measurement methods and procedures	Any future revision of the IPCC Guidelines should be taken into account
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	$EF_{C02,max}$
Unit	$tC0_2/GJ$
Description	$C0_2$ emission factor of the most carbon intensive fuel type used by the project power units during three years operational history (NG)
Source of data	IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	0.0583
Choice of data or Measurement methods and procedures	Any future revision of the IPCC Guidelines should be taken into account
Purpose of data	Calculation of leakage
Additional comment	

Data / Parameter	CAP_{max}
Unit	MW
Description	Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity
Source of data	Maximum generation capacity determined by performance tests under optimal operation conditions (optimal load, after maintenance, etc)
Value(s) applied	210
Choice of data or Measurement methods and procedures	Generation licenses or manufacturer's specification
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	T_{max}
Unit	Hours/yr
Description	Maximum amount of time during a year in which the project power units could have operated at full power generation capacity prior to the implementation of the project activity
Source of data	
Value(s) applied	8760 or calculated as per equation 6
Choice of data or Measurement methods and procedures	
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	HMR_x
Unit	Hours/yr
Description	Average number of hours during which the plant did not operate due to maintenance or repair in year x (hours)
Source of data	Project activity site
Value(s) applied	0
Choice of data or Measurement methods and procedures	Use historical records for such maintenance and repair intervals
Purpose of data	Calculation of baseline emissions
Additional comment	This parameter is not required if there is less than three years operational history for all project power units, or if a major retrofit occurred in this period. As a simplification, project proponents may also assume this parameter as zero Year x refers to each year of the unit's three years operational history

Data / Parameter	η
Unit	-
Description	Default efficiency of the project power units operated in single cycle mode
Source of data	"Tool to calculate the emission factor for an electricity system", Annex 1
Value(s) applied	
Choice of data or Measurement methods and procedures	
Purpose of data	Calculation of baseline emissions
Additional comment	This parameter is only required if there is less than three years operational data for all project power units, or if a major retrofit occurred in this period. Since three years operational data for all project power units is available, this parameter is not used.

Data / Parameter	$QH_{R,x}$
Unit	GJ/yr
Description	Quantity of heat recovered from the exhaust heat during the most recent year prior to the implementation of the project activity
Source of data	Site of the recovery process (eg. heat exchanger, etc.)
Value(s) applied	0
Choice of data or Measurement methods and procedures	Calculation from historical records from appropriate metering devices (e.g. temperature, pressure and flow meters for air or feed water)
Purpose of data	Calculation of leakage
Additional comment	There was no heat recovery in the open cycle units

Data / Parameter	GWP_{CH4}
Unit	tC02e/tCH4
Description	Global warming potential of methane valid for the relevant commitment period
Source of data	IPCC
Value(s) applied	For the first commitment period: 21
Choice of data or Measurement methods and procedures	
Purpose of data	Calculation of leakage
Additional comment	

4.2 Data and Parameters Monitored

Data / Parameter	$EG_{PJ,y}$
Unit	MWh/yr
Description	Total amount of electricity supplied to the electricity grid by the project power units in year y
Source of data	Generation records, using electricity meter
Value(s) applied	
Measurement methods an procedures	Electricity meters which are owned by the grid operator
Monitoring frequency	Continuously
QA/QC procedures	By law the grid operator calibrates the meters every 2 years. The consistency of metered net electricity generation will be cross-checked with receipts from sales
Purpose of data	Calculation of baseline emissions
Additional comment	Calibration of electricity meters is under the responsibility of the grid operator and as mentioned above the meters are calibrated every 2 years.

