JOINT IMPLEMENTATION
PROJECT DESIGN DOCUMENT FORM (JI PDD)
Version 01 – IN EFFECT AS OF: 15.JUNE. 2006

CONTENTS

Annexes

Abbreviations

Parameters Abbreviations		
ABE	annual baseline emissions	ton/y
ABE1	annual baseline emissions from natural gas combustion in boilers	ton/y
ABE2	annual baseline emissions electricity coming from the grid	ton/y
h	annual operational hours	h/y
APE	annual project emissions	ton/y
APE1	annual project emissions from gas combustion in CHP	ton/y
APE2	annual project emissions from gas combustion in back up boilers	ton/y
ARE	Total emission reduction from the realization of the Project	ton/y
Qh	Annual heat production of DHC	MWh/y
Qf	Heat introduced with natural gas fuel annually in boilers	MWh/y
Q_{CHP}	CHP annual heat output	MWh/y
Wel	CHP annual power production	MWh/y
Wel, ss	Auxiliary annual electricity needs in the substations	MWh/y
QF_{CHP}	annual heat from gas combustion in CHP	MWh/y
CHP el	CHP net power output capacity	MW_e
LCV	lower calorific value of fuel	MWh/t;MWh/th.c.m
SC	specific consumption of equivalent (conditionally) fuel with low calorific value-LCV = 8,11 MWh/t	t/MWh
EF el	emission factor for electricity supply by grid	tCO2/MWh
EFel gen	emission factor for electricity generation	tCO2/MWh
EF ng	CO_2 emission factor of natural gas	tCO2/MWh
ng	Natural gas	
SEC	specific energy consumption for power generation	kJ/kWh
BM	Build Margin	
CHP	Combined Heat and Power	
DH	District Heating	
DHC	District Heating Company	
DHS	District Heating Station	
SWB	Steam and Water Boilers	
EAD	100% State-owned Joint Stock Company	
EEEA	Energy and Energy Efficiency Act	
EPS	Electric Power System	
ER	Emission Reduction	
ERU	Emission Reduction Unit	
EU	European Union	
GDP	Gross Domestic Product	

GHG	Greenhouse Gas	
GTCC	Gas Turbine Combined Cycle	
GWh	Gigawatt hours	
HPP	Hydro Power Plant	
IRP	Integrated Resource Planning	
JI	Joint Implementation	
	Kilovolt	kV
	Kilowatt hours	kWh
MEE	Bulgarian Ministry of Economy and Energy	
	Million	mln
MOEW	Bulgarian Ministry of Environment and Water	
	Electrical Megawatt	MW_{el}
	Thermal Megawatt	MW_{th}
	Electrical Megawatt hours	$MW_{el}h$
	Thermal Megawatt hours	$MW_{th}h$
OM	Operation Margin	
NEK- EAD	Natsionalna Elektricheska Kompania EAD	
NDC	National Dispatch Centre	
NPP	Nuclear Power Plant	
PDD	Project Design Document	
PIN	Project Idea Note	
PSHPP	Pump Storage Hydro Power Plant	
TPP	Thermal Power Plant	
	Terawatt hours	TWh
UCTE	Union for the Co-ordination of Transmission of Electricity	
UNFCCC	United Nations Framework Convention on Climate Change	
BM	Build Margin	

SECTION A. General description of the project

A.1. Title of the project:

"Portfolio of new cogeneration power stations for combined production of heat and electricity in District Heating Company Pleven and District Heating Company Veliko Tarnovo, Bulgaria"

Version of the document – 04.

Date –October, 2006.

A.2. Description of the project:

The project comprises the design, construction, and operation of a portfolio of one highly-efficient gas turbine and two gas engines with a total electrical power capacity of around 37 MW. The type of installations is co-generation type, which guarantees highly efficient and reliable generation of electric and thermal power. The co-generation installations will be installed at District Heating Company (DHC) Pleven and DHC Veliko Tarnovo.

Existing situation

The main scopes of activities of **DHC Pleven** are: production of electrical and heat energy, transport, distribution and supply of heat energy, maintenance of energy facilities, engineering activity and trading activity. There are 225 people employed in the DH Company. The products and services that DHC Pleven offers to its customers are: electricity; thermal energy with hot water as heating medium; thermal energy with steam as heating medium and finally also thermal energy transfer and distribution.

There are 28,271 households connected to the district heating system, 1,201 public buildings and firms and 22 industrial enterprises. About 60% of the inhabitants of the city of Pleven use the service offered by DHC Pleven.

At the moment at the premises of the DHC station there are:

- Four steam generators with a total steam capacity of 390 t/h;
- Three turbo generators with a total electric capacity of 36 MW;
- Two water heating boilers with a total heating capacity of 232 MW.

Industrial steam is supplied by 6 steam main pipelines with a total length of 20 km. The main fuel for heat and power generation is natural gas. Heavy fuel oil is used as back-up fuel. The length of the district heating hot water network is 167 km. The total installed capacity of the plant is: 36MW electrical and 524 MW thermal.

The main scopes of activities of **DH Veliko Tarnovo** are: production of heat energy, transport, distribution and supply of heat energy and maintenance of energy facilities. The products and services that DHC Veliko Tarnovo offers to its customers are: thermal energy with hot water as heating medium; thermal energy with steam as heating medium and finally also thermal energy transfer and distribution. In the DHC Veliko Tarnovo there are 91 people employed. There are 7,242 households connected to the district heating system, 188 public buildings and firms and non industrial enterprises.

The main production unit is the Main Heat Station, which has a total hot water capacity of 135 MW and a steam capacity of 17.5 MW. This station produces around 95% of the annual district heating production in Veliko Tarnovo. The DHC was built during the 1970s and 1980s. The adjacent Boiler Station has three hot water boilers, two with a capacity of 58 MW. Further the boiler station has two steam boilers, each with a capacity of 8.7 MW. The production process is controlled automatically by an Information Controlling System. The distribution network from the Main Boiler Station in Veliko Tarnovo consists of two separate systems, the 1st Main and the 2nd Main. Finally the DH has also a district heating supply network with a length of 41 km, located in the city centre of Veliko Tarnovo using a hot water distributing system.

The newly constructed cogeneration installations will be used for production of heat and electrical energy. The produced energy will be sold to the residences, municipal and industrial customers of cities of Pleven and Veliko Tarnovo. Both DHC Pleven and DHC Veliko Tarnovo are fully gasified and no additional work on gasification is necessary. The investment into the new Combined Heat and Power units (CHPs) at the DH Stations will increase the efficiency (by using the heat from the gas engines and turbine to make steam and hot water). With the installation of new cogeneration technology the DHCs will be able to reduce costs, increase competitiveness, and achieve more efficient fuel usage as well as reduction of the released harmful gases and especially of CO_2.

Project

DHC Pleven intends to install one gas turbine unit with 32 MW electrical power capacity which has attached to it a steam generator. This unit will be connected to the existing equipment. In this configuration it will become possible that the produced superheated steam enters into the existing steam turbines that are used for electricity production. Together with the production of steam the installation will produce hot water for space heating and heat water supply to the end consumers. The preliminary study has showed that the operational hours of the cogeneration unit are estimated at 8,040 hours per year. The total production will be:

Electricity:
The total electricity production from the DHC will be 319,598 MWh/y, where the new co-generation unit will produce 247,683 MWh/y gross electricity production (the auxiliary needs of the co-generation installation are 20,526 MWh/y), 71,915 MWh/y will be produced by the existing steam turbines.

Heat energy
Total heat production will be 571,200 MWh/y, where 381,450 MWh/y per year will be produced by the new unit, 190,070 MWh/y will be produced by the existing heat installations and 127,617 MWh/y will be the heat consumption for auxiliary needs.

The total efficiency of the cogeneration installation will be 84%Gross.

DH Veliko Tarnovo foresees to install, on the existing platform, two gas engines. The total installed electrical power will be 5 MW. The installed heat power will be 5.5 MW. The existing gas pipeline will be used for delivery of the necessary amount of natural gas. The preliminary study showed that the operational hours are estimated at 7,600 hours per year. The total production will be:

Electricity:
26,700 MWh/y, where the auxiliary needs for electricity of DHC VT are 2,700 MWh/y. The electricity for sale is estimated at 24,000 MWh/y.

Heat energy
85,385 MWh/y, where 29,370 MWh will be produced by the cogeneration unit and 56,015 MWh will be produced from the existing heat installation.

The total efficiency of the cogeneration installation will be 82%Gross.

Through the installation of the described co-generation units, a significant reduction of CO_2 emissions to the atmosphere from the operation of the two DHCs compared with the existing situation will be achieved. The main portion of the achieved CO_2 reduction will be achieved through the substitution of electricity in the national electrical grid, which is produced by marginal thermal power stations having a higher CO_2 emission factor (CEF) for production of electricity compared to the CEF of the new co-generation units. The marginal thermal power stations in Bulgaria will need to reduce their electrical output and thus the amount of the released CO_2.

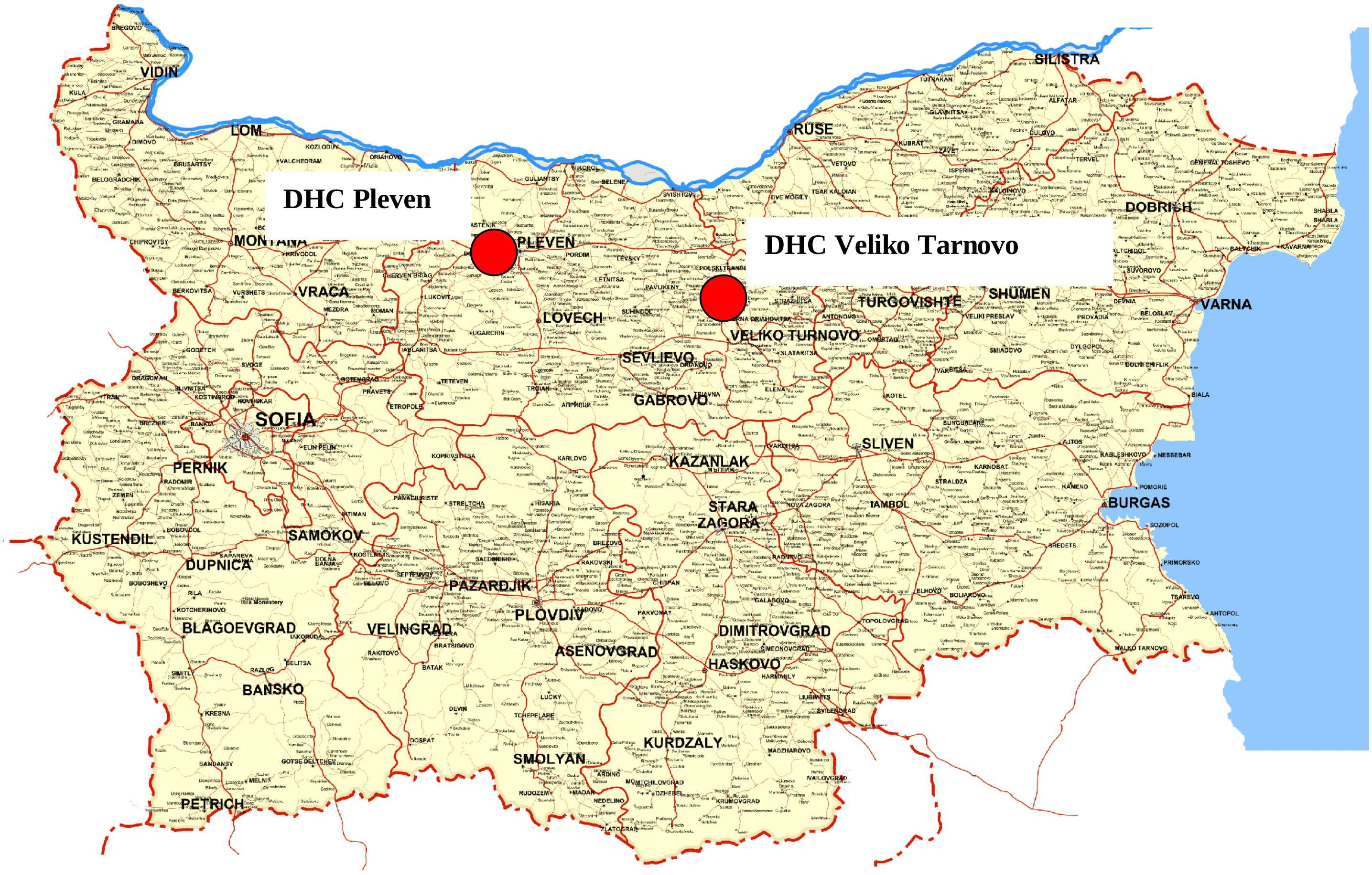
A.3. Project participants:

Party involved	Legal entity project participant (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Bulgaria (Host party)	DHC Pleven JSC (Aggregator of the AAUs&ERUs)	No
Bulgaria (Host party)	DHC Veliko Tarnovo JSC	No
Denmark	Danish Ministry of the Environment	No

A.4. Technical description of the project:

A.4.1. Location of the project:

The portfolio project comprises two sub-projects located at the two different District Heating Companies at the territory of Republic of Bulgaria. The first project is located at District Heating Pleven in the town of Pleven. The second project is located at District Heating Veliko Tarnovo in the town of Veliko Tarnovo.



