CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Santa Rosa Hydropower Plant Project
Project version: PDD – SRHPP-07
Date: 12/08/2008

A.2. Description of the project activity:

Purpose of the project activity:

The purpose of the Santa Rosa Hydropower Plant Reconstruction Project, hereinafter named SRO HPP Project, is to recover a source of renewable power generation by building a new run-of-river hydroelectric plant at the site of a hydropower plant that was destroyed by a landslide. The new plant would use part of the hydraulic infrastructure that was left undamaged. The reconstruction will bring back into operation a hydropower facility that will displace electricity and GHG emissions currently produced by thermal fossil fuel-burning facilities; particularly by units fired with natural gas, within Bolivia's National Interconnected System (SIN)[1], i.e. the dispatch system will give the project priority, over thermal power plants (single-cycle combustion turbines), to generate and deliver electricity to the grid. According to the National Dispatch Center (CNDC)[2] in charge of the energy load dispatch[3], in the year 2005 gross generation to cover electricity demand reached 4,187 GWh, 46.3% of which was supplied by hydroelectric generation and the remaining 53.7% by thermal generation. Therefore, the new Santa Rosa HPP with its average generation of 80.0 GWh will displace approximately 3.56% of the thermal generation from the Bolivian grid.

The SRO HPP Project consists of a new run-of-river hydroelectric plant with a total combined capacity of 16.3 MW. It will relocate the powerhouse structure and install two new generating units (1 low head and 1 high head), replacing the structure and equipment that were damaged during a landslide on February 17, 2003. Since the original Santa Rosa hydropower plant was destroyed in February 2003, the very low marginal revenue in the energy market, the difficulties to find funding sources and the high transaction and project development costs per generation unit involved have become significant barriers to reconstruct the plant. The Clean Development Mechanism (CDM) can provide the means and the opportunity for this reconstruction, which would otherwise not be feasible.

Because the project involves the reconstruction of a hydro generating facility that will rely on resources that had already been used, it will not be necessary to build new basic infrastructure such as intakes, canals, tunnels, penstocks, and access roads normally associated with the construction of new power generation plants within the grid-connected system. Because of that, the project will not create ancillary impacts

[1] Bolivia's National Interconnected System is named: Sistema Interconectado Nacional (SIN).

[2] Bolivia's Nacional Dispatch Center is named: Centro Nacional de Despacho de Carga (CNDC)

[3] Based on information from "Estadísticas" prepared by the CNDC and available at www.cndc.bo

normally associated with the construction of new power generation plants. Similarly, it will not be necessary to build new transmission lines. As it brings the facility back into operation, the project will seek the optimal use of resources in a 10-plant cascade system, ensuring enough water for the lower five stations.

Implementation of the project will bring capital investment to the La Paz Department, generating employment and demand for local services during the construction phase, and thereby strengthening the economy of local communities in the Murillo Province[4].

Explanation how the proposed project activity reduces greenhouse gas emissions:

The Project involves reduction of emissions of carbon dioxide through the displacement of electrical energy produced by simple cycle combustion turbines. The Project supplies electrical energy to the National Grid from run-of-river hydropower facilities and therefore displaces fossil-fueled sources that typically would provide the next increments of generation for the Bolivian national system, thereby reducing emissions of carbon dioxide from the alternate electrical energy source.

Contribution of the project activity to sustainable development

The SRO HPP Project will effectively contribute to sustainable development under the concepts described below and as further expanded in Annexes 6, 7, and 8:

- Supporting the improvement of the quality of life of the region's inhabitants. This objective will be accomplished throughout the construction and operation phases, emphasizing the hiring of local workers and complying with national health and safety standards.
- Working for the conservation of the environmental quality within the Project area. This objective will be accomplished by complying with the national environmental laws and regulations.

A.3. Project participants:

Table 1. Project Participants

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants * (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Republic of Bolivia (host country)	Public entity: • Viceministry for Land and Environmental Planning	Yes
	Private entity: • Compañía Boliviana de Energía Eléctrica S.A. – Bolivian Power Company Limited Sucursal Bolivia (COBEE S.A. – BPCo.)	Yes

[4] Bolivia's political division comprises nine Departments, each one of them divided in Provinces.

* See project participants contact information in Annex 1.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Republic of Bolivia.

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

Murillo Province in the Department of La Paz.

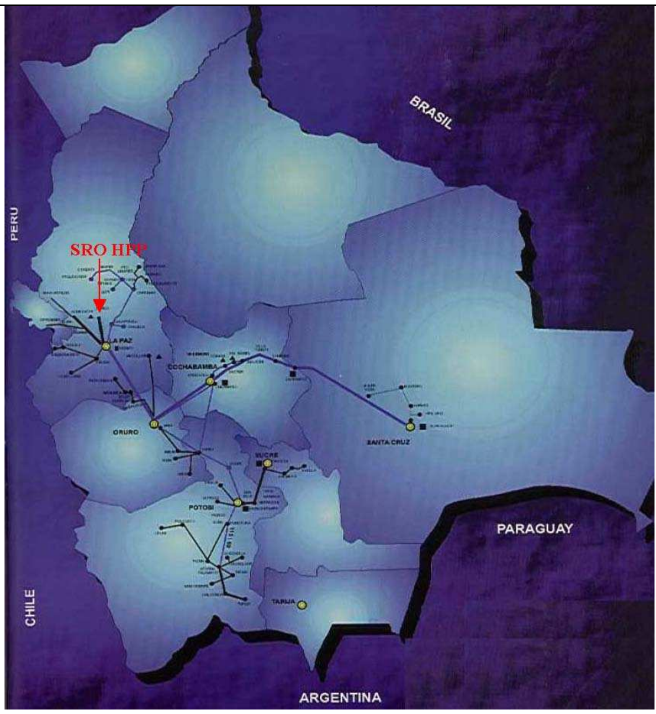
A.4.1.3. City/Town/Community etc:

Coscapa Community in the Zongo River Valley.

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

Table 2. Geographic Coordinates for Main Sites

SITE	UTM COORDINATE SYSTEM (ZONE 19)		SPHERICAL COORDINATE SYSTEM	
	NORTH	EAST	LATITUDE (South)	LONGITUDE (West)
Santa Rosa Powerhouse	8,216,670	595,390	16^{o} 07' 41.8"	68^{o} 06' 28.4"
Santa Rosa Forebay	8,217,285	594,430	16^{o} 07' 21.9"	68^{o} 07' 00.8"



The SRO HPP Project is located in the Zongo River Valley, a basin located north of La Paz City (Bolivia's government seat), with the Huayna Potosí Mountain (6088 m.a.s.l.) marking the upper limit and the confluence with Coroico River (500 m.a.s.l.) marking the lower limit.

The project is located 40 km from the city of La Paz, in the middle portion of the valley, with the powerhouse at 2570 m.a.s.l. and the forebay at 3410 m.a.s.l. The La Paz Department is one of the country's nine Departments, and consists of 18 provinces including the Murillo Province. (See Map[5]).

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

The project activity falls into Sectoral Category 1, Energy Industries (renewable/non renewable).

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

The SRO HPP Project consists of a run-of-river hydroelectric facility, a term that describes hydropower facilities without major water regulation through reservoir capacity. The Project facility has limited seasonal and hourly water regulation, and uses conventional turbine units, i.e. a reaction turbine of the Francis type and an impulse turbine of the Pelton type. The Pelton turbine operates based on the impact of high velocity jets of water on a series of specially shaped buckets mounted around the edge of a runner. The Francis turbine operating principle is based on water entering the runner under pressure and interacting with the turbine runner in such a way that the hydraulic energy is converted to kinetic energy in the turbine shaft. Technology similar to the Pelton turbine has been used along the 10-plant generating system in the Zongo River Valley, while the Francis turbine will be the first of its type to be installed in the Zongo River System.

[5] From BOCIER (Comité de Integración Energética Regional – Bolivia).

Turbines and generators will be supplied under the umbrella of a turnkey contract with the project developer and sponsor. The three bidders that submitted proposals for the turnkey project are VATECH, ALSTOM, and VOITH SIEMENS, all of whom are internationally recognized equipment suppliers for hydroelectric facilities. The EPC Contract has been awarded to the Consortium formed by VATECH and SOLUZIONA, the later a renowned engineering company from Spain.

The SRO HPP Project will consist of: 1) a low head unit with a capacity of 6.2 MW and an average generation of 36.3 GWh/year; and 2) a high head unit with 10.1 MW of capacity and an average generation of 43.7 GWh/year. The Project will supply a total of 80.0 GWh/year to the national grid under average hydrological conditions. Tables 2, 3 and 4 below provide the main design features and characteristics of the SRO HPP.

Table 2. Power Plant Characteristics – Low Head Unit

Characteristic	Specification
Gross head	187 m
Turbine Type	Francis
Installed Capacity	6.2 MW
Nominal Flow	4.19 m3/s
Energy (based on hydrology data declared for November/2003 CNDC Mid Term Report)	36.3 GWh/year

Table 3. Power Plant Characteristics – High Head Unit

Characteristic	Specification
Gross head	834 m
Turbine Type	Pelton
Installed Capacity	10.1 MW
Nominal Flow	1.87 m3/s
Energy (based on hydrology data declared for November/2003 CNDC Mid Term Report)	43.7 GWh/year.

Table 4. Overall Power Plant Characteristics

Characteristic	Specification
Number of units	2 (1 Francis + 1 Pelton)
Installed Capacity	16.3 MW
Energy	80.1 GWh/year.

Both schemes will generate 40% of the annual expected generation during the dry season (May- October) and the remaining 60% during the rainy season (November-April).

The Project will replace the old powerhouse by building a new one 50 meters away from the original location using the rock slope as a natural defence against landslides. All related infrastructure, i.e. intakes,

canals, tunnels, penstocks and substation will be repaired and improved as necessary, and will return to operation as soon as the reconstruction is completed. The electromechanical equipment will be completely new, covering major equipment such as generators, turbines and powerhouse crane, as well as minor related equipment such as governors, excitation systems, valves, control panels, switchgear, and other.

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

As calculated based on the methodology described in section B, implementation of the SRO HPP Project will provide an estimated 44,080 metric tons of CO_2 [6] equivalent in annual emission reductions and an estimated total emission reduction of 925,680 tons of CO_2 equivalent over a 21-year crediting period. Table 5 presents the estimated amount of emission reductions under the option of a renewable crediting period, i.e. 7-year crediting period renewed two times for a maximum of 21 years. (See Annex 3 for details).

Table 5. Estimated Project Emission Reductions

Years	**Annual estimation of emission reductions in tones of CO_2 e**
2009	44,080
2010	44,080
2011	44,080
2012	44,080
2013	44,080
2014	44,080
2015	44,080
Total estimated reductions (tones of CO_2 e)	308,560
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tones of CO_2 e)	44,080

A.4.5. Public funding of the project activity:

The project is a private development and does not include any kind of public funding.

SECTION B. Application of a baseline and monitoring methodology

[6] All emission and emission reduction estimates are provided in metric tons (hereinafter "tons").

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

Baseline methodology

Title: “Consolidated baseline methodology for grid-connected electricity generation from renewable sources”.

Approved consolidated baseline methodology reference number assigned by the CDM Executive Board: ACM0002 / Version 06, Sectoral Scope: 01, 19 May 2006.

Monitoring methodology

Title: “Consolidated monitoring methodology for zero emissions grid-connected electricity generation from renewable sources”.

Approved consolidated monitoring methodology reference number assigned by the CDM Executive Board: ACM0002 / Version 06, Sectoral Scope: 01, 19 May 2006.

Tool

Title: “Tool for the demonstration and assessment of additionality”.

Approved tool for the demonstration and assessment of additionality / Version 04, EB 36.

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

The proposed baseline methodology is appropriate for the SRO HPP, a renewable electric energy project that displaces electricity generated from fossil fuel sources from the grid, which falls within the eligible types of CDM project activities as per Decision 17/CP.7 of the United Nations Framework Convention on Climate Change (UNFCCC).

The chosen baseline methodology is applicable to the project activity based on the fact that:

- The Project activity is a grid-connected renewable power generation project.
- The project activity is an electricity capacity addition of a run-of-river hydropower plant with existing reservoirs and where the volume of those reservoirs is not increased.
- The project activity does not involve switching from fossil fuels to renewable energy at the site of the project activity.
- The geographic and system boundaries for the SIN (the relevant electricity grid) can be clearly identified and information on the characteristics of the grid is available.

As a renewable energy project it is appropriate to follow Paragraph 48 of Marrakech Accords and use existing actual or historical emissions, since the project activity will serve to reduce actual emissions.

The chosen monitoring methodology is applicable to the project activity because it is used in conjunction with the approved baseline methodology ACM0002.

The tool for the demonstration and assessment of additionality is used based on the specific requirement of the approved baseline methodology ACM0002.

B.3. Description of the sources and gases included in the project boundary:

As per the ACM0002 methodology, for the baseline determination only CO_2 emissions from electricity generation in fossil fuel-fired power that is displaced due to the project activity are accounted. The displaced sources are connected to the National Interconnected Grid (SIN), are mostly but not solely installed in the low lands region of the country, and are natural gas-fueled.

The Project boundary is defined by the geographic and system boundary of the SIN. Power projects that feed into the Bolivian grid can be established almost anywhere in the country. The geographic boundaries for the calculation are therefore Bolivia's national borders. Electricity imports and exports do not exist currently, although physical interconnections with neighbouring countries are expected to occur in the medium to long-term. Due to the limited size of the Bolivian Market and the significant potential to install natural gas-fired power plants, it is more likely that most of the electricity generated will tend to be exported. Following the recommendations provided in the methodology ACM0002, the SRO HPP Project will make the necessary corrections associated with electricity imports and/or exports as part of the proposed annual calculation of the ex-post emission rate.

Table 6. Sources and gases included in the project boundary

	Source	Gas	Included?	Justification/Explanation
Baseline	Fossil fuel-fired power	CO_2	Yes	The source is the only one that may be displaced within the SIN, and as per the definition of project boundary in the ACM0002 methodology only CO_2 emissions are accounted.
		CH_4	No	
		N_2O	No	
Project Activity	Hydropower run-of-river development	CO_2	No	Given the features of the project activity, hydropower with no reservoir/storage facilities, no associated emissions were identified
		CH_4	No	
		N_2O	No	

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

Baseline Analysis

The baseline scenario was identified following the basis of the ACM0002 methodology. Accordingly, the baseline scenario is that, electricity delivered to the grid by the project would have otherwise been generated by the operation of grid connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations.

The purpose of the project activity is to recover a source of renewable power generation by building a new

run-of-river hydroelectric plant at the site of a hydropower plant that was destroyed by a landslide causing the complete interruption of operations[7].

Therefore, the baseline scenario that reasonably represents the anthropogenic emission by sources of GHG that would occur in the absence of the CDM project activity is the delivery of electricity to the grid by existing and to be added power sources.

The project activity will displace existing electricity produced by fossil fuel-fired thermal power plants that would have otherwise delivered electricity to the SIN, thereby reducing emissions of carbon dioxide from the alternate electrical energy source.

Power plant dispatch in the SIN is based on marginal cost, i.e. those with the lower marginal costs are dispatched first. Under the assumed zero marginal cost of production, run-of-river hydroelectric power plants are always dispatched first. Thermal and hydroelectric power plants roughly represent 50% of the system energy dispatch each. With a market demand reaching only 80% of the system generating capacity, and the project activity accounting for less than 4% of the thermal energy generation, the most likely scenario that would take place in the absence of the proposed project activity is that fossil-fueled sources will provide the corresponding increment of generation for the SIN.

The CNDC Mid Term Report for the period Nov/2005 – Oct/2009[8] foresees that six refurbished thermal units will join the system with a total capacity of 39 MW (4% of the system installed capacity), and two thermal units will be decommissioned with a total of 5.5 MW. Therefore, in the absence of the project activity and considering the 5% growth in the system demand mentioned in the CNDC Mid Term Report, it is expected that the market demand will tend to close the gap with the system generating capacity and less efficient thermal units, currently used as system reserve, will be incorporated into the regular dispatch.

Analysis of SRO HPP scenario

The SRO HPP Project will reduce anthropogenic emissions of GHGs by displacing existing electricity produced by fossil fuel-fired thermal power plants (single-cycle combustion turbines) that would have otherwise delivered electricity to the Bolivian grid-connected system. The system can be described as follows:

a) Power plant dispatch is managed by the CNDC[9] . Following the current principle of cost minimization for the whole system, power plants are dispatched according to marginal costs, those with the lower marginal costs being dispatched first. Run-of-river hydroelectric power plants are always dispatched first since they are assumed to have zero marginal cost of production.

b) In the year 2005, hydroelectric power plants represented 46.3% of the market in terms of energy dispatch; gas fired thermal plants produced the remaining 53.7%. The SRO HPP Project with its average generation of 80.0 MWh will displace approximately 3.56% of the thermal generation from the Bolivian grid.

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[7] The operations' interruption of the original Santa Rosa power plant may be verified through CNDC reports at www.cndc.bo

[8] See Mid Term Reports at www.cndc.bo

[9] See Bolivian Electricity Law at the Superintendency of Electricity web page www.superele.gov.bo

c) System generation capacity is 949.0 MW[10], system demand is 755.5 MW[11], leaving 193.5 MW of undispatched capacity composed entirely of gas fired thermal plants. As a result of this surplus capacity, only low cost thermal plants are dispatched, leading to a significant decrease in energy prices. In light of the low marginal revenue that would be expected from new hydropower, no significant hydropower developments are foreseen.

d) In addition, it can be anticipated that in the near future thermal generation will likely be encouraged in order to boost the energy price level, and will present a more attractive market for new investments than hydropower.

The Project involves reduction of emissions of carbon dioxide through the displacement of electrical energy produced by simple cycle combustion turbines. The Project supplies electrical energy to the National Grid from run-of-river hydropower facilities and therefore displaces fossil-fueled sources that typically would provide the next increments of generation for the Bolivian national system, thereby reducing emissions of carbon dioxide from the alternate electrical energy source.

In each crediting year, the amount of emission reductions achieved by the project will vary directly with the metered net generation output of the SRO HPP Project and the baseline emission rate. The emissions estimates shown in Table 4 are based on an estimated 80,000 MWh of annual electricity output and a grid emission rate of 0.551 tCO_2equiv/MWh. The emission rate is computed from the most recent information on the Bolivian electric power sector provided by the CNDC Daily Post Dispatch Report. The actual baseline emission rate will be calculated annually, on an *ex post* basis, over the lifetime of the project as per the approved monitoring methodology (See section D).

In light of the characteristics of the Bolivian grid-connected system described above, the CO_2 emission reductions would not be achieved in the absence of this project. The existing, very low marginal revenue in the energy market, the tendency to keep energy prices low due to the availability of low-cost natural gas, and the lack of available funds to date has reduced the incentive for the implementation of the SRO HPP Project.

A 20% excess generation capacity to current demand levels has resulted in low marginal market revenue. Power generating companies, therefore, face strong energy price competition to guarantee compensation for firm capacity. Moreover, the government has established a natural gas price band for power generation, which is based on the availability of low-cost natural gas.

Because the financial market is well aware of the current electricity market conditions, it is difficult to secure finance resources for additional investments in the power generation area. However, approval of the Project under the Clean Development Mechanism will provide the means and the opportunity for this reconstruction to take place, and consequently, to provide the above mentioned CO_2 emission reductions.

B.5. 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 (assessment and demonstration of additionality):

The approved consolidated baseline methodology ACM0002 utilizes the “Tool for the demonstration and

[10] From mid term study “Estudio de Mediano Plazo Noviembre 2005 – Octubre 2009” published by the CNDC.

[11] Ibid.

assessment of additionality" as approved by the CDM Executive Board. Results of this required analysis are presented below.

In compliance with the guidelines established under the consolidated baseline methodology ACM0002, the additionality of the project activity shall be demonstrated and assessed using the latest version[12] of the "Tool for the demonstration and assessment of additionality" agreed by the CDM executive board, following the step by step approach as listed below:

- Step 1. Identification of alternatives to the project activity consistent with current laws and regulations.
- Step 2. Investment analysis.
- Step 3. Barrier analysis.
- Step 4. Common practice analysis.

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

Through the following sub-steps realistic and credible alternatives to the project activity that can be (part of) the baseline scenario are defined:

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

Realistic and credible alternatives have been identified to the project participants during the investment decision process, all of them providing outputs or services comparable with the proposed CDM project activity. In the particular case of the SRO HPP Project, the alternatives are as follows:

1. The 16.3 MW SRO HPP Project not undertaken as a CDM project activity.
2. The SRO HPP Project rebuilt with original characteristics as accepted by the underwriters in order to allow full coverage of the investment by the insurance proceeds, i.e. 12.5 MW.
3. No project is implemented; hence the continuation of current practice of electricity supply from the grid occurs. Nor the project activity or other alternatives are undertaken, allowing the project participants to receive the benefit of cashing-in the insurance proceeds.[13]
4. The project is implemented as a 48 MW natural gas-fired thermal power plant, following the latest investment trend in the SIN to define a suitable power plant size.[14]

These four alternative scenarios deliver outputs and services, either based on the implementation of new power sources or the dispatch of existing power sources in the SIN, comparable in quality and properties with the proposed CDM project activity. Alternatives 1, 2 and 4 fall within the range of new power sources comprising similar characteristics to the power infrastructure built in the SIN. Alternative 3, based on the

[12] In this case corresponds to Version 04, EB 36.

[13] See Sub-step 1b for specific consistency with mandatory laws and regulations of this alternative.

[14] Latest thermal development in the SIN took place in year 2000 with the implementation of the Bulo Bulo facility installing two GE LM6000 units.

SIN undispatched capacity[15], relies on the dispatch of existing power sources that substantially exceed the capacity of the CDM project activity. Therefore, the four alternative scenarios identified are plausible.

Outcome of Step 1a: Four realistic and credible alternative scenarios to the project activity have been identified.

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

The alternatives identified under sub-step 1a are in compliance with all applicable legal and regulatory requirements. Those requirements and the corresponding particular conditions area listed below.

The applicable legal and regulatory requirements comprise:

- Law No. 1604 (Electricity Law)[16] that regulates the activities of the electricity industry.
- Law No. 1333 (Environmental Law)[17] that has the purpose of protecting and preserving the environment and natural resources by regulating human activity and promoting sustainable development aimed at improving the population standard of living.
- COBEE S.A.-BPCo as project developer, is an electricity company that has been granted a 40-year Concession under Supreme Resolutions[18] No. 207640 dated May 4, 1990, and No. 215064 dated December 30, 1994.

After destruction of the original Santa Rosa power plant COBEE has not been subject to any demand for compliance of energy supply agreements. This is due to the following:

a) Under the terms of the Power Purchase Agreement (PPA)[19]: a force majeure situation does not create responsibility for the parties, and COBEE guarantees the supply of 90 MW capacity. The Santa Rosa power plant outage was a force majeure event, and a 12.5 MW reduction in the 180 MW capacity of COBEE; therefore the outage did not conflict with the provisions of the PPA.

b) Under the terms of the Concession Supreme Resolutions and the Electricity Law nor COBEE or any other generator in the Bolivian system is obliged to rebuild a power plant that has been destroyed by natural causes.

Therefore, not undertaking the project activity is ratified as a realistic and credible alternative.

Particular conditions specified in the legal and regulatory framework:

- Law No. 1604, Art. 2. An electricity company is the private or public entity, national or foreign, that has obtained a concession or license for the activities of the electricity industry.

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[15] See references 10 and 11.

[16] The Electricity Law may be found at http://www.bolivia.gov.bo

[17] The Environmental Law may be found at http://www.bolivia.gov.bo

[18] Supreme Resolutions from the Bolivian Government may be obtained from the official source “Gaceta Oficial de Bolivia”. The respective web reference is http://gaceta.comunica.gov.bo

[19] COBEE has a PPA in place with ELECTROPAZ. The document is available with both parties.

- Law No. 1604, Art. 2. Generation is the process of electricity production in any type of power plant. For the purpose of this Law, generation in the SIN is the production and sale of an intangible asset.
- Law No. 1604, Art. 4. Further to Art. 25 of the Bolivian National Constitution, it is specifically declared that the activities of the electricity industry are a national priority.
- Law No. 1604, Art. 6. The electricity industry is subject to the environmental legislation applicable to this activity.
- Law No. 1333, Art. 25. All public or private activities, prior to the investment stage, should identify the category for the environmental impact evaluation.
- Law No. 1333, Art. 26. All activities that require an Environmental Impact Assessment Study, prior to the implementation stage are obliged to obtain the respective Environmental License.

Outcome of Step 1b: The alternatives listed under sub-step 1a are realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project activity, and at the same time are in compliance with mandatory legislation and regulations for the electricity industry and the environment, taking into account the enforcement in the country and EB decisions on national and/or sectoral policies and regulations.

Step 2. Investment Analysis

The following analysis is meant to show that the proposed project activity is economically and financially less attractive than other alternatives without the revenue from the sale of certified emission reductions (CERs). To conduct the investment analysis, the following sub-steps are used:

Sub-step 2a. Determine appropriate analysis method

The SRO HPP Project generates economic benefits other than CDM related income, therefore the simple cost analysis (Option I) can not be applied. The investment comparison analysis (Option II) is chosen over the benchmark analysis (Option III) for the investment analysis provided below.

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

The project participants have developed a financial model that is based on the NPV as a prime financial indicator followed by the IRR as a complementary financial indicator. Considering that some of the alternatives include cash flow characteristics that do not comply with the mathematical structure of the IRR and that a comparison is required between the proposed project activity and the other alternatives, the identified/governing financial indicator for the investment comparison analysis is the NPV.

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

The NPV, identified as the suitable financial indicator, is calculated for the proposed CDM project activity and for the other alternatives. All relevant costs (such as the investment cost and the operations and maintenance costs), and revenues (excluding CER revenues) are included.

The investment analysis is presented in a transparent manner and providing all the relevant assumptions in Annex 3, so that a reader can reproduce the analysis and obtain the same results.

Assumptions and input data for the investment analysis do not differ across the project activity and its alternatives, except in those cases where differences have been well substantiated.

A clear comparison of the financial indicator for the proposed CDM activity and the alternatives is presented.

The financial model developed to evaluate the project activity encompasses the following main concepts:

1. The project activity direct cash flow as a result of: revenue from capacity and energy, investment and operation & maintenance costs.
2. The insurance proceeds that arise as a special component of the investment.
3. The tariff variation for COBEE S.A. – BPCo. (Project Developer and Sponsor) due to the project implementation. The overall impact of the tariff variation is reflected in the project activity cash flow.
4. Alternative 3 assumes the cost of a 6,382 MWh/year energy loss at the power station immediately downstream from the project due to lack of inflows diverted by the project high head scheme.
5. Insurance proceeds amount to $13.95 million for alternatives 1 and 2 because the underwriters are obliged to cover the current cost of re-building a power station of similar characteristics to the one destroyed. The amount was obtained asking the EPC bidders to quote such option, as agreed wit the underwriters.
6. Insurance proceeds amount to $3.65 million for alternative 3 because the underwriters are obliged to cover only the book value (depreciated value) of destroyed assets if Owner decides not to re-build the power station and go after a clean cash-in of insurance proceeds.

A summary table of the financial scenario for each alternative is presented under the current title, and the detailed financial model is included under Annex 5 of the PDD.

Table 7. The 16.3 MW Santa Rosa HPP Project not undertaken as a CDM project activity

Investment = $16,453,000

YEAR		PROJECT CASH FLOW STATEMENT					
CALENDAR	PROJECT	NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(1)	(2)	(72) = (71)	(73) = -(54)	(74) = (13)	(75) = -(52)*16,453,000	(76)	(77) = (72)+(73) +(74)+(75)+(76)
2004	0	$2,828,084	$0	$0	($2,467,950)	$0	$360,134
2005	1	$6,333,125	$0	$0	($8,226,500)	$0	($1,893,375)
2006	2	$6,884,748	($10,307,366)	$731,622	($5,758,550)	($943,810)	($9,393,357)
2007	3	$918,897	$0	$731,622	$0	$179,619	$1,830,138
2008	4	$865,515	$0	$731,622	$0	$148,168	$1,745,305
2009	5	$932,163	$0	$731,622	$0	$139,150	$1,802,935
2010	6	$969,769	$0	$731,622	$0	$120,919	$1,822,310
2011	7	$1,009,530	$0	$731,622	$0	$100,713	$1,841,864
2012	8	$1,059,112	$0	$731,622	$0	$80,529	$1,871,263
2013	9	$1,103,364	$0	$731,622	$0	$55,356	$1,890,342
2014	10	$1,165,683	$0	$731,622	$0	$59,863	$1,957,168
2015	11	$1,198,203	$0	$731,622	$0	$59,493	$1,989,318
2016	12	$1,243,521	$0	$731,622	$0	$0	$1,975,143
2017	13	$1,289,971	$0	$731,622	$0	$0	$2,021,593
2018	14	$1,337,583	$0	$731,622	$0	$0	$2,069,205
2019	15	$1,386,385	$0	$731,622	$0	$0	$2,118,007
2020	16	$1,436,407	$0	$731,622	$0	$0	$2,168,029
2021	17	$1,487,679	$0	$731,622	$0	$0	$2,219,301
2022	18	$1,540,234	$0	$731,622	$0	$0	$2,271,856
2023	19	$1,594,102	$0	$731,622	$0	$0	$2,325,724
2024	20	$1,531,130	$0	$731,622	$0	$0	$2,262,752
		DISCOUNT RATE = 15.0%			=>	NPV =	422,936

Table 8. The Santa Rosa HPP Project rebuilt with original characteristics, i.e. 12.5 MW

Investment = $13,953,000

YEAR		PROJECT CASH FLOW STATEMENT					
CALENDAR	PROJECT	NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(1)	(2)	(71) = (70)	(72) = -(52)	(73) = (13)	(74) = -(50)*16,453,000	(75)	(76) = (71)+(72) +(73)+(74)+(75)
2004	0	$2,828,084	$0	$0	($2,092,950)	$0	$735,134
2005	1	$6,320,749	$0	$0	($6,976,500)	$0	($655,751)
2006	2	$6,677,781	($10,307,366)	$651,622	($4,883,550)	($997,438)	($8,858,951)
2007	3	$721,412	$0	$651,622	$0	$127,955	$1,500,989
2008	4	$671,924	$0	$651,622	$0	$97,111	$1,420,657
2009	5	$759,064	$0	$651,622	$0	$92,459	$1,503,145
2010	6	$790,843	$0	$651,622	$0	$73,060	$1,515,525
2011	7	$824,630	$0	$651,622	$0	$51,658	$1,527,910
2012	8	$868,090	$0	$651,622	$0	$30,248	$1,549,960
2013	9	$906,066	$0	$651,622	$0	$3,818	$1,561,506
2014	10	$961,953	$0	$651,622	$0	$7,036	$1,620,611
2015	11	$987,880	$0	$651,622	$0	$514,094	$2,153,596
2016	12	$1,026,439	$0	$651,622	$0	$0	$1,678,061
2017	13	$1,065,963	$0	$651,622	$0	$0	$1,717,584
2018	14	$1,106,474	$0	$651,622	$0	$0	$1,758,096
2019	15	$1,147,998	$0	$651,622	$0	$0	$1,799,620
2020	16	$1,190,561	$0	$651,622	$0	$0	$1,842,182
2021	17	$1,234,187	$0	$651,622	$0	$0	$1,885,809
2022	18	$1,278,904	$0	$651,622	$0	$0	$1,930,526
2023	19	$1,324,739	$0	$651,622	$0	$0	$1,976,361
2024	20	$1,269,528	$0	$651,622	$0	$0	$1,921,150
		DISCOUNT RATE = 15.0%			=>	NPV =	903,232

Table 9. Nor the project activity or other alternatives are undertaken

Investment = $0

YEAR		PROJECT CASH FLOW STATEMENT					
CALENDAR	PROJECT	NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(1)	(2)	(71) = (70)	(72) = -(52)	(73) = (13)	(74) = -(50)*16,453,000	(75)	(76) = (71)+(72) +(73)+(74)+(75)
2004	0	($2,992,552)	$0	$7,283,654	$0	$0	$4,291,102
2005	1	($1,293,345)	$0	$0	$0	$0	($1,293,345)
2006	2	($175,961)	$0	$0	$0	$0	($175,961)
2007	3	$947,994	$0	$0	$0	$0	$947,994
2008	4	$1,879,449	$0	$0	$0	$0	$1,879,449
2009	5	($51,117)	$0	$0	$0	$0	($51,117)
2010	6	($52,442)	$0	$0	$0	$0	($52,442)
2011	7	($53,896)	$0	$0	$0	$0	($53,896)
2012	8	($56,092)	$0	$0	$0	$0	($56,092)
2013	9	($57,818)	$0	$0	$0	$0	($57,818)
2014	10	($60,942)	$0	$0	$0	$0	($60,942)
2015	11	($61,640)	$0	$0	$0	$0	($61,640)
2016	12	($63,312)	$0	$0	$0	$0	($63,312)
2017	13	($65,026)	$0	$0	$0	$0	($65,026)
2018	14	($66,783)	$0	$0	$0	$0	($66,783)
2019	15	($68,584)	$0	$0	$0	$0	($68,584)
2020	16	($70,430)	$0	$0	$0	$0	($70,430)
2021	17	($72,322)	$0	$0	$0	$0	($72,322)
2022	18	($74,261)	$0	$0	$0	$0	($74,261)
2023	19	($76,249)	$0	$0	$0	$0	($76,249)
2024	20	($74,328)	$0	$0	$0	$0	($74,328)
		DISCOUNT RATE = 15.0%			=>	NPV =	4,529,456

Table 10. Implement a 48 MW thermal (natural gas) power plant project

Investment = $28,930,000

YEAR		PROJECT CASH FLOW STATEMENT					
CALENDAR	PROJECT	NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(1)	(2)	(71) = (70)	(72) = -(52)	(73) = (13)	(74) = -(50)*16,453,000	(75)	(76) = (71)+(72) +(73)+(74)+(75)
2004	0	$0	$0	$0	($1,446,500)	$0	($1,446,500)
2005	1	$0	$0	$0	($26,037,000)	($128,955)	($26,165,955)
2006	2	$1,204,493	$0	$1,099,340	($1,446,500)	$128,955	$986,288
2007	3	$1,501,728	$0	$1,099,340	$0	$0	$2,601,068
2008	4	$1,688,696	$0	$1,099,340	$0	$0	$2,788,036
2009	5	$1,778,927	$0	$1,099,340	$0	$0	$2,878,267
2010	6	$1,846,620	$0	$1,099,340	$0	$0	$2,945,960
2011	7	$1,921,423	$0	$1,099,340	$0	$0	$3,020,763
2012	8	$2,037,497	$0	$1,099,340	$0	$0	$3,136,837
2013	9	$2,127,150	$0	$1,099,340	$0	$0	$3,226,490
2014	10	$2,294,738	$0	$1,099,340	$0	$0	$3,394,078
2015	11	$2,326,574	$0	$1,099,340	$0	$0	$3,425,914
2016	12	$2,412,690	$0	$1,099,340	$0	$0	$3,512,030
2017	13	$2,500,959	$0	$1,099,340	$0	$0	$3,600,299
2018	14	$2,591,435	$0	$1,099,340	$0	$0	$3,690,775
2019	15	$2,684,173	$0	$1,099,340	$0	$0	$3,783,513
2020	16	$2,779,229	$0	$1,099,340	$0	$0	$3,878,569
2021	17	$2,876,661	$0	$1,099,340	$0	$0	$3,976,001
2022	18	$2,976,530	$0	$1,099,340	$0	$0	$4,075,870
2023	19	$3,078,895	$0	$1,099,340	$0	$0	$4,178,235
2024	20	$2,760,730	$0	$1,099,340	$0	$0	$3,860,070
		DISCOUNT RATE = 15.0%			=>	NPV =	($8,920,323)

Every alternative has been analyzed considering the direct impact of the insurance proceeds benefit. However, in the particular case of alternative 4, the influence of the insurance proceeds arises as a consequence of initially implementing alternative 3. Therefore, the proper comparison of the selected financial indicator is included in Table 11.