Data / Parameter	$FC_{NG,y}$
Unit	Mass or volume unit/yr
Description	Quantity of fuel type i used by the project power unit(s) in year y
Source of data	site measurements
Value(s) applied	
Measurement methods and procedures	NG meters
Monitoring frequency	Continuously
QA/QC procedures	The consistency of metered fuel consumption quantities should be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Purpose of data	Calculation of project emissions, Calculation of leakage
Additional comment	

Data / Parameter	$\eta_{PJ,y}$
Unit	-
Description	Average energy efficiency of the project power units in year y of the crediting period
Source of data	Project activity site
Value(s) applied	
Measurement methods and procedures	To calculate the efficiencies: • Use the direct method (dividing the net electricity generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses); • Use recognized standards for the measurement of the power plant efficiency; The efficiency has to be referred in terms of the net calorific values of the fuels used and the net electricity produced, i.e. total electricity produced minus internal consumption of electricity
Monitoring frequency	Once during each year y of the crediting period. The first calculation shall be made during the first year after implementing the project activity and after achieving operational stability
QA/QC procedures	
Purpose of data	Calculation of baseline emissions
Additional comment	

Data / Parameter	$Q_{HR,y}$
Unit	GJ/yr
Description	Quantity of heat recovered from the exhaust heat of the project power units for purposes other than power generation in year y
Source of data	Site of the recovery process (eg. heat exchanger, etc.)
Value(s) applied	N/A
Measurement methods and procedures	Calculation from direct measurements by project participants through appropriate metering devices (e.g. temperature, pressure and flow meters for air or feed water)
Monitoring frequency	Monitoring of this parameter is only required if heat is recovered from the exhaust heat in the most recent year prior to the implementation of the project activity and the amount recovered is more than 3% of energy of the fuel consumed by the project power plant in the same year. There was no heat recovery in Los Mina plant prior to project activity; therefore this parameter is not monitored.
QA/QC procedures	
Purpose of data	Calculation of leakage
Additional comment	

Data / Parameter	$NCV_{i,y}$
Unit	GJ/mass or volume unit
Description	Average net calorific value of the natural gas used by the project power units in year y
Source of data	Values provided by the fuel supplier in invoices
Value(s) applied	
Measurement methods and procedures	In line with national or international fuel standards
Monitoring frequency	The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated. "Fuel delivery" refers to each time a ship unloads LNG at the ANDRES site which is the source of fuel for DPP. NCV value may vary a little between ship loads and the equivalent value in BTU/kg is measured by a "third party" (currently by SGS) for each load. The number of ship loads per year depends on consumption rates, but usually an LNG ship unloads fuel once every few weeks.
QA/QC procedures	
Purpose of data	Calculation of project emissions, Calculation of leakage
Additional comment	

Data / Parameter	$EF_{NG,upstream,CH4}$
Unit	tCH4/GJ
Description	Emission factor for upstream fugitive methane emissions from production, transportation, distribution of natural gas used by the project power units in year y
Source of data	Reliable and accurate national data on fugitive CH4 emissions associated with the production, or default emission factors
Value(s) applied	0.000296
Measurement methods and procedures	Default emission factors, derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range
Monitoring frequency	
QA/QC procedures	
Purpose of data	Calculation of leakage
Additional comment	The emission factor for fugitive upstream emissions for natural gas should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table of default values above. To the extent that upstream emissions occur in Annex I countries that have ratified the Kyoto Protocol, from 1 January 2OO8 onwards, these emissions should be excluded, if technically possible, in the leakage calculations. This parameter is only required to calculate the upstream leakage emissions, if applicable

Data / Parameter	$EF_{C02,upstream,LNG}$
Unit	tC02/GJ
Description	Emission factor for upstream C02 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during year y of the project activity
Source of data	Based on ACM0007, where reliable and accurate data on upstream $C0_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor If reliable and accurate data is not available, then a default value of 0.006 t C02/GJ may be used as a rough approximation.
Value(s) applied	0.006 t C02/GJ
Measurement methods and procedures	
Monitoring frequency	
QA/QC procedures	
Purpose of data	Calculation of leakage
Additional comment	

Data / Parameter	$EF_{grid,y}$
Unit	tCO_2/MWh
Description	Emission factor of the electricity grid to which the project power unit is connected
Source of data	Monitored/Calculated
Value(s) applied	
Measurement methods and procedures	If value is not published by DNA, calculation is done based on "Tool to calculate the emission factor for an electricity system" (Version 02.2.0)
Monitoring frequency	Annually
QA/QC procedures	
Purpose of data	Calculation of baseline emissions
Additional comment	Not required if Ex Ante EF is chosen

4.3 Description of the Monitoring Plan

Electricity generation, fuel consumption and its net calorific value will be monitored regularly, as part of the plant's operation. Electricity generation will be monitored through meter readings, and will be compared to invoices from the Dominican Republic's grid coordinator. Fuel consumption and fuel' NCV appear on invoices from the supplier, and are documented in the company's database.

