CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-SSC-PDD)
Version 03 - in effect as of: 22 December 2006

CONTENTS

Annexes

Revision history of this document

Version Number	Date	Description and reason of revision
01	21 January 2003	Initial adoption
02	8 July 2005	• The Board agreed to revise the CDM SSC PDD to reflect guidance and clarifications provided by the Board since version 01 of this document. • As a consequence, the guidelines for completing CDM SSC PDD have been revised accordingly to version 2. The latest version can be found at <http://cdm.unfccc.int/Reference/Documents>.
03	22 December 2006	• The Board agreed to revise the CDM project design document for small-scale activities (CDM-SSC-PDD), taking into account CDM-PDD and CDM-NM.

SECTION A. General description of small-scale project activity

A.1. Title of the small-scale project activity:

Neusberg Grid Connected Hydroelectric Power Plant, South Africa

Version number: 1.0

Date: 02/04/2012

A.2. Description of the small-scale project activity:

The aim of the project is to supply hydroelectricity to the grid of the Republic of South Africa.

The energy system of the Republic of South Africa (RSA) is managed by the state-owned company Eskom which is in charge of generation, transmission and distribution of power to end-users. The company's total net maximum capacity as of 31 March 2010 is 40 870 MW, most of which 34 658 MW is coal-fired[1].

The project envisages the construction and operation of a run-of-river hydroelectric power plant with an installed capacity of 12.57 MW. The power plant will be limited at a net output of 10 MW (at the metering point) due to governmental constrains on the capacity for small hydroelectric power plants[2]. The power plant will comprise of 3 turbines and the associated infrastructure. The produced electricity will be supplied to the national grid of the RSA[3] and sold to Eskom via a Power Purchase Agreement under "Independent Power Producer Procurement Program (IPPPP)[4]".

The proposed project is located outside of the town of Kakamas in the Northern Cape Province of the RSA. The anticipated start date for construction and installation works under this project is 08/01/2013. It is expected that construction and commissioning will be completed by 08/10/2014 (21 months after the project start date)[5]. The required capital investment for the project amounts to 433.76 million ZAR[6].

The baseline scenario assumes that electricity delivered to the grid by the hydroelectric power plant would have otherwise been generated by the operation of grid-connected Eskom power plants and by the addition of new generation sources.

The greenhouse gas (GHG) emissions from the electricity generation at the run-of-river hydroelectric power plant will amount to zero. The reduction of GHG emissions as a result of the project implementation will be achieved due to reduction of CO_2 emissions from combustion of fossil fuel at the existing grid-connected power plants and plants which would likely be built in the absence of the project activity.

[1] Eskom Annual Report 2010, page 298, http://financialresults.co.za/2010/eskom_ar2010/
[2] http://www.ipp-renewables.co.za/
[3] Eskom electricity network at the time of PDD writing
[4] http://www.ipp-renewables.co.za/
[5] Refer to the Neusberg Lender's Report, page 6
[6] Refer to the Neusberg Lender's Report, page 101: Total capital cost.

The project activity satisfies all sustainable development criteria identified by the DNA of the RSA[7]. The sustainable development is defined as "the integration of social, economic and environmental factors into planning, implementation and decision-making so as to ensure that development serves present and future generations[8]". The main benefits of the implementation of the present project are:

1. Social and economic: Promotion and development of hydroelectric power plants in the RSA which in turn will lead to the creation of new job opportunities both during the construction and operation phases and to growth in tax revenues. Sales of carbon credits generated by the project will result in increased foreign direct investment;
2. Social: Creation of 100 jobs during the construction phase and 4 jobs during the operation phase;
3. Environmental: Mitigations of the negative environmental impact. Combustion of fossil fuels (mostly coal) at Eskom power plants and hereby emissions of the harmful substances into the atmosphere, such as flue ash, oxides of sulphur and nitrogen will be reduced due to the project implementation; and
4. Political: Contribution to achievement of the goal to generate 10 000 GWh of electricity from renewable energy by 2013[9] and the objective to reduce RSA's GHG emissions by 34% below the current emissions baseline by 2020[10].

A.3. 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 South Africa (Host Party)	• Kakamas Hydro Electric Power (Pty) Ltd	No

Kakamas Hydro Electric Power (Pty) Ltd

The project is being developed by Kakamas Hydro Electric Power (Pty) Ltd, which is a Special Purpose Vehicle (SPV) established to develop and operate the proposed hydroelectric power plant.

7 See the Letter of no Objection
8 Sustainable development criteria for approval of CDM projects by the DNA of the CDM, Department of Minerals and Energy, RSA (page 1) http://www.energy.gov.za/files/esources/kyoto/Web%20info/Annex%203%20SA%20Sustainable%20Development%20Criteria.pdf
9 http://www.energy.gov.za/files/renewables_frame.html
10 http://www.unep.org/climatepledges/Default.aspx?pid=68

A.4. Technical description of the small-scale project activity:

A.4.1. Location of the small-scale project activity:

A.4.1.1. Host Party(ies):

The Republic of South Africa (RSA)

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

Northern Cape Province

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

The town of Kakamas

A.4.1.4. Details of physical location, including information allowing the unique identification of this small-scale project activity:

Figure A.4-1 shows the location of Kakamas in the RSA. This location falls under the jurisdiction of Kai! Garib Municipality and is located in the Northern Cape Province. The project activity will be constructed at the Neusberg Weir on the Orange River (Figure A.4-2). The site falls in the time zone UTC + 2. The GPS coordinates for the site are 28°46’19’’ S and 20°44’33’’ E.

Figure A.4-1: The location of Kakamas in the RSA (A indicates the project site)

Figure A.4-2: Google Earth map pinpointing the location of the project activity. The Neusberg hydropower plant is a construction that runs from the inlet (water intake) to the outlet (water release).

A.4.2. Type and category(ies) and technology/measure of the small-scale project activity:

The present project falls under Type I: Renewable energy projects and Category D: Grid connected renewable electricity generation.[11]

The project activity envisages the production of electricity which will be supplied to the national grid of the RSA. The electricity will be produced form hydro energy and the proposed facility has a maximum output capacity of less than 15 MW. Therefore it meets the eligibility criteria for small-scale CDM project activities set out in Annex II of Decision 4/CMP.1[12] and therefore 'Simplified modalities and procedures for small-scale clean development mechanism project activities' may be applied.

The project activity characteristics[13]

The project envisages the construction and operation of a run-of-river hydroelectric power plant with an installed capacity of 12.57 MW. The power plant will comprise of 3 turbines and the associated infrastructure.

The hydro turbines capture the kinetic energy and potential energy (due to drop in elevation) of water to drive a turbine which is connected to a generator where this energy is subsequently converted into electricity. Energy production is typically influenced by the efficiency of the turbine and generator, the water level difference between the head-pond and the tailrace, the amount of flow into the turbines, gravity and water density. The hydrology assessment for this project was undertaken by Entura[14]. The project applied 18 years of flow record in its energy generation calculations. The energy modelling for the project estimated 69.25 GWh of net electricity generation per year.

The characteristics of the preferred turbine supplier Hydro Power Plant (HPP)[15] is shown in Table A.4-1.

Table A.4-1: Turbine and powerhouse salient features

Parameter	Value	Source
Number of Units	3	HPP Technical and Economic Offer
Rated Head	15.34 m	HPP Technical and Economic Offer
Rated Flow	30 m3/s	HPP Technical and Economic Offer
Rated Efficiency	93%	120113 10MW Neus rev 8.xlsm
Turbine Hill Chart	-	120113 10MW Neus rev 8.xlsm
Maximum Operating Flow	30 m3/s	HPP Technical and Economic Offer
Minimum Operating Flow	5 m3/s	HPP Technical and Economic Offer
Total Installed Capacity	12.57 MW	HPP Technical and Economic Offer

[11] http://cdm.unfccc.int/methodologies/DB/RSCTZ8SKT4F7N1CFDXCSA7BDQ7FU1X
[12] http://cdm.unfccc.int/Reference/COPMOP/08a01.pdf#page=6 (page 30 and 43)
[13] Neusberg Lender's Report
[14] www.entura.com.au
[15] This is the expected turbine supplier. In the unlikely event that the turbine supplier is changed a different turbine supplier may be used for this project.

The project activity is a run-of-river design that will be constructed at the existing at the Neusberg Weir. It does not involve the construction of a reservoir[16]. Instead the project involves construction of an intake structure with stop-log gates, 1 410 m of open canal waterway, 3 buried steel penstock pipes, a partially buried powerhouse, 200 m long tailrace canal from powerhouse back to the river and infrastructure for connection to the Eskom distribution network.

Hydroelectric power is regarded as an environmentally friendly technology[17]. The basic environmental assessment report has already been completed and the government has granted the letter of authorization[18].

The project implementation schedule is presented in Table A.4-2. It is expected that the construction will be started in January 2013 and it will take 21 months to complete the power plant.

Table A.4-2: The schedule of the project implementation

Number	Action	Date
1	Completion of Basic Assessment Report	08/2011
2	Start of construction and installation works	08/01/2013
3	Commercial Operation Date (COD)	08/10/2014

A.4.3. Estimated amount of emission reductions over the chosen crediting period:

The 7-year crediting period with the option of renewal was selected for the project.

Years	Estimation of annual emission reductions in tonnes of CO_2 e
2014 (from 08/10/2014 to 31/12/2014)	15 269
2015	66 826
2016	66 826
2017	66 826
2018	66 826
2019	66 826
2020	66 826
2021(from 01/01/2021 to 07/10/2021)	51 557
Total estimated reductions (tonnes of CO_2 e)	**467 782**
Total number of crediting years	**7**
Annual average of the estimated reductions over the crediting period (t CO_2 e)	**66 826**

[16] The surface area of the existing reservoir will not be changed as a result of the project implementation.
[17] Department of Energy of the RSA (http://www.energy.gov.za/files/esources/renewables/r_solar.html)
[18] See Record of Decision (ROD)

A.4.4. Public funding of the small-scale project activity:

No public funding will be applied to the project.

A.4.5. Confirmation that the small-scale project activity is not a debundled component of a large-scale project activity

As indicated in the "Guidelines on assessment of debundling for SSC project activities" (Version 03)[19], *'Debundling is defined as the fragmentation of a large project activity into smaller parts. A small-scale project activity that is part of a large project activity is not eligible to use the simplified modalities and procedures for small-scale CDM project activities… A proposed small-scale project activity shall be deemed to be a debundled component of a large project activity if there is a registered small-scale CDM project activity or an application to register another small-scale CDM project activity:*

a. *With the same project participants;*

b. *In the same project category and technology/measure; and*

c. *Registered within the previous 2 years; and*

d. *Whose project boundary is within 1 km of the project boundary of the proposed small-scale activity at the closest point.'*

The project developer "Kakamas Hydro Electric Power (Pty) Ltd" does not have any other hydro projects within 1 km of the proposed project site. This proves that the proposed project is not a debundled component of a large project activity.