Table 11. NPV Summary for all alternatives

ALTERNATIVE	Base NPV	NPV Benefit from Alternative 3	Total NPV
1. The 16.3 MW Santa Rosa HPP Project not undertaken as a CDM project activity	$422,936	$0	**$422,936**
2. The Santa Rosa HPP Project rebuilt with original characteristics, i.e. 12.5 MW	$903,232	$0	**$903,232**
3. Nor the project activity or other alternatives are undertaken	$4,529,456	$0	**$4,529,456**
4. Implement a 48 MW thermal (natural gas) power plant project	($8,920,323)	$4,529,456	**($4,390,866)**

From the comparison among alternatives 1 to 4 above, it is concluded that:

1. Three of the four identified alternatives have a positive NPV.
2. Alternative 4 has a negative NPV, represented by a high absolute value, establishing that it is not a plausible option for the SIN.
3. The CDM project activity is not the most financially attractive.

Sub-step 2d. Sensitivity analysis

A sensitivity analysis is included below (alternative 4 is discarded based on the conclusion under sub-step 2c), showing that the conclusion regarding the financial attractiveness of the project activity is robust to reasonable variations in the critical assumptions.

The sensitivity analysis that follows presents six different scenarios, pursuing a range of reasonable variations for: the discount rate, the investment amount, and the plant factor.

Table 12. NPV variation based on discount rate sensitivity

ALTERNATIVE	DISCOUNT RATE						
	12%	**13%**	**14%**	**15%**	**16%**	**17%**	**18%**
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$2,269,584	$1,573,867	$961,945	$422,936	($52,473)	($472,277)	($843,351)
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW	$2,468,150	$1,877,916	$1,359,387	$903,232	$501,466	$147,234	($165,363)
3. Nor the project activity or other alternatives are undertaken	$4,598,857	$4,576,151	$4,552,939	$4,529,456	$4,505,895	$4,482,410	$4,459,126
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: All three alternatives are subject to the sensitivity

Table 13. NPV variation based on investment sensitivity

ALTERNATIVE	INVESTMENT						
	85%	**90%**	**95%**	**100%**	**105%**	**110%**	**115%**
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$1,960,261	$1,447,820	$935,378	$422,936	($89,505)	($602,603)	($1,116,346)
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW				$903,232			
3. Nor the project activity or other alternatives are undertaken				$4,529,456			
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: Only alternative 1 is subject to the sensitivity + comparison with the base case for alternatives 2 and 3.

Table 14. NPV variation based on plant factor sensitivity

ALTERNATIVE	PLANT FACTOR						
	62%	**60%**	**58%**	**56%**	**54%**	**52%**	**50%**
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$751,181	$641,908	$531,953	$422,936	$310,939	$200,413	$89,886
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW				$903,232			
3. Nor the project activity or other alternatives are undertaken				$4,529,456			
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: Only alternative 1 is subject to the sensitivity + comparison with the base case for alternatives 2 and 3.

Table 15. NPV variation based on discount rate & investment sensitivities

ALTERNATIVE	DISCOUNT RATE						
	12%	12%	12%	12%	12%	12%	12%
	INVESTMENT						
	85%	90%	95%	100%	105%	110%	115%
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$3,818,869	$3,302,441	$2,786,013	$2,269,584	$1,753,157	$1,236,027	$718,207
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW				$2,468,150			
3. Nor the project activity or other alternatives are undertaken				$4,598,857			
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: All three alternatives are affected by the discount rate sensitivity at the critical limit, and only alternative 1 is subject to the investment sensitivity.

Table 16. NPV variation based on discount rate and plant factor sensitivities

ALTERNATIVE	DISCOUNT RATE						
	12%	12%	12%	12%	12%	12%	12%
	PLANT FACTOR						
	62%	60%	58%	56%	54%	52%	50%
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$2,686,936	$2,547,869	$2,408,074	$2,269,584	$2,127,309	$1,986,902	$1,846,495
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW				$2,468,150			
3. Nor the project activity or other alternatives are undertaken				$4,598,857			
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: All three alternatives are affected by the discount rate sensitivity at the critical limit, and only alternative 1 is subject to the load factor sensitivity.

Table 17. NPV variation based on discount rate, investment, and plant factor sensitivities

ALTERNATIVE							
DISCOUNT RATE	12%	12%	12%	12%	12%	12%	12%
INVESTMENT	85%	85%	85%	85%	85%	85%	85%
PLANT FACTOR	62%	60%	58%	56%	54%	52%	50%
1. The 16.3 MW SRO HPP project not undertaken as a CDM project activity	$4,238,173	$4,097,764	$3,957,358	$3,818,869	$3,676,593	$3,536,186	$3,395,779
2. The SRO HPP project rebuilt with original characteristics, i.e. 12.5 MW				$2,468,150			
3. Nor the project activity or other alternatives are undertaken				$4,598,857			
Is the project activity the most financially attractive?	**No**	**No**	**No**	**No**	**No**	**No**	**No**

Note: All three alternatives are affected by the discount rate and investment sensitivities at the critical limits, and only alternative 1 is subject to the load factor sensitivity.

Outcome of Step 2: The sensitivity analysis proves that under scenarios with reasonable variations in the most critical assumptions, the project activity is not the most financially attractive. Therefore the proposed CDM project activity is additional under Step 2.

The following argumentation seeks to further assess the financial analysis by establishing that there are realistic and credible barriers that would prevent the project from being undertaken or completed and to demonstrate that by registering the project as a CDM project activity these realistic and credible barriers would be alleviated and the project enabled. Being a registered CDM project activity provides financial and institutional benefits that affect the viability of the project.

Attracting financing is the foremost relevant barrier identified for the development of the SRO HPP Project. Bolivian electricity prices are currently far too low to attract investments in hydropower stations, and there are no indications that prices will change substantially in the short term.

- Market Characteristics. The Bolivian electricity market is based on marginal cost dispatch. All thermal generators must submit their fuel costs within a regulated range on a biannual basis. Dispatch is organized by placing hydropower plants at the base and accumulating thermal units in order of variable cost, until demand is covered with a minimal system reserve. To date only 77% of the installed capacity is dispatched and therefore subject to firm capacity revenue. Drawing on Bolivia’s large reserves of natural gas[20], new gas-fired thermal power plants have been encouraged by the "Heart Law", instituted in 1999, and a bill drafted to create tax-exempt areas for energy export

[20] Bolivia holds Latin America's second-largest reserves of natural gas, after Venezuela. Most of the discoveries came about after 1998.

projects. Both instruments were intended to encourage companies to build gas-fired electricity generation capacity for export markets.

- Market Trends. The market is being driven towards a type of stand-by-investment period to secure enough demand growth in order to cover the existing over-installed capacity. During such a period, the energy process should be subject to minor variations caused only by the increasing use of more expensive thermal facilities. Once the goal of equilibrium between supply and demand is approached or reached, fuel costs may be pushed to the upper limit, thereby boosting power prices. Such a scenario typically does not prove to be sustainable, as every time a new generating investment enters the market, competition will push prices down until equilibrium has returned. Unless a long-term above-average power rate is guaranteed, new investments in hydropower plants will be discouraged.

- Access to Financing. High interest rates and short-term loans have characterized the domestic financial market in recent years[21]. While international financing sources offer more attractive interest rates and longer terms, they are difficult to access, particularly for small/medium projects in a developing country with low creditworthiness like Bolivia[22]. A high fiscal deficit and recurring political uncertainty have had the effect of suppressing private investment significantly. Moreover, as a relatively low-capacity renewable energy project, the SRO HPP Project also entails high transaction and project development costs per generation unit, which is not attractive for project financing.

- Project Cost Variation. The most significant risk in a hydroelectric project is the increase of the investment amount during the implementation period. In the case of the proposed CDM project activity, and based on the particular influence of the most unstable variable which is the civil works, it has been estimated that a 5% increase in the investment amount would fall in the normal range, and that a 10% increase in the investment amount is in the conservative range.

  Under these circumstances, it is certain that registration of the SRO HPP Project as a CDM project activity will alleviate the risk of an increased investment amount. The project investment decision has been tied to the use of the NPV as the key financial indicator, based on a 15% discount rate that is below the discount rate figure that would be used for a highly speculative-grade country like Bolivia.[23] As a result, the project activity NPV reaches a marginal value of $422,936 that cannot afford a 5% increase in the investment amount as illustrated under the present investment analysis.

[21] The average annual interest rates from the Bolivian Bank System are provided in the table below, considering the information available at the time of project investment decision.

YEAR	1997	1998	1999	2000	2001	2002	2003
Bolivian Nominal Annual Interest Rate [%]	15.56	14.87	14.54	15.14	14.63	11.78	10.89

Source: Instituto Nacional de Estadística (INE).

[22] Bolivia has a B credit rating, which is a highly speculative investment rating grade. B denotes significant credit risk.

[23] Ibid.

At the time of investment decision for the project activity, it was considered that predicting a CERs unit price in the range of 5 to 8 $/t was within acceptable limits. On the other hand, the CERs revenue stream would be affected by taxes and fees as follows: 5% estimated CDM fee, 8% estimated broker fee, and 21% estimated local taxes, for a total of 34% assigned to fees and taxes.

Those figures were used to work a sensitivity analysis covering variations in the project activity investment amount and CERs unit price, with results shown in table 18.

Table 18. NPV variation based on investment & CERs unit price sensitivities

INVESTMENT	CERs UNIT PRICE [$ / t CER]			
	$5.00	**$6.00**	**$7.00**	**$8.00**
100%	$1,003,992	$1,120,203	$1,236,415	$1,352,626
105%	$491,551	$607,762	$723,973	$840,185
110%	($21,547)	$94,664	$210,876	$327,087
115%	($535,290)	($419,079)	($302,867)	($186,656)

Figures in table 18 allow the following conclusions:

a) When the investment value remains at the original level (100% scenario) ,the CERs revenue stream increases the project activity financial hurdle to a considerable more attractive level than the one established by the marginal NPV of $422,936 (obtained when the project activity does not register as a CDM project activity).

b) The CERs revenue stream provides a solid comfort to the developer in case of a 5% increase in the investment amount (105% scenario).

c) The CERs revenue stream still allows a positive financial hurdle against a 10% investment amount increase (110% scenario), by leaving the NPV in the break-even range.

Additionally, the CERs revenue stream alleviates the financing barrier by reducing between $580,000 and $930,000 (based on the 5 to 8 $/t range for CERs) the direct investment required from the developer. If the original direct investment figure of $2,500,000 is used as a reference, then it may be concluded that the CERs revenue stream alleviates between 23% and 37% of the direct investment required from the developer.

<u>In conclusion, the approval and registration of the SRO HPP Project as a CDM project activity and the attendant benefits and incentives derived from the project activity, will alleviate the economic and financial hurdles and thus enable the project activity to be undertaken.</u>

In the case of the SRO HPP Project, the construction of the new power plant under the old concept including two low head units and one high head unit brought initial limitations to the financing due to the high costs involved in the equipment supply and the civil works. In particular, the need for a special, untypical structure to guarantee safety in an area prone to landslides increases cost and financing risk.

In order to find an optimized scheme that would allow cost savings during construction and increase the revenue stream from additional capacity and energy, Lahmeyer GmbH from Germany was hired as an expert consultant by the Owner. The optimized concept recommended by Lahmeyer included the reduction from two to one unit on the low head portion and the expansion of the high head head-pond to allow additional hourly regulating capacity for peak power benefit. This new concept ended up increasing the effective capacity by 30%.

Notwithstanding those improved figures, the project still remains below the attractive limit for financing due to the still high costs related to the need of including two generating units for only 16.3 MW of capacity and the related impact in the cost of civil works. These has been clearly reflected in the bidding process for the construction under turnkey basis, and the negotiations directed to reach a price cap substantially delayed the project implementation due to the lack of options to reduce the cost of the project.

Not even the expected benefits on the revenue stream of the SRO HPP Project, which will result from the cost-plus basis during the first three years of its commercial operation, are sufficient to offset the high costs. In 2003 (base year in terms of market information for the purpose of the 2004 investment decision period), the energy tariff at spot prices (marginal cost rate) reached 93% of the cost-plus based scenario and it was expected that spot energy prices may drop to an 84% average of the cost-plus rate in the following years.

The insurance proceeds expected to cover 85% of the SRO HPP Project overall investment have limited capacity to attract additional investment, considering that the resulting capital gain (difference between the amount of insurance proceeds and the depreciated value of destroyed portion of the Santa Rosa power station), is subject to pay 25% of income tax and at the same time causes a 7.3% tariff reduction for the sponsors' overall gross generation.

Therefore, even with the initial favourable energy and capacity rates, the significant investment savings from the retrofit of existing infrastructure, and the substantial investment coverage through insurance proceeds, the project does not provide sufficient basis to attract financing absent the CDM mechanism.

The registration of the SRO HPP Project as a CDM project activity and the sale of its resulting emission reduction credits in the international market will allow the developer to secure financing and thus to proceed with the construction. The developer has contracted a GHG brokerage firm, Natsource LLC, to advance marketing of the project's Certified Emission Reductions (CERs).

Even though the above-mentioned barriers demonstrate that the project developer would not be able to implement the SRO HPP Project, it cannot be claimed with utmost certainty that no other developer would have been able to accomplish it. It also cannot be claimed that the unfavourable situation for investment in similar projects is permanent and unchangeable. However, none of these considerations seem likely enough to cast substantial doubt on the claim that the project is in fact additional.

The prospect of registering the SRO HPP Project as a CDM project activity will help establish the reliability and creditworthiness of the developer, reducing the Project's perceived level of risk and, thereby, enabling its access to project financing.

The revenue stream for the developer is based on capacity and energy fees under cost-plus basis, and also energy fees under spot market rates. Composition of those revenues for year 2003 is summarized as follows:

Capacity revenue (cost plus basis)	55%
Energy revenue (cost plus basis)	43%

Energy revenue (marginal cost rate) 2%

The cost-plus basis will govern the revenue stream during the first three years of the project commercial operation. On the fourth year of operation the project will completely switch to the marginal cost rate for compensation of capacity and energy supply.

Once registered as a CDM project activity, the SRO HPP Project will be entitled to annual revenue from the sale of its CO_2 emission reduction credits. The project developers have estimated that this annual revenue would increase the total revenue from energy & capacity by as much as 10%. Although this represents only a small contribution to the Project's net revenue, it will help improve the Project's cash flow and thus its attractiveness. Moreover, the carbon revenue will be earned in hard currency, which further strengthens the Project's economics.

The initial source of funding for the project was foreseen to come from local banks, considering the high level of liquid resources available in the local financial market due to the tendency of increased savings and low allocation of financing in an economic environment characterized by high risk. However, the electricity market scenario is not promising enough to guarantee payback, considering the current level of marginal cost prices and the strong tendency for these to stay low. To date the existing utilities may guarantee payback capacity on marginal investments based on a revenue stream supported by a tariff that has reached the bottom limit, but those conditions are not favourable to stimulate the construction of new projects such as the SRO HPP.

In this context, the SRO HPP Project has sought a different source of funding through the issuance of bonds in the local market, which provides a more attractive interest rate. Although the bond-issuance strategy is more attractive in terms of project finance, it still does not entail a comfortable level of payback risk to investors, particularly given current payback difficulties at recently developed projects.

In summary, the Project's registration under the CDM will improve the overall investment scenario and significantly help to surmount the barriers to investment in the Project.

<u>Realistic and credible investment barriers have been identified, that may prevent the implementation of the proposed project activity from being carried out if the project activity is not registered as a CDM activity.</u>

When alternative 2 (the SRO HPP Project rebuilt with original characteristics as accepted by the underwriters in order to allow full coverage of the investment by the insurance proceeds, i.e. 12.5 MW) is compared with the proposed project activity, the following differences arise in terms of identified barriers:

- <u>Access to financing 1</u>. Alternative 2 relies fully in the insurance proceeds funds for project implementation; therefore financing barriers are significantly reduced.
- <u>Access to financing 2</u>. With alternative 2, the developer's overall tariff reduction is in the level of 4.9% (during the cost-plus basis period), which is a more attractive scenario than the 7.3% reduction caused by the implementation of the project activity; therefore cost impact barriers are lower, with a corresponding reduction in financing barriers due to the positive perception of the project in the developer's fixed tariff.
- <u>Access to financing 3</u>. An increase in the implementation cost for Alternative 2 would call for the project developer to consider providing direct financial support for the first time, facing smaller barriers due to the lower amount required to be collected.

- <u>Trends</u>. Alternative 2 involves a smaller installed capacity (MW), therefore the impact of entering the market and tending to reduce spot prices is lower.

The comparison of alternative 3 (nor the project activity or other alternatives are undertaken, allowing the project participants to receive the benefit of cashing-in the insurance proceeds) with the proposed project activity, brings the following differences in terms of identified barriers:

- <u>Access to financing 1</u>. Alternative 3 does not require a project implementation and is only concentrated in obtaining the payment of the corresponding insurance proceeds; therefore financing barriers are basically discarded.
- <u>Access to financing 2</u>. As a result of alternative 3, the developer's overall tariff reduction is in the level of 3.55% (during the cost-plus basis period), resulting in a far more attractive scenario than the 7.3% reduction caused by the implementation of the project activity; therefore cost impact barriers are lower, with a corresponding reduction in financing barriers due to the positive perception of the project in the developer's fixed tariff..
- <u>Access to financing 3</u>. If alternative 3 is adopted, all risks associated to the construction of a hydroelectric facility are erased; therefore implementation risk barriers, e.g. additional construction costs, are completely eliminated, with the corresponding reduction in financing barriers considering the tendency/perception for additional costs in hydropower projects.
- <u>Trends</u>. Alternative 3 does not involve new installed capacity (MW), therefore the impact of entering the market and tending to reduce spot prices is lower.

<u>The barriers identified for the implementation of the proposed project activity affect either less strongly or are eliminated when applied to the implementation scenario of alternatives 2 and 3, i.e. when compared with the implementation of the proposed project activity the identified barriers affect less the implementation of alternative 2 and do not prevent the implementation of alternative 3.</u>

<u>Step 3. Barrier analysis</u>

Not selected.

<u>Step 4. Common practice analysis</u>

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

The following analysis provides a thorough assessment of the state of play of private investment in hydroelectric activity in Bolivia, taking into account other activities implemented previously or underway at the time of the project activity investment decision, characterized such activities by being similar to the proposed project activity.

Recent developments relating to hydroelectric activity in Bolivia's power generation system are well reflected in the investment scenario that has emerged since the late 1990's. The installed capacity of hydropower generation was increased by 174 MW between 1998 and 2004, and all projects implemented during such period reached the investment decision stage without at least one of the following barriers:

a) The 1.30 $/TCF[24] natural gas price cap established by the Bolivian Government[25] for the electricity industry starting on January 2001, based on the enormous increase of natural gas reserves within the country. Considering that on December 2000 the maximum price registered for a thermal power plant reached 2.32 $/TCF[26], the new price cap significantly limited the energy price in the spot market.

b) A short (less than three years) cost-plus basis period guaranteeing capacity and energy prices that waved the variation risk in the spot market, a risk that throughout the years has proven to be high[27].

c) An unstable growth in the electricity demand[28] combined with a low average growth that discourages the investment scenario, compared to the period prior to 1999 when a sustainable 7% growth in the electricity demand was registered.

d) Minimum project financial indicators in order to secure a return for the developer. As part of the investment compromise during the privatization process of the electricity industry that started in 1994, new owners (private investors) had to comply with a minimum level of investment within a certain period, regardless of the investment financial feasibility hurdle.

The barrier analysis for the hydroelectric projects implemented between 1998 and 2004 is based on the four barriers listed above, and reports that:

- 47.4 MW (Cuticucho, Botijlaca and Huaji power stations). This new capacity entered commercial operation during 1998-1999 and was installed as part of an agreement between the SRO HPP Project's developer and the Bolivian government in order to guarantee a reliable level of supply to a portion of the grid that was about to be affected by capacity and energy shortfalls. At the time of investment decision the developer counted with the government repayment guarantee extended until year 2008 (> 10 years) as a cost-plus based umbrella on these investments.
- 10.8 MW (Killpani and Landara power stations). As part of an existing independent facility (subsystem) the project was incorporated into the market. This subsystem had been in commercial operation for several years and was originally conceived as part of a mining complex with the possibility of selling surplus generation to the spot market. In 2001 two of the existing power stations (Killpani and Landara) were expanded taking advantage of the existing hydraulic, energy transmission and road infrastructure. At the time of investment decision the 1.30 $/TCF natural gas price had not been enforced, and the unstable and low growth in the electricity demand had not been detected.
- 98 MW (Kanata, Chojlla and Yanacachi Stations). A set of completely new projects that entered commercial operation in 1998 (1% of the capacity), 1999 (7% of the capacity) and 2002 (92% of the capacity), and were implemented under the new Electricity Law which established that dispatch

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[24] TCF = thousand cubic feet.

[25] According to Supreme Decree No. 26037 dated December 22, 2000. See www.bolivia.gov.bo

[26] From "Operation Results for the SIN, year 2000" at www.cndc.bo

[27] Ibid.

[28] From "Operation Results for the SIN, year 2003" at www.cndc.bo

would be based on marginal cost of generation. At the time of investment decision the 1.30 $/TCF natural gas price had not been enforced, and the unstable and low growth in the electricity demand had not been detected.

- 18 MW (Santa Isabel station). Built as the expansion portion of an existing power plant that belongs to a power complex privatized in the mid 1990s, being the new owners obliged under the privatization terms to a determinate level of investment within a certain period. Therefore, the project developers were bound to treat the accomplishment of the investment as a higher priority than the financial feasibility indicators.

The circumstances under which the last 174 MW of hydropower were commissioned have changed radically and it is very unlikely that these facilities would have been built facing the above mentioned barriers. This hypothesis is supported by the absence of new hydro facilities in future investment plans.

In summary, and as explained above, new hydro developments like the SRO HPP Project face unreasonable implementation barriers under current investment conditions and market circumstances.

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

The barrier analysis presented under Sub-step 4a identifies that none of the hydropower projects implemented since 1998 may be considered similar to the proposed CDM project activity, based on the fact that essential distinctions exist in terms of: a) natural gas price caps that govern the market energy price, b) extended cost plus basis that minimize energy price variation in the spot market, c) a combination of unstable and low growth in the electricity demand, and d) minimum project financial indicators displaced as the governing figure for investment decision.

<u>Considering that Sub-step 4a demonstrates that the existence of other activities do not contradict the claim that the proposed project activity is financially unattractive or faces further financial barriers (as contended in step 2), it is certain the claim that the proposed project activity is not widely observed and is not common practice. Therefore, the proposed CDM project activity is additional under Step 4.</u>

Considering that all steps included in the “tool for the demonstration and assessment of additionality” have been fully satisfied, it has been demonstrated that the proposed CDM project activity is not the baseline scenario, therefore the SRO HPP Project can be deemed additional.

<u>Evidence that the incentive from the CDM was seriously considered in the decision to proceed with the project activity</u>

The project history is summarized in the sequential list of activities that follows[29], highlighting the corresponding CDM related activities in order to provide evidence that the incentive from the CDM was seriously considered in the decision to proceed with the project activity. This evidence is based on official, legal and/or other corporate documentation that was available at or prior to, the start of the project activity:

[29] Documented evidence that support the list of activities comprises: contracts, agreements, and letters, being all available with COBEE as well as with the acting second party.

- February 17, 2003. Santa Rosa HPP is destroyed by a landslide and severe damages are caused by floods to the remaining 10-plant cascade in the Zongo Valley.
- February 24, 2003. Mr Milos Stepanek, expert geotechnical engineer is retained to assess the damage throughout the valley. The final report includes a preliminary technical assessment of the reconstruction option for Santa Rosa HPP.
- April 23, 2003. ESAR-FUNGEOTEC S.R.L., a local consultant, is retained to carry on a geological/geotechnical assessment of the Santa Rosa HPP area for the possible reconstruction of the facility.
- **May, 2003. Internal discussion and evaluation (within COBEE) regarding project potential for CERs and possible financial feasibility that may be provided by potential CDM revenue.**
- June 23, 2003. A request for proposals covering consultancy services for the reconstruction of the Santa Rosa HPP is issued inviting the following renowned international companies: Lahmeyer International GmbH (Germany), AMEC (Canada), SwedPower AB (Sweden), and Colenco Power Engineering AG (Switzerland).
- September 11, 2003. A letter of award is issued assigning Lahmeyer GmbH the consultancy services for the planning and tendering stage of the project. The corresponding Contract is signed on October 28, 2003.
- **October 1, 2003. Agreement is signed with Natsource LLC to obtain assistance/assessment for the SRO HPP Project PDD preparation.**
- November 10, 2003. Lahmeyer issues the Project Concept Report.
- November 13, 2003. Site visit for potential EPC Contractors. Five renowned international equipment suppliers were invited as possible EPC Contract leaders: VA TECH, GE, ABB, ALSHTOM, VOITH-SIEMENS.
- **December 2, 2003. Agreement is signed with Natsource LLC to obtain brokerage services to mediate the sale of CERs from the SRO HPP Project.**
- February 12, 2004. Request for Proposals is issued for the SRO HPP Project under EPC basis to the following interested bidders: VA TECH, ALSHTOM, VOITH-SIEMENS.
- April 20, 2004. All three Bidders submit proposals.
- June 8, 2004. Contract negotiations begin with VA TECH as first ranked bidder.
- **August 2, 2004. Note of interest is obtained from the Bolivian Government to support the development of the SRO HPP Project as a CDM activity.**
- August 17, 2004. COBEE Board approves giving a special Power of Attorney to the General Manager in order to execute an EPC Contract for the Santa Rosa HPP Project for an amount up to $17.6 million.
- August 21, 2004. Insurance adjuster confirms $12.85 to indemnity COBEE for replacing a Santa Rosa HPP of liked characteristics as the damaged facility.

- August 29, 2004. EPC Contract is signed with VA TECH.
- September 17, 2004. Notice to Proceed is issued to EPC Contractor.
- **November 25, 2004. Agreement is signed with DNV to act as a DOE for the validation of the project activity.**

Therefore, the CDM incentive was considered on every stage of the project and permanent resources were allocated in order to: obtain support from an expert consultant with the purpose of guaranteeing compliance with CDM requirements, develop an attractive market scenario for the potential CERs through sound brokerage assessment, obtain host government support, retain an expert entity to perform as a DOE, and reflect the CERs market scenario in the project financial model throughout the planning stage and investment decision.

The investment decision

COBEE carried out the following analysis in the process to reach an investment decision:

1. Alternatives 1, 2, 3 and 4 were evaluated, and the NPV results obtained were the ones summarized in table 11. Alternative 4 attained a negative NPV well below a break-even point, hence it was discarded.

2. Among alternatives 1, 2 and 3, the latter emerged as the most financially attractive and alternative 2 as the second ranked based on NPV indicator.

3. When the potential benefits of the CDM incentive were introduced in the financial analysis (see table 18), alternative 1 displaced alternative 2, and ranked second on NPV basis.

4. Further in the analysis, it was established that the CDM benefits had also the potential to substantially reduce the gap between alternatives 1 and 3, providing COBEE an incentive to invest.

In the end, the CDM potential brought light on a benefit stream with significant impact in the project financial perspective, allowing alternative 1 to substantially reduce the financial gap with alternative 3, and becoming the governing incentive that COBEE required to resume a 70-year history of compromise as a hydropower investor in the country.

B.6. Emission reductions

B.6.1. Explanation of methodological choices:

The ACM0002 baseline methodology has been used without modifications. The methodology has been applied using Dispatch Data Analysis, Option c of the Consolidated Methodology for Grid Connected Projects, as this is the most complete of the options. The main source of data is the CNDC.

Only CO_2 emissions from electricity generation in fossil fuel-fired power displaced due to the Project are accounted for the baseline determination. The baseline scenario and the emission rate for the Project are calculated in Annex 3. The baseline scenario accounts for the effects of the SRO HPP Project on both the operating margin (affecting the operation of power plants on the grid) and the build margin (delaying or avoiding the construction of future power plants), and a corresponding emission rate is calculated to account for each of these effects. The spatial extent of the project electricity system is defined by the limits of the SIN, a grid that does not account for electricity transfers to and from other systems, defining therefore that there are neither imports nor exports in the project electricity system. The defaults used for the calculation of calorific values for fuel types and fuel oxidization, come from the IPCC GHG Gas Inventory Reference Manual (IPCC 2006).