Guidelines for a monitoring plan for emissions reductions

Objective
The objective of this plan is to assure the complete, consistent, clear, and accurate monitoring and calculation of the emissions reductions realized by the project during the crediting period.
Monitoring procedures
Before beginning operation, a VCU team will be assigned the responsibility for the implementation of the monitoring program namely data collection, archiving and quality control. A team manager will be assigned, and all employees involved in monitoring will have clearly defined roles and responsibilities and will undergo training by the monitoring team manager. The detailed monitoring program will be planned and agreed upon by the project developer and Elysium. A formal set of monitoring procedures will be established prior to the start of the crediting period. These procedures will detail the organization, control and steps required for certain key monitoring features, including:

- Staff training.
- Monitoring equipment.
- Data collecting and recording.
- Data management.
- Quality control and quality assurance.

Responsibilities and training:

The power plant manager will be responsible for implementing this monitoring plan.
The VCU Manager will be responsible for ensuring that the procedures are followed on site and for continuously improving the procedures to ensure the reliability of the monitoring system.
All staff involved in the VCS project will receive training from the VCU manager. The records of staff training will be retained by the VCU manager. The manager will ensure that only trained staffs are involved in the operation of the monitoring system.
Measuring documenting and archiving procedure

- Records of electricity supplied to the grid will be archived by the VCU manager.
- Copies of the inspection and calibration procedure will be archived by the VCU manager.
- The fuel delivery receipts and the third party analysis regarding the energy content of the fuel will be recorded and kept by the VCU manager.
- All Project information will be archived for a period of two years from the end of the crediting period.

Nonconformance, corrective and preventive actions

- It is the responsibility of the VCU manager to record and resolve nonconformities.
- Any concern for nonconformance will be submitted in writing to the VCU manager.
- Any person can submit a nonconformance petition.
- If a nonconformance petition is found to be justified, corrective and preventive action must be identified and implemented.
- All nonconformance petitions must be answered, justified or not.
- Nonconformance petitions, records of how they were addressed and evaluated,

Corrective and preventive action, and the responses to nonconformance petitions will be archived for at least two years after the crediting period.

5 ENVIRONMENTAL IMPACT

The project will produce energy by using the heat, generated by the existing turbines. It will therefore produce more energy without increasing significantly the pollution. Furthermore, the project is not a Greenfield, but will be built as an additional unit at the Los Mina power plant. The project activity negative environmental impacts are therefore not greater than the Los Mina plant without the project, and are mainly of the construction period and noise of the new turbine:

Impact on the landscape

The project does not have any impact on the landscape, as it is in the boundaries of the plant.

Impact on fauna and flora

The cooling technology that was chosen for the project are Cooling towers with a total make up water consumption of 2,100 GPM. The water studies have been finalized and results show evidence of a reliable source of underground water for Los Mina power plant. The main source of water will be 4 wells at Los Mina site with a capacity of 500 GPM. Additionally there will be a well at Ozama river shore that will serve as a backup.

Due to the backup well at the river the project may have impact on the fauna and flora in the Ozama river when it is used. Permitting process has been started and any requirements and regulations to minimize the environmental impact will be followed.

Impact on air and climate

The plant does not pose any risk of emitting more air pollutants to the environment, as the project is planned to consume the same amounts of fuel, and to reduce the temperatures of emitted air. The fact that more electricity will be generated from the same amount of fuel means that less GHG will be emitted per kWh and therefore the project will have positive impact on mitigating climate change.

Impact on safety

The project does not have any impact on the safety and all continuous monitoring of pollution (liquids, solids and gas) will be carried out in the same way they are being carried out without the project activity.

Noise

The project may have an impact on noise, as the two new HRSGs and the additional turbine will generate noise. During the construction period noise may be created by transportation of material and by construction works.