[19] http://cdm.unfccc.int/Reference/Guidclarif/ssc/index_guid.html

SECTION B. Application of a baseline and monitoring methodology

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

The approved simplified baseline and monitoring methodology AMS-I.D. "Grid connected renewable electricity generation" (Version 17.0)[20] is applicable to the proposed project activity.

This methodology refers to the use of the "Tool to calculate the emission factor for an electricity system" (Version 02.2.1)[21] to calculate the combined margin CO_2 emission factor of RSA's grid.

B.2. Justification of the choice of the project category:

The present project falls under Type I: Renewable energy projects and Category D: Grid connected renewable electricity generation (see Section A.4.2 for details)[22].

The project activity has a maximum installed capacity of 12.57 MW and is therefore below the 15 MW limit for Small Scale CDM projects.

The applicability criteria for activities under methodology AMS-I.D. are defined and addressed as follows:

#	Applicability criterion	Applicability	Response
1	This methodology comprises renewable energy generation units, such as photovoltaic, hydro, tidal/wave, wind, geothermal and renewable biomass a) Supplying electricity to a national or regional grid; or b) Supplying electricity to an identified consumer facility via national/regional grid through a contractual arrangement such as wheeling.	Applicable	The proposed project activity comprises renewable electricity generation, by means of a hydroelectric power plant, which will supply electricity to the national electricity grid of the RSA.
2	Illustration of respective situations under which each of the methodology (i.e. AMS-I.D, AMS-I.F and AMS-I.A) applies is included in Table 2[23].	Applicable	The proposed project falls under methodology AMS-I.D. since the project supplies electricity to a national grid.

[20] http://cdm.unfccc.int/methodologies/DB/RSCTZ8SKT4F7N1CFDXCSA7BDQ7FU1X (This version will be used throughout the PDD.)

[21] http://cdm.unfccc.int/methodologies/PAmethodologies/tools (This version of the tool will be used throughout the PDD)

[22] http://cdm.unfccc.int/methodologies/DB/RSCTZ8SKT4F7N1CFDXCSA7BDQ7FU1X

[23] AMS-I.D. (version 17), page 15

#	Applicability criterion	Applicability	Response
3	This methodology is applicable to project activities that: (a) install a new power plant at a site where there was no renewable energy power plant operating prior to the implementation of the project activity (Greenfield plant); (b) involve a capacity addition; (c) involve a retrofit of (an) existing plant(s); or (d) involve a replacement of (an) existing plant(s).	Applicable	The proposed project activity is a "greenfield plant" because it involves the installation of a new hydroelectric power plant at a site where no renewable electricity generation occurred prior to this project activity.
4	Hydro power plants with reservoirs that satisfy at least one of the following conditions are eligible to apply this methodology: • The project activity is implemented in an existing reservoir with no change in the volume of reservoir; or • The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m^2; or • The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m^2.	Applicable	The proposed project (a run-of-river hydroelectric power plant) will be implemented in an existing reservoir with no change in the volume of reservoir.[24]
5	If the new unit has both renewable and non-renewable components (e.g. a wind/diesel unit), the eligibility limit of 15 MW for a small-scale CDM project activity applies only to the renewable component. If the unit co-fires fossil fuel, the capacity of the entire unit shall not exceed the limit of 15 MW.	Not applicable	The project activity does not have non-renewable components, so it does not need to satisfy this applicability condition.

[24] Neusberg Lender's Report, (page 59)

#	Applicability criterion	Applicability	Response
6	Combined heat and power (co-generation) systems are not eligible under this category.	Not applicable	The proposed project activity does not involve co-generation. According to the AMS-I.D., the project activity must not satisfy this applicability condition.
7	In the case of project activities that involve the addition of renewable energy generation units at an existing renewable power generation facility, the added capacity of the units added by the project should be lower than 15 MW and should be physically distinct from the existing units.	Not applicable	The project activity does not involve the addition of renewable energy generation units to an existing facility, so it does not need to satisfy this applicability condition.
8	In the case of retrofit or replacement, to qualify as a small-scale project, the total output of the modified or retrofitted or replacement unit shall not exceed the limit of 15 MW.	Not applicable	The project activity does not involve retrofit or replacement of an existing facility, so it does not need to satisfy this applicability condition.

The proposed CDM project activity satisfies all the relevant applicability criteria of AMS-I.D.

B.3. Description of the project boundary:

As defined in the methodology AMS-I.D.: '*The spatial extent of the project boundary includes the project power plant and all power plants physically connected to the electricity system that the CDM project power plant is connected to*'.

The proposed project activity emits zero GHGs and only the displacement of CO_2 is considered in the baseline of this project (Table B.3.1 and Figure B.3-1).

Table B.3-1: Emissions sources included in or excluded from the project boundary

Source		Gas	Included?	Justification / Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
Project Activity	CO_2 emissions from the combustion of fossil fuels for electricity generation in the hydroelectric power plant	CO_2	No	GHG emissions for the present hydroelectric power plant are equal to zero, since there is no change in the volume of reservoir.
		CH_4	No	
		N_2O	No	

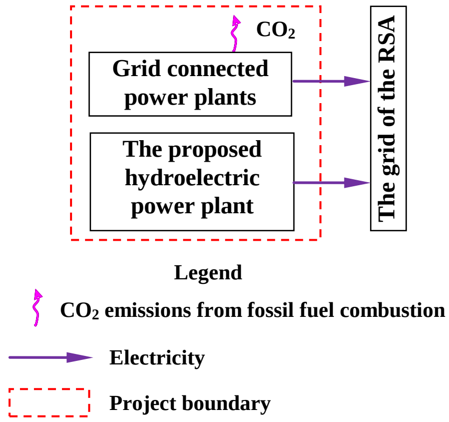

Figure B.3-1: Project boundary

B.4. Description of baseline and its development:

According to the AMS-I.D. the baseline scenario is the following:

- *The baseline scenario is that the electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources into the grid.*

The project activity is the installation of a hydroelectric power plant with an installed capacity of 12.57 MW that connects with and delivers electricity to the grid of the RSA. The baseline scenario of the proposed project, as reflected in the CM calculations presented in Section B.6, is:

- The electricity delivered to the grid by the hydroelectric power plant would have otherwise been generated by the operation of grid-connected Eskom power plants and by the addition of new generation sources to the grid.

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 small-scale CDM project activity:

The additionality is demonstrated according to Attachment A of Appendix B of the "Simplified modalities and procedures for small-scale CDM project activities" (Version 08), reported as Annex 24 to EB 63[25], which states:

"A simplified baseline and monitoring methodology listed in appendix B may be used for a small-scale CDM project activity if the project participants are able to demonstrate to a designated operational entity that the project activity would otherwise not be implemented due to the existence of one or more of the barriers listed in attachment A to appendix B. Where specified in appendix B for a project category,

[25] http://cdm.unfccc.int/Reference/Guidclarif/ssc/methSSC_guid05.pdf

quantitative evidence that the project activity would otherwise not be implemented may be provided instead of a demonstration based on the barriers listed in attachment A to appendix B. [26]

Project participants shall provide an explanation to show that the project activity would not have occurred anyway due to at least one of the following barriers[27]*:*

- *a) Investment barrier: a financially more viable alternative to the project activity would have led to higher emissions;*
- *b) Technological barrier: a less technologically advanced alternative to the project activity involves lower risks due to the performance uncertainty or low market share of the new technology adopted for the project activity and so would have led to higher emissions;*
- *c) Barrier due to prevailing practice: prevailing practice or existing regulatory or policy requirements would have led to implementation of a technology with higher emissions; and*
- *d) Other barriers: without the project activity, for another specific reason identified by the project participant, such as institutional barriers or limited information, managerial resources, organizational capacity, financial resources, or capacity to absorb new technologies, emissions would have been higher."*

The PDD developer demonstrates that the project activity would not have occurred due to investment barrier.

The project envisages the construction and operation of a run-of-river hydroelectric power plant with an installed capacity of 12.57 MW. The produced electricity will be supplied to the national grid of the RSA and sold to Eskom via a Power Purchase Agreement under government's "Independent Power Producer Procurement Program (IPPPP).

The government has capped Power Purchase Agreements (PPAs) for hydro projects to 10 MW. This poses a barrier to some projects that only become financially feasible above this capacity. The present project needed to cap its production at 10 MW, thereby reducing income from the sale of electricity. This regulation poses an investment barrier.

To demonstrate that the project will not be able to be implemented without being registered as a CDM project the project Internal Rate of Return is compared to local lending benchmarks determined by relevant national authorities by means of an investment analysis. In order to maintain a systematic approach, the investment analysis is conducted according to the Step 2 of the "Tool for the demonstration and assessment of additionality (version 06.0.0)"[28]. The tool requires the following steps[29]:

Step 2: Investment analysis

It has to be determined whether the proposed project activity is not:

(a) The most economically or financially attractive; or

(b) Economically or financially feasible without the revenue from the sale of Certified Emission Reductions (CERs).

[26] http://cdm.unfccc.int/Reference/COPMOP/08a01.pdf#page=6 , page 48
[27] http://cdm.unfccc.int/Reference/Guidclarif/ssc/methSSC_guid05.pdf
[28] http://cdm.unfccc.int/methodologies/PAmethodologies/tools (this version will be used throughout the PDD)
[29] AMS-I.D. does not require the use of this tool. This is therefore a conservative approach to facilitate easier validation of the project.

The project developer demonstrates that the proposed project activity is not economically or financially feasible without the revenue from the sale of CERs using the following Sub-steps:

Sub-step 2a: Determine appropriate analysis method

Sub-step 2b: Apply simple cost analysis (Option I), investment comparison analysis (Option II) or benchmark analysis (Option III)

Sub-step 2c: Calculation and comparison of financial indicators (only applicable to Options II and III)

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

Sub-step 2a: Determine appropriate analysis method

It has to be determined whether to apply simple cost analysis (Option I), investment comparison analysis (Option II) or benchmark analysis (Option III).

The proposed project activity generates financial and economic benefits other than CER revenues, so the simple cost analysis (Option I) is not applicable. Following the paragraph 19 of the "Guidelines on the assessment of investment analysis" (Version 05)[30] "*if the alternative to the project activity is the supply of electricity from a grid, this is not to be considered an investment and a benchmark approach is considered appropriate*" the benchmark analysis (Option III) is chosen.

Sub-step 2b: Apply benchmark analysis (Option III)

For the benchmark analysis, the project Internal Rate of Return (project IRR) before tax is used to determine the project financial viability.

Project IRR is calculated based on parameters that are standard in the market as the proposed project could be developed by an entity other than the project participant.

According to the paragraph 13 of the "Guidelines on the assessment of investment analysis" "*in the cases of projects which could be developed by an entity other than the project participant the benchmark should be based on parameters that are standard in the market.*"

The lowest rate of interest at which money may be borrowed commercially in the RSA is a prime rate provided by South African Reserve Bank. At present the prime rate in the RSA is 9.0%[31]. This rate can be considered as a conservative benchmark for post-tax project IRR. Since the project IRR is calculated before tax, the benchmark should be adjusted accordingly: 9.0%*1/(1-0.28) = 12.5%.[32]

Thus, 12.5% benchmark for project IRR before tax is assumed for hydroelectric power projects in the RSA.