A.4.1.1. Host Party(ies):

Bulgaria

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

Miziya,
Northern Bulgaria.

A.4.1.3. City/Town/Community etc:

City of Pleven,
City of Veliko Tarnovo.

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

The portfolio project comprises two sub-projects located at the two different District Heating Companies at the territory of Republic of Bulgaria.

The first project is located at District Heating Pleven: The town of Pleven is located in the very heart of Miziya, in an agricultural region. Its central location in Northern Bulgaria defines its importance as a big administrative, economic-political, cultural and transport centre. The physical coordinates of the town are: 43 degrees, 24 minutes, 58” North, 24 degrees, 37 minutes, 42” East. The District Heating Company is located in the north industrial area of the city of Pleven.

The second project is located at District Heating Veliko Tarnovo: The town of Veliko Tarnovo is situated in Northern Bulgaria, standing in tiers above Yantra River. It is located 241 km North-East of Sofia. The physical coordinates of the town are: 43 degrees, 05 minutes, 04” North, 25 degrees, 38 minutes, 16” East. The District Heating Company is located in the south industrial area of the city of V. Tarnovo.

A.4.2. Technology to be employed by the project:

This portfolio project comprises the installation of one gas turbine/generator including steam/hot water generator for DHC Pleven and two gas engines/generators for DHC Veliko Tarnovo, which will produce both heat and electricity. The co-generation installations will be used for production of heat and electrical energy. Some of the existing installations will be partly decommissioned, but the majority of this equipment will remain functional primarily as back up power capacity to cover peak demands. The produced energy will be sold to the residences, municipal and industrial customers of the respective towns. The two District Heating Companies (DHCs) are using natural gas as a main fuel. With the installation of all of the co-generation units several key objectives will be achieved:

- Efficient and sustainable electricity production from the low carbon fuel natural gas. This electricity will be sold to the national grid. This will increase the competitiveness of the DHCs and will enable the DHCs to secure the future delivery of energy to its customers;
- Efficient and sustainable heat production (by steam and hot water) from the low carbon fuel natural gas. This heat energy will be sold to the various customers, which will increase the competitiveness of the DHCs and will enable the DHCs to secure the future delivery of energy to its customers;
- Significant reduction of CO_2 emissions in the generation of electricity for the national grid compared with the existing situation;
- reduction of the releasing of other harmful gases like: NO_x and CO emissions, as a result from using State-of-the-art gas turbine and gas engine combustion technologies;
- The investment in new cogeneration facilities at these District Heating Stations will increase the efficiency and the economical stability of the two DHCs.

With the installation of the new cogeneration technology the DHCs will be able to reduce its operational costs and increase competitiveness.

The National Electricity Company (NEK) is obliged to purchase the generated electricity from the new cogeneration stations against a preferential tariff (Energy law, article 162). The DHCs will continue to sell the heat to their customers under existing contracts.

Technology to be employed in DHC Pleven

The new cogeneration unit in DHC Pleven includes:

- Gas turbine generator set with gas compressor with capacity from 26 to 34 MWe, depending on the ambient temperature;
- Heat recovery steam generator with possibility of supplementary firing of natural gas;
- Heater for district water pipe system.

The supplier of the technical equipment is General Electric from the USA.

The new co-generation installation will be commissioned at the existing platform of the DHC. It is not foreseen to decommission any of the existing equipment. The new co-generation station will produce electricity, steam and hot water. The produced electricity will be sold to the national grid except the amount needed to cover the auxiliary needs of the new-cogeneration. There will be an electrical connection from the new co-generation to the existing electrical system of the DHC. From there the electricity will be exported to the NEK. The steam produced by the new co-generation will be directed to the existing steam collector, which is currently used to supply the heat energy to the heat distribution network As a result from the construction of the co-generation installation the heat production of the existing DHC will be reduced. The production of electricity by the existing power generation capacity at the DHC will stay at the same level.

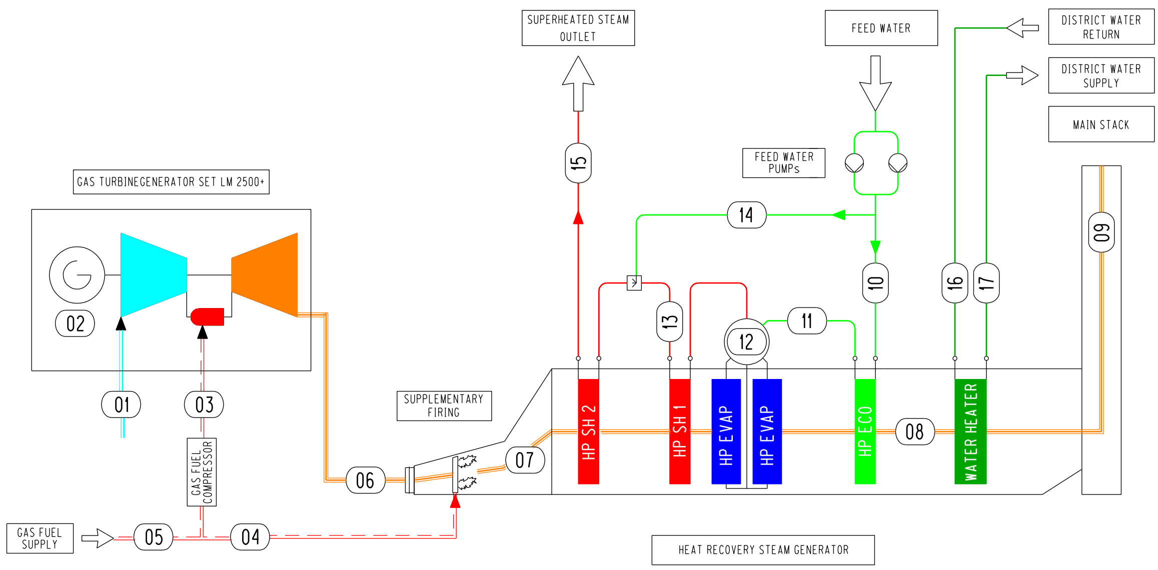


Figure 1: LM2500+ gas turbine + heat recovery boiler from GE

The thermal power output of the installation is projected at a maximum 34 MW in absence of supplementary firing. In the winter is possible to increase the thermal output up to 66 MW with supplementary firing of natural gas.

Parameter	Unit	Produced	For auxiliary needs	To the grid
Electricity by GTI	MWh/y	247,683	20,526	227,157
Electricity by existing steam turbines	MWh/y	71,915	15,737	56,178
Total electricity	MWh/y	319,598	36,263	283,335

Table 1: Project activity in DHC Pleven – production of electricity.

The produced heat energy in DHC Pleven after the realization of the project is shown in the table:

Parameter	Unit	Produced	For auxiliary needs	To the grid
Heat by GTI	MWh/y	381,450	0	381,450
Heat by existing boilers	MWh/y	190,070	127,617	62,453
Total heat	MWh/y	571,520	127,617	443,903

Table 2: Project activity in DHC Pleven – production of heat.

Technology to be employed at DHC Veliko Tarnovo

The project comprises the design, construction and operation of new cogeneration power station for combined production of heat and electricity in District Heating V.Tarnovo including two gas engines with a total electrical capacity of 5 MW.

The construction of the new co-generation modules will not lead to decommissioning of the existing equipment. The only result will be that the existing boilers will reduce its heat production, because of the heat production from the new gas engines. The electricity production will be used for covering of the auxiliary needs of the DHC and the rest of the electricity will be sold to NEK through the existing electrical transformer. This transformer is currently used for import of electricity for the needs of the DHC Veliko Tarnovo.

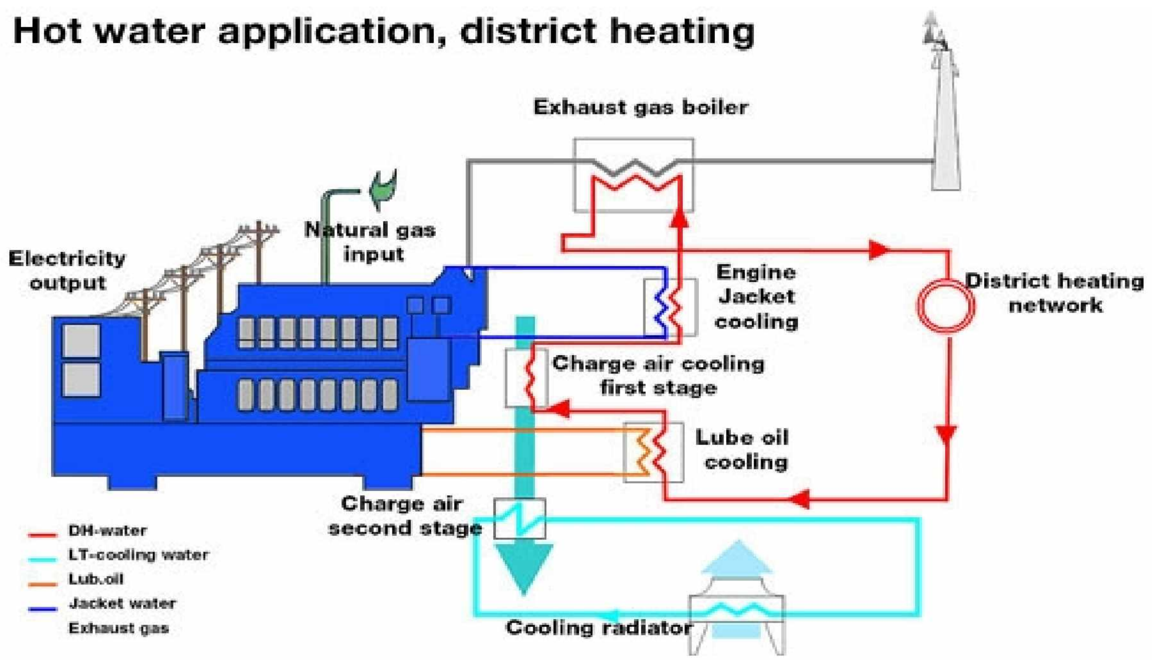


Figure 2: Gas engine set including exhaust gas boiler from Wartsila.

The production of electricity in DHC V. Tarnovo after the realization of the project is shown in the next table:

Parameter	Unit	Produced	For auxiliary needs	To the grid
Electricity by the new CHP	MWh/y	26,700	1,350	24,000
Electricity by the existing facilities	MWh/y	0	1,350	0
Total electricity	MWh/y	26,700	2,700	24,000

Table 3: Project activity in DHC V. Tarnovo – production of electricity.

The production of heat energy in DHC V. Tarnovo after the realization of the project is shown in the next table:

Parameter	Unit	Produced	For auxiliary needs	To the grid
Heat by the new CHP	MWh/y	29,370	0	29,370
Heat by the SWB	MWh/y	56,015	3,500	52,515
Total heat	MWh/y	85,385	3,500	81,885

Table 4: Project activity in DHC V. Tarnovo – production of heat.

Technical Data for Gas Engine	
Producer	Wärtsilä, Finland
Type	16V25SG, Four-stroke, with a turbo compressor
Output capacity kWe, at the following conditions:	3000
- maximal air ambient temperature	45 °C
- maximal temperature of the burning air	35 °C
- above sea level	210m
- humidity	80%
Revolutions	1000 min^{-1}
Number of cylinders	16
Volume of the cylinder	14.7 Liter
Fuel Consumption for el. production	8760 kJ/kWh

Technical Data for Generator	
Producer	ABB Industry OY
Type	AMG710 Mm6
Power	3 900 kVA
Power factor	0.845
Rated voltage	11 kV
Rotation speed	1,000 min^{-1}
Frequency	50 Hz
Insulation class	F/F
Cooling	Self air cooling
Sensors in the stator	2 x 3 PT 100
Voltage adjustment	According AVR, ±5%

A.4.3. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHG) by sources are to be reduced by the proposed JI project, including why the emission reductions would not occur in the absence of the proposed project, taking into account national and/or sect oral policies and circumstances:

DHC Pleven and DHC Veliko Turnovo propose to invest into Western state-of-the-art co-generation technology for the production of heat and electricity which will result in a reduction of anthropogenic emission of GHGs. The purpose for the realization of the project is to supply with heat and steam energy the related customers in Pleven and with heat energy the related customers in Veliko Tarnovo. The electricity, which will be produced by the project will be mainly exported to the national grid and some small portion of it will be used for covering of the own needs of the two DHCs. There is no legal technology.

In the absence of the project activity, the electricity production will take place by the existing power generation facilities currently active on the Bulgarian electricity grid or will be imported from other countries. Since Bulgaria is the biggest electricity exporter in the region, import from outside Bulgaria will not be likely. Therefore in the absence of the project activity, the electricity will be produced by Bulgarian power producers that on average have a higher Carbon Emission Factor (CEF) compared with the CEF of the co-generation units. The emissions from these producers from the baseline scenario. The regional / national and sect oral policies that guide the baseline scenario can be understood from discussions provided under Section B.

A.4.3.1. Estimated amount of emission reductions over the crediting period:

Emission reductions given below are total emission reductions from the two projects together. Besides the generation of ERUs in the timeframe 2008-2012, the project will generate Early Credits in 2006 and 2007.

