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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

El Canadá Hydroelectric Project

Version 4
Version Date: 18/11/2011

A.2. Description of the project activity:

The El Canadá Hydroelectric Project ("the Project") consists of a 48.11 MW[1] peaking run-of-river hydroelectric plant located on the Samalá River on the west coast of Guatemala, near the town of Santa María de Jesus. The western Guatemala region has 350 MW of demand and 31 MW of installed capacity. Construction began in February 2002 and was completed in December 2003. Since its commissioning, the plant has been producing an average of 194.7 GWh/year of electricity, which is sold to Guatemala's largest commercial distributor, COMEGSA, under a 10-year Power Purchase Agreement (PPA).

The Project contributes to the sustainable development of Guatemala in various ways. First, it has increased the supply of power to the local grid, improving stability and helping reduce losses in the distribution system. Second, it is reducing greenhouse gas emissions as well as emissions of local pollutants from power generation by using a cleaner energy source than what typically would have been used in the country. Third, it is one of the first renewable energy projects to be developed after the approval of Guatemala's new General Electricity Law. Its development has provided important knowledge and experience for other project developers that are striving to participate in the competitive national and regional market. Fourth, through the agreements the Project Company has entered into with the neighboring municipalities, the Project is conserving sub-surface water, it has re-forested parts of the land where it was constructed, and it is making annual payments to improve the conditions of the local communities. Finally, it has created 250 jobs, injecting at least US$ 30 million into the Guatemalan economy over the course of the construction period.

A.3. Project participants:

See Table 1 below for a list of Project Participants

[1] Two turbines with rated capacity of 21.95 MW each, totaling 43.9 MW for the power plant. Each generator has a nameplate capacity of 28.3 MVA with a power factor of 0.85, resulting to generators total maximum output of 48.11 MW.

Table 1: Project Participants

Name of Party involved (*):	Private and/or public entity(ies) Project Participants(*)	Does the Party involved wish to be considered as project participant?
Guatemala (Host Party)	Generadora de Occidente Ltda. (GdO)	No
Canada	International Bank for Reconstruction and Development (IBRD) as the Trustee of the Prototype Carbon Fund (PCF)	Yes
The Netherlands	International Bank for Reconstruction and Development (IBRD) as the Trustee of the Prototype Carbon Fund (PCF)	Yes
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		
Note: *When the PDD is filled in support of a proposed new methodology (forms CDM-NBM and CDM-NMM),* at least the host Party (ies) and any known project participants (e.g. those proposing a new methodology) shall be identified.		

Source: World Bank

Please see Annex 1 for detailed contact information on the project participants.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Guatemala

A.4.1.2. Region/State/Province etc.:

Western Guatemala

A.4.1.3. City/Town/Community etc:

12 miles south of Quetzaltenango Municipality.

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

The Project is located on the Samalá River, 12 kilometers south of the Quetzaltenango Municipality and 198 kilometers due west from Guatemala City. Quetzaltenango is Guatemala’s second largest city and is responsible for a large portion of the 350 MW maximum demand of the western region. The Samalá

River is nearly 130 kilometers in length, and has relatively high flows, due to intense rainstorms over the western slopes of the volcanic mountain ranges that act as the river’s basin. The slopes around the Project are very steep, with small plateaus. The Project is located immediately downstream from the existing Santa María hydro powerhouse owned by the national utility, Instituto Nacional de Electrificación (INDE), and utilizes some of the existing infrastructure.

Figure 1: Project Location

The geographic coordinates for the El Canadá Power House are North: 14°41´08.80” and East: 91°31´53.35”.

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

Grid-connected electricity generation from renewable energy sources.

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

Main Project Characteristics

Equipment Nameplate Data	Parameter	Unit	Value
Turbine	Type	-	Pelton
	Number of units	-	2
	Rated Head (Net)	m	365
	Rated Flow	m^3/s	13.4
	Rated Rotation Speed	r/min	514.29
	Rated Output	MW	43.9 (21.95 each turbine)
Generator	Number of units	-	2
	Rated Power	MVA	48.11 (28.3 each generator)
	Rated Voltage	kV	13.8
	Power factor	%	0.85

Estimated Electricity Generation: 194.7 GWh/year
Powerline: 69 kV

The Project collects power flows from the tailrace of the existing Santa María power plant that is owned by INDE and also collects spillages from the Santa María dam and local inflow from the area between the Santa María dam and the Project diversion dam. All power flows flow through a desander, located immediately downstream of the diversion dam, and are subsequently diverted through a tunnel, three meters in diameter and approximately 1200 m long, to a regulating pond. The regulating pond is designed to collect water inflows for daily peaking operation, totaling 5 hours. The live storage volume is 184,000 m^3, using an 8-meter pond fluctuation. The normal operating level of the reservoir is 1416.90 meters above sea level (masl) and the minimum operating level is 1409 masl. An intake structure on the regulating reservoir is equipped with trash racks and a hydraulically operated gate. The gate is equipped to close during emergency conditions in the event of penstock rupture. The penstock is approximately 2400 m long and conveys the power flows from the regulating reservoir to the powerhouse. The penstock is comprised of a low- and a high-pressure section 1590 and 800 m long, respectively. The penstock is bifurcated into two 1.45-m diameter penstock pipes, approximately 46 m from the powerhouse. The penstock pipe is buried over its total length. The low-pressure penstock diameter is 2.10 m, and the high-pressure section diameter 1.85 m. The El Canadá powerhouse contains two 21.95-MW turbines. Each generating unit has a Pelton turbine and synchronous generator. The powerhouse crane has a capacity at least equal to the heaviest lift during equipment installation of 65 tons. The control room is be air conditioned and separate from the equipment area of the powerhouse. The output from the El Canadá facility is stepped up from 13.8 kV to 69 kV, before it is transmitted to Santa María substation about 3.6 km away for delivery to the INDE utility grid. The transmission line poles are steel and the guard and the power cables are 636 MCM ACSR. Each pole of the transmission line is grounded to provide a resistance of not more than 10 ohms.

All equipment utilized in the El Canadá Project is proven technology that has been successfully applied worldwide. Each of the two generating units has a Pelton turbine and a synchronous generator. The rubber dam used in the diversion dam is a new technology introduced to Guatemala. Rubber dam technology was chosen in order to properly regulate the level at the diversion dam considering the operational restrictions due to being down stream from the Santa Maria powerhouse. This technology also has an added advantage during high volume situations during the wet season, the rubber dam can be

deflated in order to avoid diverting mud, rocks, tree trunks, and other garbage into the desander.

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

(a) Reductions of GHG emissions: The El Canadá Project employs a non-GHG emitting technology (run-of-river hydropower). In the absence of the Project, the same level of demand for electricity would be met by fossil fuel thermal power generation with associated GHG emissions. Due to their high fuel and operating costs, thermal plants, especially older less efficient ones, are generally dispatched as marginal producers of electricity in the Guatemalan system. Their output is, therefore, partly displaced by the Project activity. The average emission reductions achieved by the Project is 130,570 tCO_2 /year.

(b) National and sectoral circumstances: The 1996 General Electricity Law provided for decentralization of the Guatemalan electricity sector, and stipulated that all new electricity generation would be undertaken by private investors. Since then, there have been private investments in thermal power generation, but generation from renewable sources including hydropower, has been lagging. Indeed, the share of thermal generation in the energy mix has grown from 40% to 64% since the 1996 Law. Dispatch in the Guatemalan National Interconnected System (NIS) is by strict economic order, considering the need to supply demand, the opportunity cost of water, and the operational cost of the thermal units. This results in older plants with higher fuel and operating costs usually being dispatched last as peaking plants.

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

Based on the above average annual emission reductions, the net emission reductions over the 21-year crediting lifetime are estimated to be 2,903,061 tCO_2. The annual estimation for the first crediting period is 913,992 tCO_2 .

Year	Annual Estimation of Emission Reduction in tonnes of CO_2e
2003 (December 2003)	8,990
2004	101,471
2005	123,846
2006	138,241
2007	138,241
2008	138,241
2009	138,241
2010 (until November 2010)	126,721
Total Estimated Reductions for First Crediting Period (tonnes CO_2e)	913,992
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	130,570

A.4.5. Public funding of the project activity:

The Project has not received and is not seeking any public funding.