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

According to the "Tool for the demonstration and assessment of additionality" the project developer should while calculating a suitable financial indicator "*include all relevant costs (including, for example,*

[30] http://cdm.unfccc.int/Reference/Guidclarif/meth/index_guid.html (This version will be used throughout the PDD)
[31] www.reservebank.co.za
[32] Income tax in the RSA is 28%, www.sars.gov.za/home.asp?pid=289#Incometa

the investment cost, the operations and maintenance costs), and revenues (excluding CER revenues, but possibly including inter alia subsidies/fiscal incentives[33]*, ODA, etc*".

At the twenty-second meeting the Executive Board (EB) accepted "Clarifications on the consideration of national and/or sectoral policies and circumstances in baseline scenarios" (Version 02)[34] where EB separates out following two types of national and/or sectoral policies that are to be taken into account when establishing baseline scenarios (paragraph 6):

(a) National and/or sectoral policies or regulations that give comparative advantages to more emissions-intensive technologies or fuels over less emissions-intensive technologies or fuels (so called type E+);

(b) National and/or sectoral policies or regulations that give comparative advantages to less emissions-intensive technologies over more emissions-intensive technologies (e.g. public subsidies to promote the diffusion of renewable energy or to finance energy efficiency programs) (so called type E-).

According to the paragraph 7 of this clarifications "*national and/or sectoral policies or regulations under paragraph 6 (b) that have been implemented since the adoption by the COP of the CDM M&P (decision 17/CP.7, 11 November 2001) need not be taken into account in developing a baseline scenario (i.e. the baseline scenario could refer to a hypothetical situation without the national and/or sectoral policies or regulations being in place)*".

In November 2003 South African Department of Minerals and Energy released White Paper on Renewable Energy (White Paper)[35] where it sets out Government's vision, policy principles, strategic goals and objectives for promoting and implementing renewable energy in the RSA.

White Paper, page i,*"It is in this context that the Ministry is committed to this policy document which is intended to give much needed thrust to renewable energy; a policy that envisages a range of measures to bring about integration of renewable energies into the mainstream energy economy. To achieve this aim Government is setting as its target 10 000 GWh (0.8 Mtoe) renewable energy contribution to final energy consumption by 2013, to be produced mainly from biomass, wind, solar and small-scale hydro".*

In March 2009 the Energy Regulator of South Africa (NERSA)[36] approved the Renewable Energy Feed - In Tariff (REFIT) to meet the government target of 10,000 GWh by 2013. In March 2011 an updated REFIT values were published, but were expected to change again. In August 2011 the government launched the current national "Independent Power Producer Procurement Program (IPPPP)[37]" which is a bidding scheme developed by the Department of Energy. The current project was submitted in the second bidding round. The scheme allows for a REFIT of 1.03 ZAR/kWh or lower. The REFIT will only be allowed to increase according to the Cost Price Index (CPI). The current projected electricity price in the RSA is 0.6066 ZAR/kWh for 2013.

[33] "*See EB guidance on the consideration of national/local/sectoral policies and measures for the baseline setting"*

[34] http://cdm.unfccc.int/EB/022/eb22_repan3.pdf

[35] http://unfccc.int/files/meetings/seminar/application/pdf/sem_sup1_south_africa.pdf

[36] http://www.nersa.org.za/

[37] http://www.ipp-renewables.co.za/

According to the “Clarifications on the consideration of national and/or sectoral policies and circumstances in baseline scenarios” (Version 02) the policy pursued by NERSA falls under E- policy and need not be taken into account (see paragraph 7 (b) for more details).

Thus, an additional income that will be received due to REFIT (compared with an income which would have been received in the absence of REFIT) should be excluded from the calculation of revenues. Instead, a hypothetical feed-in tariff (FIT) which would exist in the absence of such REFIT should be used to calculate the project IRR.

Table B.5-1 shows the input data used to calculate project IRR.

Detailed information on the investment analysis of the project is given in Annex 3-6.

Table B.5-1: Input data to calculate project IRR

Parameter	Unit	Value	Data source
Net electricity generation	GWh	69.25	Project developers (Neusberg Lender’s Report)
Period of assessment	years	20	Refer to point 3 in the “Guidelines on the assessment of investment analysis” (Version 05)
Electricity tariff*	ZAR/kWh	0.6066	Media statement “NERSA review Eskom tariffs for period 01/04/2012 - 31/03/2013” 09/03/2012, page 1, Table 1[38]
Total investment cost	mil ZAR	433.73	Project developers (Neusberg Lender’s Report, page 101)
Total operating costs	mil ZAR /year	10.9	Project developers (Neusberg Lender’s Report, pages 104 & 105)[39]
ZAR exchange rate	ZAR/USD	7.923	www.x-rates.com[40]

*So far there is no FIT for Independent Power Producers in the RSA except REFIT and FIT for projects applying for Medium Term Power Purchase Programme, the programme to support implementation of co-generation projects. Therefore Eskom’s standard average electricity price is used as hypothetical FIT which would have existed in the absence of REFIT. This is a conservative assumption since the price reflects transmission costs and losses, and therefore the hypothetical FIT should actually be less than Eskom’s electricity price.

Project IRR before tax is 3.52%, which is below 12.5% benchmark.

Outcome of Sub-step 2c: The proposed project activity is not economically or financially feasible without the revenue from the sale of CERs.

[38] http://www.eskom.co.za/content/NERSAreviewEskomtariffs1Apr2012-31Mar2013.pdf
[39] 1,376 Mil USD *7.923 ZAR/USD = 10.9 mil ZAR
[40] Average over 6 months (09/2011 – 02/2012)

Sub-step 2d: Sensitivity analysis

A sensitivity analysis is included to show that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions. The investment analysis provides a valid argument in favour of additionality as this sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be economically or financially attractive.

According to the paragraph 20 of the “Guidelines on the assessment of investment analysis” only variables that constitute more than 20% of either total project costs or total project revenues should be included in the sensitivity analysis. The sensitivity analysis should at least cover the range of +10% and -10%. A more robust sensitivity analysis with a range of +20% and -20% was applied.

The following variables were included in the sensitivity analysis:

- Income from electricity sale
- Investment cost; and
- Operations and Maintenance (O&M) costs.

The results of the sensitivity analysis are shown in Table B.5-2.

Table B.5-2: Sensitivity analysis of project IRR

Variable	Variation						
	-20%	-10%	-5%	0%	+5%	+10%	+20%
Electricity Price	0.42%	2.04%	2.80%	3.52%	4.21%	4.88%	6.17%
Investment Cost	5.98%	4.65%	4.06%	3.52%	3.01%	2.54%	1.68%
O&M Cost	4.24%	3.88%	3.70%	3.52%	3.33%	3.15%	2.77%

In all cases the project IRR is less than the benchmark. Even with a decrease of 20% of the investment cost the project IRR remains significantly lower than the benchmark.

Outcome of Sub-step 2d: The proposed CDM project activity is unlikely to be financially/economically attractive.

Outcome of the additionality test: The proposed project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Project emissions

Since the project activity is a run-of-river hydroelectric power plant that uses an existing reservoir with no change in the volume of reservoir[41] the project emissions are equal to zero[42]:

$$PE_y = 0 \quad \text{(B.6-1)}$$

Where:

PE_y = Project emissions in year *y* (t CO_2/y)

Baseline emissions

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The AMS-I.D. methodology assumes that electricity delivered to the grid by the hydro power plant would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources into the grid. The baseline emissions are calculated as follows (AMS-I.D. equation 1):

$$BE_y = EG_{BL,y} * EF_{CO_2,grid,y} \quad \text{(B.6-2)}$$

Where:

BE_y = Baseline emissions in year *y* (t CO_2)

$EG_{BL,y}$ = Quantity of net electricity supplied to the grid as a result of the implementation of the CDM project activity in year *y* (MWh)

$EF_{CO_2,grid,y}$ = CO_2 emission factor of the grid in year *y* (t CO_2/MWh)

According to the AMS-I.D.: *'The emission factor can be calculated in a transparent and conservative manner as follows:*

a) A combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) according to the procedures prescribed in the "Tool to calculate the Emission Factor for an electricity system"; or

[41] The current Neusberg weir will be used. Therefore there are no increases in reservoir area.

[42] AMS-I.D. paragraph 20

b) *The weighted average emissions (in t CO_2/MWh) of the current generation mix. The data of the year in which project generation occurs must be used.'*

Option *a)* will be applied for the present project. The procedures prescribed in the "Tool to calculate the emission factor for an electricity system" will be applied to calculate a combined margin CO_2 emission factor for the grid in year y ($EF_{grid,CM,y}$).

$$EF_{CO_2,grid,y} = EF_{grid,CM,y} \quad \text{(B.6-3)}$$

Where:

$EF_{CO_2,grid,y}$	=	CO_2 emission factor of the grid in year *y* (t CO_2/MWh)
$EF_{grid,CM,y}$	=	Combined margin CO_2 emission factor for the project electricity system in year *y* (tCO_2/MWh)

Calculation of $EF_{grid,CM,y}$

Combined margin CO_2 emission factor for grid connected power generation in year *y* ($EF_{grid,CM,y}$) is calculated using the "Tool to calculate the emission factor for an electricity system". According to this tool the following six steps shall be applied:

Step 1: Identify the relevant electricity systems;

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

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

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

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

Step 6: Calculate the combined margin (CM) emissions factor.

Step 1: Identify the relevant electricity systems

Electricity generated by the proposed project activity will be supplied to the national grid of the RSA which is defined as a project electricity system by default. The national grid of the RSA is managed by the state-owned company Eskom which is the only company in South Africa in charge of generation, transmission and distribution of power to end-users. The basic scheme of the Eskom electricity network (the national grid of the RSA) is presented in Annex 3-1.

Data on Eskom grid-connected power plants as of 31 March 2010 is presented in Annex 3-2.

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

The project participant may choose between the following two options to calculate the operating margin and build margin emission factors:

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

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

Option I was chosen to calculate the operating margin and build margin emission factors.

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

'The calculation of the operating margin emission factor ($EF_{grid,OM,y}$) is based on one of the following methods, which are described under Step 4:

(a) Simple OM; or

(b) Simple adjusted OM; or

(c) Dispatch data analysis OM; or

(d) Average OM.

The simple OM method (Option a) can only be used if low-cost/must-run resources[43] constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.'

The most recent data on the electricity supplied to the national grid of the RSA is presented in Table B.6-1. Share of electricity supplied from the low-cost/must-run sources in total grid generation on average of the five most recent years constitute 7.03%. Thus, Option (a) (Simple OM method) has been chosen to calculate the operating margin emission factor.