	Years
Length of the crediting period	5 (or extended beyond 2012 if applicable)
Year	**Estimate of annual emission reductions in tones of CO2 equiv.**
Year 2006	991 (early credits)
Year 2007	132,339 (early credits)
Year 2008	202,444
Year 2009	174,163
Year 2010	164,316
Year 2011	158,255
Year 2012	145,378
Total estimated emission reductions over the period within which emission reduction units are to be earned (tones of CO_2 equiv.)	844,556
Annual average of estimated emission reductions over the crediting period/period within which emission reduction units are to be earned (tonnes of CO2 equiv.)	168,911

A.5. Project approval by the Parties involved:

The project activity has not received approval from the Parties involved. Approval is expected after successful determination of the PDD by an Independent Entity.
The project activity has applied for a Letter of Endorsement (LOE) from the Bulgarian authorities in February 2006. It is expected that this LOE will issued in June 2006.

SECTION B. Baseline

B.1. Description and justification of the baseline chosen:

Any baseline for a JI project should be established in accordance with Annex B of 16/CP.7 ('Marrakesh Accords) and in accordance with guidance of the Joint Implementation Supervisory Committee (JISC). At the moment of preparing this PDD, guidance was being drafted by the JISC.

In accordance with decision 10/CMP.1, approved CDM methodologies can be used for developing PDDs for JI projects. The approved methodology AM0014 "Natural gas-based package cogeneration" has been applied to this project. This methodology has the following conditions for applicability:
• The cogeneration system is a third party cogeneration systems, i.e. not own or operated by the consuming facility that receives the project heat and electricity;
• The cogeneration system provides all or a part of the electricity and or heat demand of the consuming facility;
• No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user.

The AM0014 methodology has been applied to the project activity with the following deviations:
• The cogeneration system is owned by the project owner, but most of the electricity and heat from the system is provided to the grid and to consumers that are connected to the heat distribution network.
• The cogeneration system provides all or a part of the electricity and or heat demand to the grid and to end consumers for the heat;
• Excess electricity is supplied to the power grid and heat from the cogeneration system is provided to a distribution network.

The consequences for the deviations described above to the application of AM0014 to the described project activity have been resolved by taking the following measures in the elaboration of the PDD:

1. Additionality

The additionality approach of AM0014 can only be applied when the cogeneration system is not owned or operated by the consuming facility. In the case of the envisaged two projects, the consuming facility (DHCs Pleven and Veliko Tarnovo) will own the cogeneration system after which they will transfer the electricity to the grid and the heat to the final consumer. Therefore, in proving the additionality of the project the most recent "Tool for the demonstration and assessment of additionality (version 02)" has been applied. Please refer to section B.2 for the application of the Tool to the proposed project.

2. Baseline carbon emission factor of electricity grid

The Bulgarian Ministry of Environment and Waters[1] has established a country-specific baseline for electricity project feeding into the national grid. The carbon emission factor (or emission coefficient) was determined in the "Baseline Study of Joint Implementation projects in the Bulgarian Energy Sector[2]". The study was elaborated by the National Electricity Company (NEK AEA). In Annex II this study has been elaborated. These baseline emissions figures from this study have been used instead of applying CDM methodology ACM0002 for the calculation of baseline emissions in the Bulgarian grid.

The merit order dispatch approach analyses the electric power sector on the basis of electricity demand forecasts – minimum and maximum; fuel prices, new capacities and envisaged rehabilitation projects; and cost estimates. For these analyses NEK uses the IRP Manager Computer model (Integrated Resource Planning Model).

There is also a current trend in Baseline determination to eliminate the output of all nuclear and hydro-power plants because the low operating costs mean that their output will not be affected by new CHP plants in the network. If NPP and HPP are eliminated from the Baseline, such assumption shall be supported by clear written records and justified.

In order to apply conservative emission factors the lower emission factors of the "Maximum Demand

[1] http://www.moew.government.bg/

[2] http://www.moew.government.bg/recent_doc/international/climate/carbon_emission_joint.pdf

Forecast" from the NEK baseline study described above have been applied. The concrete values are shown in the next table:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
DispatchDataAdjusted_OM_EF	tCO2/MWh	1.143	1.156	1.059	0.947	0.908	0.884	0.833

Table 5: Carbon emission factor of Bulgarian electricity grid, forecast "Maximum demand".

The baseline chosen is a continuation of the existing situation in accordance with AM0014. The formulae used to calculate the emissions of the baseline are given in section D.2.

B.2. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the JI project[3]:

Additionality demonstration
The additionality of the project activity has been demonstrated by applying the Standard tool for the demonstration and assessment of additionality (version 2) available from the website of the UNFCCC[4].

Step 0. Preliminary screening based on the starting date of the project activity
a) The projects at DHC Pleven and DHC V. Tarnovo have not yet been implemented and therefore the starting date of the JI project activities falls after 1 January 2000. The start of the JI project activity is projected for DHC Pleven in January 2007 and for DHC V. Tarnovo for September 2006.
b) The incentive of JI is being considered since the middle of 2004 when the CEO of Toplofikatsia Pleven, Mr. Tonev, contacted SenterNovem for potential participation in the ERUPT programme[5]. A prove that JI was seriously considered in the decision to proceed with the project activity is demonstrated by the PIN for the project activity that was sent to the Bulgarian Ministry of Environment (MOEW) to apply for Letter of Endorsement in the beginning of February 2006. In this PIN the project owner states its interest to obtain the JI incentive for their envisaged project activity.

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

Sub-step 1a. Define alternatives to the project activity:
There are two realistic alternatives (or alternative scenarios) for the project activity:
Alternative I: Implementation of the projects at DHC Pleven and DHC V. Tarnovo without selling the carbon credits under the JI mechanism. The first alternative is identical to the proposed JI project activity but is excluding the JI incentive.
Alternative II: Continuation of the existing situation.
The second alternative is a continuation of the current situation without any project activity or alternatives undertaken. In this alternative DHC Pleven and DHC V. Tarnovo would continue to purchase electricity form the regional grid and would continue to generate thermal electricity from the existing sources. The costs that would occur if the plants keep this situation would be only maintenance cost to keep the equipment operational in the future.

Sub-step 1b. Enforcement of applicable laws and regulations:
Alternative I:

[3] Demonstration of additionality has been based on EB 16 guidance "Tool for the demonstration and assessment of additionality, Version 2"

[4] http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf

[5] Proof has been made available to the validator

The Bulgarian government has several instruments in place to promote energy efficiency projects, cogeneration and other clean energy activities. The main law in this case is the new Energy Act (published in State Gazette No. 107 dated December 2003). Chapter XI of this document primarily concerns the encouragement of energy production based on renewable energy sources and from combined energy production. According to the provisions of Art. 162, clause 1 and clause 2, item 1, the public supplier of electric power, the National Electric Company (NEK) is obliged to purchase at preferential prices the whole surplus quantity of electric power produced by highly efficient combined power production plants with power capacities of up to 50 MWe. This system will be replaced by a green certificate system the Bulgarian government is developing for the renewable sector including the cogeneration sector. It was expected that the producers of thus produced energy will be issued green certificates for the produced and sold by them energy from 01.01.2006, but recently the Bulgarian government decided to postpone the start of this system to 2010 or later.
In addition to this envisaged legislation which supports the investment in cogeneration facilities, the Bulgarian law also requires new projects to elaborate on Environmental Impact Studies and other related matters. It is clear that cogeneration project activity is in full compliance with the laws and regulations Bulgaria.
Alternative II:
DHC Pleven and DHC V. Tarnovo have all the necessary licenses to operate the existing equipment. There are neither laws under development that prevent the existing equipment from operating nor the purchasing of electricity from the grid.

Step 2. Investment analysis

Sub-step 2a. Determine appropriate analysis method
Both projects, besides a JI incentive, would generate financial benefits by reducing the energy costs and by selling excess generated electricity to the National Distribution Company (NEK). Therefore the simple costs analysis cannot be used. The investment comparison analysis requires the comparison of the IRR (Internal Rate of Return) of the different project activity alternatives. The alternative II is not a realistic long-term option and is not considered seriously by the owners of DHC Pleven and DHC V. Tarnovo as a long-term solution because of the expected significant increase in energy prices in the future, the increased competition in the energy market and the decrease in efficiency of the old equipment. This leaves only alternative I as realistic alternative. For the investment analysis obtaining financial means is the main bottleneck. A financial lending institution in Bulgaria primarily focuses on the payback time of the project. Hence the appropriate analysis method is a benchmark analysis using an average payback time for Bulgarian companies with similar financial standing doing similar projects.

Sub-step 2b – Option III. Apply benchmark analysis
Bulgaria is working towards its accession to the European Union, which is projected to take place in 2007 or in 2008 given the latest news on delay with meeting the EU requirements. Although the Bulgarian government is making a lot of progress with reforming the energy and financial sector, with decreasing its governmental debt and with improving the credibility of its fiscal policy, there are also many challenges and obstacles for the Bulgarian government to work on. Especially the high unemployment rate and low wage structure, issues concerning the privatization of the energy sector and big openings in certain pieces of Bulgarian legislation prevent Standard and Poors from putting a the credit rating of not more than BB- on the country compared with BB- for Romania but A- for Hungary and Czech Republic and A+ for neighbouring Greece. The credit rating reflects the uncertainties concerning the future of the country related to investments and it is only a little more positive than neighbouring Ukraine with B+. This means that business circumstances are still more comparable to Eastern European standards than to EU standards. This results in a very modest and slow increase of investments into sectors like the energy sector in Bulgaria.

The best way to analyze investments into the energy sector in Bulgaria is to compare project payback times or project IRR with other benchmark projects. Bulgarian financing institutions and banks focus on payback time due to the uncertainties in the industrial lending market in the past several years. For the purpose of the benchmark analysis, the differences in fundamental parameters for comparable projects (differences in purchase price for natural gas, or selling price for electricity) leads to discrepancies when IRRs of such projects are compared. Therefore the comparison of payback times of similar projects in the energy sector of Bulgaria gives the best basis for a benchmark analysis.

Overall in Bulgaria commercial loans are hardly accessible, because interest rates are high (> 10-12%), tenures are short (3 – 5 years) and a high share of securities is requested (>150% of loan amount). In the commercial sector loans of several millions of Euros are not a tradition in Bulgaria. When we want to assess this benchmark we therefore have to use the limited examples that are available in the commercial market, and we also look at lending experiences from institutions such as the EBRD. The EBRD however offers conditions that are less than required by the commercial market.
From commercial banks in Bulgaria such as the biggest Bulbank (www.bulbank.bg, recently acquired by Unicredito from Italy), Biochim bank (www.biochim.com, recently acquired by Hypovereinsbank) and DSK bank (www.dskbank.bg), information on repayment times for small capital needs for investments is easily found on the internet but standard offers are very restricted on amount (even maximized at 3 million Euro) and restricted on payback time (maximum 3 years) while interest rates for project financing vary between 10 to 13%[6].
Individual discussions with big banks in Bulgaria confirm the focus on payback time rather than IRR. The discussions with Bulbank confirm the payback requirements for energy investments to be as much as 5 to maximum 6 years[7]. The recent loan in 2004 from Bulbank to Biovet from Peshtera for the financing of their new CHP investment is one of the few examples. The details of such lending construction depends on the presented cash flow model and future expectations of the investing company and project. Bulbank is one of the biggest banks in Bulgaria and can count almost all of the large Bulgarian businesses to their customers. The bank had assets worth more than 3.6 billion BGN in 2004. Energy efficiency funds made available through these banks by the EBRD for projects in the energy sector and industry offer somewhat better conditions. Based on the general financing conditions for large investments in Bulgaria the payback time seems to be limited to 5 years. Statements from Bulbank which participated in the first commercial loan for a cogeneration investment in Bulgaria, confirm this approach. Consequently most of the Bulgarian banks will require a short payback time of up to 5 years in order to minimize their risks. For reasons of conservatism, we apply for the project at DHC Pleven and DH V. Turnovo a payback benchmark of **6** years.

Sub-step 2c. Calculation and comparison of financial indicators:
In order to calculate the financial indicators we include all costs for equipment and implementation services, all revenues from the generation of heat and electricity, excluding revenues from carbon credits, but including all other related costs for operating the project activities. The complete calculation tables are included in the annexes of this PDD. As a result of the calculations the payback time for DHC Pleven is estimated at more than **7** years and also the payback time for DHC V. Tarnovo is estimated at more than **7** years.
The prices for natural gas and the electricity for the calculations are made according to the State commission for energy and water regulation[8].

Sub-step 2d. Sensitivity analysis:

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[6] See also: http://www.aeaf.minfin.bg/en/interest_rate/interest_rates_04_2005_en.php

[7] Validator has obtained confirming information from financial professional within Bulgarian banking system

[8] www.dker.bg

Selection of variables:
Within the investment analysis, the gas and electricity price are the most influential parameters to the financial results of the project activities. The variables are correlated to each other in this respect that an increased gas price will lead to an increased electricity price. Both variables will be varied in the range of 2 to 10 % increase with respect to the project activity scenario to show the robustness of the project activity scenario.

Sensitivity for the project activity
We assume that the increase of the electricity price and natural gas price takes place in the period prior to project commissioning so that they have maximum effect on the IRR calculation.