SECTION B. Application of a baseline methodology

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

Approved Consolidated Baseline Methodology (ACM0002): "Consolidated Baseline Methodology for Grid-connected Electricity Generation from Renewable Sources" (ACM0002/Version 6 Sectoral Scope: 1, 19 May 2006).

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

The project activity is a grid-connected run-of-the-river hydropower project and meets all the other conditions stated in ACM002, namely:

- the geographic and system boundaries for the relevant electricity grid can be clearly identified and information on the characteristics of grid is publicly available,

- this project does not involve switching from fossil fuels.

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

In accordance with ACM0002, a baseline emission factor (EF_y) was calculated as a combined margin *(CM),* consisting of the combination of operating margin *(OM)* and build margin *(BM)* factors, following the three steps below:

Step 1. Calculate the Operating Margin emission factor(s)

The operating margin is calculated on the basis of "(a) Simple OM" method.

It was not possible to use the Dispatch Data Analysis method, as recommended by the ACM0002, because the dispatch data made available by the AMM in Guatemala details instantaneous capacity readings for each generator taken on the hour and not the actual hourly energy output. This makes it impossible to build an exact hourly dispatch curve for the top 10% of the operating units.

Based on data on the Guatemalan grid's total generation from 2002 to 2004, low-cost must-run facilities make up less than 50% of the generation during the last three years, and therefore the choice of option (a) is appropriate for this project activity. (see Table 2)

Table 2. Detailed Calculation of the Low-cost Must-run Facilities

		Information Source	**2002**	**2003**	**2004**
Electricity to the NIS	GWh	Annual Statistics Inform AMM	6,191.19	6,561.10	7,009.25
Exports	GWh	Annual Statistics Inform AMM	439.80	427.80	464.20
Hydroelectric	GWh	Annual Statistics Inform AMM	2,110.13	2,176.59	2,547.17
Geothermal	GWh	Annual Statistics Inform AMM	129.99	195.02	194.23
Total cogeneration	GWh	Monthly Transactions Inform AMM	621.12	587.65	606.71
Cogenerators (bagasse)	GWh	Monthly Transactions Inform AMM	398.67	377.51	416.68
Cogenerators (bunker)	GWh	Monthly Transactions Inform AMM	222.45	210.14	190.03
Low operating cost plants (Hydro+geothermal)			36%	36%	39%
Low operating cost & must-run plants (Hydro+geothermal+cogenerators during harvest season)			**45%**	**44%**	**48%**

Calculation of the OM requires the calculation of the CO_2 emission coefficient for all fuels (i) $COEF_i$ as follows:

$$COEF_i = NCV_i * EF_{CO2,i} * OXID_i$$

Where

NCV_i is the net caloric value (energy content) per mass of fuel *i* ,

$OXID_i$ is the oxidation factor of the fuel

$EF_{CO2,i}$ is the CO_2 emission factor per unit of energy of fuel i.

The following information was extracted from the "*Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories Reference Manual*" and the "*IPCC Good Practice Guidance* "as corresponding to Guatemala, when applicable:

NCV:
Diesel Oil = 43.33 TJ / 10^3 Ton
Fuel Oil No. 6 = 40.19 TJ / 10^3 Ton
Orimulsion = 27.5 TJ / 10^3 Ton
Natural Gas = 51.55 10^3 Ton

Carbon emission factors in tC / TJ :
Diesel Oil = 20.2
Fuel Oil No. 6 = 21.1
Orimulsion = 22
Natural Gas = 17.2

Oxidation factor of fuel:
Oil and Oil products = 0.99
Natural Gas = 0.995
Other assumptions were as follows:

- Carbon emissions factor for imports from the El Salvador interconnected system were set at zero.
- Exports of electricity were already included in the total generation of each plant, therefore, no separate emissions factor was calculated for exports.
- In Guatemala, during the November-May harvest season, cogenerators use 70% bagasse and 30% bunker fuel (Heavy Fuel Oil No. 6). The rest of the year, they use only bunker fuel. The emissions factor for bagasse cogenerations is regarded as zero per IPCC guidance. The emissions factor for the cogenerators is calculated based on 30% bunker fuel used during the harvest season and 100% bunker fuel used the rest of the year.
- During the harvest season cogenerators operate as low-cost/ must-run plants because they have "take-or-pay" contracts, which were signed before the 1996 Electricity Law and have been grandfathered.

Considering the above factors, assumptions, and the operation of the Guatemalan power system from 2002 to 2004, and applying the Simple OM method, where the Simple OM emission factor (*EFOM,simple,y*) is calculated as the generation-weighted average emissions per electricity unit (tCO2/MWh) of all generating sources serving the system, not including low-operating cost and must-run power plants:

$$EF_{OM,simple,y} = \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

where
Fi ,j, y is the amount of fuel *i* (in a mass or volume unit) consumed by relevant power sources *j* in year(s) *y*,
j refers to the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants, and including imports5to the grid,
COEFi,j y is the CO_2 emission coefficient of fuel *i* (tCO_2 / mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y, and
GENj,y is the electricity (MWh) delivered to the grid by source *j*.

OM = 0.83 tCO_2 / MWh

Step 2. Calculate the Build Margin emission factor(s)

The BM is calculated as the generation-weighted average emission factor of a sample of power plants, *m*.

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} \cdot COEF_{i,m}}{\sum_{m} GEN_{m,y}}$$

where *Fi,m,y*, *COEFi,m* and *GENm,y* are analogous to the variables described for the simple OM method above for plants *m*. In this case, *m* denotes the capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Option 2 is chosen, where for the first crediting period, the BM emission factor will be updated annually *ex-post* for the year in which actual project generation and associated emission reductions occur. For subsequent crediting periods, the emission factor will be calculated *ex-ante*.

Capacity additions that are applying for CDM registration were excluded, as per the ACM0002.

Table 3 below summarizes the results of the BM calculation.

Table 3. BM emission factor for 20% of system generation

Plant Name	Type	Starting year	Capacity MW	Fuel	Energy during 2004 (GWh)	Fuel consumption TJ/year	emissions (2004) $tC0_2$/year	emissions factor $tC0_2$/ MWH
Pantaleon II	Cogenerators	2004	5	Bagasse	11	33.84	2,592	0.23
Magdalena II	Cogenerators	2004	5	Bagasse	0.7	2.07	159	0.23
Renace	Hydroelectric	2004	60	Water	160	1,584.16	-	-
Electro-generacion	Fuel fired	2004	5	Fuel oil No. 6	82	814.96	62,420	0.76
Amatex	Fuel fired	2003	15	Fuel oil No. 6	8	83.61	6,404	0.76
Arizona	Fuel fired	2003	150	Orimulsion	1,147	9,620.83	760,558	0.66
					1,410	12,139.46	832,133	0.59
Build Margin	0.59							

For 2004, using Option 2:

$$BM = 0.59\ tCO_2\ /\ MWh$$

Step 3. Calculate the baseline emission factor

The baseline emission factor is calculated as the weighted average of the OM and the BM, where the weights, by default, are 50%.

EF = 0.5 * (0.83 + 0.59) = **0.71 tCO_2 / MWh**

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

As prescribed in ACM0002, the additionality of the El Canadá Project was demonstrated and assessed using the latest version of the "Tool for the Demonstration and Assessment of Additionality", dated 22 October, 2004. The step-wise approach provided in the Tool was applied as follows:

Step 0. Preliminary screening based on the starting date of the project activity

(a) The starting date of the El Canadá Project was November 23, 2003, which falls between 1 January 2000 and the date of registration of a first CDM activity. The generation of Emissions Reductions began on this same date.

(b) Documentation exists in the Project files, which provides evidence that the incentives from CDM registration were considered in the decision to invest in the Project. All the information is available to the DOE.