Table B.6-1: Electricity supplied to the national grid of the RSA, GWh[44]

Type of power plant	Years*					Average	Share
	04.2005 - 03.2006	04.2006 - 03.2007	04.2007 - 03.2008	04.2008 - 03.2009	04.2009 - 03.2010		
Coal-fired	206 606	215 211	222 908	211 941	215 940	214 521	92.84%
Hydro-electric	1 141	2 443	751	1 082	1 274	1 338	0.58%
Pumped storage	2 867	2 947	2 979	2 772	2 742	2 861	1.24%
Gas turbine	78	62	1 153	143	49	297	0.13%
Nuclear	11 293	11 780	11 317	13 004	12 806	12 040	5.21%
Wind energy	3	2	1	2	1	2	0.00%
Total net generation	221 988	232 445	239 109	228 944	232 812	231 060	100.00%

*A reporting year for Eskom starts on the 1st of April and finishes on the 31st of March.

For the Simple OM the emission factor can be calculated using either of the two following data vintages:

- *Ex ante option*: The emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. For grid power plants, use a 3-year generation-weighted average;

[43] '*Low-cost/must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation.'*

[44]Eskom Annual Report 2010, page 1, http://financialresults.co.za/2010/eskom_ar2010/index.htm

- *Ex post option*: The emission factor is determined for the year in which the project activity displaces grid electricity, requiring the emissions factor to be updated annually during monitoring.

Ex ante option was chosen to calculate the OM emission factor.

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

The simple OM emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO_2/MWh) of all generating power plants serving the system, not including low-cost/must-run power plants/units.

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

Option A: Based on the net electricity generation and a CO_2 emission factor of each power unit; or

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

The *Option A* is used as data on the net electricity generation and a CO_2 emission factor of each Eskom power plant is available. The OM emission factor is calculated as follows:

$$EF_{grid,OM,y} = EF_{grid,OMsimple,y} \qquad \text{(B.6-4)}$$

Where:

$EF_{grid,OM,y}$	=	Operating margin CO_2 emission factor calculated ex ante in year y (tCO_2/MWh)
$EF_{grid,OMsimple,y}$	=	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)

The simple operating margin CO_2 emission factor is calculated as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}} \qquad \text{(B.6-5)}$$

Where:

$EF_{grid,OMsimple,y}$	=	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh). Data is presented in Annex 3-3
$EF_{EL,m,y}$	=	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
m	=	All power units serving the grid in year *y* except low-cost/must-run power units. The list of power plants included into the operating margin is presented in Annex 3-3
y	=	The relevant year as per the data vintage chosen in Step 3

Data for the three most recent reporting years on operation of Eskom power plants included into the operating margin is presented in Annex 3-3.

Determination of $EF_{EL,m,y}$

As data on fuel consumption and electricity generation for each coal-fired power unit *m* is available, the emission factor ($EF_{EL,m,y}$) for these units is determined as follows (*Option A1*):

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}} \quad \text{(B.6-6)}$$

Where:

$EF_{EL,m,y}$	=	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$FC_{i,m,y}$	=	Amount of fossil fuel type *i* consumed by power unit *m* in year *y* (mass or volume unit). Data is presented in Annex 3-3
$NCV_{i,y}$	=	Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit). Constant value was adopted (see Section B.6.2 for details)
$EF_{CO2,i,y}$	=	CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ). Constant value was adopted (see Section B.6.2 for details)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh). Data is presented in Annex 3-3
m	=	All power units serving the grid in year *y* except low-cost/must-run power units. The list of power plants included into the operating margin is presented in Annex 3-3
i	=	All fossil fuel types combusted in power unit *m* in year *y*
y	=	The relevant year as per the data vintage chosen in Step 3

As only data on electricity generation for gas turbine power plants is available, *Option A2* is used to determine $EF_{EL,m,y}$ for these plants:

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \cdot 3.6}{\eta_{m,y}} \quad \text{(B.6-7)}$$

Where:

$EF_{EL,m,y}$	=	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$EF_{CO2,m,i,y}$	=	Average CO_2 emission factor of fuel type *i* used in power unit *m* in year *y* (tCO_2/GJ). Constant value was adopted (see Section B.6.2 for details)
$\eta_{m,y}$	=	Average net energy conversion efficiency of power unit *m* in year *y* (ratio). Constant value was adopted (see Section B.6.2 for details)
m	=	All power units serving the grid in year *y* except low-cost/must-run power units.

Option A2 is only used for gas turbine power plants (see Annex 3-3)

i	=	All fossil fuel types combusted in power unit *m* in year *y*
y	=	The relevant year as per the data vintage chosen in Step 3

The calculation of the operating margin emission factor is presented in Annex 3-5.

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

In terms of vintage of data, project participants can choose between one of the following two options:

Option 1: For the first crediting period, calculate the build margin emission factor ex ante based on the most recent information available on units already built for sample group *m* at the time of CDM-PDD submission to the DOE for validation. This option does not require monitoring the emission factor during the crediting period; or

Option 2: For the first crediting period, the build margin emission factor shall be updated annually, ex post, including those units built up to the year of registration of the project activity or, if information up to the year of registration is not yet available, including those units built up to the latest year for which information is available.

Option 1 was chosen.

The build margin calculation algorithm is presented in the Figure B.6-1. For simplification three levels were identified for the calculation of the BM.

Level A: Inclusion of power units which started to supply electricity to the grid less than 10 years ago, excluding power units registered as CDM project activities;

Level B: Inclusion of power units which started to supply electricity to the grid less than 10 years ago and power units registered as CDM project activities; and

Level C: Inclusion of power units which started to supply electricity to the grid more than 10 years ago and power units registered as CDM project activities.

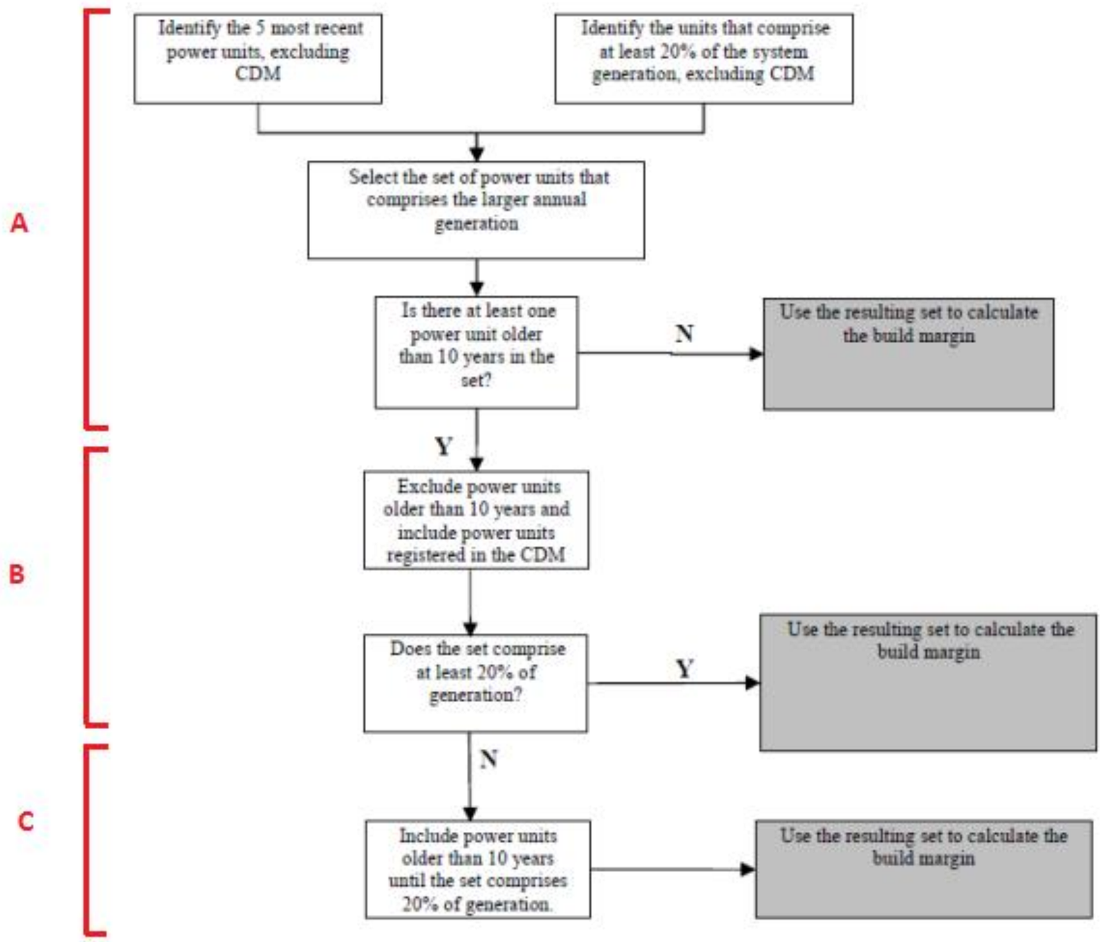

Figure B.6-1: Build margin calculation algorithm

The following procedures were applied to determine the sample group of power units *n* used to calculate the build margin:

a. Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently ($SET_{5\text{-}units}$) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-}units}$, in MWh);

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

c. From $SET_{5\text{-}units}$ and $SET_{\geq 20\%}$ select the set of power units that comprises the larger annual electricity generation (SET_{sample});

Identify the date when the power units in SET_{sample} started to supply electricity to the grid. If none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. In this case ignore steps (d), (e) and (f);

The sets of power units $SET_{5\text{-}units}$ and $SET_{\geq 20\%}$ were identified (see Annex 3-4). The set of power units $SET_{\geq 20\%}$ that comprises the larger annual electricity generation was chosen as SET_{sample}. As SET_{sample} includes power units which started to supply electricity to the grid more than 10 years ago, the conditions for *Level A* have therefore not been satisfied and the project developer move to step (d).

d. Exclude from SET_{sample} the power units which started to supply electricity to the grid more than 10 years ago. Include in that set the power units registered as CDM project activities, starting with power units that started to supply electricity to the grid most recently, until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual electricity generation ($AEG_{SET\text{-}sample\text{-}CDM}$, in MWh);

If the annual electricity generation of that set comprises at least 20% of the annual electricity generation of the project electricity system (i.e. $AEG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AEG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the build margin. Ignore steps (e) and (f);

The annual electricity generation of $SET_{sample\text{-}CDM}$ comprises less than 20% of the annual electricity generation of the national grid of the RSA (see Annex 3-4). The conditions for *Level B* have not been satisfied. Therefore continue to step (e) and (f).

e. Include in the sample group $SET_{sample\text{-}CDM}$ the power units that started to supply electricity to the grid more than 10 years ago until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation);

f. The sample group of power units *n* used to calculate the build margin is the resulting set ($SET_{sample\text{-}CDM\text{->}10yrs}$).

The power units in $\text{SET}_{\text{sample-CDM ->10yrs}}$ was used to calculate the build margin. The list of power plants included into the build margin is presented in Annex 3-4.