The calculation results for the sensitivity analysis for DHC Pleven are shown in the diagram below:

Electricity Price	**Payback**	**Payback**	**Payback**	**Payback**
10%	>5	>6	>6	8
5%	>6	7	7	9
2%	7	7	8	10
0%	7	8	9	10
Gas price	0%	2%	5%	10%

The calculation results for the sensitivity analysis for DHC V. Tarnovo are shown below:

Electricity Price	**Payback**	**Payback**	**Payback**	**Payback**
10%	>5	>6	>6	7
5%	>6	>6	7	8
2%	>6	7	8	9
0%	7	7	8	10
Gas price	0%	2%	5%	10%

The calculations shown above are the result of iterations with the software while varying the respective parameters. Unfortunately the used software does not enable to provide more detail. From the sensitivity analysis of the project at DHC Pleven it can be concluded that the impact of the increase of the electricity price is not as significant as the increase of the gas price. This is due to the large gas consumption of the cogeneration. The outcomes in the upper left and lower right side of the table should be ignored, because in the reality an increase in the gas price will always trigger an increase of the electricity price. The sensitivity analysis further shows that the project payback time never falls below an acceptable **6** years payback time as required by commercial lending institutions.

From the sensitivity analysis of the project at DHC V. Tarnovo it can be concluded that the impact of an increase of the electricity or gas prices is much less significant than for the project at DHC Pleven. The reason for this is that the consumption of gas by the gas engine at DHC V. Tarnovo is much lower. Therefore the payback time of the project at DHC V. Tarnovo is not as sensitive to changes of the parameters electricity and gas price as the payback time of the project at DHC Pleven. The results in the upper left and lower right corners of the table can be ignored, since electricity price increase will normally go hand in hand with gas price (or fuel costs) increase. The sensitivity analysis for DHC V. Tarnovo shows that the project payback time never falls below the acceptable **6** years.

In addition it is important to understand that projections for variation of electricity price and gas price are based on uncertain assumptions. These assumptions are hard to confirm. Most banks therefore favour to look only at existing price levels to assess the feasibility of the project. This is the most conservative approach.

Step 3. Barrier analysis

Sub-step 3a. Identify barriers that would prevent the implementation of type of the proposed project activity:

The following barriers are identified:

1. Investment barrier:

- lack of capital and debt funding provided to the market because of perceived risks of large investments in this sector.

The lending requirement for the implementation of the project at DHC Pleven is about 18 million Euro, which is a financing amount needed which is not typical for the Bulgarian banking sector. For the energy sector, financing institutions and banks are averse of project financing because of historical reasons and because of the future uncertainties for many companies in this sector in Bulgaria. The reasons for this uncertainty are the:

- the ongoing privatization in the energy sector
- the fluctuation of the fuel prices
- uncertainties around the implementation of the green certificate system
- the projected closing of the nuclear power plant and the possible construction of a new nuclear power plant (the Bulgarian capacity expansion plan is not clear on this).
- and the uncertain progress towards EU accession which has an influence on the capital markets.

These uncertainties make banks risk averse and therefore decrease the amounts of lending capital to companies available for project financing. Banks do offer alternatives such as credit over drafting and leasing constructions, but these financial solutions are even more expensive for the companies that require lending. Consequently the access to capital is a very influential barrier for the DCH Pleven.

The lending, necessary for the implementing of the project at DHC V. Tarnovo, is approximately 2 million Euros. The providing of an investment credit is still a barrier since the Bulgarian banks are generally reluctant to provide credits under any different than the above mentioned conditions. The lending requirement remains a barrier to overcome since according to the calculations the project payback time is higher than 6 years.

Equity barrier:

- Equity constraints at investing companies

DHC Pleven has been showing poor financial results in the last 5 years. Therefore, there is a big constraint on equity available for investments. In 2001 the company has experienced losses due to the fact that the production costs were higher than the maximum price the company was allowed to charge the customers. The revenue the company is making is not enough for investment in new technologies.

DHC V. Tarnovo is much smaller than Pleven and has less capacity. The financial results of V. Tanrono were positive, but small, in the last years. Still, investments in new technologies can not be financed with these revenues, since they are not sufficient.

For DHC V. Tarnovo as well as for DHC Pleven, project financing from banks is the only possibility for financing projects.

Technological barriers:

- Lack of experienced and trained labour to operate and maintain the new technology.

DHC Pleven has no experience with the operation and maintenance of the new cogeneration technology. In Bulgaria there are only few comparable projects, none of which have been commissioned yet. Hence the operational experience is very limited. The technology is rather new to the country and is definitely new to the personnel at the project activity locations. The operation personnel needs to be trained and supported during start up and operation of the new equipment. The technology providers will have a big role in bringing this expertise to Bulgaria.

Sub-step 3 b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

Alternative I does not represent a change from the existing situation, so no barriers are experienced. Alternative II would not involve any large investment, other than small maintenance costs, since it is a continuation of the existing situation.

Step 4. Common practice analysis

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

Although there are many business ideas identified in recent studies by for example the EBRD or the EVA from Austria, almost no Western type cogeneration system has been commissioned yet in Bulgaria. There are a few investment projects under way in the industrial and energy sector in various stages of development such as a CHP at Biovet which will install the first western type gas turbine and heat recovery boiler in Bulgaria. This project is comparable to the project at DHC Pleven. At DHC Varna there is a CHP investment project under construction and at DHC Bourgas a cogeneration project is being implemented. The project at DHC Bourgas is comparable with the project at DHC V. Tarnovo. None of the projects are currently operational.
Also, these projects are all JI projects and are therefore excluded from this common practice analysis, since only non-JI projects should be included here. Cogeneration investments by industry and district heating facilities is new to the country and has only come into development because of strong support by the government through the Energy Act from 2003 where electricity from renewable and cogeneration will be treated with preferential price and dispatch.

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

Since similar projects are hardly observed in Bulgaria, and above all there are no examples of such projects being yet operational, there is no basis for an analysis of similar activities.

Step 5. Impact of JI determination

The carbon revenues will contribute to reduce the payback time for the project at DHC Pleven to 5 years which falls within the maximum required amount of 6 years. Hence the project at DHC Pleven will become eligible for project financing from commercial lending institutions.
For DHC V. Tarnovo, the additional carbon revenues from the JI mechanism, will bring project payback down to an acceptable 6 years. It is the expectation that the payback figures together with the relatively lower investment requirement will make the project elibigle for project financing from commercial lending institutions in Bulgaria.

Impact on the identified barriers
Investment barrier
The additional JI revenues help to improve the payback time of the projects within acceptable limits. Therefore, these revenues increase the chances for the projects to obtain commercial financing for the related investments.
Equity barrier
The additional JI revenues will decrease also the amount of equity needed from the project owner. Therefore less equity will be required to finally obtain financial closure for the project investments.
Technological barrier

Western type technology is much more expensive than Eastern European technology. The additional JI revenues enable the project owner to invest in this more expensive western technology.
The above-mentioned positive impact of possible JI revenues to the conclusion that the project activity is additional.

B.3. Description of how the definition of the project boundary (related to the baseline methodology selected) is applied to the project:

For the proposed projects the project boundary includes emissions from activities that occur at the project locations. The system boundary for the proposed projects is defined as the national grid in Bulgaria. The project boundary for the baseline will include all the direct emissions related to the energy production by the facilities and power plants that will be replaced after the commissioning of the described project. This involves emissions from displaced fossil fuel used at Bulgarian power plants. The emissions related to production, transport and distribution of the fuel used for the power plants in the baseline are not included in the project boundary, because they are considered as insignificant (less than 1% of project baseline scenario). For the project boundary the emissions related to the transport are also excluded because of the same reasons.

DHC Pleven
The project emissions are related to the project boundaries and are:
- combustion of natural gas in the Gas Turbogenerator Set (GTS);
- combustion of natural gas in the Heat Recovery Steam Generator (HRSG);
- combustion of natural gas in the back up Steam and Water Boilers (SWB);
- combustion of heavy fuel oil (HFO) in SWB.

The project boundaries are shown in the next flowchart:

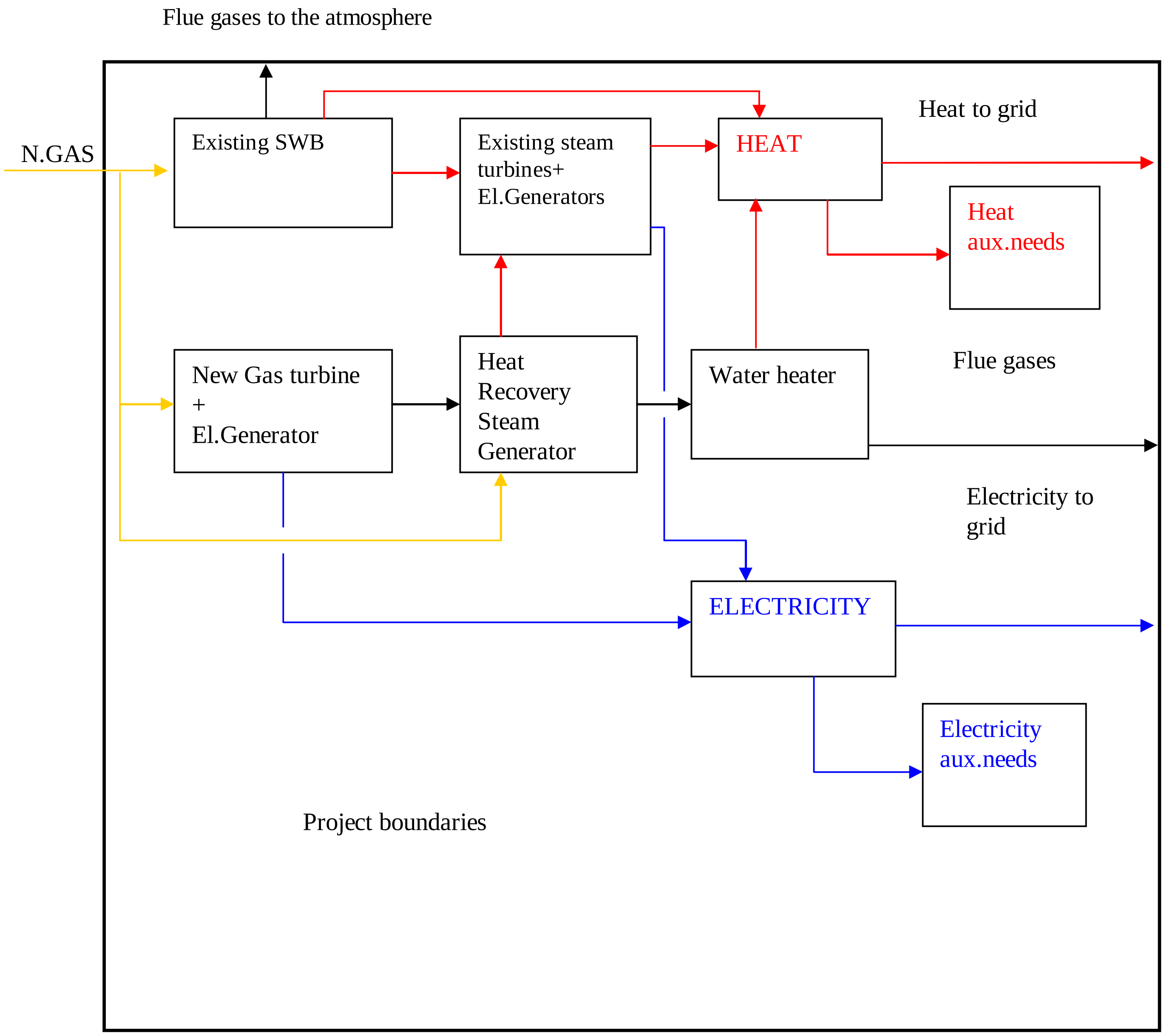

Figure 3: Project boundaries DHC Pleven

DHC Veliko Tarnovo

The project emissions are related to the project boundaries and are:

- combustion of natural gas in the gas motors (GM);
- combustion of natural gas in the back up Steam and Water Boilers (SWB);
- combustion of HFO in the SWB.

The project boundaries are shown in the next flowchart.