Step 1. Identification of alternatives to the project activity consistent with current laws and regulations

Since the deregulation of the Guatemalan power sector in 1996, of the approximately 690MW of new capacity added to the Guatemalan NIS, 64% has been thermal generation due largely to the lower investment costs and shorter lead times associated with thermal technologies. Given Guatemala's inherent country risk, these conditions are necessary to meet most investor hurdle rates. Based on these past trends, plausible and credible alternatives to the El Canadá Project that could deliver the same level of electricity output, with comparable quality, operating in the same application area, would be thermal generation plants. The Project Company, being a private power developer, would be investing in a capacity expansion in order to maximize return on its investment. Everything else being equal, technologies with the lowest costs per unit of electricity generated are likely to yield the highest returns. At the time of the decision to invest, those technologies that constituted the most economically attractive options for investment in the Guatemalan power sector were coal-fired steam plants and bunker-burning internal combustion motors, as referenced in Annex 3 and demonstrated under Step 2 below.

Step 2. Investment Analysis

The El Canadá Project is determined to be economically less attractive than thermal alternatives without the revenue from the sale of its emission reductions. This conclusion was reached by following the sub-steps below:

Sub-step 2a. Determine apropriate analysis method

The investment comparison analysis was chosen (Option II).

Sub-step 2b. Option II. Apply investment comparison analysis

Unit cost of service (levelized cost of electricity production in $/kWh) was identified as the appropriate financial indicator to be used in comparing alternative investments in the power generation sector.

Sub-step 2c. Calculation and comparison of financial indicators

As identified above under Step 1, the plausible alternative to the El Canadá Project is thermal power generation given lower generation costs that maximize return on a private power developer's investment. Table 4 summarizes the results of the investment comparison analysis performed using generation cost as the financial indicator. On the basis of the data presented, it is reasonable to assume that a least-cost baseload thermal unit would be selected for capacity expansion. A 150 MW coal-fired steam plant

appears to be a reasonably sized generic alternative, given the varied sizes of the existing plants. Since there is no gas available in Guatemala, only coal was considered as fuel. As per Table 4 below, while coal and diesel both provide more attractive alternatives to hydropower, generation costs of coal-fired steam plants are the lowest.

For purposes of further comparison, the generation costs of two other thermal options (a 30 MW gas turbine and a 30 MW diesel motor) are shown, although the least-cost option is the coal-fired steam plant. The calculations show that the generation costs for El Canadá (US$ 48.5/MWh) are higher than for the least-cost thermal option (US$ 38.8/MWh). Therefore, the El Canadá Project is not the most financially attractive investment option.

Table 4: Calculation of Generation Costs for El Canadá and Thermal Options

	Units	El Canadá Hydro	Coal-Fired Steam	Gas Turbine	Diesel Motor
Capacity	MW	48.11	150	30	50
Cost	US$/kW	1392	1200	350	825
Investment	US$ Million	66.98	180.00	10.50	41.25
Global Efficiency	%		40%	32%	41%
Cost of fuels	US$/MBTU		1.55	5.07	3.46
Annual Costs					
Capital	US$million	8.31	22.35	1.30	5.12
O&M Fix	US$million	1.13	4.50	0.30	1.90
Plant factor		0.462	0.80	0.25	0.80
Production	GWh	194.7	1051.2	65.7	350.4
Heat Consumption	b. BTU		8967	701	2916
Cost of fuels	US$million		13.90	3.55	10.09
Total costs	US$million	9.44	40.74	5.16	17.11
Generation Cost	**US$/MWH**	**48.5**	**38.8**	**78.5**	**48.8**

Assumptions:
Economic Parameters: Discount Rate: 12% p.a., Useful life of Plants: 30 years
Investment costs of equipment: Costs in US$/kW are net, without financial charges
Efficiency and plant factor of equipment: Based on state-of-the-art of the equipment and reasonable utilization
Price and heat rate of fuels:
Coal: US$ 40/t; heat rate 6500 kcal/kg; Heat cost: US$ 6.15 million Kcal= US$ 1.55 mBTU.
Fuel Oil: US$ 134/t; heat rate: 9700 kCal/Kg, US$ 13.8/mKcal; US$ 3.46/MBTU.
Diesel Oil: US$ 206/t; heat rate 10.200 kCal/Kg; US$ 20.2 mkCal, US$ 5.07/mBTU

The generation costs for each plant were calculated following the EPRI TAG [2] method, as

$$COE = \frac{CRF * I + O\&M}{E}$$

Where,

[2] EPRI: Edison Power Research Institute

COE: Levelized Cost of Energy
CRF: Capital Recovery Factor for Discount Rate *i* and Number of Years *n* (equivalent to the useful life of the plant)
I: Plant total investment accumulated by commissioning date
O & M: Annual Operation and Maintenance Costs of the Plant
E: Average Annual Energy [3]

And,

$$CRF = \frac{i*(1+i)^n}{(1+i)^n - 1}$$

Sub-step 2d. Sensitivity analysis

The conclusion in Sub-step 2c regarding the financial attractiveness of the El Canadá Project was subjected to three reasonable variations in the critical assumptions. In each of the three sensitivity tests, the conclusion remained robust to the variations that were introduced.

In the first test, the assumption regarding the discount rate was lowered from 12% to 10%, and the useful life of the project also lowered from 30 years to 20 years. The results are summarized in Table 5 below:

Table 5: First Sensitivity Test with Lower Discount Rate and Shorter Useful Life

	Units	El Canadá Hydro	Coal-Fired Steam	Gas Turbine	Diesel Motor
Capacity	MW	48.11	150	30	50
Cost	US$/kW	1392	1200	350	825
Investment	US$ Million	66.98	180.00	10.50	41.25
Global Efficiency	%		40%	32%	41%
Cost of fuels	US$/MBTU		1.55	5.07	3.46
Annual Costs					
Capital	US$million	7.87	21.14	1.23	4.85
O&M Fix	US$million	1.13	4.50	0.30	1.90
Plant factor		0.462	0.80	0.25	0.80
Production	GWh	194.7	1051.2	65.7	350.4
Heat Consumption	b. BTU		8967	701	2916
Cost of fuels	US$million		13.90	3.55	10.09
Total costs	US$million	8.99	39.54	5.08	16.83
Generation Cost	**US$/MWH**	**46.2**	**37.6**	**77.4**	**48.0**

<u>Assumptions:</u>
Economic Parameters: Discount Rate: 10% p.a., Useful life of Plants: 20 years
Investment costs of equipment: Costs in US$/kW are net, without financial charges
Efficiency and plant factor of equipment: Based on state-of-the-art of the equipment and reasonable utilization
Price and heat rate of fuels:
Coal: US$ 40/t; heat rate 6500 kcal/kg; Heat cost: US$ 6.15 million Kcal= US$ 1.55 mBTU.
Fuel Oil: US$ 134/t; heat rate: 9700 kCal/Kg, US$ 13.8/mKcal; US$ 3.46/MBTU.

[3] If costs are expressed in US$ million and Energy in GWh then the levelized generation cost results expressed in US$/MWh

Diesel Oil: US$ 206/t; heat rate 10.200 kCal/Kg; US$ 20.2 mkCal, US$ 5.07/mBTU

In the second test, the assumption regarding the investment cost was increased by 10% for the thermal generation options. The results are summarized in Table 6 below:

Table 6: Second Sensitivity Test with Higher Investment Costs for Thermal Generation

	Units	El Canadá Hydro	Coal-Fired Steam	Gas Turbine	Diesel Motor
Capacity	MW	48.11	150	30	50
Cost	US$/kW	1392	1320	385	907.5
Investment	US$ Million	66.98	198.00	11.55	45.38
Global Efficiency	%		40%	32%	41%
Cost of fuels	US$/MBTU		1.55	5.07	3.46
Annual Costs					
Capital	US$million	8.31	24.58	1.43	5.63
O&M Fix	US$million	1.13	4.50	0.30	1.90
Plant factor		0.462	0.80	0.25	0.80
Production	GWh	194.7	1051.2	65.7	350.4
Heat Consumption	b. BTU		8967	701	2916
Cost of fuels	US$million		13.90	3.55	10.09
Total costs	US$million	9.44	42.98	5.29	17.62
Generation Cost	**US$/MWH**	**48.5**	**40.9**	**80.4**	**50.3**

Assumptions:

Economic Parameters: Discount Rate: 12% p.a., Useful life of Plants: 30 years

Investment costs of equipment: Costs in US$/kW are net, without financial charges

Efficiency and plant factor of equipment: Based on state-of-the-art of the equipment and reasonable utilization

Price and heat rate of fuels:

Coal: US$ 40/t; heat rate 6500 kcal/kg; Heat cost: US$ 6.15 million Kcal= US$ 1.55 mBTU.