The project will comply with environmental regulation and any additional requirements made by local authority. An environmental license for the plant's operation together with the project activity, given by the Secretary of Environmental Management, is already given to the plant (DPP's environmental permit, "Permiso Ambiental DEA No.0481-MODIFICADO", 2012).

According to the Secretary of Environmental Management, the Subsecretaria de Gestión Ambiental, (SGA), under the Ministry of Environment, the Secretaría de Estado de Medio Ambiente y Recursos Naturales (SEMARENA), an Environmental Impact Assessment (EIA) is not required for this project activity and the Los Mina plant already holds an updated environmental license which only require the power plant to comply with local regulation and does not include any specific condition.

In consultation with the above mentioned authority it was agreed that the only environmental parameter that may change due to the Project Activity is the noise level. Therefore an environmental noise analysis was commissioned to establish the current baseline and the results will be submitted for evaluation to the environmental authorities. If additional environmental conditions relating to noise impacts will be agreed upon, DPP will comply and act accordingly.

6 STAKEHOLDER COMMENTS

Solicitation of comments from local stakeholders

Analysis of relevant stakeholders was carried out. Invitation letters were sent to specific persons and the public was invited through posters that were hanged in the area, through announcements in local newspapers and through advertisement in the company's website.

Stakeholder meeting was held on Tuesday, June 5, 2012, in which the plant manager (Mr. Adalberto Garcia) and other staff members presented the project and its benefits. The meeting included a comprehensive presentation on: the Los Mina plant, the future VCS project activity and an explanation on the environmental issues concerning the plant. The 31 stakeholders that participated in the meeting had the opportunity to ask questions and give comments regarding any issue they had.

Summary of comments received

In general comments were very positive. No one at the meeting voiced objection to the project activity. Most of the questions concerning the future VCS activity were related to matters regarding possible noise, vibration and water use.

Following is a summary of the answers for the questionnaire, filled by 26 participants.

1) Did you get enough information about this project?

Answer	**Frequency**	**Percentage**
Yes	24	92%
No	2	8%

2) Do you consider this project as positive or negative, overall?

Answer	**Frequency**	**Percentage**
Yes	25	94%
No	1	4%

3) In your opinion, what will be the greatest benefit of the combined cycle project in the DPP Los Mina Power Plant?

Common answers	**Frequency**	**Percentage**
No disadvantage.	7	27%
Noise and vibrations.	6	23%
High water consumption.	4	15%
There will be no reduction in electricity bills.	3	12%
The smoke.	2	8%
No answer.	2	8%

4) Please, rate the following aspects of the combined cycle project in the DPP Los Mina Power Plant concerning to:

a. More electricity produced

Answer	**Frequency**	**Percentage**
Positive	22	85%
Somehow Positive	3	12%
Neutral	1	4%
Somehow Negative	0	0%
Negative	0	0%

b. Lower emissions of Greenhouse Gases in the Production of Electricity

Answer	Frequency	Percentage
Positive	15	58%
Somehow Positive	6	23%
Neutral	5	19%
Somehow Negative	0	0%
Negative	0	0%

c. Contribution to the Country's economy

Answer	Frequency	Percentage
Positive	16	62%
Somehow Positive	5	19%
Neutral	4	15%
Somehow Negative	1	4%
Negative	0	0%

d. Jobs for the locals during the period of construction

Answer	Frequency	Percentage
Positive	15	58%
Somehow Positive	6	23%
Neutral	5	19%
Somehow Negative	0	0%
Negative	0	0%

5) Is there anything else you want to share?

Common answers	Frequency	Percentage
No answer	8	31%
That hired staff should be from the community.	6	23%
There should be a greater social responsibility towards the community.	5	19%
Conduct studies on the ground and vibration.	2	8%

6) Organizations represented:

	Frequency	Percentage
Locals	11	42%
NGO	2	8%
Environmental Organization	1	4%
Local Authority	0	0%
Government Authority	3	12%
Others	9	35%

Report on consideration of comments received

All comments and questions were addressed during the public meeting, and were gathered and documented for further analysis and considerations. DPP management committed to take the concerns that were raised into account and do the outmost to answer and act upon them.