The methodology is applied using the equations described in the following step-by-step process:

<u>STEP 1</u>: Calculate the Operating Margin (OM) emission factor ($EF_{OM,y}$) using the Dispatch Data Analysis approach and having the CNDC as the main source of information:

a) The ($EF_{OM,Dispatch\ Data,y}$) is calculated as the amount of emissions in tCO_2 associated with the operating margin ($E_{OM,y}$) divided by the generation of the project in MWh in year y (EG_y).

$$\boxed{EF_{OM,Dispatch\_Data,y} = \frac{E_{OM,y}}{EG_y}}$$

b) The $E_{OM,y}$ is calculated as the product of the generation of the project in MWh in each hour h (EG_h) and the hourly generation-weighted average emissions in tCO_2/MWh of the set of power plants n in the top 10% of the grid system dispatch order during hour h ($EF_{DD,h}$), accumulated for each hour of year y.

$$\boxed{E_{OM,y} = \sum_h EG_h \times EF_{DD,h}}$$

c) The $EF_{DD,h}$ is calculated as the accumulated product of the amount of fuel i in a mass or volume unit, consumed by the set of power plants n in hour h ($F_{i,n,h}$), and the CO_2 emission coefficient of fuel i in tCO_2 per mass or volume unit of the fuel, taking into account the carbon content of the fuels used by the set of power plants n and the percent oxidation of the fuel ($COEF_{i,n}$), divided by the electricity in MWh delivered to the grid by the set of power plants n ($GEN_{n,h}$) during hour h. Where the set of power plants n delivering electricity to the grid does not include low-operating cost and must-run power plants, and includes imports to the grid. In the particular case of the project activity, the following unit variations have been used based on the information available for power plants in the system[30]: $F_{i,n,h}$ has been expressed as the amount of fuel i in energy units (TJ), consumed by the set of power plants n in hour h, and $COEF_{i,n}$ has been expressed as the CO_2 emission coefficient of fuel i in tCO_2 per energy unit of the fuel (TJ), taking into account the carbon content of the fuels used by the set of power plants n and the percent oxidation of the fuel.

[30] The CNDC publishes heat rate values for every thermal unit in the system expressed in Btu/kWh for 50%, 75% and 100% loads.

$$EF_{DD,h} = \frac{\sum_{i,n} F_{i,n,h} \times COEF_{i,n}}{\sum_{n} GEN_{n,h}}$$

d) The $COEF_i$ is obtained as the product of the net calorific value per mass or volume unit of a fuel *i* (NCV_i), the oxidation factor of the fuel ($OXID_i$), and the CO_2 emission factor per unit of energy of the fuel *i* ($EF_{CO2,i}$).

To determine the set of plants (*n*), the CNDC provides: a) the grid system dispatch order of operation for each power plant of the system and for each hour *h*; and b) the amount of power (MWh) that is dispatched from all plants in the system during each hour that the project activity is operating (GEN_h). At each hour *h*, each plant's generation (GEN_h) is stacked using the merit order. The set of plants (*n*) consists of those plants at the top of the stack (i.e., having the least merit), whose combined generation ($\sum GEN_h$) comprises 10% of total generation from all plants during that hour.

The OM emission factor of the project activity has been calculated on *ex-post* basis, using the hourly generation of the system for the most recent year of available data[31] at the time of PDD submission, i.e. 2007; supported by the results of the most recent post dispatch statistic for the SIN[32] where the registered hourly generation of the project activity is informed. Under those conditions the value for the OM emission factor of the project activity is **0.661 tCO_2/MWh** (see details in Annex 3, Table A.3.1).

STEP 2: Calculate the Build Margin (BM) emission factor ($EF_{BM,y}$) following Option 1, Step 2 of the ACM0002 Methodology, using an *ex-post* approach based on the most recent information available on plants already built for sample group *m*. The sample group *m* is chosen as either the five power plants that have been built most recently or the power plant capacity additions in the electricity system that comprise 20% of the system generation in MWh, and that have been built most recently.

The BM emission factor ($EF_{BM,y}$)is calculated as the product of the total amount of fuel *i* in a mass or volume unit, consumed by the set of power plants *m* in year *y* ($F_{i,m,y}$), and the CO_2 emission coefficient of fuel *i* in tCO_2 per mass or volume unit of the fuel, taking into account the carbon content of the fuels used by the set of power plants *m* and the percent oxidation of the fuel ($COEF_{i,m}$), divided by the electricity in MWh delivered to the grid by the set of power plants *m* ($GEN_{m,y}$) during year *y*. In the particular case of the project activity, the following unit variations have been used based on the information available for power plants in the system[33]: $F_{i,m,y}$ has been expressed as the amount of fuel *i* in energy units (TJ), consumed by the set of power plants *m* in year *y*, and $COEF_{i,m}$ has been expressed as the CO_2 emission coefficient of fuel *i* in tCO_2 per energy unit of the fuel (TJ), taking into account the carbon content of the fuels used by the set of power plants *m* and the percent oxidation of the fuel.

[31] From daily post-dispatch reports published by the CNDC.

[32] From Post Dispatch hourly data for 2007, published by the CNDC.

[33] See reference 30.

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

Option 2 has been chosen to calculate the Build Margin emission factor $EF_{BM,y}$ *ex-post* based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. The sample group *m* consists of either the five power plants that have been built most recently, or the power plant capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. From these two options, it should be used that sample group that comprises the larger annual generation.

The BM emission factor of the project activity has been calculated using the sample group *m* defined by the power plant capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently, since this is the option that comprises the larger annual generation (see note under Table A.3.3 of Annex 3). The resulting $EF_{BM,y}$ is **0.440 tCO_2/MWh** (see details in Annex 3, Tables A.3.2 to A.3.4).

STEP 3: Calculate the baseline emission factor (*EFy*) as the weighted average of the Operating Margin emission factor and the Build Margin emission factor using the following formula:

$$EF_y = (w_{OM} \times EF_{OM,y}) + (w_{BM} \times EF_{BM,y})$$

where the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$), and $EF_{OM,y}$ and $EF_{BM,y}$ are calculated as described in Steps 1 and 2 above and are expressed in tCO_2/MWh.

For the purpose of the project activity the operating and build margin default weights have been adopted, with the following result:

$$Ef_y = (0.5 \times 0.661) + (0.5 \times 0.440) = \mathbf{0.551\ tCO_2/MWh}$$

Table 19 provides key information and data used to determine the baseline scenario.

Table 19. Data used to determine baseline scenario

Variable	Value	Data Source
Estimated Dispatch Data OM emission factor ($EF_{OM,y}$ in tCO_2/MWh)	0.661	Calculated using data from CNDC and IPCC
Estimated BM emission factor ($EF_{BM,y}$ in tCO_2/MWh)	0.440	Calculated using data from CNDC and IPCC
Estimated baseline emission factor (EF_y in tCO_2/MWh)	0.551	Calculated using data from CNDC and IPCC

Electricity generated by the project activity (*EG* in MWh)	80,000	Data from CNDC
Project activity baseline emissions (*BE* in tCO_2/year)	44,080	Calculated

B.6.2. Data and parameters that are available at validation:

Table 20. Data and parameters available at validation

Data / Parameter 1:	Conversion constant for C content to CO_2 fuel emission factor
Data unit:	non-dimensional
Description:	Conversion constant used to convert the Carbon content of fuels to CO_2 emission factor on a full molecular weight basis.
Source of data used:	IPCC
Value applied:	(44/12)
Justification of the choice of data or description of measurement methods and procedures actually applied:	Conversion constant in use by IPCC.
Any comment:	As per IPCC value.

B.6.3. Ex-ante calculation of emission reductions:

The project activity reduces carbon dioxide through substitution of grid electricity generation with fossil fuel fired power plants by renewable electricity. The emission reduction ER_y by the project activity during a given year *y* is the difference between baseline emissions (BE_y), project emissions (PE_y) and emissions due to leakage (L_y), as follows:

$$\boxed{ER_y = BE_y - PE_y - L_y}$$

Where the baseline emissions (BE_y in tCO_2) are the product of the baseline emission factor (Ef_y in tCO_2/MWh) calculated in Step 3 of B.6.1 above, times the electricity supplied by the project activity to the grid (EG_y in MWh).

The project activity is a run-of-river hydropower project; therefore it does not generate direct GHG emissions ($PE_y = 0$), and no leakage is associated to the Project ($L_y = 0$).

Therefore:

$$\boxed{ER_y = BE_y = EF_y \times EG_y}$$

B.6.4. Summary of the ex-ante estimation of emission reductions:

Table 21. Estimation of project activity emission reductions

Year	Estimation of project activity emissions (tonnes of CO_2 e)	Estimation of baseline emissions (tonnes of CO_2 e)	Estimation of leakage (tonnes of CO_2 e)	Estimation of overall emission reductions (tonnes of CO_2 e)
2009	0	44,080	0	44,080
2010	0	44,080	0	44,080
2011	0	44,080	0	44,080
2012	0	44,080	0	44,080
2013	0	44,080	0	44,080
2014	0	44,080	0	44,080
2015	0	44,080	0	44,080
Total (tonnes of CO_2 e)		308,560		308,560

B.7. Application of the monitoring methodology and description of the monitoring plan:

B.7.1. Data and parameters monitored:

The spatial extent of the SIN is clear and does not include connections to external electricity systems; hence electricity transfers from external grids (imports) and to external grids (exports) are not required to be monitored.

Table 22. Data and parameters monitored

Data / Parameter 2:	$COEF_i$
Data unit:	tCO_2 / TJ
Description:	CO_2 emission coefficient of each fuel type *i*, consumed by the relevant power sources and used to calculate the OM and BM emission factors.
Source of data to be used:	Local data if available or IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	56.10 tCO_2/TJ For tabulated data applied see electronic files (spreadsheets) for OM and BM calculations attached to PDD.

Description of measurement methods and procedures to be applied:	The net calorific value of the fuel is incorporated in the calculation of the amount of fuel[34]; therefore the emission factor per unit of energy of the fuel becomes the emission coefficient multiplied by the oxidation factor. This parameter shall be monitored on annual basis.
QA/QC procedures to be applied:	Local data shall be checked to be originated by a reliable source such as CNDC or equivalent.
Any comment:	Project current calculations include default IPCC values.

Data / Parameter 3:	$OXID_i$
Data unit:	number
Description:	Oxidation factor of each fossil fuel *i*.
Source of data to be used:	IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1.00
Description of measurement methods and procedures to be applied:	The use of IPCC default values is justified since local values are not available. This parameter shall be monitored on annual basis.
QA/QC procedures to be applied:	Local data shall be checked to be originated by a reliable source such as CNDC or equivalent.
Any comment:	Project current calculations include default IPCC values.

Data / Parameter 4:	$EF_{CO2,i}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor per unit of energy of fuel *i* consumed by the relevant power sources and used to calculate the OM and BM emission factors.
Source of data to be used:	IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	56.10 tCO_2/TJ For tabulated data applied see electronic files (spreadsheets) for OM and BM calculations attached to PDD.
Description of measurement methods and procedures to be applied:	The use of IPCC default values is justified due to the unavailability of local industry or country-specific values. Calculated multiplying the IPCC default value for natural gas (dry), expressed in tC/TJ, by 44/12 to reach tCO2/TJ. This parameter shall be monitored on annual basis.
QA/QC procedures to be applied:	Local data shall be checked to be originated by a reliable source such as CNDC or equivalent.
Any comment:	Project current calculations include default IPCC values.

[34] Due to the particular origin of the amount of fuel data and to simplify the overall calculation procedure, the net calorific value is relocated within the formulae without variations for the final results.

Data / Parameter 5:	EG_y
Data unit:	MWh
Description:	Generation of the project in year *y* used for OM emission factor calculation.
Source of data to be used:	CNDC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	79,213 MWh
Description of measurement methods and procedures to be applied:	Energy generation for each power plant in the SIN is determined through measurements and registers at 15-minute intervals. This parameter shall be monitored on daily basis.
QA/QC procedures to be applied:	Electricity supplied to the grid is monitored continuously. These data will be directly used for calculation of emission reductions. Sales record to the grid and other records are used to ensure consistency.
Any comment:	For the purpose of calculating emission reductions in section B.6, registered project energy generation from CNDC, available at www.cndc.bo, for year 2007 was used.
Data / Parameter 6:	EG_h
Data unit:	MWh
Description:	Generation of the project in each hour *h* used for OM emission factor calculation.
Source of data to be used:	CNDC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Varying according to hourly dispatch. For tabulated data applied see electronic files (spreadsheets) for OM calculation attached to PDD.
Description of measurement methods and procedures to be applied:	Energy generation for each power plant in the SIN is determined through measurements and registers at 15-minute intervals. This parameter shall be monitored on daily basis.
QA/QC procedures to be applied:	Electricity supplied to the grid is monitored continuously. These data will be directly used for calculation of emission reductions. Sales record to the grid and other records are used to ensure consistency.
Any comment:	For the purpose of calculating emission reductions in section B.6, registered post-dispatch project energy generation from CNDC, available at www.cndc.bo, for year 2007 was used.
Data / Parameter 7:	EF_y
Data unit:	tCO_2 / MWh
Description:	CO_2 emission factor of the grid.
Source of data to be used:	COBEE
Value of data applied for the	0.551 tCO_2/MWh

purpose of calculating expected emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	Calculated as a weighted sum of the OM and BM emission factors. This parameter shall be monitored on annual basis.
QA/QC procedures to be applied:	Verify use of proper formula and default values.
Any comment:	Calculation follows a straight forward procedure.

Data / Parameter 8:	$EF_{OM,y}$
Data unit:	tCO_2 / MWh
Description:	CO_2 Operating Margin emission factor of the grid.
Source of data to be used:	COBEE
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.661 tCO_2/MWh
Description of measurement methods and procedures to be applied:	Calculated as indicated for the dispatch data OM in the baseline methodology. This parameter shall be monitored on monthly basis.
QA/QC procedures to be applied:	Verify use of proper formulae and default values.
Any comment:	Calculation follows a step-by-step procedure.

Data / Parameter 9:	$EF_{BM,y}$
Data unit:	tCO_2 / MWh
Description:	CO_2 Build Margin emission factor of the grid.
Source of data to be used:	COBEE
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.440 tCO_2/MWh
Description of measurement methods and procedures to be applied:	Calculated over recently built power plants as indicated in the baseline methodology. This parameter shall be monitored on monthly basis.
QA/QC procedures to be applied:	Verify use of proper formulae and default values.
Any comment:	Calculation follows a step-by-step procedure.

Data / Parameter 10:	$F_{i,n/m,h/y}$
Data unit:	TJ
Description:	Amount of each fossil fuel *i* consumed by the relevant power sources *n* and *m*, in hour *h* and year *y*, expressed in energy units and used to calculate the OM and BM emission factors.
Source of data to be used:	CNDC

Value of data applied for the purpose of calculating expected emission reductions in section B.5	Varying according to hourly dispatch. For tabulated data applied see electronic files (spreadsheets) for OM and BM calculations attached to PDD.
Description of measurement methods and procedures to be applied:	Fuel consumption is not available at CNDC; hence it is obtained through heat rate values applicable for different power plant loads and energy generation for each power plant in the SIN, forcing to express the amount of fuel in energy units, i.e. TJ [35]. Energy generation is determined through measurements and registers at 15-minute intervals. This parameter shall be monitored on bi-annual basis.
QA/QC procedures to be applied:	Electricity supplied to the grid is monitored continuously, and heat rate used to calculate fossil fuel consumed by power plants is formally declared on bi-annual basis by generators and verified by the CNDC, being available as public information.
Any comment:	Calculation based on overall CNDC data.

Data / Parameter 11:	NCV_i
Data unit:	TJ/m^3
Description:	Net calorific value per volume unit of each fossil fuel *i* consumed by the relevant power sources, and used to calculate heat rate for the amount of fuel in the OM and BM emission factors.
Source of data to be used:	CNDC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Values informed by CNDC are initially expressed in Btu/scf. For tabulated data applied see electronic files (spreadsheets) for OM and BM calculation attached to PDD.
Description of measurement methods and procedures to be applied:	Net calorific values for each fossil fuel are registered by gas supply companies, reported to generating companies, and later submitted to the CNDC as a formal declaration. Data is measured on daily basis and reported as weekly and monthly averages for use by the CNDC. This parameter shall be monitored on bi-annual basis.
QA/QC procedures to be applied:	Net calorific values for each fossil fuel are monitored continuously following the standards of the American Gas Association (AGA) and are subject to be verified by the CNDC, being available as public information.
Any comment:	Calculation based on overall CNDC data.

Data / Parameter 12:	$GEN_{n/m,h/y}$
Data unit:	MWh
Description:	Electricity delivered to the grid by the relevant power sources *n* and *m*, in hour *h* and year *y*, used for OM and BM emission

[35] Energy units are of standard use in the industry to express the amount of fuel, e.g. Canadian Centre for Energy.

	factors calculation.
Source of data to be used:	CNDC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Varying according to hourly dispatch. For tabulated data applied see electronic files (spreadsheets) for OM and BM calculation attached to PDD.
Description of measurement methods and procedures to be applied:	Energy generation for each power plant in the SIN is determined through measurements and registers at 15-minute intervals. This parameter shall be monitored on daily basis.
QA/QC procedures to be applied:	Electricity supplied to the grid is monitored continuously. Sales record to the grid and other records are used to ensure consistency.
Any comment:	Calculation based on overall CNDC data.

Data / Parameter 13:	Plant name
Data unit:	Text
Description:	Set of power plants *n* in the top 10% of the grid system dispatch order during hour *h*, used for OM emission factor calculation.
Source of data to be used:	COBEE
Value of data applied for the purpose of calculating expected emission reductions in section B.5	For tabulated data applied see electronic files (spreadsheets) for OM calculation attached to PDD.
Description of measurement methods and procedures to be applied:	Identification of power plants in the top 10%, based on hourly data for 100% of the grid system dispatch. This parameter shall be monitored on monthly basis.
QA/QC procedures to be applied:	Use of standard tool developed to identify set of power plants.
Any comment:	Identification based on overall CNDC data.

Data / Parameter 14:	Plant name
Data unit:	Text
Description:	Set of power plants *m* comprising either the five power plants that have been built most recently, or the power plant capacity additions in the electricity system that comprise 20% of the system generation and that have been built most recently, and used for BM emission factor calculation.
Source of data to be used:	COBEE
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1. Guabira => 06-Oct-2007 2. Quehata => 01-Oct-2007 3. Guaracachi 11 => 14-Apr-2007 4. Aranjuez 9, 10, 11, 12 => 21-Ago-2006 5. Santa Isabel 5 => 10-May-2004 6. Landara 1 => 01-Ago-2001 7. Kilpani 3 + Landara 3 => 01-May-2001 8. Bulo Bulo 1 & 2 => 22-Jun-2000

	9. Huaji 1 y 2 => 07-Jun-1999
Description of measurement methods and procedures to be applied:	Identification of power plants based on historical data from CNDC. This parameter shall be monitored on monthly basis.
QA/QC procedures to be applied:	Use of certified information from the CNDC.
Any comment:	Identification based on overall CNDC data.
Data / Parameter 15:	Merit order
Data unit:	Text
Description:	The merit order in which power plants are dispatched by documented evidence.
Source of data to be used:	CNDC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	For tabulated data applied see electronic files (spreadsheets) for OM calculation attached to PDD.
Description of measurement methods and procedures to be applied:	Identification of merit order using the variable cost information published by the CNDC for every thermal unit in the system on hourly basis as part of the daily post dispatch report. This parameter shall be monitored on monthly basis.
QA/QC procedures to be applied:	Variable cost information of dispatched units is monitored continuously in parallel to the electricity supplied to the grid.
Any comment:	Identification based on overall CNDC data.

B.7.2. Description of the monitoring plan:

The objective of the monitoring plan is to define a standard for the collection and archiving of all relevant data necessary for determining the baseline for the project activity, according to the requirement of the monitoring methodology ACM0002.

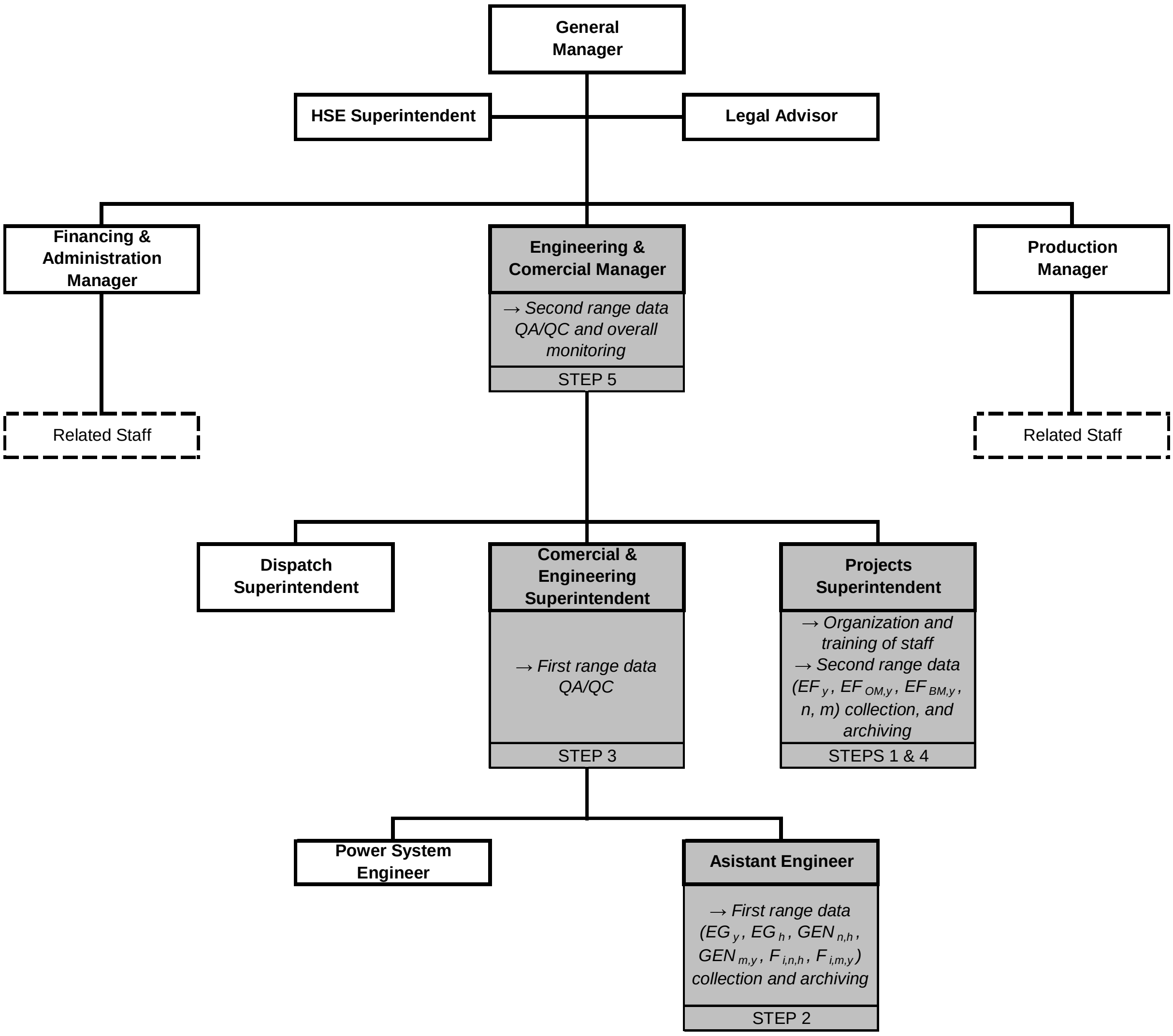
For the purpose of data and parameters to be monitored, the monitoring plan has identified two ranges:

1. The first range is comprised of data and parameters that have the CNDC as a source, including: energy generation (EG_y, EG_h, $GEN_{n,h}$, $GEN_{m,y}$), fossil fuel consumed by dispatched power plants ($F_{i,n,h}$, $F_{i,m,y}$), fuel characteristics ($COEF_i$, $OXID_i$, $EF_{CO2,i}$) and merit order in which power plants are dispatched.
2. The second range is comprised of data and parameters that have COBEE as a source, including: emission factors (EF_y, $EF_{OM,y}$, $EF_{BM,y}$) and plant name of the selected set of power plants (n, m).

The following organization chart illustrates the personnel involvement for the monitoring plan:

MONITORING PLAN

COBEE ORGANIZATION: Responsible personnel & step-by-step process



The step-by-step process for the monitoring plan is summarized as follows:

- STEP 1: The Projects Superintendent Branch will be in charge of organizing and training all responsible personnel in the appropriate monitoring, measurement and reporting techniques required to comply with the baseline methodology. The task is kept as part of the step-by-step procedure considering that the Projects Branch will further be responsible for routine training and maintenance.
- STEP 2: The Commercial Superintendent Branch will be responsible for monitoring (collection and archiving) 100% of data and parameters identified under the first range, being those data/parameters included in the daily post dispatch reports from the CNDC (see typical content in Annex 4), readily

available for commercial purposes.

- STEP 3: The head of the Commercial Superintendent Branch will be responsible for QA/QC for 100% of data and parameters identified under the first range. Project performance reviews and corrective actions shall be carried out as an extension of QA/QC for data and parameters under the first range.
- STEP 4: The Projects Superintendent Branch will be responsible for monitoring (analysis, calculation, collection and archiving) 100% of data and parameters identified under the second range, comprising the application of concepts, procedures and formulae as established in the baseline methodology, following calculation procedure executed on periodical basis of monthly extension.
- STEP 5: The head of the Engineering & Commercial Department will be responsible for QA/QC for 100% of data and parameters identified under the second range. Project performance reviews and corrective actions shall be carried our as an extension of QA/QC for data and parameters under the second range.

All archives for first and second range data/parameters will be kept on electronic basis during the crediting period and two years after.

The energy generation data collected from the CNDC under Step 1 above, is initially obtained by the Operational Unit (UO) of the CNDC based on the requirements established by the "Operational Standard No. 8 – Commercial Measurement System" [36]. This Operational Standard sets the rules for the installation, operation and maintenance of equipment dedicated to energy generation measurement in the SIN[37]. Equipment used for energy generation measurement is calibrated following the recommendations of the equipment manufacturer, i.e. with a frequency of five years.

B.8. Date of completion of the application of the baseline and monitoring methodology and the name of responsible person(s)/entity(ies):

Date of completion of the application of the methodology to the project activity study in DD/MM/YYYY:

31/07/2008

Name of person/entity responsible for the application of the baseline and monitoring methodology to the project activity:

Héctor Baldivieso
COBEE S.A.
Av. Hernando Siles No. 5635 – Obrajes
La Paz – Bolivia

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[36] See operational standards content at www.cndc.bo

[37] According to COBEE internal procedure P.ST.252 "Maintenance of Energy Metering Equipment" access, monitoring and calibration of grid and plant metering equipment is carried out under the same standards. Operational Standard No. 8 of the CNDC established the operation & maintenance standards for grid metering equipment; therefore it is confirmed that COBEE energy meters at the plant site comply with CNDC standards.

Tel.: (591) 2 278 2530
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hector.baldivieso@cobee.com

The person is a project participant listed in Annex 1.

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:

17/09/2004.

This date corresponds to the formal Notice to Proceed granted to Contractor under the terms of the EPC Contract[38] for the Santa Rosa HPP Reconstruction.

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

40y, 0m

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

The project will use a renewable crediting period.

C.2.1. Renewable crediting period

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

Expected 01/01/2009 (or earlier if registration has been completed).

C.2.1.2. Length of the first crediting period:

7y, 0m

[38] The EPC (Engineering Procurement and Construction) Contract was made effective as of 29/08/2004 and is available with COBEE as well as with the acting second party (Asociación SOLUZIONA S.A. and VA TECH ESCHER WYSS S.L.)

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Not applicable (N/A)

C.2.2.2. Length:

Not applicable (N/A)

SECTION D. Environmental impacts

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

Please see Annex 6.

D.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 activity are considered not-significant due to the fact that it will use most of the remaining infrastructure of a previous installation that was destroyed by a landslide. This fact reduces the potential impacts to a minimum when compared to a hydropower project of similar capacity and characteristics that would be implemented in an undisturbed area. Please see Annex 6 for details.

The project participants have developed an Environmental Impact Assessment to evaluate the environmental impacts related to the implementation of the project activity, as required by Law. On August 27, 2004 the project activity was formally granted the corresponding environmental license by the Ministry of Sustainable Development of Bolivia.

SECTION E. Stakeholders' comments

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

There have been consultations with the community that owns the land where the Project will be implemented as part of the requirements established for the environmental study as detailed in Annex 6.

E.2. Summary of the comments received:

The main comments obtained during the consultation process are summarized below:

1. The project participants must consider the employment of local labor for the different works to be performed during the construction of the facility.
2. COBEE must develop a permanent communication with the neighbouring communities in relation to the project activity.
3. The Project must have a strict compliance with environmental regulations, and all measures included in prevention and mitigation plans must be followed.

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

A negotiation process has taken place and a final agreement is being developed in order to allow proper compensation to the Community if land is affected beyond the area that belongs to COBEE. Once the final agreement is signed, it will be passed to the agrarian and electricity authorities in order to guarantee its fulfilment.

In the evidence of damage, it will be evaluated and, once agreements are obtained, they will be reported to the agrarian and electricity authorities in order to guarantee its fulfilment. The basic criterion established by the proponent of the project is that all negotiations will be based on giving proper compensation to the Community if land or other productive areas are affected. However, as the project will be implemented within an area that belongs to COBEE, no significant damages are anticipated.

All compensation values will be based on current market prices either for land and products.

The Company will establish an administrative mechanism to assure that all demands are thoroughly reviewed and all applicable compensation measures are fulfilled in a satisfactory manner.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Viceministry for Land and Environmental Planning
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E-Mail:	
URL:	
Represented by:	
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Represented by:	
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding is provided for the SRO HPP Project.