Fuel Oil: US$ 134/t; heat rate: 9700 kCal/Kg, US$ 13.8/mKcal; US$ 3.46/MBTU.

Diesel Oil: US$ 206/t; heat rate 10.200 kCal/Kg; US$ 20.2 mkCal, US$ 5.07/mBTU

In the third and final sensitivity test, the assumption regarding the plant capacity factor for El Canadá was lowered from 46.2% to 40%. The results are summarized in Table 7 below:

Table 7: Third Sensitivity Test with Lower Plant Capacity Factor for El Canadá

	Units	El Canadá Hydro	Coal-Fired Steam	Gas Turbine	Diesel Motor
Capacity	MW	48.11	150	30	50
Cost	US$/kW	1392	1200	350	825
Investment	US$ Million	66.98	180.00	10.50	41.25
Global Efficiency	%		40%	32%	41%
Cost of fuels	US$/MBTU		1.55	5.07	3.46
Annual Costs					
Capital	US$million	8.31	22.35	1.30	5.12
O&M Fix	US$million	1.13	30	10	38
Plant factor		0.40	0.80	0.25	0.80
Production	GWh	168.6	1051.2	65.7	350.4
Heat Consumption	b. BTU		8967	701	2916
Cost of fuels	US$million		13.90	3.55	10.09
Total costs	US$million	9.44	40.74	5.16	17.11
Generation Cost	**US$/MWH**	**56.0**	**38.8**	**78.5**	**48.8**

Assumptions:

Economic Parameters: Discount Rate: 12% p.a., Useful life of Plants: 30 years

Investment costs of equipment: Costs in US$/kW are net, without financial charges

Efficiency and plant factor of equipment: Based on state-of-the-art of the equipment and reasonable utilization

Price and heat rate of fuels:

Coal: US$ 40/t; heat rate 6500 kcal/kg; Heat cost: US$ 6.15 million Kcal= US$ 1.55 mBTU.

Fuel Oil: US$ 134/t; heat rate: 9700 kCal/Kg, US$ 13.8/mKcal; US$ 3.46/MBTU.

Diesel Oil: US$ 206/t; heat rate 10.200 kCal/Kg; US$ 20.2 mkCal, US$ 5.07/mBTU

As a result of the three sensitivity tests above, the sensitivity analysis concluded that the El Canadá Project was unlikely to be the most financially attractive investment option.

Step 3. Barrier Analysis

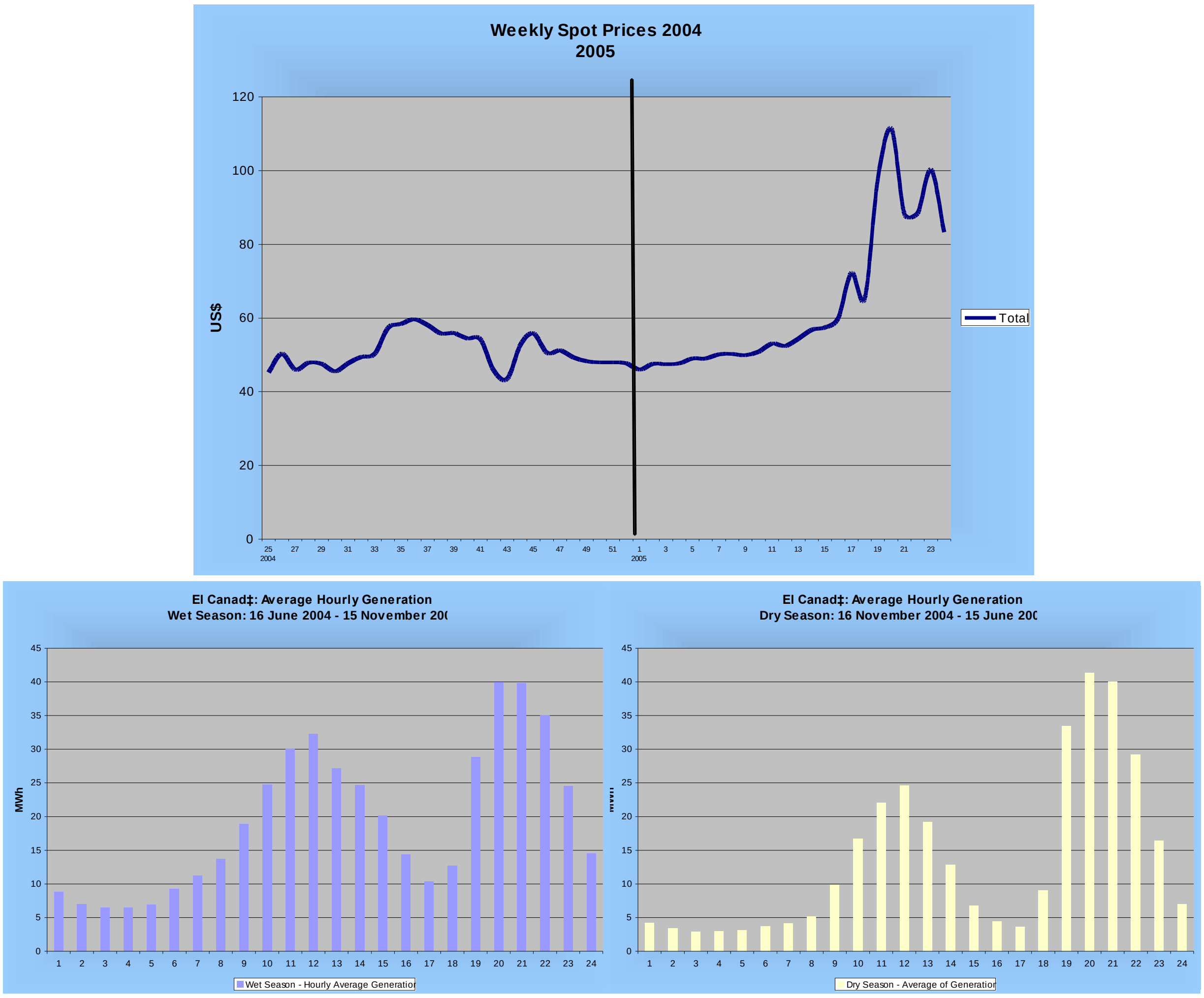
As mentioned in Step 1 and demonstrated in Annex 3, a large proportion of new capacity additions to the Guatemalan NIS since the deregulation of 1996 have been thermal-based. Many of them burn bunker fuel in medium velocity internal combustion engines for baseload, and gas for peaking power generation. Only slightly more than one-third of new additions were renewable-based, which were primarily run-of-the-river hydro peaking facilities. The heavy influx of thermal generation is due largely to the lower investment costs and shorter lead times associated with thermal technologies, which, given Guatemala's inherent country risk, are necessary to meet most investor hurdle rates.

While the generation costs for a diesel motor may seem similar in Table 4 above to the generation costs of the El Canadá hydroelectric plant, again, the risk associated with hydroelectric generation is higher than most thermal generation including diesel motors. This is due to the fact that even though hydroelectric generation bears no fuel costs, unlike thermal generation, availability of fuel is determined by external conditions such as hydrology, which are outside the control of a project developer.

A related factor that has hindered renewable investments is the relation between system pricing and seasonal hydro resource availability. Guatemala has two very pronounced seasons - a wet season ranging from May to November and a dry season from December through April. System pricing is determined by a variable-cost dispatch model that optimizes system operation through the use of available hydro/thermal facilities. System pricing is, therefore, inversely proportional to seasonal hydrology, so that prices are lower during the wet season when more water is available, and prices are higher in the dry season due to a decrease in water flows. The inverse relationship between prices and seasonal hydrology greatly increases the risk profile for hydro facilities because prices are low when the facilities have abundant generation and prices are high when generation is low due to lack of water. This, in turn, limits the competitiveness of hydro facilities in signing long-term contracts as they must assume the added risk of having to purchase highly volatile replacement energy in the spot market during the dry season.