The build margin emission factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units *n* included into the build margin during the most recent year *y* (2010 reporting year) for which electricity generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_n EG_{n,y} \cdot EF_{EL,n,y}}{\sum_n EG_{n,y}} \qquad \text{(B.6-8)}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (2010 reporting year) (tCO_2/MWh)

$EG_{n,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit *n* in year *y* (MWh). Data is presented in Annex 3-4
$EF_{EL,n,y}$	=	CO_2 emission factor of power unit *n* in year *y* (tCO_2/MWh)
n	=	Power units included in the build margin. The list of power plants included into the build margin is presented in Annex 3-4
y	=	Most recent historical year for which electricity generation data is available. The 2010 reporting year was selected

The CO_2 emission factor of power unit *n* in year *y* ($EF_{EL,n,y}$) is calculated using Formulas (B.6-6) and (B.6-7).

According to the "Tool to calculate the emission factor for an electricity system" if the power units included in the build margin *n* correspond to the sample group $SET_{sample\text{-}CDM\text{->}10yrs}$, then, as a conservative approach, only *Option A2* from *Step 4* can be used to calculate $EF_{EL,n,y}$ and the default values provided in Annex 1 of the Tool shall be used to determine the parameter $\eta_{m,y}$. Therefore Formula (B.6-7) was used to calculate $EF_{EL,n,y}$ for Majuba and Kendal power plants.

The calculation of the build margin CO_2 emission factor is presented in Annex 3-5.

<u>Step 6: Calculate the combined margin emissions factor</u>

The combined margin emission factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,CM} = EF_{grid,OM,y} \cdot w_{OM} + EF_{grid,BM,y} \cdot w_{BM} \qquad \text{(B.6-9)}$$

Where:

$EF_{grid,CM,y}$	=	Combined margin CO_2 emission factor for the project electricity system in year *y* (tCO_2/MWh)
$EF_{grid,CM}$	=	Combined margin CO_2 emission factor for grid connected power generation calculated ex ante (tCO_2/MWh)
$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in the most recent year *y* (2010 reporting year) (tCO_2/MWh)
$EF_{grid,OM,y}$	=	Operating margin CO_2 emission factor (tCO_2/MWh)
w_{OM}	=	Weighting of operating margin emission factor
w_{BM}	=	Weighting of build margin emission factor

According to the "Tool to calculate the emission factor for an electricity system" the following default values should be used for hydro power generation project activities during the first crediting period: w_{OM} = 0.50 and w_{BM} = 0.50.

The calculation of the combined margin CO_2 emission factor is presented in Annex 3-5.

Leakage

The methodology AMS-I.D. states that: "*If the energy generating equipment is transferred from another activity leakage is to be considered*".

In the proposed project activity, no energy generating equipment is transferred from another activity and there is no existing equipment that could be transferred to another activity. Hence leakage is not considered.

Emission reductions

Emission reductions are calculated as follows (AMS-I.D. equation 10):

$$ER_y = BE_y - PE_y - LE_y \quad \text{(B.6-10)}$$

Where:

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

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

Data / Parameter:	$EG_{m,y}$
Data unit:	MWh
Description:	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y*
Source of data used:	Eskom's statistic data
Value applied:	See Annex 3-3
Justification of the choice of data or description of measurement methods and procedures actually applied :	Official statistics, publicly available and reliable data source
Any comment:	The data for the three most recent reporting years is provided.

Data / Parameter:	$FC_{i,m,y}$
Data unit:	mass or volume unit
Description:	Amount of fossil fuel type *i* consumed by power unit *m* in year *y*
Source of data used:	Eskom's statistic data
Value applied:	See Annex 3-3

Justification of the choice of data or description of measurement methods and procedures actually applied :	Official statistics, publicly available and reliable data source
Any comment:	The data for the three most recent reporting years is provided.

Data / Parameter:	***$NCV_{coal,y}$***
Data unit:	GJ/t
Description:	Net calorific value of Other Bituminous Coal
Source of data used:	2006 IPCC Guidelines for National GHG Inventories, volume 2: Energy, Chapter 1, Table 1.2
Value applied:	19.9
Justification of the choice of data or description of measurement methods and procedures actually applied :	For the sake of a conservative approach the IPCC default value at the lower limit of the uncertainty at a 95% confidence interval is used. The default NCV that is available on the Eskom website is 0.02509 TJ/t fuel.[45] The 2006 IPCC Guidelines references the NCV of the different types of coal. The Eskom default value corresponds to the NCV of 'other bituminous coal'. Therefore the IPCC value for 'other bituminous coal' was applied to calculate the grid emission factor.
Any comment:	This value was appointed as a constant.

Data / Parameter:	***$EF_{CO2,coal,y}$***
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of Other Bituminous Coal
Source of data used:	2006 IPCC Guidelines for National GHG Inventories, volume 2: Energy, Chapter 1, Table 1.4
Value applied:	0.0895
Justification of the choice of data or description of measurement methods and procedures actually applied :	For the sake of a conservative approach the IPCC default value at the lower limit of the uncertainty at a 95% confidence interval is used. The default emission factor that is available on the Eskom website is 25.8 tC/TJ.[46] The 2006 IPCC Guidelines references the carbon content of the different types of coal. The Eskom default value corresponds to the carbon content of 'other bituminous coal'. Therefore the IPCC value for 'other bituminous coal' was applied to calculate the grid emission factor.
Any comment:	This value was appointed as a constant.

Data / Parameter:	***$EF_{CO2,NG,y}$***
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of Natural Gas

[45] http://www.eskom.co.za/c/article/236/cdm-calculations/
[46] http://www.eskom.co.za/c/article/236/cdm-calculations/

Source of data used:	2006 IPCC Guidelines for National GHG Inventories, volume 2: Energy, chapter 1, Table 1.4
Value applied:	0.0543
Justification of the choice of data or description of measurement methods and procedures actually applied :	For the sake of a conservative approach the IPCC default value at the lower limit of the uncertainty at a 95% confidence interval is used.
Any comment:	This value was appointed as a constant.

Data / Parameter:	η_{OCGT}
Data unit:	ratio
Description:	Average net energy conversion efficiency of open cycle gas turbine power plant
Source of data used:	Tool to calculate the emission factor for an electricity system, Annex 1
Value applied:	0.395
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value is used
Any comment:	This value was appointed as a constant.

Data / Parameter:	$\eta_{m,y}$
Data unit:	ratio
Description:	Average net energy conversion efficiency of coal fired power plant that has operated for more than 10 years for calculation of the Build Margin.
Source of data used:	Tool to calculate the emission factor for an electricity system, Annex 1
Value applied:	0.37
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value is used
Any comment:	This value was appointed as a constant to Majuba and Kendal power plants for the calculation of build margin CO_2 emission factor (refer to Annex 3-5).

Data / Parameter:	$EG_{n,y}$
Data unit:	MWh
Description:	Net quantity of electricity generated and delivered to the grid by power unit *n* in year *y*

Source of data used:	Eskom's statistic data
Value applied:	See Annex 3-4
Justification of the choice of data or description of measurement methods and procedures actually applied :	Official statistics, publicly available and reliable data source
Any comment:	The data for 2010 reporting year is provided.

Data / Parameter:	$FC_{i,n,y}$
Data unit:	mass or volume unit
Description:	Amount of fossil fuel type *i* consumed by power unit *n* in year *y*
Source of data used:	Eskom's statistic data
Value applied:	See Annex 3-4
Justification of the choice of data or description of measurement methods and procedures actually applied :	Official statistics, publicly available and reliable data source
Any comment:	The data for 2010 reporting year is provided.

Data / Parameter:	$EF_{grid,CM}$
Data unit:	tCO_2/MWh
Description:	Combined margin CO_2 emission factor for grid connected power generation calculated ex ante
Source of data used:	Calculated (see Annex 3)
Value applied:	0.965
Justification of the choice of data or description of measurement methods and procedures actually applied :	Calculated *ex ante* based on the "Tool to calculate the emission factor for an electricity system"
Any comment:	This value was appointed as a constant for the whole crediting period.

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

Combining equation (B.6-1), (B.6-2), (B.6-3), (B.6-9) and (B.6-10), the annual emission reductions can be calculated as follows:

$$ER_y = EG_{\mathrm{BL,y}} \cdot EF_{grid,CM} \qquad \text{(B.6-11)}$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2/y)
$EG_{BL,y}$	=	Quantity of net electricity supplied to the grid as a result of the implementation of the CDM project activity in year *y* (MWh)
$EF_{grid,CM}$	=	Combined margin CO_2 emission factor for grid connected power generation calculated ex ante (tCO_2/MWh)

The calculation of the combined margin CO_2 emission factor is presented in Annex 3-5. A constant emission factor of $EF_{grid,CM}$ = 0.965 tCO_2/MWh is adopted for the 7 year crediting period.

The estimated amount of electricity annually supplied by the hydroelectric power plant to the Eskom electricity network during the first 7 year crediting period is presented in Table B.6-2.

Summary of the ex-ante estimation of emission reductions is presented in Section B.6.4 below.

Table B.6-2: Quantity of net electricity generation annually supplied by the hydroelectric power plant to the grid ($EG_{BL,y}$) during the first 7-year crediting period, MWh

Year	$EG_{BL,y}$ (MWh)
2014 (from 08/10/2014 to 31/12/2014)	15 823
2015	69 250
2016	69 250
2017	69 250
2018	69 250
2019	69 250
2020	69 250
2021(from 01/01/2021 to 07/10/2021)	53 427
Total over 7 years	**484 750**

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

Year	Estimation of project activity emissions (tCO_2 e)	Estimation of baseline emissions (tCO_2 e)	Estimation of leakage (tCO_2 e)	Estimation of overall emission reductions (tCO_2 e)
2014 (from 08/10/2014 to 31/12/2014)	0	15 269	0	15 269
2015	0	66 826	0	66 826
2016	0	66 826	0	66 826
2017	0	66 826	0	66 826
2018	0	66 826	0	66 826
2019	0	66 826	0	66 826
2020	0	66 826	0	66 826
2021(from 01/01/2021 to 07/10/2021)	0	51 557	0	51 557
Total (tonnes of CO_2 e)	**0**	**467 782**	**0**	**467 782**

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

B.7.1 Data and parameters monitored:

Data / Parameter:	$EG_{BL,y}$
Unit:	MWh/y
Description:	Quantity of net electricity supplied to the grid as a result of the implementation of the CDM project activity
Source of data :	On-site measurement with electricity meters
Value of data	Estimated quantity of electricity that will be produced:

Year	Quantity of electricity (MWh)
2014 (from 08/10/2014 to 31/12/2014)	15 823
2015	69 250
2016	69 250
2017	69 250

	2018	69 250
	2019	69 250
	2020	69 250
	2021(from 01/01/2021 to 07/10/2021)	53 427
Brief description of measurement methods and procedures to be applied:	Measurement by means of electricity meters installed at the point of supply which defines the commercial boundary between Eskom and the hydroelectric power plant owner. The generated electricity will be continuously monitored, hourly measured and recorded at least on a monthly basis. Data on electricity supply will be digitally archived at least on a monthly basis.	
QA/QC procedures to be applied (if any):	Electricity meters will be calibrated according to SABS standards[47]; readings will be cross-checked with records for sold electricity.	
Any comment:	See Section B.7.2 for details. Any electricity consumed by the plant for auxiliary equipment (air conditioning, lighting etc.) will be monitored by an electricity meter. During verification this amount (kWh) will be subtracted from total electricity supplied to the grid to calculate the net electricity supplied to the grid.	