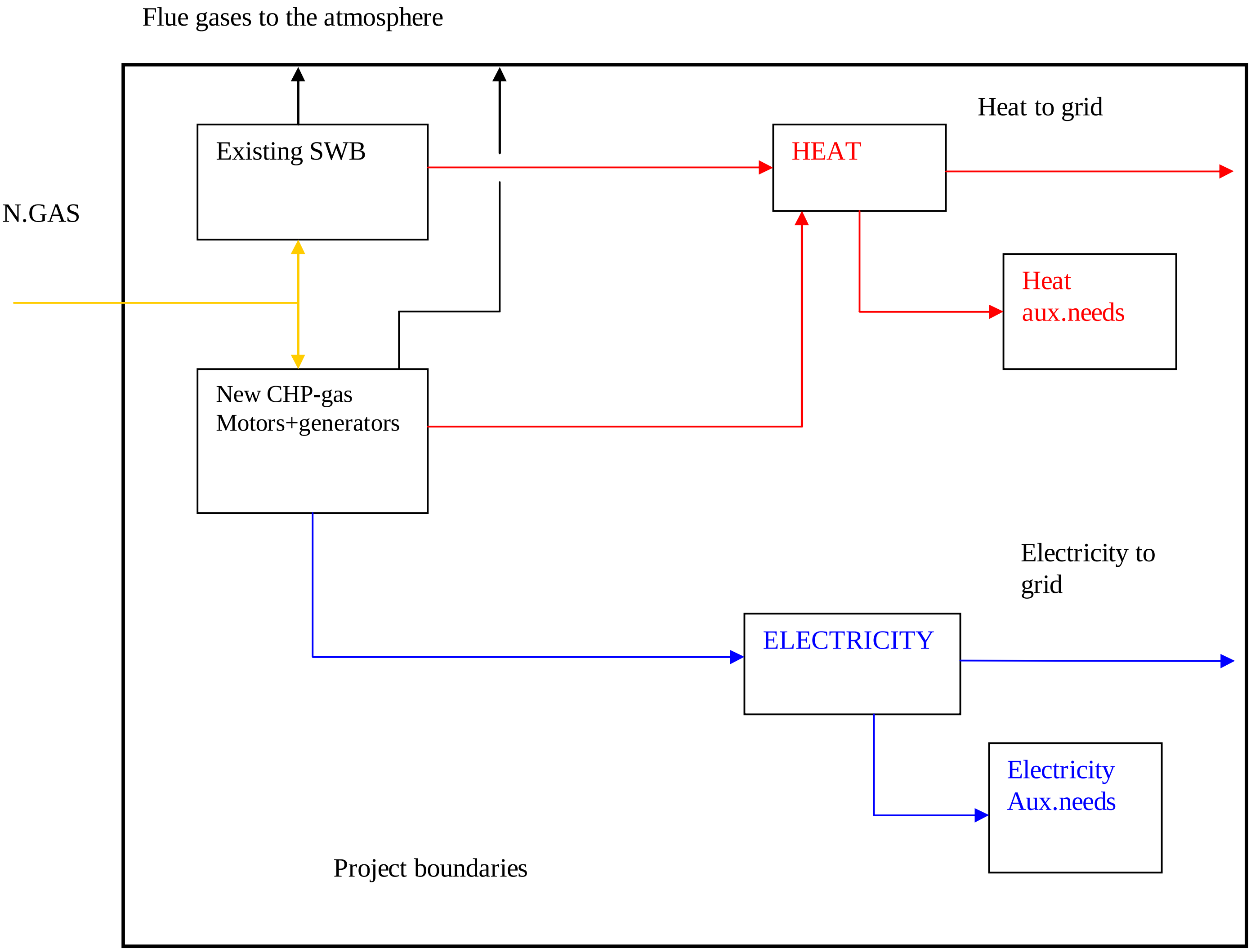

Figure 4: Project boundaries DHC V.Tarnovo

B.4. Further baseline information, including the date of baseline setting and the name of person(s)/entity(ies) setting the baseline:

The Bulgarian baseline study of Joint Implementation projects in the Bulgarian energy sector (Link: http://www.moew.government.bg/recent_doc/international/climate/carbon_emission_joint.pdf) was elaborated by NEK EAD and published by the Bulgarian Ministry of Environment and Water in March 2006. http://www.moew.government.bg/.

NEK (National Electrical Company) EAD is not a project participant.

SECTION C. Duration of the project / Crediting period

C.1 Starting date of the project:

The start of the operation (commissioning) of the first gas motor in DHC V.Tarnovo is 01.December. 2006, for the second one – 01.october.2007.
The start of the operation (commissioning) of the gas turbine in DHC Pleven is 01.June .2007.

C.2. Expected operational lifetime of the project:

The expected operational lifetime of the envisaged cogeneration units is 15 years (180 months).

C.3. Length of the crediting period:

The starting date of the generation of early credits is 01 December 2006.

The generation of Emissions Reduction Units will start on 01 January 2008 and will continue until 31 December 2012. The reduced emissions achieved in the period from the starting of the operation of the project until 31 December 2007 will be transferred as Assigned Amount Units.

SECTION D. Monitoring Plan

The Monitoring Plan (MP) provides a practical framework for the collection and management of project performance data, which will be used for the verification of the actual emissions reduction generated. The process of verification is the annual auditing of monitoring results by a third party, which makes the assessment of the achieved emission reductions. This MP does not contain specific guidelines on emissions reduction auditing and verification, but it provides sufficient detail on the project structure, the proposed data that needs to be monitored and relevant operational issues, and thus giving the opportunity to an independent verifier to develop suitable auditing and verification procedures for the CHP portfolio of the JI project activity.

D.1. Description of monitoring plan chosen

The project emissions are mainly emissions of CO_2 from the burning process of natural gas in the co-generation installations and in the existing steam water boilers. There is an insignificant quantity of methane emissions (assessed as insignificant and excluded from supervision) and emissions from nitrous oxide released during the natural gas burning process. These quantities are insignificant, because:

- the technology employed for the burning process is state-of-art one and there is not unburned quantity of natural gas in the flue gases;
- the quantity of nitrous oxide in the flue gases released during the burning process will be lower than in the existing situation.

Additionally, to the natural gas quantity feed for burning in the co-generation installation, there is a quantity of emissions from methane, from natural gas leakages during its delivery through the gas pipeline. These indirect greenhouse emissions are assessed by the delivered natural gas parameters through the incorporate gas pipelines and their length, using standard assessments for the specific leakages and emissions factors. These indirect greenhouse emissions are not evaluated, because of their insignificant quantity and they are the same as in the existing situation.

Considering the project scope, to install a co-generation installation in DHC Pleven and DHC V.Tarnovo, the following data/parameters need to be monitored:

- Natural gas consumed by the co-generation installation, in thousand Nm3;
- Natural gas consumed by the water heated and steam boilers, in thousand Nm3;
- Natural gas consumed by the DHC;
- Consumed “back up” fuel (HFO), in tons;
- LCV of the NG, in MWh/m3;
- LCV of the HFO, in MWh/t;
- Net electricity provided by the new CHP to the national electricity network, in MWh;
- Net thermal energy provided by the DHC to the heat supply network, in MWh;
- CAHO – heat output to covering heat demand, in MWh;
- Efficiency of the existing SWB;
- Emission factor of the national electricity network, in tCO2/MWh.

There is a monitoring model, expressing the specific requirements, during the assessments in this PDD. Such model is prepared under MS-Excel and is presented below in the annexes. The model requirements are to enter the monitored parameters as an input data, so it will automatically calculates simultaneously the project and the baseline emissions, for each year after the project commissioning. The electronic worksheets should be filled with information by the project manager and also the inspecting personnel, through the whole operational lifetime of the project related to the crediting period.

The baseline emissions depend on the thermal energy and electricity production of the existing co-generation system and they are determined by the input data in the model, which also determines the emissions reduction which are obtained as a result of the project activity. The personnel responsible for the monitoring should fill up the electronic worksheets on a monthly basis. The model automatically calculates the annual sum and respectively the emissions reductions of greenhouse gases obtained as a result of the project operation of the new co-generation systems. The model contains different electronic worksheets series with various functions:

Electronic worksheet – Input data:

§ *Natural gas consumed by the co-generation installation, in thousand Nm3;*
§ *Natural gas consumed by the water heated and steam boilers, in thousand Nm3;*
§ *Natural gas consumed by the DHC;*
§ *Consumed "back up" fuel (HFO), in tons;*
§ *LCV of the NG, in MWh/m3;*
§ *LCV of the HFO, in MWh/t;*
§ *Net electricity provided by the new CHP to the national electricity network, in MWh;*
§ *Net thermal energy provided by the DHC to the heat supply network, in MWh;*
§ *CAHO – heat output to covering heat demand, in MWh;*
§ *Efficiency of the existing SWB;*
§ *Emission factor of the national electricity network, in tCO2/MWh.*

Electronic worksheet - calculations:

- *Project emissions;*
- *Baseline emissions*

Electronic worksheet - Results:

D.1.1. Option 1 - Monitoring of the emissions in the project scenario and the baseline scenario:

D.1.1.1. Data to be collected in order to monitor emissions from the project, and how this data will be archived:

ID number (Please use numbers to ease cross-referencing to D.3)	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1	Quantity of NG used by the new CHP	Measuring devices of the power plant	1,000 nm3/y	m	monthly	100%	Electronic and paper	
2	Quantity of NG used by the existing SWB	Measuring devices of the power plant	1,000 nm3/y	m	monthly	100%	Electronic and paper	
3	Quantity of NG used by the DHC	Measuring devices of the supplier (Bulgar gas)	1,000 nm3/y	m	monthly	100%	Electronic and paper	
4	Quantity of HFO used by the DHC	Measuring devices of the power plant	tones/y	m	monthly	100%	Electronic and paper	

5	LCV of used NG	Data by the supplier (Bulgargas)	MWh/1,000nm3	c	monthly	100%	Electronic and paper	
6	LCV of used HFO	Data by the supplier	MWh/tone	c	monthly	100%	Electronic and paper	

D.1.1.2 Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

The project emissions will be calculated by the equation:

APE = AECng*EFng +AEChfo*EFhfo = Qng*LCVng*EFng + Qhfo*LCVhfo*EFhfo [tCO2/y], where:

APE – annual project emissions [tCO2/y];
AECng - annual energy consumption of natural gas [MWh/y];
AEChfo - annual energy consumption of heavy fuel oil [MWh/y];
Qng - annual quantity of NG used by the DHC [1000nm3/y];
LCVng - low calorific value of NG, average for the year [MWh/1000nm3];
Efng - emission factor for NG burning – 0.202 tCO2/MWh(0.0561 Kton/TJ)– emission factor for combustion of natural gas, estimated from IPCC- www.ipcc-nggip.iges.or.jp/public/gl/invsl.htm, published by Ministry of Economic Affairs of the Netherlands;
Qhfo - annual quantity of HFO used by the DHC [tones/y];
LCVhfo - low calorific value of HFO, average for the year [MWh/tone];
EFhfo - emission factor for HFO burning – 0.279 tCO2/MWh.

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary, and how such data will be collected and archived:

ID number (Please use numbers to ease cross-referencing to table D.3)	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic / paper)
7	Wel,s electricity from new CHP to the grid	Measuring device of the power plant	MWh/y	M	monthly	100%	Electronic and paper
8	Heat from DHC to the grid	Measuring device of the power plant	MWh/y	M	monthly	100%	Electronic and paper
9	CAHO-annual heat output to covering the heat demand of the DHC	Measuring device of the power plant	MWh/y	M	monthly	100%	Electronic and paper
10	Eb- Efficiency of the existing SWB	DHC	-	E	once	100%	Electronic and paper
11	EFel – emission factor for Bulgarian power grid	MoEW of Bulgaria	tCO2/MWh	C	yearly	100%	Electronic and paper

D.1.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO2 equ.):

Annual baseline GHG emissions – ABE1 = BEth - from natural gas combustion in boilers for production of heat, covering annual heat demand of the DHC is calculated as follows:
BEth = ABE1 = ABECng *EFng, tCO2/y

where:
ABECng is the heat input with natural gas fuel for covering heat demand annually, [MWh/y]

ABECng = CAHO/Eb = Bng*LCVng, MWh/y;
CAHO is annual heat output to covering heat demand of DHC, MWh/y;
Eb is efficiency of existing SWB;
Bng is quantity of natural gas used for combustion in boilers, [Tnm3/y]
LCVng is low calorific value of natural gas – 9.30 [MWh/Tnm3]-data from Bulgargas
EFng = 0.202 tCO2/MWh (0,0561 Kton/TJ)– emission factor for combustion of natural gas, estimated from IPCC.

Annual baseline GHG emissions – ABE2 = BEel - from electricity generated by the new CHP and going to grid is calculated as follows:

BEel = ABE2 = Wel,s* EFel, tCO2/y

where:
W el,s - electricity production from CHP, which will substitute generation of electricity elsewhere in the power grid, [MWh/y];
Wel,s = Wel – Wel aux, [MWh/y];
Wel – electricity production of new CHP, [MWh/y];
Wel aux – electricity for auxilary needs of CHP himself, [MWh/y].
EFel – calculated emission factor for Bulgarian Power grid [tCO2/MWh]. Description and calculation of emission factor for Bulgarian power grid are presented in paragraph B.

Total annual baseline GHG emissions, ABE, are given by:

ABE = ABE1 + ABE2 , tCO2 /y

D. 1.2. Option 2 - Direct monitoring of emission reductions from the project (values should be consistent with those in section E):

Not applicable

D.1.2.2. Description of formulae used to calculate emission reductions from the project (for each gas, source, formulae/algorithm, emissions units of CO2 equ.):

Not applicable.

D.1.3. Treatment of leakage in the monitoring plan:

Not applicable.

D.1.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:

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

D.1.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO2 equiv.):

Not applicable

D.1.4. Description of formulae used to estimate emission reductions for the project (for each gas, source, formulae/algorithm, emissions units of CO2 equiv.):

The estimated emission reductions are calculated as follows:

AER = ABE – APE [tCO2/y];
Where:
AER – annual emission reductions;
ABE – annual baseline emissions, calculated in respect of D.1.1.4;
APE – annual project emissions, calculated in respect of D.1.1.2.

D.1.5. Information to be collected in order to monitor environmental impacts of the project, and how this information will be archived:

Not applicable. There is no information related to the environmental impacts of this project which will especially be collected.

D.2 Quality control (QC) and quality assurance (QA) procedure to be performed for the data monitored:

The table below describes the procedure for the quality control and the quality assurance – (QA/QC) for every data which is changing, together with the relevant information for every variable.