Annex 3

BASELINE INFORMATION

OM Emission factor

Table A.3.1 Summary for OM Emission Factor

Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Energy - MWh: Santa Rosa Unit 1	Energy - MWh: Santa Rosa Unit 2	EG_y [MWh]	$E_{OM,y}$ [tCO_2]
1-Jan-07	Monday, January 01, 2007	1.02	582.42	0.5715	149.6	124.25	273.85	155.48
2-Jan-07	Tuesday, January 02, 2007	1.17	659.86	0.5658	149.36	131.54	280.9	158.83
3-Jan-07	Wednesday, January 03, 2007	1.24	751.34	0.6059	149.73	130.12	279.85	169.66
4-Jan-07	Thursday, January 04, 2007	1.27	757.60	0.5967	149.41	129.12	278.53	165.85
5-Jan-07	Friday, January 05, 2007	1.31	825.04	0.6278	149.53	122.51	272.04	170.29
6-Jan-07	Sunday, January 07, 2007	1.10	622.72	0.5664	149.66	130.48	280.14	157.98
7-Jan-07	Sunday, January 07, 2007	1.10	622.72	0.5664	149.66	130.48	280.14	157.98
8-Jan-07	Monday, January 08, 2007	1.27	797.09	0.6259	149.76	83.33	233.09	142.36
9-Jan-07	Tuesday, January 09, 2007	1.31	828.58	0.6333	149.41	74.55	223.96	140.36
10-Jan-07	Wednesday, January 10, 2007	1.32	816.10	0.6170	149.37	121.11	270.48	165.35
11-Jan-07	Thursday, January 11, 2007	1.30	801.83	0.6154	148.88	128.17	277.05	169.73
12-Jan-07	Friday, January 12, 2007	1.29	772.92	0.5982	149.67	133.77	283.44	169.04
13-Jan-07	Saturday, January 13, 2007	1.24	764.11	0.6176	87.12	130.49	217.61	130.76
14-Jan-07	Sunday, January 14, 2007	1.11	621.72	0.5590	149.14	110.19	259.33	144.97
15-Jan-07	Monday, January 15, 2007	1.32	813.66	0.6148	126.18	124.76	250.94	153.04
16-Jan-07	Tuesday, January 16, 2007	1.31	780.92	0.5964	149.86	134.05	283.91	168.70
17-Jan-07	Wednesday, January 17, 2007	1.31	772.57	0.5916	149.63	130.8	280.43	165.51
18-Jan-07	Thursday, January 18, 2007	1.33	811.00	0.6090	149.81	129.57	279.38	169.33
19-Jan-07	Friday, January 19, 2007	1.34	779.55	0.5801	148.97	124.83	273.8	158.55
20-Jan-07	Saturday, January 20, 2007	1.23	744.29	0.6032	149.78	94.03	243.81	144.50
21-Jan-07	Sunday, January 21, 2007	1.05	638.07	0.6056	105.07	90.78	195.85	116.05
22-Jan-07	Monday, January 22, 2007	1.30	835.08	0.6436	149.48	129.2	278.68	178.59
23-Jan-07	Tuesday, January 23, 2007	1.37	861.76	0.6284	148.8	132.35	281.15	175.31
24-Jan-07	Wednesday, January 24, 2007	1.35	878.65	0.6531	149.36	125.83	275.19	178.89
25-Jan-07	Thursday, January 25, 2007	1.33	840.06	0.6315	136.43	126.13	262.56	164.16
26-Jan-07	Friday, January 26, 2007	1.33	890.03	0.6693	140.31	110.3	250.61	164.89
27-Jan-07	Saturday, January 27, 2007	1.25	828.50	0.6643	148.87	131.02	279.89	185.54
28-Jan-07	Sunday, January 28, 2007	1.10	718.41	0.6556	148.65	127.89	276.54	181.45
29-Jan-07	Monday, January 29, 2007	1.28	876.94	0.6849	149.76	128.53	278.29	190.11
30-Jan-07	Tuesday, January 30, 2007	1.32	876.92	0.6637	149.09	129.31	278.4	183.91
31-Jan-07	Wednesday, January 31, 2007	1.28	870.82	0.6777	148.31	128.87	277.18	187.32
1-Feb-07	Thursday, February 01, 2007	1.32	901.24	0.6803	145.12	127.19	272.31	184.66
2-Feb-07	Friday, February 02, 2007	1.35	933.35	0.6932	145.75	130.53	276.28	190.78
3-Feb-07	Saturday, February 03, 2007	1.26	862.15	0.6831	95.34	123.61	218.95	143.76
4-Feb-07	Sunday, February 04, 2007	1.12	744.20	0.6617	143.44	125.4	268.84	177.20
5-Feb-07	Monday, February 05, 2007	1.27	889.04	0.7008	113.79	128.29	242.08	168.75
6-Feb-07	Tuesday, February 06, 2007	1.33	908.39	0.6851	146.44	132.49	278.93	190.47
7-Feb-07	Wednesday, February 07, 2007	1.32	917.86	0.6936	144.83	135.38	280.21	194.33
8-Feb-07	Thursday, February 08, 2007	1.34	913.19	0.6807	151.47	135.63	287.1	194.02
9-Feb-07	Friday, February 09, 2007	1.36	922.25	0.6785	155.31	130.2	285.51	192.62
10-Feb-07	Saturday, February 10, 2007	1.25	851.40	0.6788	155.69	127.29	282.98	191.75
11-Feb-07	Monday, February 12, 2007	1.34	893.49	0.6669	155.9	126.62	282.52	187.43
12-Feb-07	Monday, February 12, 2007	1.34	893.49	0.6669	155.9	126.62	282.52	187.43
13-Feb-07	Tuesday, February 13, 2007	1.37	933.73	0.6802	156.21	131.68	287.89	195.14
14-Feb-07	Wednesday, February 14, 2007	1.37	934.41	0.6823	156.08	127.82	283.9	193.45
15-Feb-07	Thursday, February 15, 2007	1.33	881.11	0.6628	156.42	128.08	284.5	188.27
16-Feb-07	Friday, February 16, 2007	1.25	828.05	0.6601	156.86	129.89	286.75	189.14
17-Feb-07	Saturday, February 17, 2007	1.12	713.56	0.6350	156.83	133.77	290.6	184.00
18-Feb-07	Sunday, February 18, 2007	1.00	585.36	0.5848	157.11	127.77	284.88	166.31
19-Feb-07	Monday, February 19, 2007	1.00	599.61	0.6008	153.2	123.13	276.33	166.09
20-Feb-07	Tuesday, February 20, 2007	0.97	582.73	0.5980	155.49	125.51	281	167.99
21-Feb-07	Wednesday, February 21, 2007	1.22	802.61	0.6576	155.85	127.35	283.2	185.71
22-Feb-07	Thursday, February 22, 2007	1.32	870.67	0.6617	155.69	128.81	284.5	187.66
23-Feb-07	Friday, February 23, 2007	1.34	897.46	0.6675	155.69	123.88	279.57	186.43
24-Feb-07	Saturday, February 24, 2007	1.27	882.79	0.6928	155.67	134.21	289.88	200.03
25-Feb-07	Sunday, February 25, 2007	1.13	726.77	0.6439	154.98	124.4	279.38	179.49
26-Feb-07	Monday, February 26, 2007	1.32	900.93	0.6824	156.01	129	285.01	193.20
27-Feb-07	Tuesday, February 27, 2007	1.38	917.97	0.6653	155.9	127.27	283.17	187.77
28-Feb-07	Wednesday, February 28, 2007	1.37	945.09	0.6906	156.83	138.8	295.63	203.67

Table A.3.1 Summary for OM Emission Factor

Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Energy - MWh		EG_y [MWh]	$E_{OM,y}$ [tCO_2]
					Santa Rosa Unit 1	Santa Rosa Unit 2		
1-Mar-07	Thursday, March 01, 2007	1.33	884.16	0.6655	157.91	132.03	289.94	192.30
2-Mar-07	Friday, March 02, 2007	1.31	869.58	0.6630	158.01	128.64	286.65	189.52
3-Mar-07	Saturday, March 03, 2007	1.21	798.53	0.6619	158.05	132.77	290.82	192.06
4-Mar-07	Sunday, March 04, 2007	1.10	664.70	0.6056	158.28	126.63	284.91	170.18
5-Mar-07	Monday, March 05, 2007	1.32	910.36	0.6906	157.21	130.98	288.19	197.44
6-Mar-07	Tuesday, March 06, 2007	1.36	946.01	0.6939	157.87	125.51	283.38	196.24
7-Mar-07	Wednesday, March 07, 2007	1.37	945.68	0.6890	156.85	131.73	288.58	197.76
8-Mar-07	Thursday, March 08, 2007	1.38	953.50	0.6927	158.06	128.24	286.3	197.46
9-Mar-07	Friday, March 09, 2007	1.37	914.99	0.6691	158.24	133.16	291.4	194.57
10-Mar-07	Saturday, March 10, 2007	1.26	814.57	0.6486	158.12	127.65	285.77	185.16
11-Mar-07	Sunday, March 11, 2007	1.11	680.21	0.6150	158.09	131.17	289.26	177.49
12-Mar-07	Monday, March 12, 2007	1.30	842.06	0.6491	157.87	132.05	289.92	187.37
13-Mar-07	Tuesday, March 13, 2007	1.36	871.33	0.6411	158.13	120.73	278.86	177.77
14-Mar-07	Wednesday, March 14, 2007	1.38	886.66	0.6432	157.58	123.37	280.95	179.85
15-Mar-07	Thursday, March 15, 2007	1.35	870.00	0.6422	158.2	136.08	294.28	188.11
16-Mar-07	Friday, March 16, 2007	1.36	863.82	0.6361	155.75	130.39	286.14	181.78
17-Mar-07	Saturday, March 17, 2007	1.23	762.11	0.6200	158	134.77	292.77	179.81
18-Mar-07	Sunday, March 18, 2007	1.10	643.76	0.5842	60.47	111.85	172.32	100.09
19-Mar-07	Monday, March 19, 2007	1.29	867.72	0.6745	111.08	124.92	236	160.12
20-Mar-07	Tuesday, March 20, 2007	1.36	862.57	0.6348	136.24	136.95	273.19	172.86
21-Mar-07	Wednesday, March 21, 2007	1.38	869.35	0.6283	132.19	125.17	257.36	161.81
22-Mar-07	Thursday, March 22, 2007	1.39	888.38	0.6384	139.67	135.71	275.38	175.17
23-Mar-07	Friday, March 23, 2007	1.41	882.24	0.6263	137.72	128.19	265.91	166.69
24-Mar-07	Saturday, March 24, 2007	1.33	871.84	0.6566	138.19	136.25	274.44	179.90
25-Mar-07	Sunday, March 25, 2007	1.17	710.58	0.6061	83.55	126.28	209.83	127.11
26-Mar-07	Monday, March 26, 2007	1.39	856.42	0.6156	158.12	135.52	293.64	180.01
27-Mar-07	Tuesday, March 27, 2007	1.42	858.61	0.6051	158.09	128.02	286.11	172.74
28-Mar-07	Wednesday, March 28, 2007	1.41	887.22	0.6303	158.11	134.57	292.68	183.99
29-Mar-07	Thursday, March 29, 2007	1.42	877.86	0.6202	158.13	130.93	289.06	178.92
30-Mar-07	Friday, March 30, 2007	1.41	882.27	0.6265	158.06	134.78	292.84	182.77
31-Mar-07	Saturday, March 31, 2007	1.28	779.23	0.6101	145.16	135.88	281.04	171.09
1-Apr-07	Sunday, April 01, 2007	1.12	652.54	0.5816	155.74	119.42	275.16	159.67
2-Apr-07	Monday, April 02, 2007	1.34	855.19	0.6389	155.79	147.63	303.42	191.84
3-Apr-07	Tuesday, April 03, 2007	1.41	901.27	0.6400	155.51	117.54	273.05	174.06
4-Apr-07	Wednesday, April 04, 2007	1.35	851.18	0.6291	158.15	144.55	302.7	190.08
5-Apr-07	Thursday, April 05, 2007	1.31	803.37	0.6130	158.1	126.59	284.69	173.67
6-Apr-07	Friday, April 06, 2007	1.11	637.29	0.5756	153.94	139.28	293.22	168.29
7-Apr-07	Saturday, April 07, 2007	1.12	697.36	0.6221	71.36	49.45	120.81	69.31
8-Apr-07	Sunday, April 08, 2007	1.10	620.03	0.5660	80.78	92.02	172.8	98.79
9-Apr-07	Monday, April 09, 2007	1.31	578.39	0.4405	157.37	148.05	305.42	137.45
10-Apr-07	Tuesday, April 10, 2007	1.38	527.25	0.3831	158.24	140.92	299.16	117.17
11-Apr-07	Wednesday, April 11, 2007	1.38	884.63	0.6407	151.54	152.05	303.59	194.07
12-Apr-07	Thursday, April 12, 2007	1.37	883.43	0.6465	158.16	145.61	303.77	195.90
13-Apr-07	Friday, April 13, 2007	1.37	880.86	0.6430	158.09	140.45	298.54	191.40
14-Apr-07	Saturday, April 14, 2007	1.29	475.28	0.3696	158.04	143.02	301.06	110.13
15-Apr-07	Sunday, April 15, 2007	1.15	577.64	0.5022	158.94	147.19	306.13	154.08
16-Apr-07	Monday, April 16, 2007	1.37	671.02	0.4889	159.56	151.22	310.78	152.38
17-Apr-07	Tuesday, April 17, 2007	1.40	732.80	0.5228	153.35	151.91	305.26	158.27
18-Apr-07	Wednesday, April 18, 2007	1.42	818.61	0.5776	156.68	151.89	308.57	176.46
19-Apr-07	Thursday, April 19, 2007	1.43	835.08	0.5851	148.25	149.59	297.84	173.81
20-Apr-07	Friday, April 20, 2007	1.43	908.67	0.6351	144.27	151.66	295.93	187.64
21-Apr-07	Saturday, April 21, 2007	1.31	800.25	0.6100	139.34	142.81	282.15	172.07
22-Apr-07	Sunday, April 22, 2007	1.15	747.18	0.6476	135.18	147.41	282.59	182.70
23-Apr-07	Monday, April 23, 2007	1.34	938.03	0.7002	135.32	145.38	280.7	196.11
24-Apr-07	Tuesday, April 24, 2007	1.37	1,000.79	0.7315	126.53	140.88	267.41	194.98
25-Apr-07	Wednesday, April 25, 2007	1.40	1,003.04	0.7187	127.34	160.39	287.73	206.85
26-Apr-07	Thursday, April 26, 2007	1.33	1,088.19	0.8201	133.76	148.69	282.45	235.52
27-Apr-07	Friday, April 27, 2007	1.29	1,107.02	0.8554	129.99	151.35	281.34	242.84
28-Apr-07	Saturday, April 28, 2007	1.22	985.49	0.8073	149.15	157.72	306.87	245.37
29-Apr-07	Sunday, April 29, 2007	1.10	925.00	0.8400	140.43	144.36	284.79	234.96
30-Apr-07	Monday, April 30, 2007	1.25	801.74	0.6431	134.03	152.06	286.09	183.48

Table A.3.1 Summary for OM Emission Factor

					Energy - MWh			
Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Santa Rosa Unit 1	Santa Rosa Unit 2	EG_y [MWh]	$E_{OM,y}$ [tCO_2]
1-May-07	Wednesday, May 02, 2007	1.31	906.09	0.6909	116.44	153.66	270.1	186.00
2-May-07	Wednesday, May 02, 2007	1.31	906.09	0.6909	116.44	153.66	270.1	186.00
3-May-07	Thursday, May 03, 2007	1.38	958.78	0.6957	103.32	153.4	256.72	178.12
4-May-07	Friday, May 04, 2007	1.39	966.25	0.6970	91.84	151.64	243.48	169.61
5-May-07	Saturday, May 05, 2007	1.28	866.01	0.6742	90.84	153.42	244.26	164.61
6-May-07	Sunday, May 06, 2007	1.15	758.35	0.6618	88.32	147.25	235.57	156.20
7-May-07	Monday, May 07, 2007	1.29	870.38	0.6731	100.59	148.75	249.34	167.47
8-May-07	Tuesday, May 08, 2007	1.28	887.96	0.6953	106.81	150.82	257.63	179.00
9-May-07	Wednesday, May 09, 2007	1.30	844.66	0.6490	150.36	145.54	295.9	191.67
10-May-07	Thursday, May 10, 2007	1.30	836.97	0.6442	132.32	147.57	279.89	180.04
11-May-07	Friday, May 11, 2007	1.29	845.50	0.6543	102.92	150.39	253.31	165.98
12-May-07	Saturday, May 12, 2007	1.21	748.99	0.6179	93.01	152.35	245.36	151.32
13-May-07	Sunday, May 13, 2007	1.08	676.28	0.6276	94.09	149.58	243.67	152.79
14-May-07	Monday, May 14, 2007	1.28	848.99	0.6648	86.4	153.42	239.82	159.06
15-May-07	Tuesday, May 15, 2007	1.34	899.80	0.6692	86.69	147.57	234.26	156.83
16-May-07	Wednesday, May 16, 2007	1.36	949.10	0.6988	86.67	157.63	244.3	170.01
17-May-07	Thursday, May 17, 2007	1.32	890.80	0.6771	81.05	152.46	233.51	158.36
18-May-07	Friday, May 18, 2007	1.27	869.01	0.6829	78	158.4	236.4	161.42
19-May-07	Saturday, May 19, 2007	1.20	788.95	0.6550	78.99	147.82	226.81	148.61
20-May-07	Sunday, May 20, 2007	1.07	729.39	0.6788	62.84	150.35	213.19	144.64
21-May-07	Monday, May 21, 2007	1.28	913.92	0.7143	71.96	140.35	212.31	151.56
22-May-07	Tuesday, May 22, 2007	1.30	902.97	0.6939	69.05	141.47	210.52	145.87
23-May-07	Wednesday, May 23, 2007	1.30	869.16	0.6695	62.95	134.75	197.7	132.29
24-May-07	Thursday, May 24, 2007	1.31	884.50	0.6763	58.18	133.06	191.24	129.61
25-May-07	Friday, May 25, 2007	1.30	870.25	0.6686	46.46	127.57	174.03	115.49
26-May-07	Saturday, May 26, 2007	1.22	823.88	0.6728	52.57	128.17	180.74	120.82
27-May-07	Sunday, May 27, 2007	1.07	731.60	0.6823	46.58	125.91	172.49	118.03
28-May-07	Monday, May 28, 2007	1.26	860.78	0.6850	55.72	118.68	174.4	119.56
29-May-07	Tuesday, May 29, 2007	1.30	892.10	0.6849	48.47	133.78	182.25	124.93
30-May-07	Wednesday, May 30, 2007	1.31	892.57	0.6810	63.57	110.1	173.67	117.84
31-May-07	Thursday, May 31, 2007	1.32	917.50	0.6944	50.79	130.72	181.51	126.28
1-Jun-07	Friday, June 01, 2007	1.32	919.18	0.6970	51.09	117.44	168.53	117.61
2-Jun-07	Saturday, June 02, 2007	1.22	830.99	0.6812	57.29	131.32	188.61	127.73
3-Jun-07	Sunday, June 03, 2007	1.09	752.39	0.6928	51.87	112.91	164.78	114.62
4-Jun-07	Monday, June 04, 2007	1.26	864.82	0.6881	58.62	125.16	183.78	126.65
5-Jun-07	Tuesday, June 05, 2007	1.32	882.16	0.6708	63.45	116.12	179.57	120.73
6-Jun-07	Wednesday, June 06, 2007	1.33	910.81	0.6842	64.64	129.48	194.12	132.72
7-Jun-07	Thursday, June 07, 2007	1.14	784.61	0.6863	50.6	46.18	96.78	66.16
8-Jun-07	Friday, June 08, 2007	1.31	944.00	0.7197	58.76	11.63	70.39	50.68
9-Jun-07	Saturday, June 09, 2007	1.26	887.00	0.7066	48.97	0	48.97	34.52
10-Jun-07	Sunday, June 10, 2007	1.12	763.22	0.6816	43.28	0	43.28	29.23
11-Jun-07	Monday, June 11, 2007	1.34	944.69	0.7034	52.77	0	52.77	37.06
12-Jun-07	Tuesday, June 12, 2007	1.38	994.90	0.7216	45.95	0	45.95	33.31
13-Jun-07	Wednesday, June 13, 2007	1.37	967.12	0.7051	44.9	0	44.9	32.32
14-Jun-07	Thursday, June 14, 2007	1.39	1,002.38	0.7196	70.66	0	70.66	51.11
15-Jun-07	Friday, June 15, 2007	1.38	991.81	0.7209	77.8	0	77.8	56.17
16-Jun-07	Saturday, June 16, 2007	1.24	868.10	0.6979	69.83	0	69.83	49.37
17-Jun-07	Sunday, June 17, 2007	1.12	799.66	0.7166	54.16	0	54.16	38.85
18-Jun-07	Monday, June 18, 2007	1.29	915.37	0.7078	70.22	0	70.22	50.01
19-Jun-07	Tuesday, June 19, 2007	1.37	966.20	0.7050	69.94	0	69.94	49.68
20-Jun-07	Wednesday, June 20, 2007	1.39	998.74	0.7161	72.55	0	72.55	51.83
21-Jun-07	Thursday, June 21, 2007	1.40	1,016.75	0.7260	74.09	0	74.09	53.71
22-Jun-07	Friday, June 22, 2007	1.41	1,016.37	0.7207	65.4	0	65.4	47.14
23-Jun-07	Saturday, June 23, 2007	1.32	925.00	0.7012	56.21	0	56.21	39.45
24-Jun-07	Sunday, June 24, 2007	1.12	789.91	0.7065	48.29	42.77	91.06	62.28
25-Jun-07	Monday, June 25, 2007	1.27	886.24	0.6987	78.62	74.13	152.75	106.59
26-Jun-07	Tuesday, June 26, 2007	1.33	904.55	0.6820	57.69	75.15	132.84	91.54
27-Jun-07	Wednesday, June 27, 2007	1.34	934.12	0.6979	52.55	74.19	126.74	89.00
28-Jun-07	Thursday, June 28, 2007	1.33	925.94	0.6945	57.15	75.13	132.28	92.70
29-Jun-07	Friday, June 29, 2007	1.33	931.73	0.7008	53.01	70.12	123.13	86.88
30-Jun-07	Saturday, June 30, 2007	1.22	839.81	0.6861	38.62	83.69	122.31	83.79

Table A.3.1 Summary for OM Emission Factor

Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Energy - MWh			
					Santa Rosa Unit 1	Santa Rosa Unit 2	EG_y [MWh]	$E_{OM,y}$ [tCO_2]
1-Jul-07	Sunday, July 01, 2007	1.07	713.77	0.6671	32.11	68.29	100.4	66.94
2-Jul-07	Wednesday, May 02, 2007	1.31	906.09	0.6909	116.44	153.66	270.1	186.00
3-Jul-07	Tuesday, July 03, 2007	1.35	932.98	0.6926	47.72	73.56	121.28	84.64
4-Jul-07	Wednesday, July 04, 2007	1.37	969.92	0.7078	53.65	82.2	135.85	95.70
5-Jul-07	Thursday, July 05, 2007	1.37	952.36	0.6968	53	71.26	124.26	87.01
6-Jul-07	Friday, July 06, 2007	1.38	994.94	0.7205	50.84	85.24	136.08	97.79
7-Jul-07	Saturday, July 07, 2007	1.28	858.59	0.6722	73.19	70.84	144.03	96.78
8-Jul-07	Sunday, July 08, 2007	1.09	746.15	0.6862	48.82	79.01	127.83	86.57
9-Jul-07	Monday, July 09, 2007	1.23	833.02	0.6763	71.31	72.46	143.77	98.16
10-Jul-07	Tuesday, July 10, 2007	1.32	898.32	0.6831	72.35	69.11	141.46	96.85
11-Jul-07	Wednesday, July 11, 2007	1.32	877.52	0.6664	72.36	63.6	135.96	90.88
12-Jul-07	Thursday, July 12, 2007	1.31	881.68	0.6718	69.53	55.22	124.75	83.93
13-Jul-07	Friday, July 13, 2007	1.34	928.47	0.6910	69.02	74.32	143.34	99.67
14-Jul-07	Saturday, July 14, 2007	1.25	879.86	0.7037	63.51	105.93	169.44	119.53
15-Jul-07	Sunday, July 15, 2007	1.09	715.40	0.6576	68.29	108.16	176.45	115.71
16-Jul-07	Monday, July 16, 2007	1.23	831.38	0.6735	43.76	99.87	143.63	96.24
17-Jul-07	Tuesday, July 17, 2007	1.38	953.46	0.6900	65.11	100.9	166.01	114.89
18-Jul-07	Wednesday, July 18, 2007	1.34	956.78	0.7136	67.54	90.58	158.12	112.52
19-Jul-07	Thursday, July 19, 2007	1.32	938.22	0.7108	51.69	92.72	144.41	103.06
20-Jul-07	Friday, July 20, 2007	1.31	918.73	0.7035	54.97	99.92	154.89	109.17
21-Jul-07	Saturday, July 21, 2007	1.31	971.69	0.7418	62.42	111.08	173.5	128.58
22-Jul-07	Sunday, July 22, 2007	1.15	805.51	0.6990	41.83	119.15	160.98	112.62
23-Jul-07	Monday, July 23, 2007	1.30	908.82	0.7006	56.37	111.98	168.35	118.55
24-Jul-07	Tuesday, July 24, 2007	1.34	947.04	0.7052	66.36	113.36	179.72	126.78
25-Jul-07	Wednesday, July 25, 2007	1.36	928.90	0.6851	76.53	80.31	156.84	107.70
26-Jul-07	Thursday, July 26, 2007	1.37	940.07	0.6885	77.43	59.2	136.63	94.63
27-Jul-07	Friday, July 27, 2007	1.36	932.24	0.6836	68.45	80.32	148.77	100.63
28-Jul-07	Saturday, July 28, 2007	1.26	861.96	0.6866	39.59	53.89	93.48	64.12
29-Jul-07	Sunday, July 29, 2007	1.12	772.00	0.6868	36.2	59.58	95.78	66.19
30-Jul-07	Monday, July 30, 2007	1.32	910.64	0.6906	56.62	68.24	124.86	86.94
31-Jul-07	Tuesday, July 31, 2007	1.40	1,003.40	0.7181	63.95	63.26	127.21	91.98
1-Aug-07	Wednesday, August 01, 2007	1.38	1,012.51	0.7321	68.11	71.65	139.76	102.34
2-Aug-07	Thursday, August 02, 2007	1.39	1,000.34	0.7186	70.54	65.77	136.31	98.28
3-Aug-07	Friday, August 03, 2007	1.36	972.34	0.7160	73.9	63.86	137.76	98.72
4-Aug-07	Saturday, August 04, 2007	1.25	854.76	0.6842	41.73	55.22	96.95	66.64
5-Aug-07	Sunday, August 05, 2007	1.10	765.65	0.6953	51.72	66.87	118.59	82.79
6-Aug-07	Monday, August 06, 2007	1.10	744.89	0.6771	27.3	53.39	80.69	54.12
7-Aug-07	Tuesday, August 07, 2007	1.28	868.93	0.6785	68.12	69	137.12	92.58
8-Aug-07	Wednesday, August 08, 2007	1.37	958.13	0.7013	73.59	56.74	130.33	92.92
9-Aug-07	Thursday, August 09, 2007	1.41	1,004.70	0.7141	82.19	73.75	155.94	111.27
10-Aug-07	Friday, August 10, 2007	1.38	988.27	0.7164	82.63	60.31	142.94	102.58
11-Aug-07	Saturday, August 11, 2007	1.28	916.81	0.7177	76.17	86.38	162.55	117.32
12-Aug-07	Sunday, August 12, 2007	1.16	833.08	0.7211	62.73	111.85	174.58	126.42
13-Aug-07	Monday, August 13, 2007	1.36	954.12	0.6994	84.8	85.79	170.59	119.60
14-Aug-07	Tuesday, August 14, 2007	1.42	1,034.85	0.7271	75.93	74.68	150.61	109.75
15-Aug-07	Wednesday, August 15, 2007	1.42	1,048.27	0.7393	76.17	66.54	142.71	105.84
16-Aug-07	Thursday, August 16, 2007	1.40	1,026.84	0.7348	82.73	62.3	145.03	106.83
17-Aug-07	Friday, August 17, 2007	1.39	1,006.94	0.7236	78.3	63.26	141.56	102.72
18-Aug-07	Saturday, August 18, 2007	1.29	927.28	0.7177	80.94	50.71	131.65	94.77
19-Aug-07	Sunday, August 19, 2007	1.16	807.05	0.6961	70.87	59.49	130.36	91.10
20-Aug-07	Monday, August 20, 2007	1.34	949.71	0.7097	62.85	66.52	129.37	92.13
21-Aug-07	Tuesday, August 21, 2007	1.42	1,013.82	0.7162	72.98	53.98	126.96	91.01
22-Aug-07	Wednesday, August 22, 2007	1.43	1,038.91	0.7268	84.73	74.22	158.95	115.70
23-Aug-07	Thursday, August 23, 2007	1.46	1,083.47	0.7443	86.35	74.51	160.86	120.16
24-Aug-07	Friday, August 24, 2007	1.46	1,068.02	0.7296	80.54	79.38	159.92	117.21
25-Aug-07	Saturday, August 25, 2007	1.37	982.74	0.7175	48.64	45.1	93.74	67.77
26-Aug-07	Sunday, August 26, 2007	1.20	853.79	0.7135	42.57	63.84	106.41	76.31
27-Aug-07	Monday, August 27, 2007	1.35	971.06	0.7170	61.42	60.72	122.14	87.67
28-Aug-07	Tuesday, August 28, 2007	1.25	880.17	0.7021	62.51	73.16	135.67	94.18
29-Aug-07	Wednesday, August 29, 2007	1.35	974.58	0.7201	62.46	71.01	133.47	95.78
30-Aug-07	Thursday, August 30, 2007	1.37	974.94	0.7139	51.66	87.51	139.17	98.69
31-Aug-07	Friday, August 31, 2007	1.39	1,000.80	0.7211	62.56	83.09	145.65	105.50

Table A.3.1 Summary for OM Emission Factor

Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Energy - MWh		EG_y [MWh]	$E_{OM,y}$ [tCO_2]
					Santa Rosa Unit 1	Santa Rosa Unit 2		
1-Sep-07	Saturday, September 01, 2007	1.31	937.82	0.7186	47.68	80.46	128.14	91.62
2-Sep-07	Sunday, September 02, 2007	1.20	862.44	0.7168	39.71	76.03	115.74	82.78
3-Sep-07	Monday, September 03, 2007	1.43	1,059.75	0.7414	56.72	86.09	142.81	105.73
4-Sep-07	Tuesday, September 04, 2007	1.47	996.52	0.6778	64.27	74.03	138.3	92.37
5-Sep-07	Wednesday, September 05, 2007	1.48	1,084.31	0.7351	45.45	79.31	124.76	92.00
6-Sep-07	Thursday, September 06, 2007	1.46	1,060.89	0.7243	43.25	86.11	129.36	93.87
7-Sep-07	Friday, September 07, 2007	1.46	1,078.74	0.7370	47.22	102.9	150.12	110.87
8-Sep-07	Saturday, September 08, 2007	1.36	970.51	0.7146	50.78	118.06	168.84	120.13
9-Sep-07	Sunday, September 09, 2007	1.21	805.20	0.6632	56.41	133.44	189.85	126.42
10-Sep-07	Monday, September 10, 2007	1.45	1,020.74	0.7038	95.83	131.06	226.89	159.77
11-Sep-07	Tuesday, September 11, 2007	1.52	1,085.64	0.7163	95.87	121.96	217.83	156.01
12-Sep-07	Wednesday, September 12, 2007	1.53	1,106.59	0.7245	106.12	123.58	229.7	166.44
13-Sep-07	Thursday, September 13, 2007	1.56	1,106.82	0.7094	98.42	101.69	200.11	142.29
14-Sep-07	Friday, September 14, 2007	1.57	1,106.83	0.7046	81.72	76.19	157.91	111.09
15-Sep-07	Saturday, September 15, 2007	1.44	1,061.74	0.7384	83.94	71.68	155.62	114.11
16-Sep-07	Sunday, September 16, 2007	1.21	857.14	0.7089	50.82	91.35	142.17	100.33
17-Sep-07	Monday, September 17, 2007	1.48	1,092.83	0.7396	64.4	82.46	146.86	108.85
18-Sep-07	Tuesday, September 18, 2007	1.55	1,079.68	0.6951	54.75	83.37	138.12	94.71
19-Sep-07	Wednesday, September 19, 2007	1.55	1,135.94	0.7335	67.53	80.42	147.95	108.35
20-Sep-07	Thursday, September 20, 2007	1.58	1,124.24	0.7114	51.11	96.81	147.92	104.43
21-Sep-07	Friday, September 21, 2007	1.60	1,062.55	0.6650	44.84	79.46	124.3	80.87
22-Sep-07	Saturday, September 22, 2007	1.47	1,060.26	0.7224	75.52	79.35	154.87	110.93
23-Sep-07	Sunday, September 23, 2007	1.28	929.59	0.7270	52.15	86.89	139.04	101.17
24-Sep-07	Monday, September 24, 2007	1.33	878.51	0.6612	114.1	138.91	253.01	166.47
25-Sep-07	Tuesday, September 25, 2007	1.42	912.74	0.6450	88.02	116.91	204.93	129.92
26-Sep-07	Wednesday, September 26, 2007	1.46	974.70	0.6659	75.98	144.79	220.77	146.03
27-Sep-07	Thursday, September 27, 2007	1.50	1,006.09	0.6720	141.56	122.09	263.65	176.59
28-Sep-07	Friday, September 28, 2007	1.53	1,049.63	0.6872	139.56	139.21	278.77	190.39
29-Sep-07	Saturday, September 29, 2007	1.38	907.61	0.6562	136.11	128.5	264.61	173.44
30-Sep-07	Sunday, September 30, 2007	1.30	876.93	0.6767	101.11	119.41	220.52	149.54
1-Oct-07	Monday, October 01, 2007	1.53	1,055.57	0.6899	114.84	102.62	217.46	150.10
2-Oct-07	Tuesday, October 02, 2007	1.57	1,142.86	0.7293	125.17	115.3	240.47	175.42
3-Oct-07	Wednesday, October 03, 2007	1.58	1,109.87	0.7006	112.6	125.4	238	166.71
4-Oct-07	Thursday, October 04, 2007	1.53	1,143.57	0.7463	106.1	127.76	233.86	174.57
5-Oct-07	Friday, October 05, 2007	1.50	1,072.52	0.7169	80.51	111.24	191.75	137.46
6-Oct-07	Saturday, October 06, 2007	1.38	996.14	0.7198	52.62	108.66	161.28	116.21
7-Oct-07	Sunday, October 07, 2007	1.16	776.12	0.6690	52.78	102.35	155.13	103.56
8-Oct-07	Monday, October 08, 2007	1.41	1,018.65	0.7243	1.99	136.05	138.04	100.08
9-Oct-07	Tuesday, October 09, 2007	1.51	1,084.29	0.7204	0	117.73	117.73	84.20
10-Oct-07	Wednesday, October 10, 2007	1.58	1,085.25	0.6863	0	111.53	111.53	76.43
11-Oct-07	Thursday, October 11, 2007	1.52	1,119.64	0.7348	0	113.97	113.97	83.95
12-Oct-07	Friday, October 12, 2007	1.48	1,081.74	0.7314	0	106.82	106.82	78.02
13-Oct-07	Saturday, October 13, 2007	1.37	997.66	0.7261	0	105.35	105.35	76.44
14-Oct-07	Sunday, October 14, 2007	1.24	852.14	0.6899	47.5	110.03	157.53	107.67
15-Oct-07	Monday, October 15, 2007	1.43	1,014.88	0.7119	55.03	127.02	182.05	129.84
16-Oct-07	Tuesday, October 16, 2007	1.49	1,080.82	0.7264	76.7	126.68	203.38	147.68
17-Oct-07	Wednesday, October 17, 2007	1.51	1,029.59	0.6807	111.89	146.87	258.76	175.37
18-Oct-07	Thursday, October 18, 2007	1.54	1,056.04	0.6864	105.08	130.53	235.61	161.76
19-Oct-07	Friday, October 19, 2007	1.51	1,035.25	0.6850	92.38	134.61	226.99	155.70
20-Oct-07	Saturday, October 20, 2007	1.45	968.99	0.6666	77.65	147.67	225.32	150.31
21-Oct-07	Sunday, October 21, 2007	1.28	818.15	0.6376	76.25	143.39	219.64	139.52
22-Oct-07	Monday, October 22, 2007	1.47	1,003.46	0.6843	113.32	144.48	257.8	175.36
23-Oct-07	Tuesday, October 23, 2007	1.49	1,030.32	0.6899	137.02	149.27	286.29	196.60
24-Oct-07	Wednesday, October 24, 2007	1.51	1,053.37	0.6979	144.97	155.64	300.61	207.87
25-Oct-07	Thursday, October 25, 2007	1.56	1,107.01	0.7111	137.73	141.3	279.03	198.13
26-Oct-07	Friday, October 26, 2007	1.54	1,118.77	0.7260	119.19	143.3	262.49	191.05
27-Oct-07	Saturday, October 27, 2007	1.44	1,015.21	0.7047	119.06	104.38	223.44	156.48
28-Oct-07	Sunday, October 28, 2007	1.27	813.22	0.6385	138.89	139.77	278.66	178.37
29-Oct-07	Monday, October 29, 2007	1.54	1,035.34	0.6711	145.78	146.89	292.67	195.17
30-Oct-07	Tuesday, October 30, 2007	1.60	1,105.62	0.6914	146.08	139.46	285.54	196.64
31-Oct-07	Wednesday, October 31, 2007	1.55	1,009.67	0.6501	102.77	147.57	250.34	161.51