B.7.2 Description of the monitoring plan:

The monitoring plan is devised as per AMS-I.D. The following procedures shall be applied:

1. Monitoring period

A 7-year crediting period with the option of renewal was chosen for the project. The monitoring period starts from the date of commissioning of the hydroelectric power plant or the date of registration of the proposed project by CDM Executive Board (whichever is later).

2. Data monitored and sources

Quantity of net electricity generation supplied by the hydroelectric power plant to the grid shall be determined on the basis of electricity meters located at the point of supply to the Eskom electricity network. The generated electricity will be continuously monitored, measured at least hourly, and recorded at least on a monthly basis by the power plant personnel. The metering instruments shall be installed in accordance with the requirements of Grid and the Distribution Metering Codes at the point of supply which defines the commercial boundary between Eskom and the hydroelectric power plant owner. Readings of the electricity meters shall be cross-checked with records for sold electricity. Data on electricity supply will be digitally archived at least on a monthly basis.

Any electricity consumed by the plant for auxiliary equipment (air conditioning, lighting etc.) will be monitored by an electricity meter. During verification this amount (kWh) will be subtracted from total electricity production to calculate the net electricity supplied to the grid.

The sources of data for calculation of GHG emission reductions in the course of monitoring shall be the internal reports of the hydroelectric power plant.

The emission reductions shall be calculated using the Formula (B.6-11).

[47] The South African Bureau of Standards requires that the latest version of SANS 474 must be followed.

3. The monitoring team

The power plant staff shall undergo the necessary training related to operation and maintenance of the hydroelectric power plant and all of the installed equipment. The training shall take place at the manufacturer's facility and on site at the power plant. The maintenance personnel of the hydroelectric power plant are responsible for daily control over the monitoring plan implementation.

The Chief Engineer of the hydroelectric power plant is responsible for timely calibration of all instrumentation in accordance with the South African Bureau of Standards and the manufacturer's requirements. The management of Kakamas Hydro Electric Power (Pty) Ltd is fully responsible for the project implementation and overall control as well as collection of all data required for calculation of GHG emission reductions.

Specialists of Blue World Carbon Asset Management (Pty) Ltd will calculate GHG emission reductions with data that will be provided by Kakamas Hydro Electric Power (Pty) Ltd.

In case of any doubts as to the accuracy of the data, the specialists of Kakamas Hydro Electric Power (Pty) Ltd shall check and correct the data. The preliminary version of the monitoring report shall be submitted to the specialists of Kakamas Hydro Electric Power (Pty) Ltd for review. In case any mistakes are found in the calculations of GHG emission reductions, the specialists of Blue World Carbon Asset Management (Pty) Ltd shall correct these calculations accordingly.

Specialists of Blue World Carbon Asset Management (Pty) Ltd shall regularly (at least annually) carry out "test verifications" with a view to ensure that the monitoring plan at Kakamas Hydro Electric Power (Pty) Ltd is applied correctly.

4. Data storage

All data collected as part of monitoring plan should be archived electronically and be kept at least for 2 years after the end of the crediting period.

5. Instrumentation calibration

The instrumentation calibration and check-out shall be carried out by contracted specialized organisations that are licenced for this type of activity according to the requirements of the manufacturing company and the South African Bureau of Standards (SABS) standards by Kakamas Hydro Electric Power (Pty) Ltd. Documentary evidence of calibration shall be archived, and may be required during verification.

6. Emergency situations

If any instrument that is used in the monitoring process fails, Kakamas Hydro Electric Power (Pty) Ltd shall remedy the situation as soon as possible and if necessary shall replace the instrument. In case of breakdown of any of the equipment or the electricity generation will go down, and amount of electricity supplied to the grid by the hydroelectric power plant will be reduced. All accidents that may occur at the hydroelectric power plant shall be recorded by Kakamas Hydro Electric Power (Pty) Ltd. Information on major accidents shall be included in the monitoring report.

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

Date of completion: 28/11/2011

Baseline was developed by Blue World Carbon Asset Management (Pty) Ltd. (Blue World Carbon Asset Management (Pty) Ltd is not the project participant).

Contact persons: Ilya Goryashin (i.goryashin@ccgs.ru), Tom Hugo (tom.hugo@blueworldcarbon.com), Niel Theron (niel@mulilo.com)

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

No implementation or construction or real action of the proposed project activity has begun thus far. The expected starting date of the proposed project activity is the 08/01/2013 (start of construction).

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

40 years (0 months)[48]

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

C.2.1. Renewable crediting period:

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

08/10/2014

C.2.1.2. Length of the first crediting period:

7 years (0 months)

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Not applicable (this project chose to apply a renewable crediting period)

C.2.2.2. Length:

Not applicable (this project chose to apply a renewable crediting period)

[48] Project developers (the equipment will undergo a major refurbishment after about 20 – 25 years).

SECTION D. Environmental impacts

D.1. If required by the host Party, documentation on the analysis of the environmental impacts of the project activity:

In terms of the South Africa's Environmental Impact Assessment (EIA) Regulations this project activity had to undertake a Basic Assessment (BA) which requires a Record of Decision (ROD) before the project will be allowed to commence. The present project received a ROD from the Department of Environmental Affairs on 13/10/2011, which grants environmental authorisation for the layout alternative 6.

The final Basic Assessment Report (BAR) provides a comprehensive assessment of the potential environmental impacts, identified by the environmental team and I&APs, associated with the proposed hydroelectric power plant. The assessment of impacts was informed by the following specialist studies, where relevant:

1. Aquatic Ecology Impact Assessment
2. Heritage Impact Assessment
3. Botanical Impact Assessment
4. Palaeontology desktop study

To minimize potential environmental impacts 6 different layout alternatives[49] are considered for the project activity. A summary on the finding of the environmental assessment is provided in Table D.1-1.

Table D.1-1: summary of environmental impacts with and without mitigation

	WITHOUT MITIGATION	WITH MITIGATION
CONSTRUCTION		
Botanical		
Aqueduct and new access road impacts		
Alternatives 1-5	Medium - High (-)	Low (-)
Alternative 6 (preferred)	Low (-)	Low (-)
Turbine hall impacts		
Alternatives 1-5	High (-)	Low (-)
Alternative 6 (preferred)	Medium (-)	Low (-)
Distribution lines impacts	Low (-)	Low (-)
Fauna (including avifauna)	Low (-)	Low (-)
Aquatic ecology	Medium (-)	Low (-)
Visual	Low (-)	Very low (-)
Agriculture		
Alternatives 1-4	Low (-)	Very Low (-)
Alternative 5	-	-
Alternative 6 (preferred)	Low (-)	Very Low (-)
Noise	Low (-)	Low (-)
Socio-economic	*Low (+)*	*Low (+)*

[49] The layout alternatives are summarized on p.5 of the Final BAR, and p.92 shows the respective drawings.

	WITHOUT MITIGATION	WITH MITIGATION
OPERATION		
Fauna (including Avifauna)		
Hydropower station		
Alternatives 1-5	Low (-)	Low (-)
Alternative 6 (preferred)	-	-
Distribution lines	Medium (-)	Low (-)
Aquatic ecology		
River banks and water quality	Medium – High (-)	Medium (-)
Fishway attraction flows		
Alternatives 1, 2, 5 & 6 (preferred)	High (-)	Medium (-)
Alternative 3	High (-) (fatally flawed)	High (-)
Alternative 4	High (-)	Low (-)
Decreased dry season flows	*Low (+)*	*Low (+)*
Heritage	High (-)	Low (-)
Visual	Medium (-)	Low - Medium (-)
Agriculture		
Alternatives 1-4 & 6 (preferred)	Low (-)	Low (-)
Alternative 5	-	-
Noise		
Alternatives 1-5	Low (-)	Very Low (-)
Alternatives 6 (preferred)	Medium (-)	Low (-)
Flow gauging	High (-)	Neutral
Economic (Energy Generation)	*Low (+)*	*Low (+)*
Socio-economic	*Low (+)*	*Low (+)*
DECOMMISSIONING		
-	-	-
CUMULATIVE		
-	-	-

From an overall environmental impact perspective, the preferred alternative is Alternative 4, with mitigation, due to the preference of this alternative from an aquatic ecology perspective. However, based on the information provided above, Alternatives 1, 2, 5 and 6 (KHEP‘s preferred) are considered to be acceptable from an environmental perspective. Alternative 3 is considered to be fatally flawed from an aquatic perspective due to its potential impact on fishway attraction flows. KHEP preferred alternative 6, which includes an intake structure. No potential impacts would result from the no-go alternative. Since this would be a continuation of the current state the potential for positive impacts such as the provision of renewable electricity for South Africa would not be realised. Environmental authorization was obtained for the (preferred) alterative 6[50].

[50] See Final layout

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:

Based on the findings of all the credible specialists who undertook their respective specialist studies, it was concluded that there are no negative impacts that cannot be adequately mitigated. All mitigatory measures and recommendations are outlined in the BAR. These measures are considered achievable and should be included as conditions of approval.

SECTION E. Stakeholders' comments

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

CDM stakeholders meeting[51]

A CDM stakeholders meeting was held on 28/03/2012 at the Kalahari Gateway Hotel, Kakamas by Blue World Carbon Asset Management (Pty) Ltd. An attendance register and comment form was completed at the stakeholder conference. The following topics were discussed:

1. What is CDM – the purpose of CDM was discussed.
2. Project Details – Project details for the current project were discussed. The benefits of the project were discussed including the fact that it will annually produce 69.25 GWh of hydro generated electricity. Finally it was mentioned that the project seeks to be registered as a CDM project.
3. CDM in RSA Projects – It was explained that the current CDM project will generate carbon credits because is substitutes greenhouse gas emissions. The Carbon Credits will be sold to bring additional revenue to the project.
4. Blue World Carbon's Role – It was explained that it is Blue World Carbon's responsibility to prepare the documentation and oversee auditing procedures in order to register the project.

Environmental Stakeholders meeting

The project owner appointed Aurecon to undertake the Basic Assessment (BA) as well as the Public Participation Process (PPP) in terms of the NEMA EIA Regulations, for the proposed project activity. The CDM requirements based on the Kyoto protocol were followed. The draft Basic Assessment Report (BAR) was published for public review and comment over a period of 40 days from October 2010. Hereafter the BAR was submitted to the Department of Environmental Affairs (DEA) in November 2010 for a decision. On 13/10/2011 the Record of Decision (ROD) was obtained and environmental authorisation was granted for the hydroelectric power plant.

The activities undertaken to canvass public opinion regarding the proposed project activity are listed below and are summarised in Table E.1-1. All supplementary documentation to the public participation process is available in the BAR. The following steps we undertaken as part of the public participation process:

1. The project was advertised in the Volksblad in English and Afrikaans on 17 September 2010. Interested and Affected Parties (I&APs) were invited to register as an I&AP, obtain more information and comment on the proposed project.
2. A Background Information Document (BID) in English and Afrikaans was posted and emailed to all identified I&APs on 17 September 2010. I&APs were given until 18 October 2010 to comment on the proposed project.
3. Comments were received from four I&APs and are included in BAR. Comments have been included in a Comments and Response Report (CRR) Version 1. All those who commented were sent a copy of the CRR.