The situation described above can be observed in Figure 2 below, which plots weekly spot prices for each hourly band (Peak, Off-peak, and Shoulder) from June 2004 – 2005. As Figure 2 indicates, during the June-November 2004 wet season electricity prices were lower, whereas during the November-June dry season prices were much higher, particularly from April through June when prices spiked to $220 for several weeks. This demonstrates the point made above, where as a hydroelectricity generator, the El Canadá Project, would have been buying power in the Spot Market to cover its contractual obligations; whereas, thermal units would have simply generated power since all they had to do was to acquire adequate supplies of fuel oil or coal.

Figure 2: Weekly Spot Prices (2004-2005) and Average Hourly Generation



In addition, owners of hydroelectric facilities assume total market/regulatory risk. Thermal plants however, have some flexibility to move facilities if the market/regulatory environment changes. In fact, Duke Energy International recently dismantled and moved its facilities from Guatemala to El Salvador where market conditions were more beneficial.

Hydroelectric plants face increased financial barriers. Development of the El Canada Hydroelectric Project began in the last half of 1999. In October of 1999, the special purpose Guatemala company was formed – Generadora de Occidente Limitada ("GdO"), in order to apply for and obtain the necessary rights and permits for the project, including, Environmental Impact Assessment, Water Concession, Land rights, as well as the initial technical feasibility study. At that time, GdO was a subsidiary of Energia Global International ("EGI"), a corporation with mainly US investors. EGI was a small company concentrating on developing and owning environmentally friendly, renewable energy projects in Central America. As a small, early-stage company, EGI had very limited liquidity and carried a large amount of debt from international financial institutions including OPIC and GE Capital. In 1999 the company's consolidated debt was greater than US$60 million. Upon finalizing the feasibility study near the end of 2000, EGI recognized the need to secure 3rd party financing for the project to proceed. At that time, the conditions for project financing in Guatemala were complicated, and the local market lacked the liquidity

and experience to lend to projects such as El Canada. Local banks seldom offered terms of more than 5 years and interest rates were close to 10%. Based on the above conditions, EGI realized that for the project to be feasible it would have to secure the required US$37 million loan from international banks, specifically from the multi and bilateral lending institutions. After one year of negotiations and corresponding due diligence, on January 31, 2002, the project signed a letter of intent with the IFC on a best efforts basis, to syndicate the loan. Both IFC and EGI, considered the additional cash flows from the potential sale of emission reductions as part of the review. The parties singed the Loan Agreement one year later on December 12, 2002 and IFC was able to arrange for a loan of US$ 27 million, US$ 15 million directly from IFC and US$ 12 million from FMO. The first disbursement was on January 14, 2003. In retrospect, the project finalized the development phase in December 2001, and construction was scheduled to begin in February 2002. However, due to the long lead time for securing financing, 24 months, construction was being delayed. As a result, the project was in danger of defaulting on the PPA with COMEGSA. Only the intervention of ENEL through the purchase of EGI, let the project maintain its timetable for completion. In addition, if not for the inclusion of the cash flows from the sale of ERs, the project may not have met ENEL's requirement for a project in Guatemala. Financing for renewable energy projects is still a strong barrier as the process is very slow, expensive and legally complex.

It is also worth mentioning here that the El Canadá Project was evaluated on a merchant basis, taking into account the impact of a deregulated competitive electric market. The power contract the Project has with COMEGSA does not, in any way, offer the "security" associated with traditional PPA's. There is no sovereign guarantee, no take-or-pay provision, nor buy -out clause in the contract. The contract simply provides for a payment and contract compliance guarantee, which, if the contract were rescinded, would provide "make-up" income for the two year period it is estimated, would be necessary in order to rebuild an off-taker portfolio in similar terms to the COMEGSA contract. Furthermore, under the COMEGSA agreement, El Canadá is still subject to the hydrological risk and must make-up any deficits in on-peak energy through spot market purchases. As explained above, the Project must purchase replacement power when prices are high and has excess energy during the wet season when prices are low. The Contract with COMEGSA also explicitly refers to CDM reductions and requires that the project entity transfer 12.5% of the resulting benefits from such reductions to COMEGSA. This situation confirms El Canada's exposure to technology and pricing barriers.

Step 4. Common Practice Analysis

Sub-step 4a. Analyze other activities similar to the proposed project

As shown in Table 2, activities similar to the El Canadá Project, i.e. privately developed, small, hydroelectric power generation, that are not CDM projects, do not yet prevail in Guatemala.

Sub-step 4.b. Discuss any similar options that are occurring

Most of Guatemala's generation capacity expansion since 1997 has been thermal, as shown in Table A3.1 of Annex 3. When the project go-ahead decision was made in 2001, hydro expansion represented only 8% (35MW) of capacity additions in the previous 5 years (1996-2001), whereas thermal-bunker C units represented 87% (378MW) and geothermal 5% (22MW) during this same time period. Given the higher capital costs and associated project and operating risks of hydroelectric power generation, the trend of capacity additions through thermal plants is likely to continue in the foreseeable future.

Step 5. Impact of CDM Registration

As demonstrated in Sub-step 2c and 3 above, the El Canadá Project was not the most financially attractive investment option for the project company unless certain benefits and incentives could be derived from undertaking this particular type of activity: zero-emissions power generation from a

renewable energy source. The financial benefit from the sale of CERs was a crucial factor in the initial decision to invest in this type of, otherwise financially unattractive, activity. The potential CER revenue stream has been factored into the Project's earliest cash flow analyses since conception as shown in step 0. These revenues are of fundamental importance to the Project's viability as they constitute a long term contract, with payments of hard currency made outside Guatemala, thus mitigating country risk. This important leverage provided by the CDM registration was acknowledged by the IFC in its decision-making on the debt financing of the Project.

As all the above steps are satisfied, it is thus demonstrated that the proposed CDM activity is not part of the baseline scenario and, therefore, it is additional.

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

Consistent with the definition provided in ACM0002, the spatial extent of the project boundary consists of the El Canadá Project site, (including the tunnel, regulating pond, penstock, powerhouse) and all power plants connected physically to the same electricity system the Project is connected to (the Guatemalan national electricity grid, i.e. the NIS).

In determining the BM, the spatial extent of the project boundary was limited to the project electricity system; i.e. the set of power plants that can be dispatched without significant transmission constraints. In determining the OM, the emission factor for imports from the connected electricity system in El Salvador was 0 tCO_2/MWh.

As per ACM0002, electricity exports were not subtracted from electricity generation data used for calculating and monitoring the baseline emissions rate.

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

Date of completion is October 20, 2005. Baseline was determined by:

Prototype Carbon Fund
Contact: Joelle Chassard (jchassard@worldbank.org)

and,

Generadora de Occidente, Ltda.
Contact: Rene Oswaldo Smith Gonzalez (oswaldo.smith@enel.com)

SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

11/23/2003.

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

50 years.

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

C.2.1. Renewable crediting period

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

11/23/2003.

C.2.1.2. Length of the first crediting period:

7 years.

C.2.2. Fixed crediting period: Not applicable.

C.2.2.1. Starting date:

>>

C.2.2.2. Length:

SECTION D. Application of a monitoring methodology and plan

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

Approved Consolidated Monitoring Methodology (ACM0002): "Consolidated Monitoring Methodology for Zero-Emissions Grid-connected Electricity Generation from Renewable Sources" ACM0002/Version 6 Sectoral Scope: 1, 19 May 2006).

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

This monitoring methodology is used in conjunction with the Approved Consolidated Baseline Methodology (ACM0002), which is the baseline methodology chosen for the Project. The ACM0002 monitoring methodology is applicable to electricity capacity additions from run-of-river hydroelectric plants such as El Canadá. Moreover, the geographic and system boundaries of the Guatemalan national electricity grid can be clearly identified, and information on the characteristics of the grid is available from the AMM.