Table A.3.1 Summary for OM Emission Factor

					Energy - MWh			
Date	Day and Date	Gwh	t CO2	t CO2 / MWh	Santa Rosa Unit 1	Santa Rosa Unit 2	EG_y [MWh]	$E_{OM,y}$ [tCO_2]
1-Nov-07	Thursday, November 01, 2007	1.45	967.27	0.6658	150.12	133.81	283.93	189.06
2-Nov-07	Friday, November 02, 2007	1.17	703.91	0.6004	144.51	143.12	287.63	172.29
3-Nov-07	Saturday, November 03, 2007	1.26	872.29	0.6947	143.93	139.93	283.86	196.91
4-Nov-07	Sunday, November 04, 2007	1.19	785.46	0.6583	132.39	141.58	273.97	179.88
5-Nov-07	Monday, November 05, 2007	1.44	971.14	0.6755	131.21	138.74	269.95	181.32
6-Nov-07	Tuesday, November 06, 2007	1.49	1,008.60	0.6755	133.17	141	274.17	183.73
7-Nov-07	Wednesday, November 07, 2007	1.57	1,030.69	0.6567	138.3	136.17	274.47	179.28
8-Nov-07	Thursday, November 08, 2007	1.56	1,035.61	0.6632	138.36	135.58	273.94	181.16
9-Nov-07	Friday, November 09, 2007	1.56	1,034.85	0.6634	135.11	135.45	270.56	178.81
10-Nov-07	Saturday, November 10, 2007	1.41	954.59	0.6763	121.83	145.4	267.23	180.90
11-Nov-07	Sunday, November 11, 2007	1.16	743.13	0.6401	107.95	136.58	244.53	155.09
12-Nov-07	Monday, November 12, 2007	1.36	843.95	0.6222	139.58	139.57	279.15	173.39
13-Nov-07	Tuesday, November 13, 2007	1.47	977.14	0.6639	132.27	143.65	275.92	183.05
14-Nov-07	Wednesday, November 14, 2007	1.44	1,012.45	0.7016	135.96	134.57	270.53	189.28
15-Nov-07	Thursday, November 15, 2007	1.44	964.19	0.6699	136.55	145.14	281.69	188.48
16-Nov-07	Friday, November 16, 2007	1.49	1,008.91	0.6761	144.43	138.12	282.55	190.08
17-Nov-07	Saturday, November 17, 2007	1.45	987.52	0.6814	141.56	127.15	268.71	183.18
18-Nov-07	Sunday, November 18, 2007	1.32	820.43	0.6205	141.39	147.29	288.68	178.10
19-Nov-07	Monday, November 19, 2007	1.55	1,076.76	0.6938	142.29	138.42	280.71	193.54
20-Nov-07	Tuesday, November 20, 2007	1.51	1,046.14	0.6942	130.27	138.42	268.69	186.55
21-Nov-07	Wednesday, November 21, 2007	1.50	1,051.41	0.7026	152.34	143.06	295.4	206.96
22-Nov-07	Thursday, November 22, 2007	1.57	1,052.09	0.6685	146.08	136.11	282.19	187.14
23-Nov-07	Friday, November 23, 2007	1.57	1,038.15	0.6626	149.77	131.74	281.51	186.73
24-Nov-07	Saturday, November 24, 2007	1.35	858.63	0.6356	150.15	138.67	288.82	182.81
25-Nov-07	Sunday, November 25, 2007	1.26	755.76	0.6017	150.55	143.04	293.59	176.56
26-Nov-07	Monday, November 26, 2007	1.42	960.37	0.6779	150.98	140.07	291.05	196.79
27-Nov-07	Tuesday, November 27, 2007	1.53	1,008.86	0.6606	151.58	139.95	291.53	191.89
28-Nov-07	Wednesday, November 28, 2007	1.45	898.36	0.6200	152.52	141.15	293.67	181.58
29-Nov-07	Thursday, November 29, 2007	1.57	1,037.51	0.6592	153.36	134.96	288.32	189.20
30-Nov-07	Friday, November 30, 2007	1.63	1,053.48	0.6478	152.62	143.65	296.27	190.02
1-Dec-07	Saturday, December 01, 2007	1.50	1,029.36	0.6863	151.88	138.08	289.96	199.35
2-Dec-07	Sunday, December 02, 2007	1.31	820.28	0.6248	151.78	135.7	287.48	179.38
3-Dec-07	Monday, December 03, 2007	1.55	1,050.20	0.6795	152	137	289	195.69
4-Dec-07	Tuesday, December 04, 2007	1.54	1,073.46	0.6951	151.31	143.13	294.44	204.41
5-Dec-07	Thursday, November 29, 2007	1.57	1,037.51	0.6592	153.36	134.96	288.32	189.20
6-Dec-07	Thursday, December 06, 2007	1.51	989.95	0.6557	135.61	144.46	280.07	182.87
7-Dec-07	Friday, December 07, 2007	1.52	1,013.13	0.6648	133.53	138.27	271.8	180.42
8-Dec-07	Saturday, December 08, 2007	1.42	949.67	0.6676	125.55	144.3	269.85	179.83
9-Dec-07	Sunday, December 09, 2007	1.25	771.77	0.6156	132.37	142.99	275.36	169.73
10-Dec-07	Monday, December 10, 2007	1.46	979.64	0.6714	143.65	143.53	287.18	191.80
11-Dec-07	Tuesday, December 11, 2007	1.47	972.26	0.6632	139.39	147.36	286.75	186.53
12-Dec-07	Wednesday, December 12, 2007	1.51	968.93	0.6413	84.12	146.28	230.4	147.86
13-Dec-07	Thursday, December 13, 2007	1.48	987.89	0.6667	130	144.38	274.38	183.48
14-Dec-07	Friday, December 14, 2007	1.46	960.66	0.6571	130.71	145.78	276.49	181.21
15-Dec-07	Saturday, December 15, 2007	1.31	843.76	0.6426	145.16	59.88	205.04	129.55
16-Dec-07	Sunday, December 16, 2007	1.22	776.88	0.6354	138.74	50.94	189.68	121.59
17-Dec-07	Monday, December 17, 2007	1.46	979.87	0.6705	145.89	155.61	301.5	201.10
18-Dec-07	Tuesday, December 18, 2007	1.51	1,027.18	0.6788	134.35	147.76	282.11	191.56
19-Dec-07	Wednesday, December 19, 2007	1.52	1,032.53	0.6778	152.55	131.72	284.27	192.32
20-Dec-07	Thursday, December 20, 2007	1.52	1,021.12	0.6700	143.89	81.38	225.27	150.27
21-Dec-07	Friday, December 21, 2007	1.54	1,044.83	0.6790	140.24	40.55	180.79	122.18
22-Dec-07	Saturday, December 22, 2007	1.48	997.93	0.6731	123.32	25.6	148.92	100.11
23-Dec-07	Sunday, December 23, 2007	1.36	879.14	0.6452	152.81	31.18	183.99	118.43
24-Dec-07	Monday, December 24, 2007	1.46	935.64	0.6415	150.07	29.8	179.87	115.12
25-Dec-07	Tuesday, December 25, 2007	1.23	699.04	0.5664	148.98	40.71	189.69	107.46
26-Dec-07	Wednesday, December 26, 2007	1.44	923.96	0.6404	149.69	42.06	191.75	121.61
27-Dec-07	Thursday, December 27, 2007	1.46	953.92	0.6519	148.97	25.22	174.19	112.91
28-Dec-07	Friday, December 28, 2007	1.47	945.68	0.6436	150.14	31.37	181.51	116.65
29-Dec-07	Saturday, December 29, 2007	1.40	921.51	0.6572	152.65	24.66	177.31	116.03
30-Dec-07	Sunday, December 30, 2007	1.26	752.00	0.5959	148.8	24.09	172.89	103.16
31-Dec-07	Monday, December 31, 2007	1.43	930.54	0.6525	149.01	18.15	167.16	108.66
		489.72	328,987.55	244.73	39,360.81	40,259.62	**79,620.43**	**52,632.39**
							=> $EF_{OM,y}$ =	**0.661**

BM Emission Factor

Table A.3.2 SIN New Generation 1998-2007

Five Power Plants most recently built

No.	COMPANY	POWER STATION	UNIT	TYPE	COMMERCIAL OPERATION	EFFECTIVE CAPACITY	5 most recent	ENERGY 2007 [GWh]
16	HIDROELECTRICA BOLIVIANA	CHOJLLA ANTIGUA	CHJ 12	HYDRO	01-Sep-98	0.85		1.29
15	GUARACACHI	GUARACACHI	GCH 09	THERMO	03-May-99	59.85		335.47
14	GUARACACHI	GUARACACHI	GCH 10	THERMO	15-May-99	59.85		308.41
13	SYNERGIA	KANATA	KAN	HYDRO	24-May-99	7.60		17.21
12	COBEE	HUAJI	HUA 01 & 02	HYDRO	07-Jun-99	30.00		201.31
11	CEC BULO BULO	BULO BULO	BUL 01 & 02	THERMO	22-Jun-00	90.18		440.11
10	RIO ELECTRICO	KILPANI + LANDARA	KIL 03 + LAN 03	HYDRO	01-May-01	9.10		14.15
9	RIO ELECTRICO	LANDARA	LAN 01	HYDRO	01-Aug-01	1.65		0.00
8	HIDROELECTRICA BOLIVIANA	CHOJLLA + YANACACHI	CHJ + YAN	HYDRO	19-Jun-02	89.50		347.55
7	CORANI	SANTA ISABEL	SIS 05	HYDRO	10-May-04	18.03	**5**	2.34
6	COBEE	SANTA ROSA LH	SRO 01	HYDRO	03-Jun-06	7.00		39.48
5	COBEE	SANTA ROSA HH	SRO 02	HYDRO	18-Jul-06	10.50		39.73
4	GUARACACHI	ARANJUEZ	ARJ 9, 10, 11, 12	THERMO	21-Aug-06	6.40	**4**	45.00
3	GUARACACHI	GUARACACHI	GCH 11	THERMO	14-Apr-07	63.39	**3**	265.51
2	SDB	QUEHATA	QUE 01, 02	HYDRO	01-Oct-07	1.96	**2**	0.95
1	GUABIRA	GUABIRA	GBE 01	THERMO *	06-Oct-07	16.60	**1**	14.20
							TOTAL	**328.01**

Project Activity and power plants registered as CDM projects

Table A.3.3 SIN New Generation 1998-2007

Most recently built that comprise 20% of system generation

No.	COMPANY	POWER STATION	UNIT	TYPE	COMMERCIAL OPERATION	EFFECTIVE CAPACITY	20% most recent	ENERGY 2007 [GWh]
16	HIDROELECTRICA BOLIVIANA	CHOJLLA ANTIGUA	CHJ 12	HYDRO	01-Sep-98	0.85		1.29
15	GUARACACHI	GUARACACHI	GCH 09	THERMO	03-May-99	59.85		335.47
14	GUARACACHI	GUARACACHI	GCH 10	THERMO	15-May-99	59.85		308.41
13	SYNERGIA	KANATA	KAN	HYDRO	24-May-99	7.60		17.21
12	COBEE	HUAJI	HUA 01 & 02	HYDRO	07-Jun-99	30.00	**9**	201.31
11	CEC BULO BULO	BULO BULO	BUL 01 & 02	THERMO	22-Jun-00	90.18	**8**	440.11
10	RIO ELECTRICO	KILPANI + LANDARA	KIL 03 + LAN 03	HYDRO	01-May-01	9.10	**7**	14.15
9	RIO ELECTRICO	LANDARA	LAN 01	HYDRO	01-Aug-01	1.65	**6**	0.00
8	HIDROELECTRICA BOLIVIANA	CHOJLLA + YANACACHI	CHJ + YAN	HYDRO	19-Jun-02	89.50		347.55
7	CORANI	SANTA ISABEL	SIS 05	HYDRO	10-May-04	18.03	**5**	2.34
6	COBEE	SANTA ROSA LH	SRO 01	HYDRO	03-Jun-06	7.00		39.48
5	COBEE	SANTA ROSA HH	SRO 02	HYDRO	18-Jul-06	10.50		39.73
4	GUARACACHI	ARANJUEZ	ARJ 9, 10, 11, 12	THERMO	21-Aug-06	6.40	**4**	45.00
3	GUARACACHI	GUARACACHI	GCH 11	THERMO	14-Apr-07	63.39	**3**	265.51
2	SDB	QUEHATA	QUE 01, 02	HYDRO	01-Oct-07	1.96	**2**	0.95
1	GUABIRA	GUABIRA	GBE 01	THERMO *	06-Oct-07	16.60	**1**	14.20
							TOTAL	**983.57**

<u>**Note:**</u> *According to ACM0002 / Version 06:* If 20% falls on part capacity of a plant, that plant is fully included in the calculation. In this case HUAJI should be fully included in the calculation and the most recently built powerplants that comprise 20% of the system generation would have an annual generation higher than the five power plants that have been built most recently. As a result, the option of the power plants capacity addition comprising 20% of the system generation is chosen to calculate the Build Margin emission factor.

Project Activity and power plants registered as CDM projects

Table A.3.4 Summary from hourly data for calculation of BM Emission factor

	tCO2
Jan	29,273.58
Feb	28,574.79
Mar	18,184.37
Apr	27,423.15
May	36,308.33
Jun	34,255.08
Jul	35,894.46
Aug	40,242.81
Sep	38,869.14
Oct	45,127.77
Nov	49,346.17
Dec	49,289.83

Table A.3.5 Summary calculation of BM Emission factor

No.	UNIT	TYPE	COMMERCIAL OPERATION	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
12	HUA 01 & 02	HYDRO	07-Jun-99	11,198	10,169	11,081	10,638	9,138	5,708	4,614	4,287	5,140	8,017	10,214	11,303	**101,507**
				11,187	10,148	11,108	10,634	9,094	5,729	4,442	4,262	4,912	8,137	9,220	10,930	**99,802**
11	BUL 01 & 02	THERMO	22-Jun-00	25,276	24,653	2,415	0	0	0	0	0	0	11,899	26,685	27,913	**118,841**
				25,551	24,569	27,247	26,440	27,742	26,906	27,230	27,921	26,317	27,690	26,788	26,863	**321,264**
10	KIL 03	HYDRO	01-May-01													
	Lan 03	HYDRO	01-May-01	1,396	1,202	1,376	1,176	1,165	1,186	1,215	1,185	774	1,166	1,120	1,186	**14,147**
9	LAN 01	HYDRO	01-Aug-01													
8	CHJ + YAN	HYDRO	19-Jun-02													
7	SIS 05	HYDRO	10-May-04	0	0	0	2,337	0	0	0	0	0	0	0	0	**2,337**
6	SRO 01	HYDRO	03-Jun-06													
5	SRO 02	HYDRO	18-Jul-06													
4	ARJ 9	THERMO	21-Aug-06	291	933	986	962	1,023	1,055	1,071	1,016	960	942	876	1,002	**11,117**
	ARJ 10			1,147	953	995	970	1,031	1,055	1,058	877	859	949	837	979	**11,710**
	ARJ 11			447	953	997	969	1,048	1,059	1,107	949	960	815	958	737	**11,000**
	ARJ 12			1,046	813	997	814	685	1,053	1,077	980	993	854	992	875	**11,178**
3	GCH 11	THERMO	14-Apr-07				17,591	30,241	27,497	29,035	36,484	35,482	34,145	28,216	26,822	**265,515**
2	QUE 01, 02	HYDRO	01-Oct-07										305	283	362	**950**
1	GBE 01	THERMO *	06-Oct-07										3,985	4,389	5,827	**14,201**
			[MWh]	77,538	74,392	57,202	72,531	81,168	71,248	70,850	77,961	76,396	98,904	110,578	114,800	**983,569**
			[tCO_2]	29,274	28,575	18,184	27,423	36,308	34,255	35,894	40,243	38,869	45,128	49,346	49,290	**432,789**

$EF_{BM,y}$ [tCO_2/MWh]	**0.440**

Annex 4

MONITORING PLAN

The Monitoring Plan is described in Section B.7.2. This Annex includes a set of typical daily post dispatch reports, as published by the CNDC.

Daily Post Dispatch Report – Typical Content:

Comite Nacional de Despacho de Carga
UNIDAD OPERATIVA

DESPACHO DE CARGA REALIZADO (MW)
Friday, 18 de May de 2007

HORA	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00	TOTAL
SISTEMA ZONGO	85.9	84.1	84.4	83.2	82.1	80.2	89.7	126.0	111.2	102.1	102.2	101.6	98.0	98.1	102.3	102.7	101.5	102.2	137.7	137.2	137.2	120.1	109.7	83.2	2457.7
SISTEMA TAQUESI	26.1	0.0	0.0	0.0	0.0	0.0	0.0	26.2	26.4	26.4	0.0	0.0	0.0	0.0	0.0	0.0	26.7	44.3	81.0	80.3	81.0	80.5	80.4	54.1	629.0
SISTEMA CORANI	83.9	78.2	64.2	62.4	70.3	86.7	115.7	87.4	111.8	96.2	108.7	94.4	86.7	94.9	114.4	102.1	99.5	109.5	139.4	124.0	115.5	106.0	103.8	75.6	2363.5
SISTEMA MIGUILLA	13.3	13.3	13.3	13.2	13.3	13.2	13.1	13.1	13.4	13.4	13.7	13.6	13.7	13.6	13.6	13.6	13.6	13.7	15.8	15.8	15.8	15.8	15.8	13.3	331.7
SISTEMA YURA	5.2	5.2	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	12.5	17.2	17.2	17.2	17.2	7.9	4.2	182.6
KANATA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.6	6.8	6.9	6.9	6.9	0.0	0.0	38.2
SUBTOTAL HIDRO	214.3	180.8	167.3	164.3	171.2	185.6	224.1	258.3	268.3	243.1	229.5	214.7	203.3	211.7	235.3	223.4	252.3	288.7	397.8	381.3	373.5	346.5	317.6	230.4	6002.7
GCH1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GCH2	M	M	M	M	M	M	M	M	M	5.7	12.7	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.4
GCH4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GCH6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GCH7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GCH8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GCH9	0.0	0.0	0.0	0.0	0.0	15.9	48.4	47.0	56.5	50.4	43.5	39.2	39.2	38.8	38.6	45.3	39.6	55.3	58.5	58.2	58.5	39.6	0.0	0.0	769.0
GCH10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.5	47.2	47.2	39.0	39.1	39.5	45.8	37.1	55.9	59.7	59.0	59.3	50.4	39.8	39.8	706.1
GCH11	41.2	49.5	55.0	54.1	55.0	53.8	55.0	47.0	56.7	44.5	55.2	55.6	55.2	55.2	55.3	56.0	54.2	55.6	57.9	58.7	60.4	59.3	40.3	39.5	1275.8
BUL1	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	0.0
BUL2	36.3	36.7	36.4	36.2	36.2	36.1	37.3	40.4	38.2	38.0	38.1	38.2	38.1	38.1	37.9	38.2	38.0	38.0	40.7	40.2	41.0	40.3	40.2	37.7	908.0
CAR1	47.8	47.8	47.8	47.8	47.8	48.0	48.2	50.3	50.2	50.2	49.8	49.5	49.0	49.0	49.2	49.0	49.0	49.1	51.9	52.5	52.4	52.6	52.5	49.3	1194.0
CAR2	47.7	47.8	47.6	47.8	47.8	48.0	48.1	50.4	50.4	50.2	49.9	49.5	49.5	49.0	49.1	49.1	49.1	49.2	52.2	52.4	52.4	52.6	52.4	49.4	1192.0
VHE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VHE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.7	16.6	16.8	11.0	0.0	0.0	0.0	49.2
VHE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4	16.7	0.0	0.0	0.0	0.0	39.8
VHE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	16.7	0.0	0.0	0.0	0.0	20.2
KEN1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.9	7.9	8.0	7.8	7.7	7.6	7.6	7.4	5.9	7.6	8.2	8.3	8.4	8.4	0.0	0.0	110.3
KEN2	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	0.0
KAR	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	9.1	6.7
ARJ8	10.8	11.2	11.6	10.7	10.5	14.9	15.7	15.3	15.1	15.5	15.7	15.7	15.5	14.9	14.9	14.2	10.6	15.7	16.7	17.2	16.9	11.1	11.0	11.0	328.4
ARJ9	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.5	35.7
ARJ10	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.2	28.7
ARJ11	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	M	M	M	31.4
ARJ12	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	0.0
ARJ1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ARJ2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ARJ3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ARJ5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ARJ6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL TERMO	187.8	197.0	202.4	200.6	201.3	220.7	256.7	254.6	279.2	307.1	324.3	327.5	297.4	295.9	296.3	309.2	287.7	341.3	393.7	401.2	364.8	317.2	239.1	238.5	6731.7
TOTAL	402.1	377.8	369.7	364.9	372.5	406.3	480.8	512.9	547.5	550.2	553.8	542.2	500.7	507.5	531.5	532.6	540.1	630.1	791.5	782.6	738.3	663.7	556.7	468.9	12734.4
RESERVA ROTANTE	111.3	98.4	98.3	98.8	98.2	111.2	103.5	99.2	100.1	115.4	106.8	102.7	103.1	103.4	98.1	102.6	112.7	125.7	80.4	87.5	83.2	81.5	72.9	106.7	
RESERVA PARADA	348.3	348.8	349.4	350.0	350.7	284.2	284.4	283.8	271.8	202.5	198.9	196.8	216.1	214.4	213.8	213.8	216.1	200.2	164.1	164.1	202.1	221.2	296.4	296.4	
SEGURIDAD DE AREAS																									
NORTE	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	SI	

RF: Reserva Fría *ND: No Disponible* *M: Mantenimiento*

Comite Nacional de Despacho de Carga
UNIDAD OPERATIVA

DESPACHO DE CARGA REALIZADO
Friday, 18 de May de 2007

DESPACHO DE CENTRALES HIDROELECTRICAS (MW)

HORA	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00	TOTAL
SISTEMA ZONGO																									
ZONGO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.5	0.4	0.5	0.4	0.5	0.5	0.4	0.4	0.5	0.1	1.1	1.0	1.0	1.0	0.9	0.4	11.7
TIQUIMANI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	1.0	1.0	0.0	0.0	0.0	3.9
BOTIJLACA	0.5	0.5	0.5	0.5	1.5	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.6	2.5	2.5	2.5	4.5	4.5	4.5	2.0	2.0	1.0	52.8
CUTICUCHO	4.9	5.0	5.0	5.0	5.4	6.1	6.6	13.1	10.0	9.0	9.1	9.0	9.0	9.1	9.0	9.0	9.0	8.7	16.5	16.5	15.0	10.1	7.8	4.9	210.1
SANTA ROSA 1	1.8	2.0	2.1	2.1	2.1	2.3	2.5	4.7	3.6	3.5	3.4	3.2	3.2	3.2	3.2	3.2	3.3	4.0	5.5	5.5	5.2	4.0	2.5	2.0	76.4
SANTA ROSA 2	4.1	4.5	4.6	4.8	5.6	6.3	6.2	9.1	6.3	6.3	6.3	6.3	6.2	6.3	6.2	6.3	6.3	6.1	9.1	9.1	9.1	9.4	9.4	5.1	157.1
SAINANI	7.2	6.3	6.3	6.5	7.0	7.0	7.5	9.0	9.5	9.0	8.0	8.0	8.0	8.0	8.5	8.0	8.0	10.0	10.1	10.2	10.3	10.2	10.0	6.0	199.6
CHURURAQUI	12.0	12.1	11.5	11.4	9.9	10.0	12.5	21.5	18.8	13.6	14.7	15.0	14.6	14.6	14.6	14.2	14.2	15.7	22.2	22.0	21.0	16.3	13.8	12.1	354.5
HARCA	16.9	16.5	17.1	16.1	14.9	13.9	15.5	26.7	20.9	17.1	18.0	18.6	18.6	18.3	18.5	19.6	18.2	17.3	25.9	25.7	24.8	21.7	18.7	10.1	453.9
CAHUA	14.9	14.5	14.8	14.8	14.8	13.4	14.4	15.2	15.3	15.3	15.3	15.2	15.3	15.2	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.2	360.5
HUAJI	23.6	22.8	22.5	22.0	20.9	19.3	22.3	22.6	24.2	25.7	24.7	23.8	20.0	20.4	24.0	24.3	24.3	22.3	26.3	26.5	30.1	30.2	29.4	26.6	577.1
TOTAL ZONGO	85.9	84.1	84.4	83.2	82.1	80.2	89.7	126.0	111.2	102.1	102.2	101.6	98.0	98.1	102.3	102.7	101.5	102.2	137.7	137.2	137.2	120.1	109.7	83.2	2457.7
SISTEMA TAQUESI																									
CHOJLLA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0	34.8	34.4	34.6	34.6	34.6	24.6	198.6
YANACACHI	26.1	0.0	0.0	0.0	0.0	0.0	0.0	26.2	26.4	26.4	0.0	0.0	0.0	0.0	0.0	0.0	26.7	25.3	46.2	45.9	46.4	45.9	45.8	29.5	430.4
CHOJLLA ANTIGUA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL TAQUESI	26.1	0.0	0.0	0.0	0.0	0.0	0.0	26.2	26.4	26.4	0.0	0.0	0.0	0.0	0.0	0.0	26.7	44.3	81.0	80.3	81.0	80.5	80.4	54.1	629.0
SISTEMA CORANI																									
CORANI	36.4	30.6	21.7	22.3	25.8	38.0	44.8	39.6	41.2	43.7	47.8	39.0	40.8	42.0	42.8	42.2	42.9	48.3	52.3	50.3	50.8	45.3	45.4	39.6	968.0
SANTA ISABEL	47.5	47.6	42.5	40.1	44.5	48.7	70.9	47.8	70.6	52.5	60.9	55.4	45.9	52.9	71.6	59.9	56.6	61.2	87.1	73.7	64.7	60.7	58.4	36.0	1395.5
TOTAL CORANI	83.9	78.2	64.2	62.4	70.3	86.7	115.7	87.4	111.8	96.2	108.7	94.4	86.7	94.9	114.4	102.1	99.5	109.5	139.4	124.0	115.5	106.0	103.8	75.6	2363.5
SISTEMA MIGUILLA																									
MIGUILLA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.8	0.8	0.8	0.8	0.8	0.4	12.7
ANGOSTURA	3.4	3.4	3.4	3.4	3.4	3.4	3.3	3.3	1.3	1.3	3.4	3.4	3.4	3.4	3.4	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	76.8
CHOQUETANGA	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	5.6	5.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	5.6	5.7	5.7	5.7	5.7	4.5	114.8
CARABUCO	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.9	5.9	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	6.0	5.9	5.9	5.9	5.9	4.9	127.4
TOTAL MIGUILLA	13.3	13.3	13.3	13.2	13.3	13.2	13.1	13.1	13.4	13.4	13.7	13.6	13.7	13.6	13.6	13.6	13.6	13.7	15.8	15.8	15.8	15.8	15.8	13.3	331.7
SISTEMA YURA																									
KILLPANI	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	93.0
LANDARA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	41.0
PUNUTUMA	2.0	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.2	2.2	2.2	2.2	1.0	1.0	48.6
TOTAL YURA	5.2	5.2	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.4	5.4	5.4	5.4	4.2	4.2	182.6
KANATA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.6	6.8	6.9	6.9	6.9	0.0	0.0	38.2
TOTAL HIDRO	214.3	180.8	167.3	164.3	171.2	185.6	224.1	258.3	268.3	243.1	229.5	214.7	203.3	211.7	235.3	223.4	252.3	281.2	386.0	369.5	361.7	334.7	313.9	230.4	6002.7

Comité Nacional de Despacho de Carga
UNIDAD OPERATIVA

Hoja 3 de 4

COSTOS DE GENERACION TERMICA (US$/MWh)
Viernes, 18 de Mayo de 2007

	01:00	02:00	03:00	04:00	05:00	06:00	07:00	08:00	09:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
GCH01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH02	-	-	-	-	-	-	-	-	-	20.16	20.19	17.96	17.66	-	-	-	-	-	-	-	-	-	-	-
GCH04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH09	-	-	-	-	-	15.87	15.34	14.68	14.37	13.97	14.83	15.71	15.60	16.04	16.07	15.69	15.58	15.39	13.61	13.58	13.57	13.95	15.97	-
GCH10	15.82	-	-	-	-	-	-	-	-	15.90	15.45	14.81	15.37	16.04	16.07	15.69	15.70	15.40	13.62	13.57	13.57	13.75	14.81	15.88
GCH11	15.73	15.53	14.32	13.92	13.96	13.97	13.95	14.04	14.25	14.10	14.35	13.79	13.85	13.84	13.83	13.85	13.86	13.88	13.58	13.53	13.53	13.50	14.07	15.89
BUL01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BUL02	10.98	10.99	10.98	10.99	11.01	11.01	11.00	10.86	10.91	10.90	10.89	10.92	10.92	10.92	10.92	10.92	10.92	10.92	10.77	10.80	10.77	10.80	10.79	11.35
CAR01	12.93	12.93	12.93	12.93	12.93	12.93	12.91	12.78	12.77	12.78	12.79	12.82	12.84	12.87	12.87	12.87	12.88	12.87	12.71	12.70	12.68	12.68	12.68	12.84
CAR02	12.94	12.94	12.94	12.94	12.94	12.94	12.92	12.79	12.78	12.79	12.80	12.83	12.85	12.88	12.88	12.88	12.89	12.89	12.73	12.71	12.69	12.69	12.69	12.85
VHE01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VHE02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.36	17.05	16.14	16.12	18.18	-	-
VHE03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.93	16.14	17.25	-	-	-
VHE04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.27	16.14	18.22	-	-	-
KEN01	-	-	-	-	-	-	-	-	16.06	15.24	15.21	15.25	15.25	15.29	15.36	15.36	15.96	16.62	15.13	14.99	14.96	14.96	15.26	-
KEN02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KAR01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.25
ARJ08	16.38	16.38	16.37	16.36	16.36	15.60	15.04	14.84	14.82	15.01	14.93	15.08	15.02	15.10	15.07	15.14	16.13	16.63	14.92	14.78	14.78	14.86	16.44	16.42
ARJ09	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.74	11.74	11.74	11.74	11.74	11.74	11.74	11.74	11.66	11.66	11.66	11.66	11.65	11.73
ARJ10	11.76	11.76	11.76	11.76	11.76	11.76	11.76	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.63	11.63	11.63	11.63	11.63	11.70
ARJ11	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.72	11.65	11.65	11.65	12.22	-	-
ARJ12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Comité Nacional de Despacho de Carga
UNIDAD OPERATIVA

Hoja 4 de 4

ENERGIA Y COSTO DE UNIDADES FORZADAS
Viernes, 18 de Mayo de 2007

	MWh																								TOTAL
	01:00	02:00	03:00	04:00	05:00	06:00	07:00	08:00	09:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00	
GCH01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH02	-	-	-	-	-	-	-	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	0.4
GCH04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH09	-	-	-	-	-	-	11.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.2
GCH10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH11	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.5
BUL01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BUL02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAR01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAR02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VHE01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VHE02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	13.0	16.1	16.2	2.7	-	-	48.3
VHE03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.9	16.1	10.6	-	-	-	38.7
VHE04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6	16.1	2.7	-	-	-	20.4
KEN01	-	-	-	-	-	-	-	-	3.1	7.7	3.9	-	-	5.7	7.5	5.6	4.8	6.0	1.9	-	-	2.0	6.9	-	55.1
KEN02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KAR01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ08	10.6	10.8	11.3	10.8	10.8	13.1	15.4	16.2	16.3	15.4	15.8	3.8	11.6	15.1	15.3	15.0	11.7	10.6	-	-	-	3.7	10.9	11.0	255.3
ARJ09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	US$/MWh																							
	01:00	02:00	03:00	04:00	05:00	06:00	07:00	08:00	09:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
GCH01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH02	-	-	-	-	-	-	-	-	-	-	-	-	20.31	-	-	-	-	-	-	-	-	-	-	-
GCH04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH09	-	-	-	-	-	-	14.98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GCH11	-	-	-	-	-	-	13.91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BUL01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BUL02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAR01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAR02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VHE01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VHE02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.36	17.05	16.14	16.12	18.18	-	-
VHE03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.93	16.14	17.25	-	-	-
VHE04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.27	16.14	18.22	-	-	-
KEN01	-	-	-	-	-	-	-	-	16.06	15.24	15.20	-	-	15.29	15.36	15.36	16.16	16.62	15.26	-	-	14.96	15.26	-
KEN02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
KAR01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ08	16.38	16.38	16.37	16.36	16.36	15.60	15.04	14.84	14.82	15.01	14.93	15.04	15.00	15.10	15.07	15.14	16.13	16.63	-	-	-	15.12	16.44	16.42
ARJ09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ARJ06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annex 5

DOCUMENTATION RELATED TO THE DEMONSTRATION AND ASSESSMENT OF ADDITIONALITY

Supporting information for Table 7.