[51] Attendance register and stakeholder comments

4. A site notice, inviting I&APs to register and comment on the proposed project, was erected on site.
5. The Draft BAR was lodged at the Kakamas Public Library and on Aurecon's website (wwww.aurecongroup.com) and was available for comment from 6 June 2011 until 19 July 2011.
6. Registered I&APs were notified on 6 June 2011, by post and e-mail, of the availability of the Draft BAR for comment and invited to an Open House and Public Meeting on 23 June 2011.
7. An Open House and Public Meeting were held on 23 June 2011, from 16h00 - 19h00 at the Kalahari Gateway Hotel, Kakamas. The Open Day was held between 16h00 and 17h00 and information from the BAR was on view (e.g. posters and maps), and the project team was available to provide further clarity and answer questions. The formal meeting started at 17h00. A list of attendees, copies of the posters and notes of the meeting are included in Annexure J.
8. Notes of the meeting were sent to all those who attended together with notification of the availability of the Final BAR on 2 August 2011.
9. A meeting was held with Mr Lucas Becker of the Kai! Garib Municipality in Kakamas on 21 July 2011.
10. Three comments were received on the Draft BAR, copies of which are included in Annexure K. These have been included and responded to in the CRR Version 2, which is included in Annexure L. All those who commented were sent a copy of the CRR.

11. Table E.1-1: Summary of activities undertaken and proposed during public consultation

Activity	Date
Advertisement and invitation of I&APs to register	17/09/2010
Distribution BID and invitation for comments	17/09/2010 – 18/10/2010
Comment period for Draft BAR (lodged at the Kakamas Public Library and on wwww.aurecongroup.com)	06/06/2011 until 19/07/2011
Registered I&APs invited to an Open House and Public Meeting at Kalahari Gateway Hotel, Kakamas	06/06/2011
Public Meeting - notes on the meeting were sent to all attendees.	23/06/2011
Meeting with Mr Lucas Becker of the Kai! Garib Municipality in Kakamas	21/07/2011
All comments that were received on the Draft BAR were included into the Comments and Response Report (CRR). The CRR was sent to those who provided comments.	
Final BAR	02/08/2011
Record of Decision (ROD) from Department of Energy	13/10/2011

E.2. Summary of the comments received:

All the questions at the CDM stakeholder conference were on how the CDM process works[52].

The following main comments were received[53]:

1. The Neusberg weir is of critical importance to the Department of Water Affairs (DWA), especially because it is essential for hydrological measurements. Therefore any water to be drawn out of Neusberg Weir, to feed the hydroelectric power plant, should be measured accurately and that these measurements should adhere to the gauging requirements and standards of the Directorate Hydrological Services in DWA.
2. The proposed project will impact negatively on the fish way at Neusberg Weir. In certain conditions the flow may be too low to provide the necessary attraction for the fish to migrate further upstream in the river channel past the outlet works.
3. Possible negative impact on aquatic ecosystems
4. Are alternative sites, designs and types of renewable energy being considered
5. Possible impact on heritage resources
6. Possible impact on palaeontological resources

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

No negative comments were raised by the stakeholders. All stakeholders' comments and concerns were taken into account and considered in the BAR and environmental management plan.

[52] Attendance register and stakeholder comments
[53] Refer to Annexure L on page 369 of the final BAR for Neusberg that provides a full report on all comments and responses.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Annex 3

BASELINE INFORMATION

Annex 3-1. The national grid of the RSA (Eskom electricity network)[54]

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54 http://www.eskom.co.za/content/2008EskomPoster.jpg

Annex 3-2. Data on Eskom grid-connected power plants (at the 31st of March 2010)[55,56]

Name of power plant	Location	Type of power plant (PP)	Type of fuel	Date of commissioning/ (Re-commissioning)*	Total net maximum capacity, MW
Arnot	Middelburg, Mpumalanga	Thermal PP	Coal	1971.09.21	2 232
Camden[57]	Ermelo, Mpumalanga	Thermal PP	Coal	(2005.03.31)	1 440
Duvha	Witbank, Mpumalanga	Thermal PP	Coal	1980.01.18	3 450
Grootvlei[58]	Balfour, Mpumalanga	Thermal PP	Coal	(2008.03.31)	760
Hendrina	Mpumalanga	Thermal PP	Coal	1970.05.12	1 865
Kendal	Witbank, Mpumalanga	Thermal PP	Coal	1988.10.01	3 840
Komati[59]	Middelburg, Mpumalanga	Thermal PP	Coal	(2009.01.05)	170
Kriel	Bethal, Mpumalanga	Thermal PP	Coal	1976.05.06	2 850
Lethabo	Viljoensdrift, Free State	Thermal PP	Coal	1985.12.22	3 558
Majuba	Volksrust, Mpumalanga	Thermal PP	Coal	1996.04.01	3 843
Matimba	Lephalale, Limpopo	Thermal PP	Coal	1987.12.04	3 690
Matla	Bethal, Mpumalanga	Thermal PP	Coal	1979.09.29	3 450
Tutuka	Standerton, Mpumalanga	Thermal PP	Coal	1985.06.01	3 510

[55]Eskom Annual Report 2010, page 298, http://financialresults.co.za/2010/eskom_ar2010/
[56]Data Requirements for Calculating the Carbon Emission Factor (CEF) for the South African Grid, General Information, http://www.eskom.co.za/content/calculationTable.htm
[57] Re-commissioned power plant, Eskom Annual Report 2009, page 63 http://www.financialresults.co.za/eskom_ar2009/ar_2009/downloads.htm
[58] Re-commissioned power plant, Eskom Annual Report 2010, page 126, http://financialresults.co.za/2010/eskom_ar2010/
[59] Re-commissioned power plant, Eskom Annual Report 2010, page 127, http://financialresults.co.za/2010/eskom_ar2010/

Name of power plant	Location	Type of power plant (PP)	Type of fuel	Date of commissioning/ (Re-commissioning)*	Total net maximum capacity, MW
Acacia	Cape Town, Western Cape	Gas turbine PP	Kerosene	1976.05.13	171
Port Rex	East London, Eastern Cape	Gas turbine PP	Kerosene	1976.09.30	171
Ankerlig	Atlantis, Western Cape	Gas turbine PP	Natural gas	2007.03.29	1 327
Gourikwa	Mossel Bay, Western Cape	Gas turbine PP	Natural gas	2007.03.30	740
Colley Wobbles	Mbashe River, Eastern Cape	Hydro PP	-	1900.01.01	0
Ncora	Ncora River, Eastern Cape	Hydro PP	-	1900.03.01	0
First Falls	Umtata River, Eastern Cape	Hydro PP	-	1900.02.01	0
Gariep	Norvalspont, Free State	Hydro PP	-	1971.09.08	360
Second Falls	Umtata River, Eastern Cape	Hydro PP	-	1900.04.01	0
Vanderkloof	Petrusville, Northern Cape	Hydro PP	-	1977.01.01	240
Drakensberg	Bergville Kwazulu-Natal	Hydroelectric Pumped Storage PP	-	1981.06.17	1 000
Palmiet	Grabouw, Western Cape	Hydroelectric Pumped Storage PP	-	1988.04.18	400
Koeberg	Cape Town, Western Cape	Nuclear PP	-	1984.07.21	1 800
Klipheuwel	Klipheuwel, Western Cape	Wind farm	-	**	3

* Re-commissioned units are: Camden, Grootvlei and Komati.**No data available

Annex 3-3. Data on operation of Eskom grid-connected power plants included into the operating margin for the 3 most recent reporting years

The list of power plants included into the operating margin[60]

Name of power plant	Type of power plant (PP)	Type of fuel	Total net maximum capacity, MW
Arnot	Thermal PP	Coal	2 232
Camden	Thermal PP	Coal	1 440
Duvha	Thermal PP	Coal	3 450
Grootvlei	Thermal PP	Coal	760
Hendrina	Thermal PP	Coal	1 865
Kendal	Thermal PP	Coal	3 840
Komati	Thermal PP	Coal	170
Kriel	Thermal PP	Coal	2 850
Lethabo	Thermal PP	Coal	3 558
Majuba	Thermal PP	Coal	3 843
Matimba	Thermal PP	Coal	3 690
Matla	Thermal PP	Coal	3 450
Tutuka	Thermal PP	Coal	3 510
Ankerlig	Gas turbine PP	Natural gas	1 327
Gourikwa	Gas turbine PP	Natural gas	740

[60]Kerosene-fired gas turbine power plants were excluded from the operating margin since they were not operated for the 3 most recent reporting years.

Net quantity of electricity generated and delivered to the grid by the power plants included into the operating margin ($EG_{m,y}$)[61]

Name of power plant	Type of fuel	Unit	Years* 04.2007 - 03.2008	Years* 04.2008 - 03.2009	Years* 04.2009 - 03.2010	Total 04.2007 - 03.2010
Arnot	Coal	MWh	11 905 060	11 987 281	13 227 864	37 120 205
Camden	Coal	MWh	5 171 057	6 509 079	7 472 070	19 152 206
Duvha	Coal	MWh	23 622 732	21 769 489	22 581 228	67 973 449
Grootvlei	Coal	MWh	237 138	1 249 556	2 656 230	4 142 924
Hendrina	Coal	MWh	13 756 351	12 296 687	12 143 292	38 196 330
Kendal	Coal	MWh	26 517 420	23 841 401	23 307 031	73 665 852
Komati	Coal	MWh	0	0	1 016 023	1 016 023
Kriel	Coal	MWh	17 762 398	18 156 686	15 906 816	51 825 900
Lethabo	Coal	MWh	25 701 723	23 580 232	25 522 698	74 804 653
Majuba	Coal	MWh	23 680 971	22 676 924	22 340 081	68 697 976
Matimba	Coal	MWh	29 021 742	26 256 068	27 964 141	83 241 951
Matla	Coal	MWh	24 549 833	21 863 400	21 954 536	68 367 769
Tutuka	Coal	MWh	20 980 242	21 504 122	19 847 894	62 332 258
Ankerlig**	Natural gas	MWh	1 153 000	143 000	49 000	1 345 000
Gourikwa**	Natural gas	MWh				
					Total net electricity generation:	651 882 496

*A reporting year for Eskom starts on the 1st of April and finishes on the 31st of March.