. Data	Uncertainty level of data (High/Medium/Low)	Are QA/QC procedures planned for these data?	Justification why QA/QC procedures are or aren't being planned?
1	Low	Yes	These data will be directly used for calculation of emissions reductions
2	Low	Yes	These data will be directly used for calculation of emissions reductions
3	Low	Yes	These data will be directly used for calculation of emissions reductions
4	Low	Yes	These data will be directly used for calculation of emissions reductions
5	Low	Yes	These data will be directly used for calculation of emissions reductions
6	Low	Yes	These data will be directly used for calculation of emissions reductions
7	Low	Yes	These data will be directly used for calculation of emissions reductions
8	Low	Yes	These data will be directly used for calculation of emissions reductions
9	Low	Yes	These data will be directly used for calculation of emissions reductions
10	Low	Low	These data will be directly used for calculation of emissions reductions
11	Low	Low	These data will be directly used for calculation of emissions reductions

D.3.Please describe the operational and management structure that the project operator will implement regarding the monitoring plan:

For monitoring, collection, registration, visualization, archiving, reporting of the monitored dates and periodical checking of the measurement devices are responsible the measurement team. The authorises are not divided separately between the people. Every one from the team is authorized and responsible for all actions connected with the servicing of the monitoring system.

The monitoring system is built with modern measurement devices, equipped with specialized computers for collecting of probes information and calculation of the measurement results. The communication ports of the devices permit the dates to be collected automatically in the Central monitoring system of DHC.

All measurement devices are equipped with fiscal memory and can be recorded in every time.

The existing measurement devices which are not equipped with communication ports will be reading and their results will be recorded in the tables of the Central monitoring system 1 time of day from the measurement team people.

The measurement team will record the measurement dates from all measurement devices and will compare with the dates recorded in the Central monitoring system 1 time monthly like internal audit of the monitoring system.
The measurement team carry out all maintenances of the measurement devices from the Monitoring system / cleaning the probes etc./ described in maintenance documentation of the suppliers.
The manager of the team is authorized for preparing of the annuals report for the verification company with the results from the measurement and evidence of authenticity.
The manager of the team is authorized to organize periodical checking of the measurement devices from the authorized laboratory. The plan and the report data for the periodical checking are record and automatically generated in the Central monitoring system.
In accordance with the procedures for checking the recorded monitoring dates, emergency preparedness and replacing missing data shall be marked:

- All measurement devices are registered in the State Register like trade devices;
- All suppliers of the measurement devices have services in the country and are obligated to respond in 48 hours;
- DHC keep in its storage spare parts in accordance with the recommendations of the suppliers, which the monitoring team is ready to change;
- All measurement devices are with fiscal memory;
- The Central monitoring system archives all measurement data for very long period inside. The missing data for the period of damage will be replaced with enough precision with archived dates for similar period.

DHC Pleven

For monitoring, collection, registration, visualization, archiving, reporting of the monitored dates and periodical checking of the measurement devices is responsible the measurement team from 4 people and its manager Mr Erdinai Muratov. The responsibilities are not divided separately between the people. Every one from the team is authorized and responsible for all activities.
The team is formed by:

1. Mr.Erdinai Muratov – Eng., Chief of department „Production and Technology“;
2. Mr.Andrian Andreev – Eng., Chief of department „Measurements“;
3. Mr. Aleksander Nikolov – Eng., department „Measurements“;
4. Mrs. Desislava Toteva – department „Production and Technology“

DHC Veliko Tarnovo

For monitoring, collection, registration, visualization, archiving, reporting of the monitored dates and periodical checking of the measurement devices are responsible the measurement team from 3 people and its manager Mr Dimitar Georgiev. The responsibilities are not divided separately between the people. Every one from the team is authorized and responsible for all activities.

The team is formed by:

1. Mr. Dimitar Georgiev – Eng., Chief of department „Measurements“;

2. Mr. Toncho Penev - department „Measurements“;
3. Mr. Borislav Mihailov - department „Measurements“.

D.4. Name of person(s)/entity(ies) determining the monitoring plan:

The monitoring plan was established by Global Carbon BV in consultation with technical staff from DHC Pleven and DHC V. Tarnov

SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

DHC Pleven

The amount of the GHG emissions of the project activities is formed by:

- combustion of natural gas in the Gas Turbogenerator Set (GTS);
- combustion of natural gas in the Heat Recovery Steam Generator (HRSG);
- combustion of natural gas in the back up Steam and Water Boilers (SWB);
- combustion of heavy fuel oil (HFO) in SWB.

The calculated project emissions are shown in the next table:

Parameter	Unit	2007	2008	2009	2010	2011	2012
Quantity of NG to GTS	Tnm3/y	39,199	67,198	67,198	67,198	67,198	67,198
Quantity of NG to HRSG	Tnm3/y	4,502	7,718	7,718	7,718	7,718	7,718
Quantity of NG to SWB	Tnm3/y	14,026	26,829	26,829	26,829	26,829	26,829
Total quantity of NG	Tnm3/y	57,727	101,745	101,745	101,745	101,745	101,745
Heat with NG	MWh/y	536,861	946,229	946,229	946,229	946,229	946,229
Em. Factor of NG combustion	tCO2/MWh	0.202	0.202	0.202	0.202	0.202	0.202
Emissions of CO2 by NG comb.	tCO2/y	108,446	191,138	191,138	191,138	191,138	191,138
Quantity of HFO to SWB	t/y	0	0	0	0	0	0
Heat with HFO	MWh/y	0	0	0	0	0	0
Em. Factor of HFO comb.	tCO2/MWh	0.279	0.279	0.279	0.279	0.279	0.279
Emissions of CO2 by HFO comb.	tCO2/y	0	0	0	0	0	0
Total project emissions Pleven	tCO2/y	108,446	191,138	191,138	191,138	191,138	191,138

Table 6: Estimated project emissions for DHC Pleven

DHC Veliko Tarnovo

The amount of the GHG emissions of the project activities is formed by:

- combustion of natural gas in the gas motors (GM);
- combustion of natural gas in the back up steam and water boilers (SWB);
- combustion of HFO in the SWB.

The calculated project emissions are shown in the next table:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Quantity of NG to GM	Tnm3/y	450	5,561	8,300	8,300	8,300	8,300	8,300
Quantity of NG to SWB	Tnm3/y	712	8,672	7,086	7,086	7,086	7,086	7,086
Total quantity of NG	Tnm3/y	1,162	14,233	15,386	15,386	15,386	15,386	15,,386
Heat with NG	MWh/y	10,807	132,367	143,090	143,090	143,090	143,090	143,090
Em. Factor of NG combustion	tCO2/MWh	0.202	0.202	0.202	0.202	0.202	0.202	0.202
Emissions of CO2 by NG comb.	tCO2/y	2,183	26,738	28,904	28,904	28,904	28,904	28,904
Quantity of HFO to SWB	t/y	0	0	0	0	0	0	0
Heat with HFO	MWh/y	0	0	0	0	0	0	0
Em. Factor of HFO comb.	tCO2/MWh	0.279	0.279	0.279	0.279	0.279	0.279	0.279
Emissions of CO2 by HFO comb.	tCO2/y	0	0	0	0	0	0	0

Emissions of CO2 by HFO comb.	tCO2/y	0	0	0	0	0	0	0
Total project emissions V.Tarnovo	tCO2/y	2,183	26,738	28,904	28,904	28,904	28,904	28,904

Table 7: Estimated project GHG emissions in DHC V.Tarnovo

The estimated project GHG emissions for the two DHCs are shown in the table below:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Total project emissions For the two DHCs	tCO2/y	2,183	135,184	220,042	220,042	220,042	220,042	220,042

Table 8: Estimated project GHG emissions in the two DHCs

E.2. Estimated leakage:

Not applicable. There was no leakage identified

E.3. The sum of E.1 and E.2:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Total project emissions for the two DHCs	tCO2/y	2,183	135,184	220,042	220,042	220,042	220,042	220,042

E.4. Estimated baseline emissions:

Baseline emissions can be collected in the “direct on-site” and “indirect off-site” categories and comprise the following two components:

- **CO_2 combustion** corresponds to natural gas that would have been used for covering the whole heat demand during the investigated period for every year.
- **CO_2 electricity** – emissions associated with the electricity that would have been generated by the power grid if the new CHP did not provide electricity to the DHC Plant for auxiliary needs plus the rest of produced by CHP electricity, which substitutes the electricity produced elsewhere, distributed in the same grid. The auxiliary needs for electricity in the substations in the city are covered by the electricity grid independently of project activity realization.

DHC Pleven

The estimated baseline emissions for DHC Pleven are formed by ABE 1 – from natural gas combustion in boilers to covering annual heat demand of DHC and ABE 2 – associated with the electricity produced by the new CHP and going to the grid.
The estimated baseline emissions for DHC Pleven is given in the table below:

Parameter	Unit	2007	2008	2009	2010	2011	2012
Quantity of NG Combustion in boilers to covering heat demand	Tnm3/y	41,840	71,726	71,726	71,726	71,726	71,726
Heat with NG	MWh/y	389,112	667,052	667,052	667,052	667,052	667,052
Eb	%	85.68	85.68	85.68	85.68	85.68	85.68
Heat total produced	MWh/y	333,391	571,520	571,520	571,520	571,520	571,520
Em. factor of NG comb.	tCO2/MWh	0,202	0,202	0,202	0,202	0,202	0,202
ABE 1	**tCO2/y**	**78,601**	**134,745**	**134,745**	**134,745**	**134,745**	**134,745**
Electricity produced by the New CHP	MWh/y	144,482	247,683	247,683	247,683	247,683	247,683
Electricity for aux. needs Of the new CHP	MWh/y	11,973	20,526	20,526	20,526	20,526	20,526
Electricity by the new CHP To the grid	MWh/y	132,509	227,157	227,157	227,157	227,157	227,157
Dispatch Data Adj_OM_EF Of Bulgarian Grid	tCO2/MWh	1.156	1.059	0.947	0.908	0.884	0.833
ABE 2	**tCO2/y**	**153,180**	**240,559**	**215,118**	**206,259**	**200,807**	**189,222**
Baseline emissions (ABE 1 + ABE 2) for DHC Pleven	**tCO2/y**	**231,781**	**375,304**	**349,863**	**341,004**	**335,552**	**323,967**

Table 9: Baseline emissions DHC Pleven

DHC V. Tarnovo

The estimated baseline emissions for DHC V Tarnovo are formed by ABE 1 – from natural gas combustion in boilers to covering annual heat demand of DHC and ABE 2 – associated with the electricity produced by the new CHP and going to the grid.

The estimated baseline emissions for DHC V. Tarnovo are given in the table below:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Quantity of NG Combustion in boilers to covering heat demand	Tnm3/y	902	10,825	10,825	10,825	10,825	10,825	10,825
Heat with NG	MWh/y	8,389	100,672	100,672	100,672	100,672	100,672	100,672
Eb	%	85	85	85	85	85	85	85
Heat total produced	MWh/y	7,131	85,571	85,571	85,571	85,571	85,571	85,571
Em. factor of NG comb.	tCO2/MWh	0.202	0.202	0.202	0.202	0.202	0.202	0.202
ABE 1	**tCO2/y**	**1,695**	**20,336**	**20,336**	**20,336**	**20,336**	**20,336**	**20,336**
Electricity produced by the New CHP	MWh/y	1,350	14,167	26,700	26,700	26,700	26,700	26,700
Electricity from new CHP for aux. needs of CHP himself	MWh/y	56	840	1,350	1,350	1,350	1,350	1,350
Electricity to the grid by the new CHP	MWh/y	1,294	13,327	25,350	25,350	25,350	25,350	25,350
Dispatch Data Adj_OM_EF Of Bulgarian Grid	tCO2/MWh	1.143	1.156	1.059	0.947	0.908	0.884	0.833
ABE 2	**tCO2/y**	**1,479**	**15,406**	**26,846**	**24,006**	**23,018**	**22,409**	**21,117**

Baseline emissions (ABE 1 + ABE 2) For DHC V.Tarnovo	**tCO2/y**	**3,174**	**35,742**	**47,182**	**44,342**	**43,354**	**42,745**	**41,453**

Table 10: Baseline emissions DHC V.Tarnovo

The total baseline emissions for the two DHCs are shown in the next table:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Total baseline emissions For the two DHCs	tCO2/y	3,174	267,523	422,486	394,205	384,358	378,297	365,420

Table 11: Total baseline emissions for the project activity.