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

The key features of the application of this Option are:

- Monitoring of monthly and annual electricity generated by the Project and sold to the grid;
- At the renewal of each crediting period, determination of the OM emission factor (weighted average excluding low-cost/must run sources);
- At the renewal of each crediting period, determination of the BM emission factor (weighted average of the most recently built plants that comprise 20% of the grid generation;
- At the renewal of each crediting period, determination of the CM;
- Correction of emission factors due to electricity imports and exports, as necessary;
- At the renewal of each crediting period, confirmation that the Project meets applicability requirements, especially with regards to additionality.

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

As there are no project emissions, no data needs to be collected.

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

As there are no project emissions, no formulae are provided.

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :

ID number (Please use numbers to ease cross-referencing to table D.3)	*Data variable*	*Source of data*	*Data unit*	*Measured (m), calculated (c) or estimated (e)*	*Recording frequency*	*Proportion of data to be monitored*	*How will the data be archived? (electronic/ paper)*	*Comments*
1	Net Electricity supplied to the grid by both El Canada and Montecristo Plants (E1)	GdO	MWh	(m)	monthly	100%	Electronic and paper. Data will be archived during the crediting period and 2 more years.	Official metering data sent monthly to the AMM *. Invoices to the final buyer COMEGSA have to match official metering data to AMM. There is one principal meter and back meter installed in the El Canada substation. The backup meter readings will be used in case of problems with the main meter and also to cross check with the principal meter readings. The meters are calibrated as per the requirements of the norm ANSI C12.20.

2	Net Electricity supplied to the grid by Montecristo Hydroelectric Plant (E2)	GdO	MWh	(m)	monthly	100%	Electronic and paper. Data will be archived during the crediting period and 2 more years.	Official metering data sent monthly to the AMM *. Invoices to the final buyer COMEGSA have to match official metering data to AMM. There is one principal meter and back meter installed in the Montecristo substation. The backup meter readings will be used in case of problems with the main meter and also to cross check with the principal meter readings. The meters are calibrated as per the requirements of the norm ANSI C12.20.
3	Net Electricity supplied by the project to the grid (EGy)	GdO	MWh	(c)	monthly	100%	Electronic and paper. Data will be archived during the crediting period and 2 more years	The net electricity supplied by the project to the grid is calculated based on the difference between the meter readings of E! and E2. Hence, EGy = E1 – E2*.

*El Canadá Hydroelectric plant is located 2 km upstream from Montecristo plant. The electricity produced by the Montecristo Hydroelectric plant is transformed from 13.8 kV to 69 kV in an own substation and then is delivered to the 69 kV busbar of El Canadá Substation, through a 69 kV line, whose length is of 2.8 km. The reason of the connection of Montecristo power plant to the grid, through El Canadá substation, was to reduce investment costs using the same line to export the electricity from El Canadá substation to the grid and to reduce the environmental impacts.

Each power plant has its own electricity meter to read the net electricity supplied to the grid, El Canadá Electricity Meter is located in the 69 kV busbar of El Canadá Substation and the Montecristo Electricity Meter is located in the 69 kV busbar of Montecristo Substation. The 69 kV busbar of El Canadá Substation was chosen as the sale busbar for both plants, but the net electricity supplied to the grid by each plant is commercialized separately and in different way in the electricity market.

The monthly net electricity supplied to the grid will be collected from the commercial energy meter installed in the El Canada Substation (installed on 19 November 2003), which measures the net electricity supplied by both El Canada Hydroelectric Project and Montecristo Hydroelectric Projects and in the Montecristo Substation in the 69 KV busbar which measures net electricity supplied to the grid by the Montecristo Hydroelectric Project alone (installed on 14 May 2006 and started supplying to the grid from the same month through El Canada substation meter, evidence for the same submitted to DOE), therefore the net electricity supplied by the El Canadá Hydroelectric Project will be calculated by the difference.Net Electricity supplied by the project activity to the grid (EGy) = Meter reading at El Canada Hydro 69 kV substation – Meter reading at Montecristo 69 kV substation.

The generation data is reported in a spreadsheet for measuring control and register. The commercial meter data collection of the monitored month takes place during the first week of the following month. **D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)**

The formulae and the algorithms to be used are the same described in section B.2. of this PDD:

OM is calculated *ex-ante*, using the Simple OM Method of the approved methodology.

BM is calculated *ex-ante*, using the algorithm described in the approved methodology.

CM is equal to the simple average of the OM and the BM, as indicated in the approved methodology.

CM is multiplied by the net annual electricity generation, which yields the new baseline emissions.

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

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

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

D.2.3. Treatment of leakage in the monitoring plan

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

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

Indirect emissions can result from project construction, transportation of materials and fuel and other up-stream activities. In the case of the proposed Project, these emissions are thought to be comparable to the life cycle emissions that would result from the eventual construction and operation of alternative capacity. The life-cycle emissions of alternative power generation plants, in particular of fossil fuel power plants, are typically higher than from hydro power plants when including emissions due to the mining, refining and transportation of fossil fuel. The Project does not claim emission reductions from these activities. Therefore, no significant net leakage from the above activities was identified.

Project emissions in the form of methane can also result from the construction and operation of a water reservoir if biomass is permanently submerged in this process. The Project is a run-of-the-river hydropower plant, therefore it does not have a reservoir that allows biomass emissions and its eventual conversion to methane.

Thus, no sources of emissions were identified, and therefore no data will be collected and archived.

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

The Project targets only CO_2 emissions and will not claim the reductions of other GHGs included in Annex A of the Kyoto Protocol. Additionally, the Project has not been identified as a source of emissions of any of these GHGs.

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

The Project is a hydropower project; it does not give rise to direct GHG emissions. Therefore, no formulae for calculation of direct emissions are provided here.

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

Data (Indicate table and ID number e.g. 3.-1.; 3.2.)	*Uncertainty level of data (High/Medium/Low)*	*Explain QA/QC procedures planned for these data, or why such procedures are not necessary.*
D.3.1 Net Electricity supplied to the grid by El Canada and Montecristo Plants	Low	There is one principal and backup meter. The Serial number of the principal meter - PT-0511A048-0; For the back-up meters: Serial Number is 85 762 983. The meters are calibrated yearly to fulfill the requirements of the norm ANSI C12.20. Official metering data will be sent monthly to the AMM. Invoices to the final buyer COMEGSA will have to match the official metering data to AMM.
D.3.2 Net Electric supplied to the grid by Montecristo Hydroelectric Plant	Low	There is one principal and backup meter. The Serial number of the principal meter - PT-0511A045-000; For the back-up meters: Serial Number is 85 762 982. The meters are calibrated yearly to fulfill the requirements of the norm ANSI C12.20. Official metering data will be sent monthly to the AMM. Invoices to the final buyer COMEGSA will have to match the official metering data to AMM
D.3.3 Net Electricity supplied by the project to the grid.	Low	Calculated based on the readings of meters installed for parameters D3.1 and D3.2.

According to the NCC-14 clause 14.12 "Periodic Verifications" the principal and supporting meters need to be checked every year for the fulfillment of the requirement of the Administrador del Mercado Mayorista, AMM (Wholesale Market Administrator) or of the manufacturer. Generadora de Occidente, Ltda. Every as per the requirements of the norm ANSI C12.20. The meters are certified by a company that is approved by the AMM.

Also Generadora Montecristo, S.A. as same of Generadora de Occidente, Ltda. every year proceed to the calibration of the meters of energy, the principal meter and the support meter; in order to verify that the meters fulfill the requirements of the norm ANSI C12.20. The meters were certified by a company that is approved by the AMM.

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

The management and operation of the Project are the responsibility of GdO. For calculating the ERs, GdO relies on data issued by the AMM based on the actual operation of the NIS. Independent verifiers will periodically audit the operational and management systems to ensure credibility and transparency of the reported ERs and other performance indicators of the Project.