Table A.5.1 The 16.3 MW Santa Rosa HPP Project not undertaken as a CDM project activity Investment = $16,453,000

YEAR		ESCALATION FACTOR	PROJECT DEPRECIATION UNDER RATE BASE										
CALENDAR	PROJECT	for annual rate of 2.5%	INVESTMENT BOOK VALUE	CIVIL WORKS INVESTMENT PORTION	ELECTROMECHANICAL EQUIPMENT INVESTMENT PORTION	CIVIL WORKS DEPRECIATION RATE	ELECTROMECHANICAL EQUIPMENT DEPRECIATION RATE	INVESTMENT DEPRECIATION	DEPRECIATION OF ASSET BEFORE DESTRUCTION	DEPRECIATION OF PORTION OF ASSET DESTROYED	DEPRECIATION OF PORTION OF ASSET NOT DESTROYED	TOTAL DEPRECIATION OF REMAINING ASSETS	NET BOOK VALUE
(1)	(2)	(3)	(4) = $(14)_{year\ before}$	(5)	(6)	(7)	(8)	(9) = (4)*[(5)*(7)+(6)*(8)]	(10)	(11)	(12) = (10) - (11)	(13) = (9) + (12)	(14) = (4) - (13)
2004	0	0.976	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2005	1	1.000	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2006	2	1.025	$16,453,000	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$15,721,378
2007	3	1.051	$15,721,378	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$14,989,756
2008	4	1.077	$14,989,756	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$14,258,134
2009	5	1.104	$14,258,134	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$13,526,512
2010	6	1.131	$13,526,512	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$12,794,891
2011	7	1.160	$12,794,891	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$12,063,269
2012	8	1.189	$12,063,269	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$11,331,647
2013	9	1.218	$11,331,647	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$10,600,025
2014	10	1.249	$10,600,025	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$9,868,403
2015	11	1.280	$9,868,403	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$9,136,781
2016	12	1.312	$9,136,781	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$8,405,159
2017	13	1.345	$8,405,159	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$7,673,537
2018	14	1.379	$7,673,537	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$6,941,915
2019	15	1.413	$6,941,915	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$6,210,293
2020	16	1.448	$6,210,293	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$5,478,671
2021	17	1.485	$5,478,671	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$4,747,050
2022	18	1.522	$4,747,050	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$4,015,428
2023	19	1.560	$4,015,428	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$3,283,806
2024	20	1.599	$3,283,806	40%	60%	2%	4%	$526,496	$404,326	$199,200	$205,126	$731,622	$2,552,184

ESTIMATED PRICES & SALES (ENERGY & CAPACITY)												
REGULATED ENERGY PRICE [$/MWh]	REGULATED CAPACITY PRICE INCREASE	REGULATED CAPACITY PRICE [$/kW-month]	NOMINAL SPOT ENERGY PRICE [$/MWh]	REAL SPOT ENERGY PRICE [$/MWh]	NOMINAL SPOT CAPACITY PRICE [$/kW-month]	REAL SPOT CAPACITY PRICE [$/kW-month]	GROSS ENERGY [MWh]	ENERGY LOSSES	ENERGY SALES [MWh]	GROSS CAPACITY [MW-month]	CAPACITY LOSSES	CAPACITY SALES [MW-month]
(15)	(16)	(17) = [1+(16)]*$(17)_{year\ before}$	(18)	(19) = (3)*(18)	(20)	(21) = (3)*(20)	(22)	(23)	(24) = (22)*[1-(23)]	(25)	(26)	(27) = (25)*[1-(26)]
12.787		6.722	5.352	5.222	6.400	6.244	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	14.34%	7.686	6.272	6.272	6.400	6.400	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	-7.33%	7.123	10.102	10.354	6.400	6.560	80,000	2.93%	77,656	16.30	3.0%	15.81
12.787	-7.33%	6.600	10.934	11.488	6.400	6.724	80,000	2.93%	77,656	16.30	3.0%	15.81
12.787	-7.33%	6.117	11.378	12.253	6.400	6.892	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.379	12.561	6.400	7.064	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.288	12.771	6.400	7.241	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.214	13.005	6.400	7.422	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.349	13.490	6.400	7.608	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.326	13.800	6.400	7.798	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.542	14.414	6.400	7.993	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	14.463	6.400	8.193	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	14.824	6.400	8.397	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	15.195	6.400	8.607	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	15.575	6.400	8.822	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	15.964	6.400	9.043	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	16.363	6.400	9.269	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	16.772	6.400	9.501	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	17.192	6.400	9.738	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	17.621	6.400	9.982	80,000	2.93%	77,656	16.30	3.0%	15.81
			11.298	18.062	6.400	10.231	80,000	2.93%	77,656	16.30	3.0%	15.81

RATE BASE EFFECT FOR COMPANY (to be reflected in project economics)

INCREMENTAL ASSET BOOK VALUE	BASE CASE DEPRECIATION	INCREMENTAL DEPRECIATION	INCREMENTAL RATE BASE	INCREMENTAL ENERGY SALES [MWh]	INCREMENTAL CAPACITY SALES [MW]	INCREMENTAL OPERATING REVENUE	CAPITAL GAIN	TOTAL REVENUE	UNIT WHEELING TOLL [$/MWh]	INCREMENTAL WHEELING TOLL	CNDC FEE RATE	CNDC FEE	SIRESE FEE RATE	SIRESE FEE	TRANSACTION TAX RATE	TRANSACTION TAX	INCREMENTAL EBT	INCOME TAX RATE	INCOME TAX	NET INCOME	ADDITIONAL REVENUE TO REACH 9% RATE BASE
(28) = $(31)_{year\ before}$	(29) = 13,953,000* [(5)*(7)+(6)*(8)]	(30) = (9) - (29)	(31) = (28) - (30)	(32) = [(22)-80,000]*[1-(23)]	(33) = [(25)-12.5]*[1-(26)]	(34) = [(15)*(32)] +[(17)*(33)*1000*12]	(35) = (16,453,000-2,500,000) - (6,164,434-2,518,800)	(36) = (34)+(35)	(37)	(38) = (32)*(37)	(39)	(40) = (34)*(39)	(41)	(42) = (34)*(41)	(43) = 3%/0.87	(44) = (34)*(43)	(45) = (36)-[(30)+(38)+(40)+(42)+(44)]	(46)	(47) = [(46)*(45)] - $(44)_{next\ year}$	(48) = (45) - (47)	(49) = [9%*(31)]+(30)+(38)+(40)+(42)+(44)+(47)-(36)
$0	$0	$0	$0	0	0.00	$0		$0	1.277	$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0		$0	1.222	$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$2,500,000	$446,496	$80,000	$2,420,000	0	3.69	$315,045	$10,307,366	$10,622,411	1.626	$0	0.80%	$2,520	1.0%	$3,150	3.45%	$10,864	$10,525,876	25.0%	$2,621,402	$7,904,475	($7,686,675)
$2,420,000	$446,496	$80,000	$2,340,000	0	3.69	$291,952		$291,952	1.569	$0	0.80%	$2,336	1.0%	$2,920	3.45%	$10,067	$196,630	25.0%	$39,828	$156,802	$53,798
$2,340,000	$446,496	$80,000	$2,260,000	0	3.69	$270,552		$270,552	1.566	$0	0.80%	$2,164	1.0%	$2,706	3.45%	$9,329	$176,353	25.0%	$44,088	$132,265	$71,135
$2,260,000	$446,496	$80,000	$2,180,000						1.496		0.80%		1.0%		3.45%			25.0%			
$2,180,000	$446,496	$80,000	$2,100,000						1.421		0.80%		1.0%		3.45%			25.0%			
$2,100,000	$446,496	$80,000	$2,020,000						1.352		0.80%		1.0%		3.45%			25.0%			
$2,020,000	$446,496	$80,000	$1,940,000						1.354		0.80%		1.0%		3.45%			25.0%			
$1,940,000	$446,496	$80,000	$1,860,000						1.304		0.80%		1.0%		3.45%			25.0%			
$1,860,000	$446,496	$80,000	$1,780,000						1.217		0.80%		1.0%		3.45%			25.0%			
$1,780,000	$446,496	$80,000	$1,700,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,700,000	$446,496	$80,000	$1,620,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,620,000	$446,496	$80,000	$1,540,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,540,000	$446,496	$80,000	$1,460,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,460,000	$446,496	$80,000	$1,380,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,380,000	$446,496	$80,000	$1,300,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,300,000	$446,496	$80,000	$1,220,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,220,000	$446,496	$80,000	$1,140,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,140,000	$446,496	$80,000	$1,060,000						1.129		0.80%		1.0%		3.45%			25.0%			
$1,060,000	$446,496	$80,000	$980,000						1.129		0.80%		1.0%		3.45%			25.0%			

PROJECT REVENUE STREAM

RATE BASE REVENUE	SPOT MARKET REVENUE	DISTRIBUTION OF INSURANCE PROCEEDS	PAYMENT OF INSURANCE PROCEEDS	CAPITAL GAIN	ADDITIONAL REVENUE TO REACH 9% RATE BASE	TOTAL REVENUE
(50) = [(15)*(24)] + [(17)*(27)*1000*12]	(51) = [(19)*(24)] + [(21)*(27)*1000*12]	(52)	(53) = (52)*13,953,000	(54) = (35)	(55) = (49)	(56) = (50)+(51) +(53)+(54)+(55)
$1,971,058		15%	$2,092,950		$0	$4,064,008
$2,111,311		50%	$6,976,500		$0	$9,087,811
$2,344,384		35%	$4,883,550	$10,307,366	($7,686,675)	$9,848,626
$2,245,328					$53,798	$2,299,127
$2,153,533					$71,135	$2,224,669
	$2,315,748					$2,315,748
	$2,365,587					$2,365,587
	$2,418,094					$2,418,094
	$2,490,984					$2,490,984
	$2,551,114					$2,551,114
	$2,635,790					$2,635,790
	$2,677,503					$2,677,503
	$2,744,440					$2,744,440
	$2,813,051					$2,813,051
	$2,883,378					$2,883,378
	$2,955,462					$2,955,462
	$3,029,349					$3,029,349
	$3,105,082					$3,105,082
	$3,182,709					$3,182,709
	$3,262,277					$3,262,277
	$3,343,834					$3,343,834

PROJECT OPERATING EXPENSES

NOMINAL FIXED O&M COSTS	REAL FIXED O&M COSTS	NOMINAL VARIABLE O&M COSTS	REAL VARIABLE O&M COSTS	TOTAL WHEELING TOLL	CNDC FEE	SIRESE FEE	TRANSACTION TAX	TOTAL OPERATING EXPENSES
(57)	(58) = (3)*(57)	(59)	(60) = (3)*(59)	(61) = (24)*(37)	(62) = (39)* [(50)+(51)+(55)]	(63) = (41)* [(50)+(51)+(55)]	(64) = (43)* [(50)+(51)+(55)]	(65) = (13)+(58)+(60) +(61)+(62)+(63)+(64)
$192,354	$187,662	$0	$0	$99,192	$15,768	$19,711	$67,968	$390,301
$192,354	$192,354	$0	$0	$94,860	$16,890	$21,113	$72,804	$398,022
$192,354	$197,163	$0	$0	$126,262	($42,738)	($53,423)	($184,217)	$774,669
$192,354	$202,092	$0	$0	$121,836	$18,393	$22,991	$79,280	$1,176,214
$192,354	$207,144	$0	$0	$121,597	$17,797	$22,247	$76,713	$1,177,119
$192,354	$212,323	$0	$0	$116,145	$18,526	$23,157	$79,853	$1,181,626
$192,354	$217,631	$0	$0	$110,333	$18,925	$23,656	$81,572	$1,183,738
$192,354	$223,072	$0	$0	$104,981	$19,345	$24,181	$83,383	$1,186,583
$192,354	$228,648	$0	$0	$105,122	$19,928	$24,910	$85,896	$1,196,126
$192,354	$234,365	$0	$0	$101,271	$20,409	$25,511	$87,969	$1,201,147
$192,354	$240,224	$0	$0	$94,470	$21,086	$26,358	$90,889	$1,204,649
$192,354	$246,229	$0	$0	$87,705	$21,420	$26,775	$92,328	$1,206,079
$192,354	$252,385	$0	$0	$87,705	$21,956	$27,444	$94,636	$1,215,748
$192,354	$258,695	$0	$0	$87,705	$22,504	$28,131	$97,002	$1,225,659
$192,354	$265,162	$0	$0	$87,705	$23,067	$28,834	$99,427	$1,235,817
$192,354	$271,791	$0	$0	$87,705	$23,644	$29,555	$101,912	$1,246,229
$192,354	$278,586	$0	$0	$87,705	$24,235	$30,293	$104,460	$1,256,902
$192,354	$285,551	$0	$0	$87,705	$24,841	$31,051	$107,072	$1,267,841
$192,354	$292,689	$0	$0	$87,705	$25,462	$31,827	$109,749	$1,279,054
$192,354	$300,007	$0	$0	$87,705	$26,098	$32,623	$112,492	$1,290,547
$192,354	$307,507	$0	$0	$87,705	$26,751	$33,438	$115,305	$1,302,328

PROJECT / **PROJECT NET INCOME**

EBT	INCOME TAX RATE	INCOME TAX	REMMITANCE TAX RATE	REMMITANCE TAX	NET INCOME
(66) = (56) - (65)	(67)	(68) = [(66)*(67)] - (64)$_{\text{next year}}$	(69)	(70) = (69)*[(66)-(68)]	(71) = (66)-(68)-(70)
$3,673,707	25.0%	$845,623	0.0%	$0	$2,828,084
$8,689,789	25.0%	$2,356,664	0.0%	$0	$6,333,125
$9,073,956	25.0%	$2,189,209	0.0%	$0	$6,884,748
$1,122,913	25.0%	$204,015	0.0%	$0	$918,897
$1,047,549	25.0%	$182,034	0.0%	$0	$865,515
$1,134,121	25.0%	$201,958	0.0%	$0	$932,163
$1,181,849	25.0%	$212,080	0.0%	$0	$969,769
$1,231,511	25.0%	$221,982	0.0%	$0	$1,009,530
$1,294,857	25.0%	$235,745	0.0%	$0	$1,059,112
$1,349,967	25.0%	$246,602	0.0%	$0	$1,103,364
$1,431,141	25.0%	$265,457	0.0%	$0	$1,165,683
$1,471,423	25.0%	$273,220	0.0%	$0	$1,198,203
$1,528,692	25.0%	$285,171	0.0%	$0	$1,243,521
$1,587,393	25.0%	$297,421	0.0%	$0	$1,289,971
$1,647,561	25.0%	$309,978	0.0%	$0	$1,337,583
$1,709,233	25.0%	$322,848	0.0%	$0	$1,386,385
$1,772,447	25.0%	$336,040	0.0%	$0	$1,436,407
$1,837,241	25.0%	$349,562	0.0%	$0	$1,487,679
$1,903,655	25.0%	$363,422	0.0%	$0	$1,540,234
$1,971,730	25.0%	$377,628	0.0%	$0	$1,594,102
$2,041,506	25.0%	$510,377	0.0%	$0	$1,531,130

PROJECT CASH FLOW STATEMENT

NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(72) = (71)	(73) = -(54)	(74) = (13)	(75) = -(52)*16,453,000	(76)	(77) = (72)+(73) +(74)+(75)+(76)
$2,828,084	$0	$0	($2,467,950)	$0	$360,134
$6,333,125	$0	$0	($8,226,500)	$0	($1,893,375)
$6,884,748	($10,307,366)	$731,622	($5,758,550)	($943,810)	($9,393,357)
$918,897	$0	$731,622	$0	$179,619	$1,830,138
$865,515	$0	$731,622	$0	$148,168	$1,745,305
$932,163	$0	$731,622	$0	$139,150	$1,802,935
$969,769	$0	$731,622	$0	$120,919	$1,822,310
$1,009,530	$0	$731,622	$0	$100,713	$1,841,864
$1,059,112	$0	$731,622	$0	$80,529	$1,871,263
$1,103,364	$0	$731,622	$0	$55,356	$1,890,342
$1,165,683	$0	$731,622	$0	$59,863	$1,957,168
$1,198,203	$0	$731,622	$0	$59,493	$1,989,318
$1,243,521	$0	$731,622	$0	$0	$1,975,143
$1,289,971	$0	$731,622	$0	$0	$2,021,593
$1,337,583	$0	$731,622	$0	$0	$2,069,205
$1,386,385	$0	$731,622	$0	$0	$2,118,007
$1,436,407	$0	$731,622	$0	$0	$2,168,029
$1,487,679	$0	$731,622	$0	$0	$2,219,301
$1,540,234	$0	$731,622	$0	$0	$2,271,856
$1,594,102	$0	$731,622	$0	$0	$2,325,724
$1,531,130	$0	$731,622	$0	$0	$2,262,752
DISCOUNT RATE = 15.0%			=>	NPV =	422,936

Supporting information for Table 8.

Table A.5.2 The Santa Rosa HPP Project rebuilt with original characteristics, i.e. 12.5 MW Investment = $13,953,000

YEAR		ESCALATION FACTOR	PROJECT DEPRECIATION UNDER RATE BASE										
CALENDAR	PROJECT	for annual rate of 2.5%	INVESTMENT BOOK VALUE	CIVIL WORKS INVESTMENT PORTION	ELECTROMECHANICAL EQUIPMENT INVESTMENT PORTION	CIVIL WORKS DEPRECIATION RATE	ELECTROMECHANICAL EQUIPMENT DEPRECIATION RATE	INVESTMENT DEPRECIATION	DEPRECIATION OF ASSET BEFORE DESTRUCTION	DEPRECIATION OF PORTION OF ASSET DESTROYED	DEPRECIATION OF PORTION OF ASSET NOT DESTROYED	TOTAL DEPRECIATION OF REMAINING ASSETS	NET BOOK VALUE
(1)	(2)	(3)	(4) = $(14)_{year\ before}$	(5)	(6)	(7)	(8)	(9) = (4)*[(5)*(7)+(6)*(8)]	(10)	(11)	(12) = (10) - (11)	(13) = (9) + (12)	(14) = (4) - (13)
2004	0	0.976	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2005	1	1.000	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2006	2	1.025	$13,953,000	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$13,301,378
2007	3	1.051	$13,301,378	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$12,649,756
2008	4	1.077	$12,649,756	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$11,998,134
2009	5	1.104	$11,998,134	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$11,346,512
2010	6	1.131	$11,346,512	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$10,694,891
2011	7	1.160	$10,694,891	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$10,043,269
2012	8	1.189	$10,043,269	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$9,391,647
2013	9	1.218	$9,391,647	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$8,740,025
2014	10	1.249	$8,740,025	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$8,088,403
2015	11	1.280	$8,088,403	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$7,436,781
2016	12	1.312	$7,436,781	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$6,785,159
2017	13	1.345	$6,785,159	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$6,133,537
2018	14	1.379	$6,133,537	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$5,481,915
2019	15	1.413	$5,481,915	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$4,830,293
2020	16	1.448	$4,830,293	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$4,178,671
2021	17	1.485	$4,178,671	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$3,527,050
2022	18	1.522	$3,527,050	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$2,875,428
2023	19	1.560	$2,875,428	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$2,223,806
2024	20	1.599	$2,223,806	40%	60%	2%	4%	$446,496	$404,326	$199,200	$205,126	$651,622	$1,572,184

ESTIMATED PRICES & SALES (ENERGY & CAPACITY)

REGULATED ENERGY PRICE [$/MWh]	REGULATED CAPACITY PRICE INCREASE	REGULATED CAPACITY PRICE [$/kW-month]	NOMINAL SPOT ENERGY PRICE [$/MWh]	REAL SPOT ENERGY PRICE [$/MWh]	NOMINAL SPOT CAPACITY PRICE [$/kW-month]	REAL SPOT CAPACITY PRICE [$/kW-month]	GROSS ENERGY [MWh]	ENERGY LOSSES	ENERGY SALES [MWh]	GROSS CAPACITY [MW-month]	CAPACITY LOSSES	CAPACITY SALES [MW-month]
(15)	(16)	(17) = [1+(16)]*$(17)_{year\ before}$	(18)	(19) = (3)*(18)	(20)	(21) = (3)*(20)	(22)	(23)	(24) = (22)*[1-(23)]	(25)	(26)	(27) = (25)*[1-(26)]
12.787		6.722	5.352	5.222	6.400	6.244	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	14.34%	7.686	6.272	6.272	6.400	6.400	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	-7.33%	7.123	10.102	10.354	6.400	6.560	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	-7.33%	6.600	10.934	11.488	6.400	6.724	80,000	2.93%	77,656	12.50	3.0%	12.13
12.787	-7.33%	6.117	11.378	12.253	6.400	6.892	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.379	12.561	6.400	7.064	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.288	12.771	6.400	7.241	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.214	13.005	6.400	7.422	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.349	13.490	6.400	7.608	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.326	13.800	6.400	7.798	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.542	14.414	6.400	7.993	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	14.463	6.400	8.193	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	14.824	6.400	8.397	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	15.195	6.400	8.607	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	15.575	6.400	8.822	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	15.964	6.400	9.043	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	16.363	6.400	9.269	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	16.772	6.400	9.501	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	17.192	6.400	9.738	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	17.621	6.400	9.982	80,000	2.93%	77,656	12.50	3.0%	12.13
			11.298	18.062	6.400	10.231	80,000	2.93%	77,656	12.50	3.0%	12.13

RATE BASE EFFECT FOR COMPANY (to be reflected in project economics)

INCREMENTAL ASSET BOOK VALUE	BASE CASE DEPRECIATION	INCREMENTAL DEPRECIATION	INCREMENTAL RATE BASE	INCREMENTAL ENERGY SALES [MWh]	INCREMENTAL CAPACITY SALES [MW]	INCREMENTAL OPERATING REVENUE	CAPITAL GAIN	TOTAL REVENUE	CNDC FEE RATE	CNDC FEE	SIRESE FEE RATE	SIRESE FEE	TRANSACTION TAX RATE	TRANSACTION TAX	INCREMENTAL EBT	INCOME TAX RATE	INCOME TAX	NET INCOME	ADDITIONAL REVENUE TO REACH 9% RATE BASE
(28) = $(31)_{year\ before}$	(29) = 13,953,000*[(5)*(7)+(6)*(8)]	(30) = (9) - (29)	(31) = (28) - (30)	(32) = [(22)-80,000]*[1-(23)]	(33) = [(25)-12.5]*[1-(26)]	(34) = [(15)*(32)]+[(17)*(33)*1000*12]	(35) = (13,953,000) - (6,164,434-2,518,800)	(36) = (34)+(35)	(37)	(38) = (34)*(37)	(39)	(40) = (34)*(39)	(41) = 3%/0.87	(42) = (34)*(41)	(43) = (36) - [(30)+(38)+(40)+(42)]	(44)	(45) = [(44)*(43)] - $(42)_{next\ year}$	(46) = (43) - (45)	(47) = [9%*(31)]+(30)+(38)+(40)+(42)+(45)-(36)
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$446,496	$0	$0	0	0.00	$0	$10,307,366	$10,307,366	0.80%	$0	1.0%	$0	3.45%	$0	$10,307,366	25.0%	$2,576,842	$7,730,525	($7,730,525)
$0	$446,496	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$446,496	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$446,496	$0	$0						0.80%		1.0%		3.45%			25.0%			

PROJECT REVENUE STREAM						
RATE BASE REVENUE	SPOT MARKET REVENUE	DISTRIBUTION OF INSURANCE PROCEEDS	PAYMENT OF INSURANCE PROCEEDS	CAPITAL GAIN	ADDITIONAL REVENUE TO REACH 9% RATE BASE	TOTAL REVENUE
(48) = [(15)*(24)] + [(17)*(27)*1000*12]	(49) = [(19)*(24)] + [(21)*(27)*1000*12]	(50)	(51) = (50)*13,953,000	(52) = (35)	(53) = (47)	(54) = (48)+(49) +(51)+(52)+(53)
$1,971,058		15%	$2,092,950		$0	$4,064,008
$2,111,311		50%	$6,976,500		$0	$9,087,811
$2,029,339		35%	$4,883,550	$10,307,366	($7,730,525)	$9,489,731
$1,953,376					$0	$1,953,376
$1,882,981					$0	$1,882,981
	$2,003,275					$2,003,275
	$2,045,303					$2,045,303
	$2,089,803					$2,089,803
	$2,154,485					$2,154,485
	$2,206,203					$2,206,203
	$2,282,256					$2,282,256
	$2,315,130					$2,315,130
	$2,373,009					$2,373,009
	$2,432,334					$2,432,334
	$2,493,142					$2,493,142
	$2,555,471					$2,555,471
	$2,619,357					$2,619,357
	$2,684,841					$2,684,841
	$2,751,962					$2,751,962
	$2,820,761					$2,820,761
	$2,891,281					$2,891,281

PROJECT OPERATING EXPENSES									
NOMINAL FIXED O&M COSTS	REAL FIXED O&M COSTS	NOMINAL VARIABLE O&M COSTS	REAL VARIABLE O&M COSTS	UNIT WHEELING TOLL [$/MWh]	TOTAL WHEELING TOLL	CNDC FEE	SIRESE FEE	TRANSACTION TAX	TOTAL OPERATING EXPENSES
(55)	(56) = (3)*(55)	(57)	(58) = (3)*(57)	(59)	(60) = (24)*(59)	(61) = (37)* [(48)+(49)+(53)]	(62) = (39)* [(48)+(49)+(53)]	(63) = (41)* [(48)+(49)+(53)]	(64) = (13)+(56)+(58) +(60)+(61)+(62)+(63)
$192,354	$187,662	$0	$0	1.277	$99,192	$15,768	$19,711	$67,968	$390,301
$192,354	$192,354	$0	$0	1.222	$94,860	$16,890	$21,113	$72,804	$398,022
$192,354	$197,163	$0	$0	1.626	$126,262	($45,609)	($57,012)	($196,593)	$675,833
$192,354	$202,092	$0	$0	1.569	$121,836	$15,627	$19,534	$67,358	$1,078,068
$192,354	$207,144	$0	$0	1.566	$121,597	$15,064	$18,830	$64,930	$1,079,187
$192,354	$212,323	$0	$0	1.496	$116,145	$16,026	$20,033	$69,078	$1,085,227
$192,354	$217,631	$0	$0	1.421	$110,333	$16,362	$20,453	$70,528	$1,086,929
$192,354	$223,072	$0	$0	1.352	$104,981	$16,718	$20,898	$72,062	$1,089,353
$192,354	$228,648	$0	$0	1.354	$105,122	$17,236	$21,545	$74,293	$1,098,466
$192,354	$234,365	$0	$0	1.304	$101,271	$17,650	$22,062	$76,076	$1,103,046
$192,354	$240,224	$0	$0	1.217	$94,470	$18,258	$22,823	$78,698	$1,106,095
$192,354	$246,229	$0	$0	1.129	$87,705	$18,521	$23,151	$79,832	$1,107,061
$192,354	$252,385	$0	$0	1.129	$87,705	$18,984	$23,730	$81,828	$1,116,254
$192,354	$258,695	$0	$0	1.129	$87,705	$19,459	$24,323	$83,874	$1,125,678
$192,354	$265,162	$0	$0	1.129	$87,705	$19,945	$24,931	$85,970	$1,135,336
$192,354	$271,791	$0	$0	1.129	$87,705	$20,444	$25,555	$88,120	$1,145,237
$192,354	$278,586	$0	$0	1.129	$87,705	$20,955	$26,194	$90,323	$1,155,384
$192,354	$285,551	$0	$0	1.129	$87,705	$21,479	$26,848	$92,581	$1,165,786
$192,354	$292,689	$0	$0	1.129	$87,705	$22,016	$27,520	$94,895	$1,176,447
$192,354	$300,007	$0	$0	1.129	$87,705	$22,566	$28,208	$97,268	$1,187,375
$192,354	$307,507	$0	$0	1.129	$87,705	$23,130	$28,913	$99,699	$1,198,576

PROJECT	PROJECT NET INCOME				
EBT	INCOME TAX RATE	INCOME TAX	REMMITANCE TAX RATE	REMMITANCE TAX	NET INCOME
(65) = (54) - (64)	(66)	(67) = [(65)*(66)] - (63)$_{\text{next year}}$	(68)	(69) = (68)*[(65)-(67)]	(70) = (65)-(67)-(69)
$3,673,707	25.0%	$845,623	0.0%	$0	$2,828,084
$8,689,789	25.0%	$2,369,040	0.0%	$0	$6,320,749
$8,813,898	25.0%	$2,136,117	0.0%	$0	$6,677,781
$875,308	25.0%	$153,897	0.0%	$0	$721,412
$803,795	25.0%	$131,870	0.0%	$0	$671,924
$918,048	25.0%	$158,984	0.0%	$0	$759,064
$958,374	25.0%	$167,531	0.0%	$0	$790,843
$1,000,449	25.0%	$175,820	0.0%	$0	$824,630
$1,056,019	25.0%	$187,929	0.0%	$0	$868,090
$1,103,157	25.0%	$197,091	0.0%	$0	$906,066
$1,176,161	25.0%	$214,208	0.0%	$0	$961,953
$1,208,069	25.0%	$220,189	0.0%	$0	$987,880
$1,256,754	25.0%	$230,315	0.0%	$0	$1,026,439
$1,306,656	25.0%	$240,694	0.0%	$0	$1,065,963
$1,357,806	25.0%	$251,332	0.0%	$0	$1,106,474
$1,410,234	25.0%	$262,236	0.0%	$0	$1,147,998
$1,463,973	25.0%	$273,413	0.0%	$0	$1,190,561
$1,519,056	25.0%	$284,869	0.0%	$0	$1,234,187
$1,575,515	25.0%	$296,611	0.0%	$0	$1,278,904
$1,633,386	25.0%	$308,647	0.0%	$0	$1,324,739
$1,692,704	25.0%	$423,176	0.0%	$0	$1,269,528

PROJECT CASH FLOW STATEMENT					
NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(71) = (70)	(72) = -(52)	(73) = (13)	(74) = -(50)*16,453,000	(75)	(76) = (71)+(72) +(73)+(74)+(75)
$2,828,084	$0	$0	($2,092,950)	$0	$735,134
$6,320,749	$0	$0	($6,976,500)	$0	($655,751)
$6,677,781	($10,307,366)	$651,622	($4,883,550)	($997,438)	($8,858,951)
$721,412	$0	$651,622	$0	$127,955	$1,500,989
$671,924	$0	$651,622	$0	$97,111	$1,420,657
$759,064	$0	$651,622	$0	$92,459	$1,503,145
$790,843	$0	$651,622	$0	$73,060	$1,515,525
$824,630	$0	$651,622	$0	$51,658	$1,527,910
$868,090	$0	$651,622	$0	$30,248	$1,549,960
$906,066	$0	$651,622	$0	$3,818	$1,561,506
$961,953	$0	$651,622	$0	$7,036	$1,620,611
$987,880	$0	$651,622	$0	$514,094	$2,153,596
$1,026,439	$0	$651,622	$0	$0	$1,678,061
$1,065,963	$0	$651,622	$0	$0	$1,717,584
$1,106,474	$0	$651,622	$0	$0	$1,758,096
$1,147,998	$0	$651,622	$0	$0	$1,799,620
$1,190,561	$0	$651,622	$0	$0	$1,842,182
$1,234,187	$0	$651,622	$0	$0	$1,885,809
$1,278,904	$0	$651,622	$0	$0	$1,930,526
$1,324,739	$0	$651,622	$0	$0	$1,976,361
$1,269,528	$0	$651,622	$0	$0	$1,921,150
DISCOUNT RATE = 15.0%			=>	NPV =	903,232

Supporting information for Table 9.