**Data was taken from Table B.6-1.

[61] Data Requirements for Calculating the Carbon Emission Factor (CEF) for the South African Grid, General Information, http://www.eskom.co.za/content/calculationTable.htm

Amount of fossil fuel consumed by the power plants included into the operating margin ($FC_{i,m,y}$)[62]

Name of power plant	Type of fuel	Unit	Years*			Total 04.2007 - 03.2010
			04.2007 - 03.2008	04.2008 - 03.2009	04.2009 - 03.2010	
Arnot	Coal	tonnes	6 210 700	6 395 805	6 794 134	19 400 639
Camden	Coal	tonnes	3 218 873	3 876 211	4 732 163	11 827 247
Duvha	Coal	tonnes	12 425 531	11 393 553	11 744 606	35 563 690
Grootvlei	Coal	tonnes	130 748	674 538	1 637 371	2 442 657
Hendrina	Coal	tonnes	7 794 220	7 122 918	6 905 917	21 823 055
Kendal	Coal	tonnes	15 986 131	15 356 595	13 866 514	45 209 240
Komati	Coal	tonnes	0	0	664 497	664 497
Kriel	Coal	tonnes	9 059 934	9 420 764	8 504 715	26 985 413
Lethabo	Coal	tonnes	18 314 572	16 715 323	18 170 227	53 200 122
Majuba	Coal	tonnes	12 853 342	12 554 406	12 261 833	37 669 581
Matimba	Coal	tonnes	14 862 323	13 991 453	14 637 481	43 491 257
Matla	Coal	tonnes	13 795 309	12 689 387	12 438 391	38 923 087
Tutuka	Coal	tonnes	10 627 575	11 231 583	10 602 839	32 461 997
Ankerlig	Natural gas	thousand m^3	N/A**	N/A	N/A	N/A
Gourikwa	Natural gas	thousand m^3	N/A	N/A	N/A	N/A
					Total coal consumption:	369 662 482

*A reporting year for Eskom starts on the 1st of April and finishes on the 31st of March.

**No data available

[62]Data Requirements for Calculating the Carbon Emission Factor (CEF) for the South African Grid, General Information, http://www.eskom.co.za/content/calculationTable.htm

Annex 3-4. Determination of power units included into the build margin[63]

Determination of the set of power units SET_{sample}

			Name of power plant	Type of power plant (PP)	Type of fuel	Date of commissioning	Net electricity generation ($EG_{n,y}$), MWh	Weight fraction in total net electricity generation*	Accumulated weight fraction
SET_{sample}	$SET_{\geq 20\%}$	$SET_{5-units}$	Komati	Thermal PP	Coal	2009.01.05	1 016 023	0.0044	0.0044
			Grootvlei	Thermal PP	Coal	2008.03.31	2 656 230	0.0114	0.0158
			Gourikwa	Gas turbine PP	Natural gas	2007.03.30	49 000	0.0002	0.0160
			Ankerlig	Gas turbine PP	Natural gas	2007.03.29			
			Camden	Thermal PP	Coal	2005.03.31	7 472 070	0.0321	**0.0481**
			Majuba	Thermal PP	Coal	1996.04.01	22 340 081	0.0960	0.1440
			Kendal	Thermal PP	Coal	1988.10.01	23 307 031	0.1001	**0.2441**

*Total net electricity generation in 2010 reporting year is 232 812 GWh (see Table B.6-1).

$AEG_{SET\text{-}5\text{-}units}$ = 11 193 323 MWh, $AEG_{SET\text{-}\geq 20\%}$ = 56 840 435 MWh.

[63] Based on data presented in Annexes 3-2 and 3-3

The sets of power units $SET_{sample\text{-}CDM}$

	Name of power plant	Type of power plant (PP)	Type of fuel	Date of commissioning	Net electricity generation ($EG_{n,y}$), MWh	Weight fraction in total net electricity generation*	Accumulated weight fraction
$SET_{sample\text{-}CDM}$	Bethlehem Hydro	Small Scale Hydro	Renewable	2009.07.18	34 031	0.0001	0.0001
	Komati	Thermal PP	Coal	2009.01.05	1 016 023	0.0044	0.0045
	Grootvlei	Thermal PP	Coal	2008.03.31	2 656 230	0.0114	0.0159
	Gourikwa	Gas turbine PP	Natural gas	2007.03.30	49 000	0.0002	0.0161
	Ankerlig	Gas turbine PP	Natural gas	2007.03.29			
	Camden	Thermal PP	Coal	2005.03.31	7 472 070	0.0321	0.0482

*Total net electricity generation in 2010 reporting year including power units registered as CDM project activities is 232 846 GWh (see Annex 3-5)

$AEG_{SET\text{-}sample\text{-}CDM}$ = 11 227 354 MWh

Data on operation of Eskom grid-connected power plants and power plants registered as CDM project activities included into the build margin during 2010 reporting year

Name of power plant	Type of power plant (PP)	Type of fuel	Date of commissioning	Fuel consumption ($FC_{i,n,y}$), tonnes	Net electricity generation ($EG_{n,y}$), MWh	Weight fraction in total net electricity generation*	Accumulated weight fraction
Bethlehem Hydro[64]	Small Scale Hydro	Renewable	2009.07.18	0	34 031	0.0001	0.0001
Komati	Thermal PP	Coal	2009.01.05	664 497	1 016 023	0.0044	0.0045
Grootvlei	Thermal PP	Coal	2008.03.31	1 637 371	2 656 230	0.0114	0.0159
Gourikwa	Gas turbine PP	Natural gas	2007.03.30	N/A**	49 000	0.0002	0.0161
Ankerlig	Gas turbine PP	Natural gas	2007.03.29				
Camden	Thermal PP	Coal	2005.03.31	4 732 163	7 472 070	0.0321	0.0482
Majuba	Thermal PP	Coal	1996.04.01	12 261 833	22 340 081	0.0959	0.1442
Kendal	Thermal PP	Coal	1988.10.01	13 866 514	23 307 031	0.1001	**0.2443**

*Total net electricity generation in 2010 reporting year including power units registered as CDM project activities is 232 846 GWh (see Annex 3-5)

**No data available

[64] http://cdm.unfccc.int/Projects/DB/SGS-UKL1245061289.99, CDM PDD, page 12

Annex 3-5. The calculation of the combined margin emission factor

Total net electricity generation in 2010 reporting year including power units registered as CDM project activities, MWh

Net electricity generation	Value
Total Eskom	232 812 000
Bethlehem Hydro	34 031
Total	**232 846 031**

CO_2 emission factors of power units *m* in year *y* ($EF_{EL,m,y}$), tCO_2/MWh

Name of power plant	Years		
	04.2007 - 03.2008	04.2008 - 03.2009	04.2009 - 03.2010
Arnot	0.929	0.950	0.915
Camden	1.109	1.061	1.128
Duvha	0.937	0.932	0.926
Grootvlei	0.982	0.961	1.098
Hendrina	1.009	1.032	1.013
Kendal	1.074	1.147	1.060
Komati	-	-	1.165
Kriel	0.908	0.924	0.952
Lethabo	1.269	1.263	1.268
Majuba	0.967	0.986	0.978
Matimba	0.912	0.949	0.932
Matla	1.001	1.034	1.009
Tutuka	0.902	0.930	0.951
Ankerlig Gourikwa	0.495	0.495	0.495

CO_2 emissions of power units *m* in year *y* ($EG_{m,y} \cdot EF_{EL,m,y}$), tCO_2

Name of power plant	Years 04.2007 - 03.2008	04.2008 - 03.2009	04.2009 - 03.2010	Total 04.2007 - 03.2010
Arnot	11 061 567	11 391 248	12 100 692	34 553 508
Camden	5 732 974	6 903 726	8 428 219	21 064 918
Duvha	22 130 492	20 292 488	20 917 731	63 340 710
Grootvlei	232 868	1 201 386	2 916 240	4 350 494
Hendrina	13 881 896	12 686 273	12 299 783	38 867 952
Kendal	28 472 099	27 350 864	24 696 955	80 519 917
Komati	0	0	1 183 502	1 183 502
Kriel	16 136 195	16 778 852	15 147 323	48 062 370
Lethabo	32 619 168	29 770 826	32 362 083	94 752 077
Majuba	22 892 445	22 360 025	21 838 938	67 091 407
Matimba	26 470 540	24 919 477	26 070 086	77 460 103
Matla	24 570 135	22 600 433	22 153 396	69 323 964
Tutuka	18 928 242	20 004 011	18 884 186	57 816 440
Ankerlig Gourikwa	570 604	70 769	24 249	665 622
			Total emissions:	659 052 985

Calculation of simple operating margin CO_2 emission factor ($EF_{grid,OMsimple}$)

Parameter	Unit	Value
Total net electricity generation of power units *m* for the 3 most recent reporting years	MWh	651 882 496
Total CO_2 emissions of power units *m* for the 3 most recent reporting years	tCO_2	659 052 985
Simple operating margin CO_2 emission factor	**tCO_2/MWh**	**1.011**

Calculation of build margin CO_2 emission factor ($EF_{grid,BM,y}$)

Name of power plant	Net electricity generation ($EG_{n,y}$), MWh	CO_2 emission factor ($EF_{EL,n,y}$), tCO_2/MWh	CO_2 emissions ($EG_{n,y} \cdot EF_{EL,n,y}$), tCO_2	Build margin CO_2 emission factor ($EF_{grid,BM,y}$), tCO_2/MWh
Bethlehem Hydro	34 031	0	0	
Komati	1 016 023	1.165	1 183 502	
Grootvlei	2 656 230	1.098	2 916 240	
Gourikwa	49 000	0.495	24 249	
Ankerlig				
Camden	7 472 070	1.128	8 428 219	
Majuba	22 340 081	0.871*	19 453 984	
Kendal	23 307 031	0.871*	20 296 015	
Total	**56 874 466**		**52 302 209**	**0.920**

*Recalculated emission factor for power plants which started to supply electricity to the grid more than 10 years ago

Calculation of combined margin CO_2 emission factor ($EF_{grid,CM}$)

Parameter	Unit	Value
Operating margin CO_2 emission factor	tCO_2/MWh	1.011
Weighting of operating margin emission factor	-	0.50
Build margin CO_2 emission factor	tCO_2/MWh	0.920
Weighting of build margin emission factor	-	0.50
Combined margin CO_2 emission factor	**tCO_2/MWh**	**0.965**

Annex 3-6. Calculation of project IRR before tax for the proposed project activity

Calculation of the net cash flow in ZAR

	Year	Construction over 21 months		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Investment cost	mZAR	-216.9	-216.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income from electricity sale	mZAR	0.0	0.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Cost of electricity generation	mZAR	0.0	0.0	-10.90	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9
Total income from the project implementation	mZAR	0.0	0.0	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1
Net cash flow	mZAR	-216.9	-216.9	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1	31.1

Pre-tax Project IRR

Parameter	Unit	Value
Pre-tax Project IRR	%	**3.52%**

Calculation of the net cash flow in USD

	Year	Construction over 21 months		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Investment cost	mUSD	-27.4	-27.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income from electricity sale	mUSD	0.0	0.0	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Cost of electricity generation	mUSD	0.0	0.0	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4
Total income from the project implementation	mUSD	0.0	0.0	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Net cash flow	mUSD	-27.4	-27.4	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9

Pre-tax Project IRR

Parameter	Unit	Value
Pre-tax Project IRR	%	**3.52%**

Annex 4

MONITORING INFORMATION

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