Components of the operational and management structure implemented by GdO are:

- A transparent system for the collection, computation and storage of data, including adequate record keeping and data monitoring systems;
- Clear procedures and protocols for collection and entry of data, use of workbooks and spreadsheets and any assumptions made, so that compliance with requirements can be assessed by a third party. Paper-based systems are also used as back-ups in the event of electronic system failures;
- A competent Project Manager, who is in charge of, and accountable for, the generation of data, monitoring, record keeping, and computation of ERs, and of audits and verification. He officially signs all worksheets;
- Regular reporting to the PCF via copies of completed worksheets, semi-annual ER statements, and brief annual ER reports, as set forth in the Emission Reductions Purchase Agreement (ERPA), while maintaining originals on file;
- Internal training to staff to enable them to undertake the tasks required by the MP.

In El Canada Substation, the Plant Manager is responsible to collect electronically and monthly the electricity supplied to the grid data from the commercial energy meter installed in the El Canada Substation, which measures the energy supplied to the grid by both El Canada Hydroelectric Project and Montecristo Hydroelectric Project. In the Montecristo Substation, again the plant manager of the Montecristo plant is responsible to collect the electricity supplied to the grid by the Montecristo Hydroelectric Project in the 69 KV bus , therefore the electricity supplied to the grid by the El Canadá Hydroelectric Project can be calculated by difference of two substation meter readings.

In both substations, the generation data is reported in a spreadsheet for measuring control and register. The commercial meter data collection of the monitored month takes place during the first week of the following month.

Calibration certificates for both the meters are available.

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

Prototype Carbon Fund
Contact: Joelle Chassard (jchassard@worldbank.org)

Generadora de Occidente, Ltda.
Contact: Rene Oswaldo Smith Gonzalez (oswaldo.smith@enel.com)

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

Since the El Canadá Project is a run-of-river hydropower plant, it does not give rise to direct GHG emissions.

E.2. Estimated leakage:

No leakage was identified.

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

The sum is zero.

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

Following the ACM0002 in Section B above, baseline emissions are calculated by multiplying the net annual generation of the Project with the baseline emission rate.

Baseline emissions = (194,707 MWh) * (0.71 tCO_2/MWh) = **138,241 tCO_2**

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

Since the project emissions and leakage are zero, the Project's emission reductions are those calculated in E.4., i.e. 130,570 tCO_2 / year on average.

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

Table 4: Emission Reductions

Year	Estimation of project activity emissions reductions (tonnes of CO_2e)	Estimation of baseline emission reductions (tonnes of CO_2e/MWh)	Estimation of Leakage (tonnes of CO_2e)	Estimation of Emission Reductions (tonnes of CO_2e)
2003	0	8,990	0	8,990
2004	0	101,471	0	101,471
2005	0	123,846	0	123,846
2006	0	138,241	0	138,241
2007	0	138,241	0	138,241
2008	0	138,241	0	138,241
2009	0	138,241	0	138,241
2010	0	126,721	0	126,721
Total	**0**	**913,992**	**0**	**913,992**

SECTION F. Environmental impacts

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

An Environmental Impact Assessment (EIA) was prepared and approved by the National Environmental Commission (CONAMA), in accordance with Guatemalan law governing new electricity generation projects. The EIA was also reviewed and cleared by the International Finance Corporation (IFC) as fully complying with this financing institution's environmental and social safeguards policies.

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

The environmental impacts of the Project are considered insignificant.

SECTION G. Stakeholders' comments

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

IFC carried out and prepared the Project Environmental and Social Review, which was published on the IFC web site and in the local press. This review was also available for public discussion in the El Palmar and Zunil municipalities. If required, the IFC documentation regarding the process is available for DOE review at the ENEL offices in Guatemala City.

G.2. Summary of the comments received:

No concerns about the Project were voiced by the local stakeholders during the process described above.

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

No concerns about the Project were voiced.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The Project has not received and is not seeking any public funding.

Annex 3

BASELINE INFORMATION

Table A3. 1. Installed Capacity in the Guatemalan NIS

GENERATION PLANTS	UNITS	CAPACITY			LOCATION	
		NAME PLATE (MW)	EFFECTIVE (MW)	DATE OF INSTALLATION	MUNICIPALITY	DISTRICT
NATIONAL INTEGRATED SYSTEM		**1,978.1**	**1,727.4**			
HYDROELECTRIC		**722.6**	**655.3**			
CHIXOY	5	300.0	275.0	Nov-83	San Cristóbal Pueblo Nuevo	Alta Verapaz
AGUACAPA	3	90.0	80.0	Feb-82	Viñas	Santa Rosa
JURÚN MARINALÁ	3	75.0	60.0	Feb-70	Palín San Pedro	Escuintla
RENACE	3	63.0	60.0	Mar-04	Carchá	Alta Verapaz
EL CANADÁ	2	48.1	47.4	Nov-03	Zunil	Quezaltenango
LAS VACAS	1	45.7	43.5	May-02	Chinautla	Guatemala
SECACAO	1	16.5	15.0	Jul-98	Senahú	Alta Verapaz
ESCLAVOS	2	15.0	14.0	Aug-66	Cuilapa	Santa Rosa
PASABIEN	2	12.8	12.3	Jun-01	Río Hondo	Zacapa
MATANZAS	1	12.0	11.7	Jul-02	San Jerónimo Quebradas,	Baja Verapaz
RIO BOBOS	1	10.0	10.0	Aug-95	Morales Pueblo Nuevo	Izabal
POZA VERDE	2	8.4	8.0	Jun-01	Viñas	Santa Rosa
SISTEMA MICHATOYA	5	6.7	1.0	Oct-27	Escuintla	Escuintla
SANTA MARÍA	3	6.9	6.0	Jun-66	Zunil	Quezaltenango
SAN ISIDRO	2	3.9	3.9	Jul-02	San Jerónimo	Baja Verapaz
EL PORVENIR	1	2.3	2.0	Sep-68	San Pablo	San Marcos
CHICHAIC	2	0.6	0.5	Jul-79	Cobán	Alta Verapaz
PALIN II	2	5.8	5.0	Jul-05	Palín	Escuintla
THERMAL		**1255.5**	**1072.2**			
STEAM TURBINES		**192.0**	**132.0**			
SAN JOSÉ	1	139.0	132.0	Jan-00	Masagua	Escuintla
ESC.VAPOR 2	1	53.0	0.0	Apr-77	Escuintla	Escuintla

GAS TURBINES		**197.9**	**132.9**			
TAMPA STEWART &	2	80.0	77.9	Jun-95	Escuintla	Escuintla
STEVENSON	1	51.0	23.0	Dec-92	Escuintla	Escuintla
ESC.GAS 5	1	41.9	15.0	Nov-85	Escuintla	Escuintla
ESC.GAS 3	1	25.0	17.0	Aug-76	Escuintla	Escuintla
INTERNAL COMBUSTION MOTORS		**646.4**	**593.0**			
ARIZONA	10	165.0	150.0	May-03	San José	Escuintla
LA ESPERANZA	7	129.4	124.7	May-00	Puerto Quetzal	Escuintla
PQPC	20	118.0	114.4	Jun-93	Puerto Quetzal	Escuintla
LAS PALMAS	5	66.8	65.0	Sep-98	Escuintla	Escuintla
SIDEGUA	10	44.0	34.2	Jun-95	Escuintla	Escuintla
GENOR GENERADORA	2	46.2	31.8	Oct-98	Puerto Barrios	Izabal
PROGRESO	1	22.0	20.4	Jun-93	Sanarate	El Progreso
LAGOTEX	3	25.0	25.0	Jul-96	Amatitlán	Guatemala
AMATEX	2	15.0	12.5	Nov-03	Amatitlán	Guatemala
ELECTROGENERACIÓN	2	15.0	15.0	Nov-03	Amatitlán	Guatemala
SUGARCANE BAGASSE COGENERATION		**190.3**	**187.8**	**1992 - 1996**	**Varios**	**Escuintla**
PANTALEÓN		38.5	38.5			Escuintla
SANTA ANA		33.8	33.8			Escuintla
LA UNIÓN		29.5	29.5			Escuintla
CONCEPCIÓN	1	27.5	27.5			Escuintla
MADRE TIERRA		19.0	19.0			Escuintla
MAGDALENA		21.0	21.0			Escuintla
TULULA		19	16.5			Suchitepequez
SAN DIEGO		2	2.0	Dec-04		Escuintla
GEOTHERMAL		**29.0**	**26.5**			
ZUNIL	1	24.0	22.0	Aug-99	Zunil San Vicente	Quezaltenango
CALDERAS	1	5.0	4.5	Dec-02	Pacaya	Guatemala

Fuel Consumption per plant.