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

DHC Pleven

The emission reductions of the project activities in DHC Pleven are shown in the table below:

Parameter	Unit	2007	2008	2009	2010	2011	2012
Baseline emissions DHC Pleven	tCO2/y	231,781	375,304	349,863	341,004	335,552	323,967
Project emissions DHC Pleven	tCO2/y	108,446	191,138	191,138	191,138	191,138	191,138
Emission reductions DHC Pleven	tCO2/y	123,335	184,166	158,725	149,866	144,414	132,829
Total AAUs	tCO2	123,335					
Total ERUs	tCO2	770,000					
Total reduction Pleven	tCO2	893,335					

Table 12: Emission reductions DHC Pleven

DHC V. Tarnovo

The emission reductions of the project activities in DHC V. Tarnovo are shown in the table below:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Baseline emissions DHC V.Tarnovo	tCO2/y	3,174	35,742	47,182	44,342	43,354	42,745	41,453
Project emissions DHC V.Tarnovo	tCO2/y	2,183	26,738	28,904	28,904	28,904	28,904	28,904
Emission reductions DHC V.Tarnovo	tCO2/y	991	9,004	18,278	15,438	14,450	13,841	12,549
Total AAUs	tCO2	9,995						
Total ERUs	tCO2	74,556						
Total reduction V.Tarnovo	tCO2	84,551						

Table 13: Emission reductions DHC Veliko Tarnovo

Total emission reductions by the project activity:

Parameter	Unit	2006	2007	2008	2009	2010	2011	2012
Emission reductions DHC Pleven	tCO2/y	0	123,335	184,166	158,725	149,866	144,414	132,829
Emission reductions DHC V.Tarnovo	tCO2/y	991	9,004	18,278	15,438	14,450	13,841	12,549
Total em.reductions By the two companies	tCO2/y	991	132,339	202,444	174,163	164,316	158,255	145,378
Total AAUs	tCO2	133,330						
Total ERUs	tCO2	844,556						
Total(AAUs + ERUs)	tCO2	977,886						

Table 14: Total emission reductions of the project activity.

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

YEAR	Estimated Project Emissions (tones CO2 Equivalent)	Estimated Leakage (tones CO2 Equivalent)	Estimated Baseline Emissions (tones CO2 Equivalent)	Estimated Emissions Reductions (tones CO2 Equivalent)
2006	2,183	0	3,174	991
2007	135,184	0	267,523	132,339
2008	220,042	0	422,486	202,444
2009	220,042	0	394,205	174,163
2010	220,042	0	384,358	164,316
2011	220,042	0	378,297	158,255
2012	220,042	0	365,420	145,378
Total (tones CO2 Equivalent)	1,237,577	0	2,215,463	977,886

The project emissions will be calculated by the equation:

APE = Qng*LCVng*EFng + Qhfo*LCVhfo*EFhfo [tCO2/y], where:

APE – annual project emissions [tCO2/y];
Qng - annual quantity of NG used by the DHC [1000nm3/y];
LCVng - low calorific value of NG, average for the year [MWh/1000nm3];
EFng - emission factor for NG burning – 0.202 tCO2/MWh;
Qhfo - annual quantity of HFO used by the DHC [tones/y];
LCVhfo - low calorific value of HFO, average for the year [MWh/tone];
EFhfo - emission factor for HFO burning – 0.279 tCO2/MWh.

The baseline emissions will be calculated by the equations:

Annual baseline GHG emissions – ABE1 from natural gas combustion in boilers for production of heat, covering annual heat demand of the DHC is calculated as follows:
ABE1 = Qf *EFng, tCO_2/y, or

Qf= CAHO/Eb, MWh/y;

ABE1 = (CAHO/Eb)*EFng, tCO_2/y

where:
Qf is heat introduced with natural gas fuel for covering heat demand annually,[MWh/y]

Qf = Bng * LCVng, MWh/y,

CAHO is annual heat output to covering heat demand of DHC, MWh/y;
Eb is efficiency of existing SWB;

Bng is quantity of natural gas used for combustion in boilers, [Tnm^3/y]
LCVng is low calorific value of natural gas – 9.30 [MWh/Tnm^3]-data from Bulgargas

EFng = 0.202 tCO_2/MWh (0.0561 Kton/TJ)– emission factor for combustion of natural gas (data from PDD guide)

Annual baseline GHG emissions – ABE2 from electricity generated by the new CHP and going to grid is calculated as follows:
ABE2 = Wel,s* EFel, tCO_2/y
where:
W el,s - electricity production from CHP, which will substitute generation of electricity elsewhere in the power grid, [MWh/y];
Wel,s = Wel – Wel aux, [MWh/y];
Wel – electricity production of new CHP, [MWh/y];
Wel aux – electricity for auxilary needs of CHP himself, [MWh/y].
EFel – calculated emission factor for Bulgarian Power grid [tCO_2/MWh]. Description and calculation of emission factor for Bulgarian power grid are presented in paragraph B.

Total annual baseline GHG emissions, ABE, are given by:

ABE = ABE1 + ABE2 , tCO_2 /yr

SECTION F: Environmental impacts

F.1. Documentation on the analysis of the environmental impacts of the project, including transboundary impacts, in accordance with procedures as determined by host party:

General
It is an established fact that projects for the construction of cogeneration plant fuelled by natural gas are not a source of hazardous air and soil pollution. In this case, in accordance with the provisions of the Environmental Protection Act of the Republic of Bulgaria, Article 93, paragraph 1, item 3, this project is subject to an assessment for the necessity on an Environmental Impact Assessment (EIA). This is the official position of The Ministry of Environment and Waters, expressed by the statement of the Department of Preventive Activities. In accordance with these requirements, the DHC Pleven and DHC Veliko Tarnovo already have submitted the required documents for the elaboration of this assessment in accordance with the requirements of the Regulation on Terms and Conditions for the Elaboration of Assessment of the Environmental Impact Reports for Buildings, Activities, and Technologies (State Gazette, No. 25 dated 18.03.2003).

DHC Pleven has submitted a request fro MoEW for issuing of EIA on 13.03.2006. It is expected the statement of the MoEW to be issued until the end of June 2006.

DHC Veliko Tarnovo has received a decision with number № 15-ПР-2005 from MoEW for non necessity of EIA for a project „Projecting, supply and commissioning of cogeneration installation for combined production of electricity and heat production with 9 MWel and 9.9 MWth in Heating Station "Veliko Tarnovo". At this stage DHC Veliko Tarnovo will install two gas engines with respectively 2.8 MWel / 2.2 MWel electrical and 3.08 MWth / 2.42 MWth thermal power, where the total installed capacity will be in accordance with the approved by MoEW installed power with its decision № 15-ПР-2005.

EIA analysis
An environmental impact analysis after the model of the country based extended environmental impact analysis for the two separate projects making up the co-generation portfolio has been executed. In general types and ranges of environmental influences were assessed after their impact on air, water and land, people and borders. The responsible persons are:
- For DHC Pleven: Erdinai Muratov
- For DHC Veliko Tarnovo: Nikola Nikolov

A summary of the EIA analysis regarding the environmental impacts from the project activity is given below:

	DHC Pleven and DHC Veliko Tarnovo
1. Influence over the people and their health.	The influence is defined as not to have a negative effect. This is confirmed by the not necessity of executing of Environmental Impact Assessment. The cogenerations employed are state-of-securing and thus securing low levels of emissions.
2. Influence over the elements that are part form the National ecological network.	The projects will not influence negatively on the environment.
3. Type of influence	
3.1 Emissions in the air.	Direct, permanent. Higher level of emissions compare to the current situation, but without having a negative effect on the air.
3.2 Emissions in the water.	Direct, short time, slightly negativity on the base of the used oils.
3.3 Noise influence.	Direct, permanent, negative.
3.4 Gassing of the engaged area in case of a gas leakage.	Direct, short time, negative
3.5 Fire within installation.	Direct, short time, negative
3.6 Explosion of the installation.	Direct, short time, negative
4. Range of influence- geographical area - affected population - populated area	The project is situated in industrial and non-residential area
5. Possibility of appearance of the Influence.	
5.1 Influence on the air.	Incidentally possibility to appear.
5.2 Influence on the water.	Incidentally possibility to appear.
5.3 Noise influence.	Not possibility to appear over the limits.
5.4 Gassing of the engaged area in case of a gas leakage.	Incidentally possibility to appear.
5.5 Fire within the installation.	Incidentally with very low possibility to appear.
5.6 Explosion of the installation.	Incidentally with very low possibility to appear.
6. Preventive measures in the investment suggestion.	
6.1 Influence on the air.	The influence of the gas engines is not subject of European directive 2001/80/EC.
6.2 Influence on the water.	The two DHCs have installed WPSs. The installations contaminate the water only with remainders from the used oils and from the washing of the engines.
6.3 Noise influence.	The gas engine cogeneration is deposited in a special container. The container will be situated inside of special closed site. The level of the noise outside of the container (1m) is less than 85 dB. The norms in accordance with Bulgarian legislation are 85 dB for the working facilities.
6.4 Gassing of the engaged area in case of a gas leakage.	There are planned emergency installations for protection and an implemented system for notification.
6.5 Fire within the installation.	There are planned emergency installations for protection and an implemented system for notification and extinguish.
6.6 Explosion of the installation.	There are planned emergency installations for protection, computerized regulation of the burning process and an automatic system for gas detecting and ventilation.
7. Influence over the international border.	The two projects are not situated close to international border areas and there will not be any influence over the borders.

SECTION G. Stakeholders' comments

G.1. Information on stakeholders' comments on the project, as appropriate:

DHC Pleven
In accordance with regulations, the DHC Pleven have made announcement about the project to the Municipality and citizens of Pleven with number 402 from 16.03.2006. No comments have been received until now.

DHC V.Tarnovo
In accordance with regulations, the DHC V.Tarnovo have made announcement about the project to the Municipality and citizens of V.Tarnovo with number 26-35 from 26.07.2005. No comments have been received until now.

Annex 1: CONTACT INFORMATION ON DHC PLEVEN

Organization:	DHC “TOPLOFIKATSIA PLEVEN”
Street/P.O.Box:	INDUSTRIAL ZONE, Ivan Mindilikov Str.,2
Building:	
City:	PLEVEN
State/Region:	PLEVEN
Postfix/ZIP:	5800
Country:	BULGARIA
Telephone:	
FAX:	
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile tel:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

DHC V.TARNOVO

Organization:	DHC "TOPLOFIKATSIA VELIKO TARNOVO"
Street/P.O.Box:	NIKOLA GABROVSKI Str., 71A
Building:	
City:	VELIKO TARNOVO
State/Region:	VELIKO TARNOVO
Postfix/ZIP:	5002
Country:	BULGARIA
Telephone:	
FAX:	
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile tel:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

GLOBAL CARBON BV

Organization:	GLOBAL CARBON BV
Street/P.O.Box:	Benoordenhoutseweg 23
Building:	
City:	The Hague
State/Region:	
Postfix/ZIP:	2596 BA
Country:	The Netherlands
Telephone:	+31703142456
FAX:	+31703142457
E-Mail:	saat@global-carbon.com
URL:	www.global-carbon.com
Represented by:	
Title:	Director
Salutation:	
Last Name:	Saat
Middle Name:	
First Name:	Erik
Department:	
Mobile tel:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

Annex 2: BASELINE STUDY OF JOINT IMPLEMENTATION PROJECTS IN THE BULGARIAN ENERGY SECTOR.

CARBON EMISSION FACTOR

The Bulgarian baseline study of Joint Implementation projects in the Bulgarian energy sector (Link: http://www.moew.government.bg/recent_doc/international/climate/carbon_emission_joint.pdf) was elaborated by NEK EAD and published by the Bulgarian Ministry of Environment and Water. http://www.moew.government.bg/.

1. Introduction

Bulgaria complies with the requirements of the UN Framework Convention on Climate Changes (UNFCCC) ratified by the Bulgarian Parliament in March 1995. Besides, the Parliament of the country ratified the Kyoto Protocol to the Convention on 17th July 2002. The Protocol was based on the ideas and principles set forth in it and develop them further adding new obligations, larger in scope and detail than those in the Convention.

According to Art. 6 of the Kyoto Protocol, in order to perform its obligations for emission reduction and limitation, each of the countries listed in Annex 1 may transfer to another country on the list, or receive from it, emission reduction limits obtained as a result of projects for reduction of anthropogeneous emissions of greenhouse gases by sources. In practice, such projects are mostly implemented in countries with economies in the process of transition where there are more opportunities for emission reduction, and at a lower cost. The amounts of Emission Reduction Units achieved as a result of the project may be bought by a developed country for the purpose of keeping its obligation under the Protocol.

In Bulgaria, joint implementation of projects is viewed as an economically acceptable way of reducing the emissions of anthropogeneous greenhouse gases and receiving, at the same time, financial, economic, technical assistance and expertise.

In order to start work by the so-called “flexible mechanism” under the Kyoto Protocol – Joint implementation (JP) Projects – a bilateral agreement has to be signed between the Government of Bulgaria and another developed country or an international fund for protection of the environment.

So far, bilateral Memoranda of Understanding and Bilateral Cooperation for implementation of JP Projects have been signed with the Kingdom of Netherlands, the Republic of Austria, the Kingdom of Denmark and EBRD in the latter’s capacity of trustee of a Prototype Carbon Fund.

2. Purpose of the Study

The purpose of the present assignment is to carry out a study in order to define the Baseline scenarios of the Bulgarian Electricity Power System and calculate the annual Baseline Carbon Emission Factor (BCEF) the process of operation of the electric power sector.

3. Introduction to the Baseline Study

The most important part of the preparation for a greenhouse gas reduction project is the Baseline Study. It should define, in a transparent and comprehensive manner, what rate of CO2eq reduction and related financing can be expected. Besides, the Baseline defines and provides the methodology of assessing which of several possible developments is the most probable in the absence of the project and what emissions would be generated by that scenario.

The Marrakesh Accords (the decisions of COP7 in Marrakesh in November 2001) constitute the central guidance as far as documents required by COP for climate protection projects are concerned.