Table A.5.3 Nor the project activity or other alternatives are undertaken

Investment = $0

YEAR		ESCALATION FACTOR	PROJECT DEPRECIATION UNDER RATE BASE										
CALENDAR	PROJECT	for annual rate of 2.5%	INVESTMENT BOOK VALUE	CIVIL WORKS INVESTMENT PORTION	ELECTROMECHANICAL EQUIPMENT INVESTMENT PORTION	CIVIL WORKS DEPRECIATION RATE	ELECTROMECHANICAL EQUIPMENT DEPRECIATION RATE	INVESTMENT DEPRECIATION	DEPRECIATION OF ASSET BEFORE DESTRUCTION	DEPRECIATION OF PORTION OF ASSET DESTROYED	DEPRECIATION OF PORTION OF ASSET NOT DESTROYED	TOTAL DEPRECIATION OF REMAINING ASSETS	NET BOOK VALUE
(1)	(2)	(3)	(4) = $(14)_{\text{year before}}$	(5)	(6)	(7)	(8)	(9) = (4)*[(5)*(7)+(6)*(8)]	(10) = (4)	(11)	(12) = (10) - (11)	(13) = (9) + (12)	(14) = (4) - (13)
2004	0	0.976	$7,283,654	40%	60%	2%	4%	$0	$7,283,654	$0	$7,283,654	$7,283,654	$0
2005	1	1.000	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2006	2	1.025	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2007	3	1.051	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2008	4	1.077	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2009	5	1.104	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2010	6	1.131	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2011	7	1.160	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2012	8	1.189	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2013	9	1.218	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2014	10	1.249	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2015	11	1.280	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2016	12	1.312	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2017	13	1.345	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2018	14	1.379	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2019	15	1.413	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2020	16	1.448	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2021	17	1.485	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2022	18	1.522	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2023	19	1.560	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0
2024	20	1.599	$0	40%	60%	2%	4%	$0	$0	$0	$0	$0	$0

ESTIMATED PRICES & SALES (ENERGY & CAPACITY)												
REGULATED ENERGY PRICE [$/MWh]	REGULATED CAPACITY PRICE INCREASE	REGULATED CAPACITY PRICE [$/kW-month]	NOMINAL SPOT ENERGY PRICE [$/MWh]	REAL SPOT ENERGY PRICE [$/MWh]	NOMINAL SPOT CAPACITY PRICE [$/kW-month]	REAL SPOT CAPACITY PRICE [$/kW-month]	GROSS ENERGY [MWh]	ENERGY LOSSES	ENERGY SALES [MWh]	GROSS CAPACITY [MW-month]	CAPACITY LOSSES	CAPACITY SALES [MW-month]
(15)	(16)	(17) = $[1+(16)]*(17)_{\text{year before}}$	(18)	(19) = (3)*(18)	(20)	(21) = (3)*(20)	(22)	(23)	(24) = (22)*[1-(23)]	(25)	(26)	(27) = (25)*[1-(26)]
12.787		6.722	5.352	5.222	6.400	6.244	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
12.787	14.34%	7.686	6.272	6.272	6.400	6.400	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
12.787	-7.33%	7.123	10.102	10.354	6.400	6.560	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
12.787	-7.33%	6.600	10.934	11.488	6.400	6.724	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
12.787	-7.33%	6.117	11.378	12.253	6.400	6.892	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.379	12.561	6.400	7.064	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.288	12.771	6.400	7.241	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.214	13.005	6.400	7.422	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.349	13.490	6.400	7.608	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.326	13.800	6.400	7.798	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.542	14.414	6.400	7.993	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	14.463	6.400	8.193	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	14.824	6.400	8.397	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	15.195	6.400	8.607	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	15.575	6.400	8.822	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	15.964	6.400	9.043	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	16.363	6.400	9.269	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	16.772	6.400	9.501	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	17.192	6.400	9.738	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	17.621	6.400	9.982	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00
			11.298	18.062	6.400	10.231	(6,382)	2.93%	(6,200)	0.00	3.0%	0.00

RATE BASE EFFECT FOR COMPANY (to be reflected in project economics)																				
INCREMENTAL ASSET BOOK VALUE	BASE CASE DEPRECIATION	INCREMENTAL DEPRECIATION	INCREMENTAL RATE BASE	INCREMENTAL ENERGY SALES [MWh]	INCREMENTAL CAPACITY SALES [MW]	INCREMENTAL OPERATING REVENUE	CAPITAL GAIN	TOTAL REVENUE	CNDC FEE RATE	CNDC FEE	SIRESE FEE RATE	SIRESE FEE	TRANSACTION TAX RATE	TRANSACTION TAX	INCREMENTAL EBT	INCOME TAX RATE	INCOME TAX	NET INCOME	ADDITIONAL REVENUE TO REACH 9% RATE BASE
(28) = $(31)_{\text{year before}}$	(29) = $0* [(5)*(7)+(6)*(8)]	(30) = (9) - (29)	(31) = (28) - (30)	(32) = (24)	(33) = (27)	(34) = [(15)*(32)] +[(17)*(33)*1000*12]	(35) = $0	(36) = (34)+(35)	(37)	(38) = (34)*(37)	(39)	(40) = (34)*(39)	(41) = 3%/0.87	(42) = (34)*(41)	(43) = (36) - [(30)+(38)+(40)+(42)]	(44)	(45) = [(44)*(43)] - $(42)_{\text{next year}}$	(46) = (43) - (45)	(47) = [9%*(31)]+(30) +(38)+(40)+(42)+(45)-(36)
$0	$0	$0	$0	(6,200)	0.00	($79,281)		($79,281)	0.80%	($634)	1.0%	($793)	3.45%	($2,734)	($75,120)	25.0%	($16,046)	($59,074)	$59,074
$0	$0	$0	$0	(6,200)	0.00	($79,281)		($79,281)	0.80%	($634)	1.0%	($793)	3.45%	($2,734)	($75,120)	25.0%	($16,046)	($59,074)	$59,074
$0	$0	$0	$0	(6,200)	0.00	($79,281)	$0	($79,281)	0.80%	($634)	1.0%	($793)	3.45%	($2,734)	($75,120)	25.0%	($16,046)	($59,074)	$59,074
$0	$0	$0	$0	(6,200)	0.00	($79,281)		($79,281)	0.80%	($634)	1.0%	($793)	3.45%	($2,734)	($75,120)	25.0%	($16,046)	($59,074)	$59,074
$0	$0	$0	$0	(6,200)	0.00	($79,281)		($79,281)	0.80%	($634)	1.0%	($793)	3.45%	($2,734)	($75,120)	25.0%	($18,780)	($56,340)	$56,340
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			

PROJECT REVENUE STREAM

RATE BASE REVENUE	SPOT MARKET REVENUE	DISTRIBUTION OF INSURANCE PROCEEDS	PAYMENT OF INSURANCE PROCEEDS	CAPITAL GAIN	ADDITIONAL REVENUE TO REACH 9% RATE BASE	TOTAL REVENUE
(48) = [(15)*(24)] + [(17)*(27)*1000*12]	(49) = [(19)*(24)] + [(21)*(27)*1000*12]	(50)	(51) = (50)*3,645,634	(52) = (35)	(53) = (47)	(54) = (48)+(49) +(51)+(52)+(53)
($79,281)		100%	$3,645,634		$59,074	$3,625,427
($79,281)		0%	$0		$59,074	($20,207)
($79,281)		0%	$0	$0	$59,074	($20,207)
($79,281)					$59,074	($20,207)
($79,281)					$56,340	($22,941)
	($77,876)					($77,876)
	($79,179)					($79,179)
	($80,629)					($80,629)
	($83,638)					($83,638)
	($85,558)					($85,558)
	($89,365)					($89,365)
	($89,669)					($89,669)
	($91,910)					($91,910)
	($94,208)					($94,208)
	($96,563)					($96,563)
	($98,978)					($98,978)
	($101,452)					($101,452)
	($103,988)					($103,988)
	($106,588)					($106,588)
	($109,253)					($109,253)
	($111,984)					($111,984)

PROJECT OPERATING EXPENSES

NOMINAL FIXED O&M COSTS	REAL FIXED O&M COSTS	NOMINAL VARIABLE O&M COSTS	REAL VARIABLE O&M COSTS	UNIT WHEELING TOLL [$/MWh]	TOTAL WHEELING TOLL	CNDC FEE	SIRESE FEE	TRANSACTION TAX	CAPACITY TARIFF REDUCTION	ASSETS' WRITE-OFF	TOTAL OPERATING EXPENSES
(55)	(56) = (3)*(55)	(57)	(58) = (3)*(57)	(59)	(60) = (24)*(59)	(61) = (37)* [(48)+(49)+(53)]	(62) = (39)* [(48)+(49)+(53)]	(63) = (41)* [(48)+(49)+(53)]	(64)	(65) = (13)	(66) = (56)+(58)+(60) +(61)+(62)+(63)+(64)+(65)
$0	$0	$0	$0	1.277	($7,919)	($162)	($202)	($697)	$339,893	$7,283,654	$7,614,567
$0	$0	$0	$0	1.222	($7,574)	($162)	($202)	($697)	$1,711,959		$1,703,324
$0	$0	$0	$0	1.626	($10,081)	($162)	($202)	($697)	$224,620		$213,479
$0	$0	$0	$0	1.569	($9,727)	($162)	($202)	($697)	($1,274,467)		($1,285,254)
$0	$0	$0	$0	1.566	($9,708)	($184)	($229)	($791)	($2,521,542)		($2,532,454)
$0	$0	$0	$0	1.496	($9,273)	($623)	($779)	($2,685)	$0		($13,360)
$0	$0	$0	$0	1.421	($8,809)	($633)	($792)	($2,730)	$0		($12,964)
$0	$0	$0	$0	1.352	($8,382)	($645)	($806)	($2,780)	$0		($12,613)
$0	$0	$0	$0	1.354	($8,393)	($669)	($836)	($2,884)	$0		($12,782)
$0	$0	$0	$0	1.304	($8,085)	($684)	($856)	($2,950)	$0		($12,576)
$0	$0	$0	$0	1.217	($7,542)	($715)	($894)	($3,082)	$0		($12,233)
$0	$0	$0	$0	1.129	($7,002)	($717)	($897)	($3,092)	$0		($11,708)
$0	$0	$0	$0	1.129	($7,002)	($735)	($919)	($3,169)	$0		($11,826)
$0	$0	$0	$0	1.129	($7,002)	($754)	($942)	($3,249)	$0		($11,947)
$0	$0	$0	$0	1.129	($7,002)	($773)	($966)	($3,330)	$0		($12,070)
$0	$0	$0	$0	1.129	($7,002)	($792)	($990)	($3,413)	$0		($12,197)
$0	$0	$0	$0	1.129	($7,002)	($812)	($1,015)	($3,498)	$0		($12,327)
$0	$0	$0	$0	1.129	($7,002)	($832)	($1,040)	($3,586)	$0		($12,460)
$0	$0	$0	$0	1.129	($7,002)	($853)	($1,066)	($3,675)	$0		($12,596)
$0	$0	$0	$0	1.129	($7,002)	($874)	($1,093)	($3,767)	$0		($12,736)
$0	$0	$0	$0	1.129	($7,002)	($896)	($1,120)	($3,862)	$0		($12,880)

PROJECT / **PROJECT NET INCOME**

EBT	INCOME TAX RATE	INCOME TAX	REMMITANCE TAX RATE	REMMITANCE TAX	NET INCOME
(67) = (54) - (66)	(68)	(69) = [(68)*(67)] - $(63)_{next\ year}$	(70)	(71) = (70)*[(67)-(69)]	(72) = (67)-(69)-(71)
($3,989,140)	25.0%	($996,588)	0.0%	$0	($2,992,552)
($1,723,532)	25.0%	($430,186)	0.0%	$0	($1,293,345)
($233,686)	25.0%	($57,725)	0.0%	$0	($175,961)
$1,265,047	25.0%	$317,053	0.0%	$0	$947,994
$2,509,513	25.0%	$630,064	0.0%	$0	$1,879,449
($64,516)	25.0%	($13,399)	0.0%	$0	($51,117)
($66,215)	25.0%	($13,773)	0.0%	$0	($52,442)
($68,016)	25.0%	($14,120)	0.0%	$0	($53,896)
($70,856)	25.0%	($14,764)	0.0%	$0	($56,092)
($72,982)	25.0%	($15,164)	0.0%	$0	($57,818)
($77,133)	25.0%	($16,191)	0.0%	$0	($60,942)
($77,960)	25.0%	($16,321)	0.0%	$0	($61,640)
($80,084)	25.0%	($16,773)	0.0%	$0	($63,312)
($82,262)	25.0%	($17,236)	0.0%	$0	($65,026)
($84,493)	25.0%	($17,710)	0.0%	$0	($66,783)
($86,781)	25.0%	($18,197)	0.0%	$0	($68,584)
($89,125)	25.0%	($18,695)	0.0%	$0	($70,430)
($91,528)	25.0%	($19,207)	0.0%	$0	($72,322)
($93,992)	25.0%	($19,731)	0.0%	$0	($74,261)
($96,516)	25.0%	($20,268)	0.0%	$0	($76,249)
($99,104)	25.0%	($24,776)	0.0%	$0	($74,328)

PROJECT CASH FLOW STATEMENT

NET INCOME	CAPITAL GAIN	ASSETS' WRITE-OFF	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(73) = (72)	(74) = -(52)	(73) = (65)	(74) = -(50)*0	(75)	(76) = (71)+(72) +(73)+(74)+(75)
($2,992,552)	$0	$7,283,654	$0	$0	$4,291,102
($1,293,345)	$0	$0	$0	$0	($1,293,345)
($175,961)	$0	$0	$0	$0	($175,961)
$947,994	$0	$0	$0	$0	$947,994
$1,879,449	$0	$0	$0	$0	$1,879,449
($51,117)	$0	$0	$0	$0	($51,117)
($52,442)	$0	$0	$0	$0	($52,442)
($53,896)	$0	$0	$0	$0	($53,896)
($56,092)	$0	$0	$0	$0	($56,092)
($57,818)	$0	$0	$0	$0	($57,818)
($60,942)	$0	$0	$0	$0	($60,942)
($61,640)	$0	$0	$0	$0	($61,640)
($63,312)	$0	$0	$0	$0	($63,312)
($65,026)	$0	$0	$0	$0	($65,026)
($66,783)	$0	$0	$0	$0	($66,783)
($68,584)	$0	$0	$0	$0	($68,584)
($70,430)	$0	$0	$0	$0	($70,430)
($72,322)	$0	$0	$0	$0	($72,322)
($74,261)	$0	$0	$0	$0	($74,261)
($76,249)	$0	$0	$0	$0	($76,249)
($74,328)	$0	$0	$0	$0	($74,328)
DISCOUNT RATE = 15.0%			=>	NPV =	4,529,456

Supporting information for Table 10.

Table A.5.4 Implement a 47.95 MW thermal (natural gas) power plant project Investment = $28,930,000

YEAR		ESCALATION FACTOR	PROJECT DEPRECIATION UNDER RATE BASE											
CALENDAR	PROJECT	for annual rate of 2.5%	INVESTMENT BOOK VALUE	CIVIL WORKS INVESTMENT PORTION	ELECTROMECHANICAL EQUIPMENT INVESTMENT PORTION	CIVIL WORKS DEPRECIATION RATE	ELECTROMECHANICAL EQUIPMENT DEPRECIATION RATE	INVESTMENT DEPRECIATION	DEPRECIATION OF ASSET BEFORE DESTRUCTION	DEPRECIATION OF PORTION OF ASSET DESTROYED	DEPRECIATION OF PORTION OF ASSET NOT DESTROYED	TOTAL DEPRECIATION OF REMAINING ASSETS	NET BOOK VALUE
(1)	(2)	(3)	(4) = $(14)_{\text{year before}}$	(5)	(6)	(7)	(8)	(9) = (4)*[(5)*(7)+(6)*(8)]	(10)	(11)	(12) = (10) - (11)	(13) = (9) + (12)	(14) = (4) - (13)
2004	0	0.976	$0	10%	90%	2%	4%	$0	$0	$0	$0	$0	$0
2005	1	1.000	$0	10%	90%	2%	4%	$0	$0	$0	$0	$0	$0
2006	2	1.025	$28,930,000	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$27,830,660
2007	3	1.051	$27,830,660	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$26,731,320
2008	4	1.077	$26,731,320	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$25,631,980
2009	5	1.104	$25,631,980	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$24,532,640
2010	6	1.131	$24,532,640	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$23,433,300
2011	7	1.160	$23,433,300	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$22,333,960
2012	8	1.189	$22,333,960	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$21,234,620
2013	9	1.218	$21,234,620	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$20,135,280
2014	10	1.249	$20,135,280	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$19,035,940
2015	11	1.280	$19,035,940	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$17,936,600
2016	12	1.312	$17,936,600	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$16,837,260
2017	13	1.345	$16,837,260	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$15,737,920
2018	14	1.379	$15,737,920	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$14,638,580
2019	15	1.413	$14,638,580	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$13,539,240
2020	16	1.448	$13,539,240	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$12,439,900
2021	17	1.485	$12,439,900	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$11,340,560
2022	18	1.522	$11,340,560	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$10,241,220
2023	19	1.560	$10,241,220	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$9,141,880
2024	20	1.599	$9,141,880	10%	90%	2%	4%	$1,099,340	$0	$0	$0	$1,099,340	$8,042,540

ESTIMATED PRICES & SALES (ENERGY & CAPACITY)												
REGULATED ENERGY PRICE [$/MWh]	REGULATED CAPACITY PRICE INCREASE	REGULATED CAPACITY PRICE [$/kW-month]	NOMINAL SPOT ENERGY PRICE [$/MWh]	REAL SPOT ENERGY PRICE [$/MWh]	NOMINAL SPOT CAPACITY PRICE [$/kW-month]	REAL SPOT CAPACITY PRICE [$/kW-month]	GROSS ENERGY [MWh]	ENERGY LOSSES	ENERGY SALES [MWh]	GROSS CAPACITY [MW-month]	CAPACITY LOSSES	CAPACITY SALES [MW-month]
(15)	(16)	(17) = [1+(16)]*$(17)_{\text{year before}}$	(18)	(19) = (3)*(18)	(20)	(21) = (3)*(20)	(22)	(23)	(24) = (22)*[1-(23)]	(25)	(26)	(27) = (25)*[1-(26)]
12.787		6.722	5.352	5.222	6.400	6.244	0	2.93%	0	0.00	3.0%	0.00
12.787	14.34%	7.686	6.272	6.272	6.400	6.400	0	2.93%	0	0.00	3.0%	0.00
12.787	-7.33%	7.123	10.102	10.354	6.400	6.560	357,036	2.93%	346,575	47.95	3.0%	46.51
12.787	-7.33%	6.600	10.934	11.488	6.400	6.724	357,036	2.93%	346,575	47.95	3.0%	46.51
12.787	-7.33%	6.117	11.378	12.253	6.400	6.892	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.379	12.561	6.400	7.064	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.288	12.771	6.400	7.241	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.214	13.005	6.400	7.422	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.349	13.490	6.400	7.608	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.326	13.800	6.400	7.798	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.542	14.414	6.400	7.993	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	14.463	6.400	8.193	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	14.824	6.400	8.397	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	15.195	6.400	8.607	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	15.575	6.400	8.822	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	15.964	6.400	9.043	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	16.363	6.400	9.269	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	16.772	6.400	9.501	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	17.192	6.400	9.738	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	17.621	6.400	9.982	357,036	2.93%	346,575	47.95	3.0%	46.51
			11.298	18.062	6.400	10.231	357,036	2.93%	346,575	47.95	3.0%	46.51

RATE BASE EFFECT FOR COMPANY (to be reflected in project economics)																			
INCREMENTAL ASSET BOOK VALUE	BASE CASE DEPRECIATION	INCREMENTAL DEPRECIATION	INCREMENTAL RATE BASE	INCREMENTAL ENERGY SALES [MWh]	INCREMENTAL CAPACITY SALES [MW]	INCREMENTAL OPERATING REVENUE	CAPITAL GAIN	TOTAL REVENUE	CNDC FEE RATE	CNDC FEE	SIRESE FEE RATE	SIRESE FEE	TRANSACTION TAX RATE	TRANSACTION TAX	INCREMENTAL EBT	INCOME TAX RATE	INCOME TAX	NET INCOME	ADDITIONAL REVENUE TO REACH 9% RATE BASE
(28) = $(31)_{\text{year before}}$	(29) = 13,953,000* [(5)*(7)+(6)*(8)]	(30) = (9) - (29)	(31) = (28) - (30)	(32) = [(22)-80,000]*[1-(23)]	(33) = [(25)-12.5]*[1-(26)]	(34) = [(15)*(32)] +[(16)*(33)*1000*12]	(35) = $0	(36) = (34)+(35)	(37)	(38) = (34)*(37)	(39)	(40) = (34)*(39)	(41) = 3%/0.87	(42) = (34)*(41)	(43) = (36) - [(30)+(38)+(40)+(42)]	(44)	(45) = [(44)*(43)] - $(42)_{\text{next year}}$	(46) = (43) - (45)	(47) = [9%*(31)]+(30) +(38)+(40)+(42)+(45)-(36)
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0	$0	$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0	0	0.00	$0		$0	0.80%	$0	1.0%	$0	3.45%	$0	$0	25.0%	$0	$0	$0
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			
$0	$0	$0	$0						0.80%		1.0%		3.45%			25.0%			

PROJECT REVENUE STREAM						
RATE BASE REVENUE	SPOT MARKET REVENUE	DISTRIBUTION OF INSURANCE PROCEEDS	PAYMENT OF INSURANCE PROCEEDS	CAPITAL GAIN	ADDITIONAL REVENUE TO REACH 9% RATE BASE	TOTAL REVENUE
(48) = [(15)*(24)] + [(17)*(27)*1000*12]	(49) = [(19)*(24)] + [(21)*(27)*1000*12]	(50)	(51) = (50)*12,852,000	(52) = (35)	(53) = (47)	(54) = (48)+(49) +(51)+(52)+(53)
$0		5%	$0		$0	$0
$0		90%	$0		$0	$0
$0	$7,249,948	5%	$0	$0	$0	$7,249,948
$0	$7,734,318				$0	$7,734,318
$0	$8,093,451				$0	$8,093,451
	$8,296,094					$8,296,094
	$8,467,550					$8,467,550
	$8,649,637					$8,649,637
	$8,921,384					$8,921,384
	$9,134,850					$9,134,850
	$9,456,488					$9,456,488
	$9,584,977					$9,584,977
	$9,824,602					$9,824,602
	$10,070,217					$10,070,217
	$10,321,972					$10,321,972
	$10,580,021					$10,580,021
	$10,844,522					$10,844,522
	$11,115,635					$11,115,635
	$11,393,526					$11,393,526
	$11,678,364					$11,678,364
	$11,970,323					$11,970,323

PROJECT OPERATING EXPENSES									
NOMINAL FIXED O&M COSTS	REAL FIXED O&M COSTS	NOMINAL VARIABLE O&M COSTS	REAL VARIABLE O&M COSTS	UNIT WHEELING TOLL [$/MWh]	TOTAL WHEELING TOLL	CNDC FEE	SIRESE FEE	TRANSACTION TAX	TOTAL OPERATING EXPENSES
(55)	(56) = (3)*(55)	(57)	(58) = (3)*(57)	(59)	(60) = (24)*(59)	(61) = (37)* [(48)+(49)+(53)]	(62) = (39)* [(48)+(49)+(53)]	(63) = (41)* [(48)+(49)+(53)]	(64) = (13)+(56)+(57) +(60)+(61)+(62)+(63)
$0	$0	$0	$0	1.277	$0	$0	$0	$0	$0
$0	$0	$0	$0	1.222	$0	$0	$0	$0	$0
$2,820,000	$2,890,500	$1,039,725	$1,065,718	1.626	$563,503	$58,000	$72,499	$249,998	$5,999,558
$2,820,000	$2,962,763	$1,039,725	$1,092,361	1.569	$543,746	$61,875	$77,343	$266,701	$6,104,127
$2,820,000	$3,036,832	$1,039,725	$1,119,670	1.566	$542,679	$64,748	$80,935	$279,085	$6,223,287
$2,820,000	$3,112,752	$1,039,725	$1,147,661	1.496	$518,349	$66,369	$82,961	$286,072	$6,313,505
$2,820,000	$3,190,571	$1,039,725	$1,176,353	1.421	$492,410	$67,740	$84,676	$291,984	$6,403,075
$2,820,000	$3,270,335	$1,039,725	$1,205,762	1.352	$468,525	$69,197	$86,496	$298,263	$6,497,919
$2,820,000	$3,352,094	$1,039,725	$1,235,906	1.354	$469,156	$71,371	$89,214	$307,634	$6,624,714
$2,820,000	$3,435,896	$1,039,725	$1,266,803	1.304	$451,969	$73,079	$91,348	$314,995	$6,733,431
$2,820,000	$3,521,794	$1,039,725	$1,298,473	1.217	$421,616	$75,652	$94,565	$326,086	$6,837,526
$2,820,000	$3,609,838	$1,039,725	$1,330,935	1.129	$391,425	$76,680	$95,850	$330,516	$6,934,585
$2,820,000	$3,700,084	$1,039,725	$1,364,209	1.129	$391,425	$78,597	$98,246	$338,779	$7,070,680
$2,820,000	$3,792,586	$1,039,725	$1,398,314	1.129	$391,425	$80,562	$100,702	$347,249	$7,210,178
$2,820,000	$3,887,401	$1,039,725	$1,433,272	1.129	$391,425	$82,576	$103,220	$355,930	$7,353,163
$2,820,000	$3,984,586	$1,039,725	$1,469,104	1.129	$391,425	$84,640	$105,800	$364,828	$7,499,723
$2,820,000	$4,084,201	$1,039,725	$1,505,831	1.129	$391,425	$86,756	$108,445	$373,949	$7,649,947
$2,820,000	$4,186,306	$1,039,725	$1,543,477	1.129	$391,425	$88,925	$111,156	$383,298	$7,803,927
$2,820,000	$4,290,963	$1,039,725	$1,582,064	1.129	$391,425	$91,148	$113,935	$392,880	$7,961,756
$2,820,000	$4,398,238	$1,039,725	$1,621,615	1.129	$391,425	$93,427	$116,784	$402,702	$8,123,531
$2,820,000	$4,508,194	$1,039,725	$1,662,156	1.129	$391,425	$95,763	$119,703	$412,770	$8,289,350

PROJECT	PROJECT NET INCOME				
EBT	INCOME TAX RATE	INCOME TAX	REMMITANCE TAX RATE	REMMITANCE TAX	NET INCOME
(65) = (54) - (64)	(66)	(67) = [(65)*(66)] - $(63)_{next\ year}$	(68)	(69) = (68)*[(65)-(67)]	(70) = (65)-(67)-(69)
$0	25.0%	$0	0.0%	$0	$0
$0	25.0%	$0	0.0%	$0	$0
$1,250,390	25.0%	$45,897	0.0%	$0	$1,204,493
$1,630,191	25.0%	$128,463	0.0%	$0	$1,501,728
$1,870,165	25.0%	$181,469	0.0%	$0	$1,688,696
$1,982,589	25.0%	$203,663	0.0%	$0	$1,778,927
$2,064,475	25.0%	$217,856	0.0%	$0	$1,846,620
$2,151,718	25.0%	$230,296	0.0%	$0	$1,921,423
$2,296,670	25.0%	$259,173	0.0%	$0	$2,037,497
$2,401,419	25.0%	$274,269	0.0%	$0	$2,127,150
$2,618,962	25.0%	$324,224	0.0%	$0	$2,294,738
$2,650,392	25.0%	$323,819	0.0%	$0	$2,326,574
$2,753,921	25.0%	$341,232	0.0%	$0	$2,412,690
$2,860,039	25.0%	$359,080	0.0%	$0	$2,500,959
$2,968,809	25.0%	$377,374	0.0%	$0	$2,591,435
$3,080,298	25.0%	$396,125	0.0%	$0	$2,684,173
$3,194,575	25.0%	$415,346	0.0%	$0	$2,779,229
$3,311,708	25.0%	$435,047	0.0%	$0	$2,876,661
$3,431,770	25.0%	$455,240	0.0%	$0	$2,976,530
$3,554,833	25.0%	$475,939	0.0%	$0	$3,078,895
$3,680,973	25.0%	$920,243	0.0%	$0	$2,760,730

PROJECT CASH FLOW STATEMENT					
NET INCOME	CAPITAL GAIN	DEPRECIATION	INVESTMENT COST	VAT RECOVERY	NET CASH FLOW
(71) = (70)	(72) = -(52)	(73) = (13)	(74) = -(50)*28,930,000	(75)	(76) = (71)+(72) +(73)+(74)+(75)
$0	$0	$0	($1,446,500)	$0	($1,446,500)
$0	$0	$0	($26,037,000)	($128,955)	($26,165,955)
$1,204,493	$0	$1,099,340	($1,446,500)	$128,955	$986,288
$1,501,728	$0	$1,099,340	$0	$0	$2,601,068
$1,688,696	$0	$1,099,340	$0	$0	$2,788,036
$1,778,927	$0	$1,099,340	$0	$0	$2,878,267
$1,846,620	$0	$1,099,340	$0	$0	$2,945,960
$1,921,423	$0	$1,099,340	$0	$0	$3,020,763
$2,037,497	$0	$1,099,340	$0	$0	$3,136,837
$2,127,150	$0	$1,099,340	$0	$0	$3,226,490
$2,294,738	$0	$1,099,340	$0	$0	$3,394,078
$2,326,574	$0	$1,099,340	$0	$0	$3,425,914
$2,412,690	$0	$1,099,340	$0	$0	$3,512,030
$2,500,959	$0	$1,099,340	$0	$0	$3,600,299
$2,591,435	$0	$1,099,340	$0	$0	$3,690,775
$2,684,173	$0	$1,099,340	$0	$0	$3,783,513
$2,779,229	$0	$1,099,340	$0	$0	$3,878,569
$2,876,661	$0	$1,099,340	$0	$0	$3,976,001
$2,976,530	$0	$1,099,340	$0	$0	$4,075,870
$3,078,895	$0	$1,099,340	$0	$0	$4,178,235
$2,760,730	$0	$1,099,340	$0	$0	$3,860,070
DISCOUNT RATE = 15.0%			=>	NPV =	($8,920,323)

Annex 6

ANALYSIS OF ENVIRONMENTAL IMPACTS & PUBLIC CONSULTATION

Environmental Impacts for the Santa Rosa Hydropower Plant Project

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

Characteristics of the project:

The implementation of the project for the Santa Rosa Hydropower Project entails the installation of the facilities needed for generation of electricity in an area already developed by generation activities which was developed since the 1920's. Specifically, the Santa Rosa Hydropower infrastructure was originally built in 1952, with an expansion in 1997. The project will be directed to build all the facilities for a new generating plant in the same areas where all the previous installations were located.