Plant	AVAILABLE MW	Starting year	Energy produced (GWh) 2004	Fuel	Net caloric values TJ/103 tonnes	Fuel Consumption 2004 TJ/year
	AMM		AMM Statistic Report, Economic Transactions Reports 2004	Plant data	Inventory Workbook (IPCC, 1996)	
STEAM TURBINES	**174.9**		**1,029.96**			**11,682**
SAN JOSÉ	128.9	2000	1,029.96	Coal		11,682
ESCUINTLA VAPOR 2	24.0	1977	-	Fuel oil No.6	40.19	-
LAGUNA VAPOR 3	11.0	1959	-	Fuel oil No.6	40.19	-
LAGUNA VAPOR 4	11.0	1961	-	Fuel oil No.6	40.19	-
GAS TURBINES	**186.3**		**7.02**			**95**
TAMPA	79.3	1995	1.87	Diesel	43.33	19
STEWART & STEVENSON	23.0	1992	2.11	Diesel	43.33	27
ESC.GAS 5	15.0	1985	0.52	Diesel	43.33	8
LAG. GAS 4	27.0	1989	-	Diesel	43.33	-
ESC.GAS 3	17.0	1976	0.95	Diesel	43.33	15
ESC.GAS 4	*	1976	-	Diesel	43.33	-
LAGUNA GAS 2	17.0	1978	-	Diesel	43.33	-
ESCUINTLA GAS 2	*	1968	-	Diesel	43.33	-
LAGUNA GAS 1	8.0	1964	1.58	Diesel	43.33	26
INTERNAL COMBUSTION MOTORS	**595.6**		**2,588.53**			**22,699**
ARIZONA	160.0	2003	1,147.03	Oremulsion	27.5	9,621
ELECTROGENERACIÓN	15.0	2003	82.37	Fuel oil No.6	40.19	815
AMATEX	15.0	2003	8.45	Fuel oil No.6	40.19	84
LA ESPERANZA	124.0	2000	655.85	Fuel oil No.6	40.19	5,856
PQPC	110.0	1993	174.80	Fuel oil No.6	40.19	1,561
LAS PALMAS	65.0	1998	307.16	Fuel oil No.6	40.19	2,742
SIDEGUA	36.0	1995	78.79	Fuel oil No.6	40.19	788
GENOR	41.6	1998	82.21	Fuel oil No.6	40.19	757
GENERADORA PROGRESO	19.0	1993	46.48	Fuel oil No.6	40.19	452
LAGOTEX	25.0	1996	87.77	Fuel oil No.6	40.19	838
COGENERATORS (Non harvest)	**180.2**	**1992 - 1996**	**14.05**			**205**
PANTALEÓN	38.5		-	Fuel oil No.6	40.19	-
SANTA ANA	33.8		3.20	Fuel oil No.6	40.19	50
LA UNIÓN	29.5		0.08	Fuel oil No.6	40.19	1
CONCEPCIÓN	27.5		9.73	Fuel oil No.6	40.19	154
MADRE TIERRA	19.0		0.01	Fuel oil No.6	40.19	0
MAGDALENA	15.4		-	Fuel oil No.6	40.19	-
TULULA	16.5		-	Fuel oil No.6	40.19	-
DARSA	1.0		1.02	Fuel oil No.6	40.19	-
COGENERATORS (Harvest Season)	**180.2**	**1992 - 1996**	**542.93**			**2,612**
PANTALEÓN II	5.0	2004	11.40		40.19	34
MAGDALENA II	5.0	2004	0.70		40.19	2
PANTALEÓN	38.5		144.95		40.19	671
SANTA ANA	33.8		57.47		40.19	269
LA UNIÓN	29.5		117.51		40.19	554
CONCEPCIÓN	27.5		87.64		40.19	416
MADRE TIERRA	19.0		48.52		40.19	236

MAGDALENA	15.4		69.03		40.19	341
TULULA	16.5		16.25		40.19	80
DARSA	1.0		1.58		40.19	9

Table A.3. 2. Operating Margin

	A	B	C	D	E	F	G
	fuel share	fuel consumptio n	carbon content	fraction carbon oxidised	emissions	generation	emission s rate
	%	TJ/year	tC/TJ	0	tC02/year	GWh	tCO2 / MWh
	See table A.3.1	See table A.3.1	Inventory Workbook (IPCC, 1996)	Inventory Workbook (IPCC, 1996)	(= B x C X D) * 44/12	See Table A.3.3	(= E / D)
Bunker	65.2%	28,077	21.1	0.99	2,150,520	2,381	0.903
Orimulsion	7.5%	3,207	22.0	0.99	256,106	382	0.670
Diesel	2.1%	915	20.2	0.99	67,109	80	0.844
Coal	25.2%	10,832	26.8	0.98	1,043,182	963	1.083
Cogeneradores (biomass)	0.0%	0.0	0.0	-	0	417	-
	100%	**43,032**			**3,516,917**	**4,223**	**0.83**

Table A.3.3. Included/Excluded Generation

	A	B	C	D
	generation GWh	excluded sources 0	included generation GWh	excluded generation GWh
	Average of years 2002, 2003, 2004	Annex 3, Baseline Methodology	(= A) if included	(= A) if excluded
Bunker	2,381	0	1,489	-
Turbogas	80	0	7	-
Orimulsion	382	0	1,147	-
Geothermal	173	X	-	194
Coal	963	0	1,030	-
Hydraulic	2,262	X	-	2,547
Cogenerators (biomas)	402	0	-	595
Imports	-	X	-	-
Exports		X		
	6,643	**-**	**3,673**	**3,336**

Table A.3.4. Build Margin

	A	B	C	D	E	F
	fuel share **%**	**fuel consumption** **TJ/year**	**carbon content** **tC/TJ**	**emissions** **tC02/year**	**generation** **GWh**	**emissions rate** **tCO2/MWh**
	See Table A.3.1.	**See Table A.3.1.**	**Inventory Workbook (IPCC, 1996)**	**(= B x C)*44/12**	**See Table A.3.2.**	**(= D / E)**
Option 2. Additions that represent 20% of system generation (1401 MWh)						
Pantaleon II	0.00%	33.84	21.1	2,592	11	0.230
Magdalena II	0.00%	2.07	21.1	159	0.7	0.230
Renace	0.00%	1,584.16	-	-	160	-
Electrogeneracion	8.57%	814.96	21.1	62,420	82	0.758
Arizona	91.43%	9,620.83	22.0	760,558	1,147	0.66
		12,139.46		832,133	1,410	**0.59**

Table A.3.5. Estimated Baseline Emission Rate

		units	**equation or source**	
A	**Estimated operating margin emission rate**	tCO2/MWh	Table A.3.2	0.83
B	**Estimated build margin emission rate**	tCO2/MWh	Table A.3.4	0.59
C	**Estimated baseline emission rate***	tCO2/MWh	(= (A + B) / 2)	**0.71**

* This is the ex ante approximation to the baseline. Actual baseline will be calculated ex post as per monitoring methodology

Table A.3.6. Estimated Emission Reductions

TABLE A.3.6 Emissions estimated		units	equation or source	
A	El Canada capacity	MW	project developers	48.11
B	capacity factor	%	project developers	46.2%
C	annual generation*	MWh	(=A x B x 8760)	194,707
D	baseline emission rate	tCO2/MWh	See Table A.3.5	0.71
E	annual emissions reductions	tCO2	(= C x D)	138,241
F	crediting period	years	project developers	2007 - 2028
G	crediting lifetime	years	difference	21
H	total emissions reductions over crediting lifetime	tCO2	(= E x G)	**2,903,061**

*This is an estimate. Actual generation will be monitored as per monitoring methodology.

Annex 4

MONITORING PLAN

The instructions in the approved monitoring methodology ACM0002 will be followed, as described in Section D.