The Generating System installed troughout the Zongo Valley includes ten (10) generating stations on a run-of-river scheme. It has obtained the environmental license by the Sustainable development and Environment Ministry of Bolivia on 1997 based on an Environmental Impact Assessment for all the generating system developed in the Zongo Valley.

In the particular case of the Santa Rosa Hydropower Plant Project, the project participants have developed an Environmental Impact Assessment study to evaluate the environmental impacts related to the implementation of the project, as required by the Bolivian Government. On August 27, 2004 the SRO HPP Project was formally granted the corresponding environmental license by the Ministry of Sustainable Development of Bolivia.

This Exhibit summarizes the most important environmental impacts identified for the construction and operation of the new installations required by the Santa Rosa Hydropower Plant Project.

Environmental impacts:

The project will use some remaining infrastructure of a previous installation that was destroyed by a landslide. The new facility will be installed in an area that has been previously disturbed and all associated environmental impacts are expected to be low to moderated.

The detailed impacts evaluated by the assessment are:

Construction phase:

1. Generation of debris produced by the excavation of the area related to the activities of demolition of the old powerhouse and the building of the new one. The impact is considered of low, but permanent effect, since the material will be adequately disposed in areas specifically prepared to avoid damage to natural watercourses and productive land.

2. Local, moderated and temporal impacts due to the generation of liquid and solid domestic wastes by personnel in charge of the construction and installation of the new plants. A management plan for the operations on campsites during construction phase is part of the assessment. All areas used by the project will be restored to conditions similar to the ones existing previous to the project. As the project occurs in an already developed area, the project will not affect undisturbed or natural areas. All activities take place in previously developed areas.

3. Operative risks associated with the project implementation activities (e.g., machinery, personnel, use of dangerous materials like explosives). All these risks are evaluated by a Security Operative Plan to avoid and control adverse effects produced by these activities. The impacts are expected to be low, temporal and specifically limited to the small area where the project activities are to take place.

4. Positive economic effects for the population in the project area. The Zongo valley is a rural area with low productivity based on non-intensive agriculture. The implementation of the project will generate a positive impact in the local economy by generating employment and increasing local commercial activity to meet needs of project's personnel. The impacts are expected to be local, low and with temporary positive effect.

Public Consultation

Process:

A public consultation process (PCP) was implemented as part of the EIA of the project, as required by the assessment process.

The process included a presentation of the activities that would be implemented by the project, detailing all environmental aspects that are expected to be significant. It also asked people to participate and present any requirements that local communities may wish to be taken into account by the project proponent at the moment of implementation of the project.

The PCP for the Santa Rosa HPP Project was performed by the technical team contracted for the elaboration of the EIA from May 19th to May 21st, 2004. The consultation process included the participation of all communities near the project's area of influence. Local authorities, including municipal and community representatives, also took part in the process. As no NGO works in the project's area of influence, none was included in the consultation process.

Comments received

The main comments obtained during the consultation process are resumed on points detailed below:

1. The project must consider the employment of local workers for the different types of work to be performed during the construction of the facilities.
2. COBEE must develop a permanent communication with communities in relation to project activities.

3. The project must have a strict compliance with environmental regulations, and the measures included in their prevention and mitigation plans must be implemented.

Compensation

All negotiations will be based on giving proper compensation to the Community if land or other productive areas are affected.

In the evidence of damage, it will be evaluated and, once agreements are obtained, they will be reported to the agrarian and electricity authorities in order to guarantee its fulfillment. The basic criterion established by the proponent of the project is that all negotiations will be based on giving proper compensation to the Community if land or other productive areas are affected. However, as the project will be implemented within an area that belongs to COBEE, no significant damages are anticipated.

All compensation values will be based on current market prices either for land and products.

The Company will establish an administrative mechanism to assure that all demands are thoroughly reviewed and all applicable compensation measures are fulfilled in a satisfactory manner.

Operative phase:

The upper and middle part of the Zongo Valley has been used for hydroelectric generation since the 1920s. The system has been increasing its capacity to meet the growing energy demand of major populated urban centers in Bolivia. The maximum potential of the valley was reached by year 2000 when a total generation capacity of 180 MW was obtained through the installation of ten (10) hydropower plants across the Zongo River connected to the national power grid.

This ten-hydropower plant has feature a cascade system, whereby the water used by plants in the upper part of the basin is diverted through channels and tunnels to be subsequently used by the plants located in the lower part of the river. This way, water is transported through a parallel course to the natural river flow.

The evaluation of potential impacts resulting from operation of the new reconstructed hydropower plant are summarized as follows:

1. The generating system has produced a moderate impact on the river flow. The basin presents a regulation, which is evident on dry season (April – October) where the water flow is constrained to a minimal superficial course, which affects the central part of the watershed. However, this regulation which is exerted during several years (The old Santa Rosa Plant had an operating life of more than 50 year since their construction) has produced a moderated impact to biota in the watershed: The presence of fishes was constrained to areas where a permanent water flux is maintained (upper and lower part of the basin); on the other hand, the presence of macro invertebrates through the watershed has not been significantly affected, vegetal species and terrestrial population of animals have maintained equilibrium with all the environment.

2. The proposed Santa Rosa Hydroelectric plant is placed in the middle of the power generation system, where watercourses regulation is more evident. The effects of regulation have modified permanently the hydrological regimen of the area. The regulation imposed to the area will be maintained even if the NO DEVELOPMENT option is pursued, because the water resources in the area are mainly diverted to supply the plants already installed downstream of the project location. This is mostly evident in during the dry season. The project will increase the availability of resources in the central area of the basin allowing for a non-restrictive regulation in the area. The overall impact of the new facility will be positive and its potential long-term effects on the hydrological system are expected to improve.

3. Additionally, the use of water resources of the tributaries will not affect significantly the hydrological equilibrium of the area, not only because only part of the river flow will be used, but also because all the area has multiple secondary watercourses that naturally replenish the water flow of the main rivers. The tributary river of the watershed, the Coscapa River has multiple inflows that maintain a permanent water flow during all the year.

4. The use of run-of-river schemes and the implementation of Pelton type turbines increases the efficiency of the systems, because the high difference in altitude in the basin requires less water to produce energy than systems based on dams/reservoirs. This minimizes leakage emissions of greenhouse gases related to the flooding of large vegetated areas. Indeed, the use of resources placed on areas of high altitude represents the use of water resources of glacial origin where a low vegetal mass is existent in the areas where the resources are originated diminishing even more the possibility of leakage on the system.

5. Additionally, because the new installation will not increase the resources used previously by the old one, and all infrastructure (e.g., intakes, canals, tunnels) will be maintained, additional potential impacts are not likely to happen, as opposed to any other new facility with similar capacity and characteristics.

2: If impacts are considered significant by the project participants or the host party:

The significance of the project is based on the fact that it will be installed in already altered areas and using most of the existing infrastructure from the old facility. This fact reduces the potential impacts to a minimum when compared to a hydropower project of similar capacity and characteristics that would be implemented on a new and undisturbed area. The fact that no complementary construction work such as access roads, tunnels, canals and other facilities, is needed for the implementation of this project reduces to a minimum the potential environmental impact on the area.

The NO DEVELOPMENT option does not diminish the existing local impacts but implies waste of available water resources reducing, therefore, the efficiency of a known, suitable area for power generation.

Annex 7

SUSTAINABLE DEVELOPMENT CRITERIA AS REQUIRED BY HOST GOVERNMENT EVALUATION CRITERIA ON FACTORS AFFECTING SUSTAINABLE DEVELOPMENT

I. According to project PPD, the accomplishment of such a project will generate local employment as previously mentioned it will preferably make use of local hand labor in the construction phase. It is necessary to introduce some indicators to compare both situations either with or without project and produce sufficient information to establish the net contribution to the generation of employment. It is important to gather all this information to measure how the environmental impact of this project contributes to sustainable development.

I.1 Impact on job creation

The project is located in the Zongo Valley, near the small community of Coscapa.
The actual population of this community is approximately 167 inhabitants
According to information obtained by the National Census Bureau in the year 2001 the 100 % of this population belongs to the aymara culture, with a very low level of basic instruction (more than 92% of the children of six years and older have at best access to primary instruction). The data can be seen in Appendix A.

The size of adult population economically active (PEA) in the Coscapa Community is as follows

Table 1: Activity Pattern of Adult, Actively Working Population (PEA)
Coscapa Community
(Number of people)

Variable	2001	2005
Total Population	159	167
PEA	63	66
Worker or Employee	50	53
Self employed	9	9
Others	4	4

Source: 2001, INE: Population and Housing National Census 2001; 2005: Own creation based on annual growth rate

Due to peculiar characteristics in the rural area , it is significant to emphasize that no idle people has been reported , people work outside their plot of land only when they have the opportunity of a permanent job.

For the analysis of project impact on the living conditions of the population, it can be distinguished two phases: Construction and Operation. The hiring of hand labor for these two phases, appears in table No.2 (a good average of actual data, is included during the construction phase, as well as its projection until project completion)

Table 2: Hand Labor Hired by the Santa Rosa Project

(Number of people)

	Construction	**Operation**
Qualified	60	3
Non qualified	40	0
Total	100	3

Source: SESA

The construction phase of the project has already been started, and during the third week in June 2005, it has been reported 122 people hired, with 45 belonging to the Coscapa community. It should be mentioned that the total number of laborers coming from Coscapa are none qualified and it is estimated to have approximately 40 laborers of this community along the construction phase as an average.

The total number of jobs created by the project during construction phase is equivalent to 0.00012 jobs for each ton of reduced CO_2 emissions (see calculation in Appendix B), or in other terms a reduction of 8008 tons of $C0_2$ per employee. Appendix B shows data in terms of employees/$tC0_2$/year as well.

The project impact in employment, expressed in indicators, is as follows

Table 3: Employment Indicators of Project Impact

	Formula	Value
Employment attributed to the Project	(Laborers coming form Coscapa/ Total Coscapa PEA) * 100	61 %
Coscapa employees working for the Project	(Laborers coming form Coscapa/ Total Employees and Workers PEA) * 100	40 %

PEA means Actively Working Population. Source: Own creation

It is considered irrelevant the creation of indirect jobs in the area of influence of project because of the following:

- The Company will provide lodging and food for their workers.
- The vicinity of the city of La Paz allows the employees to provide themselves with goods and services not available in the zone.

As a means of monitoring the project, it is proposed that the evaluation of comparative data of the impact on job creation to be carried out during project execution, on a quarterly basis. The job creation indices generated by project during the operation stage as well as maintenance should be reported annually as part of environmental monitoring of project.

During the construction phase there will be an indirect impact in job creation outside the limits of the project. Unfortunately, it is not possible to measure such an impact for lack of information.[39]

I.2 Income Impact

The following table shows the direct impact of the project on income in the Coscapa population, during construction phase.

Table 4: Income Indicators for Project Impact
(Monthly income)

Occupational Category	Without Project			With Project		
	Quantity People	**Individual Income Bs.**	**Group Income Bs.**	**Quantity People**	**Individual Income Bs.**	**Group Income Bs.**
Workers or employees	53	500	26,500	53	802	42,500
Outside the Project				13	500	6,500
Inside the Project				40	900	36,000
Self employed	9	249	2,237	9	249	2,237
Others	4	270	1,080	4	270	1,080
Total Community	66	452	29,817	6.6	694	45,817
Per capita income (Bs.)	179			274		

Source: Own Creation based on SESA and INE information

During the 18 month period of the construction phase, the direct impact on the income of the community is important, as it can be observed. In terms of per capita income it represents an increase of 54%. This is the direct impact on income.

The project impact on the family income will be substantially reduced in the maintenance stage, due to low requirement of personnel for maintenance.[40]

With regard to indirect impact incomes on remaining community citizens, it can be foreseen that demand for agricultural products coming from this zone will increase with an additional increase in family incomes. Nevertheless it is not possible to measure it.

[39] To reach this purpose, we should have access to a consumption-product matrix of the economics of area, including Productivity indicators for different economic activities

[40] COBEE estimates that has a requirement of 30 people during two weeks/year

I.3 Social Entities Participation

Another indicator of social criteria that contributes to sustainable development in the country, is the level of participation of social entities (see document "Guide to procedures……"). In the specific case of the Santa Rosa reconstruction project, the participation of social entities was important, as proof of such a process, we mention:

- Broad participation of local individuals and local authorities in the process of a local consultation (see EIA study)
- A 100% of the non qualified workers were hired by COBEE from Coscapa, according with a compromise assumed by the Company, and detailed in the EIA study.

II. Project should contribute to the National Economy as a whole, and therefore an economic evaluation is recommended to establish such a contribution.

II.1 Total Amount and Composition in Project Investment.

The project plans an investment of approximately 19M $us., consisting exclusively in net fixed capital formation, where does not exist an inventory variation.

This amount of investment means that it will be required an equivalent of $us. 22.35 of investment for each ton of reduced C02 emissions. The detailed indicator calculations are shown in Annex 2.

The investment in the project represents a 4.4% in net fixed capital formation at a national level[41], considered highly significant.

The project investment costs, is as follows:

Table 5: Project Costs

(in American $us.)

Item	Value	%
Goods and Local Services	5,750,850	30.2
Goods and External Services	9,933,000	52.2
Local Taxes	3,341,600	17.6
Total	19,025,450	100.0

Source: COBEE BPCo.

[41] Indicator based on data from INE (National Statistics Bureau)

It is important to mention that 30% correspond to local purchases, promoting a multiplier impact on the economy.

II.2 Production.

With energy sale up to 80 GWh/year and a remunerative power of 15.5MW, we have estimated net revenues equivalent to $us. 2,581,970 per year[42] .This value represent:

- 0.1 % of the local GDP for the La Paz province[43].
- 2.2 % of the total generation of electrical power in the country, year 2003

II.3 Prices

The fundamental result of the project is that the hydroelectric energy produced by the plant will replace the thermoelectric one. Since productions costs of former are sensibly lower than the latter, there will be necessarily a reduction in the unit price in energy in the grid market at a national level. Nevertheless, since the project represents only 2.2% of the total energy produced, the impact of a lower price will not be significant.

II.4 Taxes

National taxes collected in the construction phase, amount to $us. 3.3M that represent 18% of the total investment in the project. This is a significant amount, since it represents 1% of the total amount collected in the La Paz Province during 2004[44].

This amount implies that National Revenue Service will collect an equivalent of $us. 4.17 for each ton of reduced of C02 emissions. For detailed calculations, see Annex 2.

III: The PDD project document, shall mention about effective technology transfer. The bidder shall specify if the project will receive assistance for development of certain capacities in operation and maintenance or in the technological development, such an indicator will reflect the sustainability of the project.

III.1. Technology transfer

Project execution correspond to a contract under a "turn key" modality, awarded to a Spanish Consortium conformed by SOLUZIONA Y VATECH, with worldwide recognition in engineering and equipment production for hydroelectric generation. The equipment and auxiliary services to be provided, including control systems correspond to state of the art in technological development.

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[42] Value determined from average prices of contract for the year 2004, from COBEE (14.314 USD/MWh and 7.725 USD / kW-month)

[43] Figure calculated from INE (National Statistics Bureau)

[44] Figure calculated from information of the National Revenue Service.

Project comprises installment of two hydroelectric turbines: one Pelton of 10.1 MW for a total head of 832m; and the second a Francis turbine of 6.2 MW for total head of 182m. The latter one is a type of turbine used for the first time in the COBEE compound; along all its operative history and successive projects of electric generation in their plants of the Zongo and Miguilla Valleys has exclusively used Pelton turbines. This innovation corresponds to the principal technological contribution for the project. All hydroelectric turbines in general have the same operative principle, nevertheless the introduction of a Francis turbine represent operative and control differences that will require development of new capacities of personnel in charge of maintenance and operation of the main Control Center.

The introduction of different technology to the actual one will require specific training programs to allow the COBEE personnel assume all the operation and maintenance activities without external assistance.

Another of the technological contribution of the project it's referred to the Control Center. It will necessarily produce changes in the communication systems with the so called "Load Dispatch", which will clearly differentiate from actual operative patterns between control centers with actual operative units actually installed in the Zongo Valley. This system comprises the annulment of RTU equipment with the direct use of autonomous control modules during data transfer including time recording logs.
The system will allow application of a remote operative command, with a capacity to operate locally trough Programmable Logic Controllers (PLC) modules.

III.2. Capacities Development

The "turn key" contract, has established an intensive training program for technical personnel in all areas. It has been placed special emphasis in the area of control and communications because it includes the last developments in data processing and specialized software for plant operation. The scope, as well in other projects, it contemplates personnel training to assume all operating tasks, light and heavy maintenance works.
In the training part, COBEE will appoint 2 engineers and 3 operators for them to directly participate in this program. The program will mainly take place in the plant, and according to the specific field and function, will take an estimated training period of 2 – 4 months during the commissioning and start-up procedures. It is also foreseeable to have technical personnel for acceptance and approval of testing procedures of equipment in origin. The attendance of technical personnel during the commissioning stage; also implies an intrinsic training in control procedures and methodologies of the equipment to be installed.

III. 3. Other Innovations and Improvements

The area of civil engineering comprises very specialized tasks. Due to the potential risk of landslides around the plant reconstruction area; the top of the power house will be covered by a concrete sealing and a 1.3 meter thick gravel cover in order to protect it from falling objects coming from the nearby slope. Moreover, it will be installed a sophisticated dynamic protecting fence from falling rocks up to 3 ton in weight.

The storage chamber facility suffered the failure of its foundations, just after its initial commissioning in 1952, which then collapsed and reduced its capacity down to 15% of its designed original capacity (1,500 of the original 10,000 m3). Actual program includes the chamber reestablished to its original capacity.

In order to rehabilitate the storage chamber, conducted a number of studies of the soil and consequently the designs so as to provide the supporting terrain with an adequate capacity, this implied specialized soil studies, and the development of an alternative and innovative technology consisting in the incorporation of gravel columns to provide the actual soil, with actual limited load capacity, improved load capacity to withstand water column cyclic efforts of a water column from 0 to 4.5 m. The procedure to be implemented comprises the installation of a net, 50 cm. in diameter , with holes in it, to variable depths, between 4 and 5 m; these will be refilled with compacted gravel, at the same time will allow to improve the capacity of the reservoir bottom. Additionally, it will be carried on some adaptation works, and for its preservation, improve water drainage underneath storage chamber.

IV. The document of the project shall mention in which way it contributes and is compatible with the government's policies and indicative plans.

The law regulating electricity related activities (Law No.1604, December 21, 1994) establishes that:

1. Art. 3, a) the efficiency premise obliges to the correct and optimum assignment and resources utilization in the electricity provision at the minimum cost.

2. Art. 3, d) the continuity premise means that the service provided must be a continuous one, without interruptions.

The National Committee of Load Dispatch (CNDC) every six months produces "The medium term programming report", in which the last version for May 2005 – April 2009 period concludes that:

1. For the demand projections in the Wholesaler Electric Market (MEM),according to the minimum conditions of compliance from the National Interconnected System (SIN) and considering the generating capacity offer and transmission for the period, it is expected a power deficit (Power + cold reserve) starting from the Nov/2006 – Oct/ 2007 period.

2. During the dry season, due to low water availability; and with the criteria to satisfy all the minimum requirements for fulfillment, the power available for dispatch from the passing hydroelectric units are diminished. In the dry periods during the years 2003 and 2004 it has been necessary the support of expensive thermoelectric units to satisfy the requirements of the system

The report "Updating the Referential Plan for the National Interconnected System" (March 2005) belonging to the "Electricity, Alternative Energies and Telecommunications" Vice Ministry which in turn depend of the "Services and Public Works" Ministry, present among others, the following conclusions:

1. For a medium and sustained growth scenario and for the medium and the long term span (2007 onwards) it is necessary additional power generation.

2. A high and sustained growth in the demand obliges to bring forward the expansion of the generation plan, requiring the entry of the new operating units in the year 2006.

3. The resulting expansion plan is possible to be shouldered by private investment. For this propose investments have to be promoted, for them to be attractive for potential private investors.

4. The economic feasibility to Interconnect the Bolivian and Peruvian Electric Systems Project, to export energy to Peru, should be evaluated in case new generating plants are incorporated in the La Paz area in the future; specially some projects that would allow development of the hydraulic potential existing in the area.

5. The construction of a new hydroelectric plant, capable to supply part of the SIN demand, should produce a reduction to the supply costs, because it delays the need to incorporate new thermal generating unit for a lower operative cost of the plant.

The reconstruction project of the Santa Rosa Hydroelectric Plant in the Zongo valley (La Paz area) is compatible with the government policies and with the indicative plans of the electric sector mentioned above, since it:

a) Moves away the more expensive thermal generating units, according to the efficiency principle for the power supply at a minimum cost.

b) Increases the generating capacity, which guarantees a non-stopping power supply in growing demand, according to the continuity principle.

c) Satisfies the system demand requirements in the medium term, which foresees a power deficit from the November/2006 – October/2007 period.

d) Increases the capacity for power dispatch from the transitory hydroelectric units, during the dry period, moving away the use of thermal units of high cost for the system.

e) Satisfies the additional generating requirements in a medium and sustained growth scenario, which would require the increase of generating power from year 2007.

f) Satisfies the additional generating requirements in a higher and sustained growth scenario, which would require of new generating power from year 2006.

g) As a private undertaking, supports the strategy to attract new investment in the electric sector.

h) Strengthens the generating capacity in the La Paz area and consequently the interconnection project of the power systems of Bolivia and Peru, towards power export to the later.

i) A hydroelectric plant leads to the reduction of the supply costs, which has lower operating costs in the system; therefore it displaces thermal generating units.

APPENDIXES

Appendix A: Coscapa Population Characteristics, year 2001

Variable	Unit	Value
Basic data		
2001 total population	Citizens	159
Economically Active People (EAP)	Citizens	63
Illiteracy rate	%	30
Maximum instruction level		
None	%	33.3
Pre-school	%	13.8
Primary	%	45.7
Secondary	%	5.8
Technician	%	1.4
Working population by occupational category		
Worker or employee	Citizens	50
Self employed worker	Citizens	9
Working population by activity field		
Agriculture, cattle raising	Citizens	51
Mine and quarry exploitation	Citizens	2
Electric power generation and distribution	Citizens	5
Construction	Citizens	3
Social and health services	Citizens	1
Community, social and personal services	Citizens	1

Source: own elaboration, from the National Statistics Bureau (INE)

Appendix B: Calculations of indicators with relation to reduced tCO2

Identification	Variable	Equation or source	Unit	Value
A	Emissions Reduction Rate	PDD	tC02/MWh	0.551
B	Annual Generation from Project	PDD	MWh/year	80,000
C	Life span of Project	COBEE	Years	21
D	Total Generating Power	B* C	MWh	1,680,000
E	Reduced Emissions per year	A* B	t C02/year	44,080
F	Total Reduced Emissions	A* D	t C02	925,680
G	Total employment brought by Project	COBEE	People	100
H	No. of jobs per ton of reduced C02	G/E	people/t C02 /year	0.00227
J	No. of jobs per ton of reduced C02	G/F	people /t C02	0.00011
K	Total investment	COBEE	$us.	19,025,450
L	Required invest per t. reduced C02/yr.	K/E	$us./ t C02 / year	432
M	Required invest per t reduced C02	K/F	$us./ t C02	20.55
N	Total additional tax revenues	COBEE	$us.	3,341,600
P	Taxes per ton of reduced C02/yr.	N/E	$us./ t C02/ year	75.81
Q	Taxes per ton of reduced C02	N/F	$us. / C02	3.61

(*) In spite of the fact that calculations are realized for a 21 year life span, the real life span with the characteristics of the equipment considered in the project is 40 years.

Source: Own Creation

Appendix C: References and Sources of Information

CDM (2004): “Project Design Document form – Santa Rosa Hydropower Plan Project”

COBEE (2003): “Environmental Data for the Reconstruction of the Santa Rosa Hydroelectric Project”. La Paz.

(2004): “Environmental Impact Evaluation Study for the Reconstruction of the Santa Rosa Hydroelectric Project”. La Paz

INE (2004): The National Statistics Bureau, statistical information available At: www.ine.gov.bo and other processed information on request.

PNCC – ODL (2003): “ “Guide of Procedures for Project Presentation to the Program for a “clean” development in Bolivia” , La Paz

National Tax (Revenue) Service (2005): Information on tax revenue collection, available at www.impuestos.gov.bo

UDAPE (2005) The “Office for Economic Policy Support”, `Statistical Dossier of Economic Information 2004`, La Paz; available in www.udape.gov.bo

Superintendencia de Electricidad, “The Electric Services Regulatory Board (2004-2005) “Yearly Statistics Report of the Electric Sector”, La Paz. Available at www.superele.gov.bo

Annex 8

HOST GOVERNMENT APPROVAL

República de Bolivia

Ministerio de Planificación del Desarrollo

LETTER OF APPROVAL

TO: The Executive Board of the Clean Development Mechanism of the Kyoto Protocol

Office of the Secretariat of the UNFCCC

Mr. Miguel Angel Rojas Castro, Viceminister for Land and Environment Planning, as the appointed Designated National Authority (DNA) of Bolivia for the Clean Development Mechanism (CDM), the authority in charge of the issuance of the present Letter of Approval,

Referring to: The Santa Rosa Hydropower Plant Project, as set out in the PDD of 17 June 2008,Version 5, hereinafter to be referred to as "the CDM project activity", implemented in the city of La Paz, Bolivia by Compañía Boliviana de Energía Eléctrica S.A, (COBEE) to be referred to as "the project participant".

Declares that:

Bolivia has ratified the Kyoto Protocol becoming a Party to it, by National Law N° 1988 on the 14th July of 1999.

The Bolivian Designated National Authority confirms its participation in the CDM on a voluntary basis.

The Designated National Authority of Bolivia confirms that the present project contributes to the sustainable development of the country.

The Bolivian Designated National Authority authorizes the project participants to participate in the CDM project activity.

The Bolivian Designated National Authority confirms that the project activity, as proposed, is in compliance with all relevant Host Country national laws;

The Bolivian Designated National Authority authorizes the transfer of any Certified Emissions Reductions (CER) accruing from the CDM project activity, issued to the project participants, in accordance to the contractual arrangements among project participants, and the distribution agreements between the Government of Bolivia represented by the DNA and COBEE S.A.

The Bolivian DNA here by authorizes the transfer of CERS to the CDM registry accounts opened by the project participants, for the crediting period of the project of 21 years in accordance to the contractual arrangements among project participants, and the distribution agreements between the Government of Bolivia represented by the DNA and COBEE S.A.

Signed for the Government of Bolivia in the city of La Paz:

By: Miguel Angel Rojas Castro
Viceminister for Land and Environment Planning

Signature:
Seal: Ing. Miguel Angel Rojas Castro
VICEMINISTRO DE PLANIFICACION TERRITORIAL Y AMBIENTAL
MINISTERIO DE PLANIFICACION

Date: July 28th of 2008

Av. Mariscal Santa Cruz No.1092 * Casilla 12814 Central Piloto 2116000 Fax: 2116000 int. 1213 Fax: Despacho 2312641 La Paz - Bolivia *www.planificación.gov.bo

Annex 9

REFERENCES

[1] Bolivia's National Interconnected System is named: Sistema Interconectado Nacional (SIN).

[2] Bolivia's Nacional Dispatch Center is named: Centro Nacional de Despacho de Carga (CNDC)

[3] Based on information from "Estadísticas" prepared by the CNDC and available at www.cndc.bo

[4] Bolivia's political division comprises nine Departments, each one of them divided in Provinces.

[5] From BOCIER (Comité de Integración Energética Regional – Bolivia).

[6] All emission and emission reduction estimates are provided in metric tons (hereinafter "tons").

[7] The operations' interruption of the original Santa Rosa power plant may be verified through CNDC reports at www.cndc.bo

[8] See Mid Term Reports at www.cndc.bo

[9] See Bolivian Electricity Law at the Superintendency of Electricity web page www.superele.gov.bo

[10] From mid term study "Estudio de Mediano Plazo Noviembre 2005 – Octubre 2009" published by the CNDC.

[11] Ibid.

[12] In this case corresponds to Version 04, EB 36.

[13] See Sub-step 1b for specific consistency with mandatory laws and regulations of this alternative.

[14] Latest thermal development in the SIN took place in year 2000 with the implementation of the Bulo Bulo facility installing two GE LM6000 units.

[15] See references 10 and 11.

[16] The Electricity Law may be found at http://www.bolivia.gov.bo

[17] The Environmental Law may be found at http://www.bolivia.gov.bo

[18] Supreme Resolutions from the Bolivian Government may be obtained from the official source "Gaceta Oficial de Bolivia". The respective web reference is http://gaceta.comunica.gov.bo

[19] COBEE has a PPA in place with ELECTROPAZ. The document is available with both parties.

[20] Bolivia holds Latin America's second-largest reserves of natural gas, after Venezuela. Most of the discoveries came about after 1998.

[21] The average annual interest rates from the Bolivian Bank System are provided in the table below, considering the information available at the time of project investment decision.

YEAR	1997	1998	1999	2000	2001	2002	2003
Bolivian Nominal Annual Interest Rate [%]	15.56	14.87	14.54	15.14	14.63	11.78	10.89

Source: Instituto Nacional de Estadística (INE).

[22] Bolivia has a B credit rating, which is a highly speculative investment rating grade. B denotes significant credit risk.

[23] Ibid.

[24] TCF = thousand cubic feet.

[25] According to Supreme Decree No. 26037 dated December 22, 2000. See www.bolivia.gov.bo

[26] From "Operation Results for the SIN, year 2000" at www.cndc.bo

[27] Ibid.

[28] From "Operation Results for the SIN, year 2003" at www.cndc.bo

[29] Documented evidence that support the list of activities comprises: contracts, agreements, and letters, being all available with COBEE as well as with the acting second party.

[30] The CNDC publishes heat rate values for every thermal unit in the system expressed in Btu/kWh for 50%, 75% and 100% loads.

[31] From daily post-dispatch reports published by the CNDC.

[32] From Post Dispatch hourly data for 2007, published by the CNDC.

[33] See reference 30.

[34] Due to the particular origin of the amount of fuel data and to simplify the overall calculation procedure, the net calorific value is relocated within the formulae without variations for the final results.

[35] Energy units are of standard use in the industry to express the amount of fuel, e.g. Canadian Centre for Energy.

[36] See operational standards content at www.cndc.bo

[37] According to COBEE internal procedure P.ST.252 "Maintenance of Energy Metering Equipment" access, monitoring and calibration of grid and plant metering equipment is carried out under the same standards. Operational Standard No. 8 of the CNDC established the operation & maintenance standards for grid metering equipment; therefore it is confirmed that COBEE energy meters at the plant site comply with CNDC standards.

[38] The EPC (Engineering Procurement and Construction) Contract was made effective as of 29/08/2004 and is available with COBEE as well as with the acting second party (Asociación SOLUZIONA S.A. and VA TECH ESCHER WYSS S.L.)