According to the Marrakesh Accords, the Baseline shall meet the following more significant requirements:

3.1 To be transparent in terms of assumptions, method, project boundary, parameters, data sources, key factors

and Additionality;
3.2 To account of important national and industrial policy measures and circumstances such as sector-related reforms, availability of indigenous fuels, plans for expansion of the electric power sector, and economic situation in the sector;
3.3 To be formed in such a manner that it would be impossible to generate ERUs and CERs for reduction of activities beyond the project boundary on the basis of Force Majeure events;
3.4 To be project-based or standard oriented;
3.5 To take data uncertainty into account. The assumptions shall be selected conservatively.

It means that the assumptions as to calculations in the event of hesitation (data range, data uncertainty, etc.) shall be selected in such a manner that the resulting total Baseline emissions would be low rather than high. As a result of that, the calculated emission reduction is underestimated rather than overestimated and is, therefore, more stable with respect to data status variations or with respect to criticism from outside. That increases the probability for the Baseline to be accepted by the Independent Entity and by the stakeholders.

3.6 Besides, the Baseline selection shall be substantiated.
3.7 There is a restriction upon the choice of a Baseline composition method for projects under CDM, but not for 3JI projects. The following three Baseline approaches are possible only:

a) “Historical or existing emissions”. That generally well sustained wording probably leaves room for all substantial Baseline methods because, in principle, every method can be supported by the argument that, directly or indirectly, it rests on historical or existing emissions.

b) “Emission of a technology that, due to obstacles before investments, is an economically attractive alternative”
Practically, the purpose of that wording could be to extend the investment analysis method – an economically attractive alternative.

c) “the mean percentage of emissions from comparable project activities during the last five years implemented in similar social, economic, environmental and technological conditions, the project activities of which belong to the best 20% in their category”.
That last requirement may be interpreted to mean that JI/CDM projects should not lead to implementation of outdated technologies or used equipment, but to technological and social progress, that is, to sustainable development in the countries where they are implemented.
Beside these official requirements of the Marrakesh Accords, theoretically there are no other substantial directions restricting the Baseline development. This is to emphasize that, in the development of a Baseline, the question “What would happen to the system and its emissions if no financial resources came from Carbon Credit sales” has priority over adherence to preset criteria.

Although, in principle, individual routes may be chosen to the implementation of that task, the previous experience offers several already proven methodological approaches that should be favored. Other routes should be chosen only where there are special reasons for that and where they are, respectively, adduced intelligibly by the author of the Baseline. Method selection depends on the type of project, the data status, the preferences of Carbon Credit buyers, resp. the parties to the Contract, the Baseline author’s experience, etc.

4. Methodological Approaches to Baseline Determination

The Baseline Determination Methodologies fall into two broad categories – project-specific approaches and multi-project approaches.

4.1 Project-Specific Baseline

a) Reference Group
From the point of view of a project specific Baseline, it is often emphasized that the type of project, its size and availability of data are the main factors that determine the choice of Baseline methodology.
The Reference Group approach requires finding of a similar country, region or project with conditions comparable to the particular project for the purpose of studying a development that does not include the Joint Implementation Project. The definition of a reference group in a similar situation in the electric power industry, would be difficult due to different circumstances with respect to fuels used, technologies implemented, economic aspects, electricity market liberalization status and policy, etc.

b) Investment Analyses
In these analyses, all probable and realistic possibilities are determined taking into account the technical, economic, political, social and environmental aspects graded by economic benefit, for example through determination of the Internal Rate of Return. The highest-return alternative is defined as Baseline Alternative. Due to the fact that economic aspects are the determining factors for that aspect, such approach requires a solution model guided mainly by economic considerations and the clear comparability of different options.
The potential for use of investment analysis in the electric power sector is quite limited because, in principle, the new projects compete with a variety of generation units in the electric power sector. It is very seldom that a new project competes directly with an existing unit. For that reason the investment approach is not considered very useful in the electric power sector.

c) Scenario analysis
Risk-based analyses deal with the possible development scenarios in the absence of a project taking into consideration various influencing factors such as technologies, policies and market restrictions. Possibilities leading to high risk are dismissed and the most probable scenario is selected as baseline. The main challenge in this approach is selecting the main influencing factors and to determine the best and most reliable data sources for the study.

4.2 Standard-oriented, or Multi-project Baseline

There are a number of different approaches to Multi-project Baselines. They can vary from average-emission specific emissions for a sector to technological standards of broad modeling within the frameworks of the particular sector such as, for example, merit order dispatch analysis in the electric power sector. In spite of the variety of approaches, the main point is to provide a set of standard data that shall be used as a baseline for a number of different projects. That can be also bases for comparison with respect to the baselines specific to a project and could be expressed in specific emissions per unit of electricity output (i.e., Baseline Carbon Emission Factor (BCEF) determined in tons of CO2/GWh).
The multi-project approach is launched because, through the use of such methods, the transaction costs of Joint-Implementation Projects will be significantly reduced. In other words, the baseline development costs in Joint-Implementation Projects will be much lower than those developed in countries that already have a Multi-project Baseline and, therefore, the project developers' and investors' costs will be significantly reduced. Therefore the present study will also launch a number of projects that will be implemented by means of these mechanisms, as it will launch implementation of smaller but environmentally friendly and stable energy projects as well. Besides, there will be better predictability to the project developer in terms of number of emission reduction units that will be achieved through a project.
More particularly, in the power plant case, the multi-project approach to a Baseline seems to be a reliable and efficient solution.

5. Multi-Project Baseline for the Electric Power Sector

Considering the electric power sector, Multi-project Baselines find wide application in Joint-Implementation Projects and in Clean Development Mechanism Projects. The reason is that, in most cases, implementation of a project with capacity exceeding 20MWe, there is a marginal impact on the whole electric power sector. Therefore, project-specific Baselines are not suitable and multi-project approaches are preferred.

In the next section, an analysis of different Baseline methodologies based on multi-project approaches is made, and their compatibility with the subject of discussion is examined. Institutional conditions, available data and specificity of the Bulgarian electric power sector should also be taken into account when the most appropriate Baseline methodology is finally selected.

5.1 Mean specific emissions will all plants participating

At present, this is the most simplified methodology for Baseline determination. It assumes that the project will displace part of the integral electricity generation mix. The problem with that method is that it encompasses all plants with low operating costs that usually operate as base load plants, inclusive of hydro- and nuclear power plants. There is, however, almost no chance for a new investment to replace the output of these plants; it is much more probable for an investment to replace plants with higher operating costs such as plants fired with fossil fuel. Therefore, that methodology may be rejected by the investor countries because the share of nuclear generation added to that of hydro-power (about 50%) is large within the power system of Bulgaria.

5.2 Mean specific emissions less Nuclear, Pumped-Storage and Hydro-Power Plants

In principle, there will be technologies that will continue to work irrespective of the adoption of a Joint-Implementation Project. The best example of that are the Chaira Pumped-Storage Hydro-Power Plant and the four large existing hydro-power cascades with hydro-power plants built downstream of the dams that have extremely flexible load-following capacity and can operate in peak-load periods. That is not due to the high operating costs but rather to the opportunity offered by them to choose the time of electricity generation in the event of unexpected need for generation capacity in the system.

There is also a current trend in Baseline determination to eliminate the output of all nuclear and hydro-power plants because the low operating costs mean that their output will not be affected by new plants in the network. If NPP and HPP are eliminated from the Baseline, such assumption shall be supported by clear written records and justified.

Therefore, this approach attempts to consider matters related only to consideration of mean values in the system; however, precision here still remains questionable. The benefit of that approach is that it will yield the variety of all loads that will be replaced by the project; however, it will not yield the mean weighted value against the current (operating) costs.

5.3 Mean emissions for each Load Category

That involves load curve grouping into different load categories such as seasonal, peak, shoulder, and base loads. After determining the load profile of a project, a direct comparison to the same load category in the Baseline forecasts can be made.

5.4 Consideration of Solely Marginal Plants (Merit order dispatch Analysis)

The Least-Cost Method assumes that plants operating at the margin (at highest costs and, most probably, with highest emissions) will be the first to be replaced. The method should indicate the generation from each plant for every hour (or group of hours) within one year. The assumption is that commissioning of the new capacity will displace plants that currently operate at the end limit of the load curve. That analysis will require evaluation of the last unit(s) that should be connected, for every hour or group of hours in a year and, in that manner, the specific emissions per hour. That type of approach proves to be the most precise with respect to determining which unit actually stops generating electricity. The negative aspect is the quality and quantity of data needed for that method.

5.5 Operating Margin/Build Margin Methodology of IEA and OECD

OECD recommends to use the weighted mean between the operating margin and build margin for determination of the Baseline. That is based on the assumption that a Joint Implementation Project will very likely have an impact on the operation of an existing and new plant in the short term (marginal operating costs) as well as delay the implementation of a new plant in the longer term (marginal build costs). It will be possible to use a power sector model for forecasting of the build margin as well as of the operating margin.

6. Baseline Determination and Computation of the Carbon Emission Factor (CEF) Common to the Bulgarian Power Sector

6.1. Mean specific emissions (all plants included)

The study enables determination of the mean specific emissions and the corresponding CEF for every plant and system-total. That analysis encompasses all power plants, inclusive of nuclear power plants and hydro-power plants that release no emissions but contribute power generation to the system. This approach is too imprecise to

analyze CEF and, respectively, reduction of CO2 emissions in a Joint-Implementation Project, because the operation of nuclear power plants and, to less extent, the operation of the four large hydro-power cascades of the power system are not influenced by the implementation of such projects.

6.2. Mean Specific Emissions (less NPP and HPP)

The study calculates and determines the mean specific emissions and the corresponding CEF for every plant and system-total, only excluding NPP and HPP from the calculation of Baseline emissions because they have low operating costs and, for that reason, there is not probability of their replacement. An option with starting up of the hydro-power cascades with HPP participating in the regulation of the system according to the above-mentioned calculations was developed for the event that a JP project hypothetically replaces peak-load hydro-power capacities of the system (HPP or gas-fired combined-cycle power plant over 20 MW).

That methodology can have quite extensive application in projects but still it remains a less refined methodology and is recommended only in cases of smaller-volume emission reductions in the sector. For example, when integration of JI projects with less than 200 MW installed capacity into the system is considered.

6.3. Mean Specific Emissions for Each Load Category

This approach is not considered in detail because it requires CEF determination for the overall power system. The approach does not add much to the two previous methodologies and it can be said again that it is a less refined approach and it does not reach far in determining what will actually be replaced by the new capacity.

6.4. Integrated Resource Planning (Least-Cost Planning Analysis)

Merit order dispatch analysis for the power sector indicates, in economic terms, what technologies or which particular generating units can be possibly replaced by a new generation in the network. That can provide a realistic picture of replacement, more specifically in the open electricity markets.

This method requires detailed information on the generating capacities and evaluation of the marginal units that shall be started up from a cold reserve state for every hour of the year. The power plants with guaranteed supply contracts shall be taken into consideration.

6.5. Operation Margin/Build Margin Methodology

This approach is a combination of marginal operating costs and marginal construction costs. It can be applied in countries where the power system capacities are expanding. The problem with this methodology is that it is difficult to determine the weighted mean between the Operation Margin and the Build Margin.

7. Selection of Baseline Study Methodology

Following the argumentation here above, the methodology used for Baseline Determination was developed on the basis of merit order dispatch analysis. This type of approach is considered the most precise for analysis which unit will be replaced by a new capacity.

The merit order dispatch approach analyses the electric power sector on the basis of electricity demand forecasts – minimum and maximum; fuel prices, new capacities and envisaged rehabilitation projects; and cost estimates. For these analyses NEK uses the IRP Manager computer model (Integrated Resource Planning Model).
The US software company Electric Power Software in Minneapolis has developed the software called IRP Manager for US institute EPRI. Since 1995 the model is implemented in the Bulgarian National Electric Company for the least cost expansion planning of the power sector development.

The IRP-Manager model provides comprehensive management of demand, supply, financial and rate data needed for long-term integrated resource planning of the power sector. It coordinates an expansive “Tool Box” of capabilities including: chronological simulation of demand and resources, automated resource strategy development, decision analysis and complete forecasts of impacts from all perspectives.
The forecast power balances obtained by merit order dispatching are used to develop the Baseline study. The basis study itself was developed using the ACM0002 Methodology, “Consolidated Baseline Methodology for Grid-Connected Electricity Generation from Renewable Sources” of UNFCCC CDM – Executive Board.
In order that the study can be as complete as possible and applied to the widest possible range of JP projects in the Bulgarian power sector, all methods offered in the power plant operation margin determination methodology are applied. The relation between operation margin and build margin is assumed everywhere as 50/50 % for BCEF determination.

Baseline Carbon Emission Factor of Bulgarian Electricity and Heat Power System

		Unit	2000	2001	2002	2003	2004		
1.	Total system power generation	GWh	41 805	44 785	41 943	41 990	43 621		
2.	Total system heat generation	$MW_{th}h$	14 398 244	17 092 947	17 104 183	18 945 487	15 622 107		
3.	Total CO2 emissions of power generation	kt/a	20 686,07	24 186,09	21 130,37	23 502,96	26 141,93		
4.	Total CO2 emissions of energy transformation	kt/a	25 364,83	29 868,93	27 206,40	29 968,99	31 566,24		
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	Dispatch Data_OM_EF	tonne/MWh	1,215	1,287	1,214	1,226	1,199		
2.	Dispatch Data Adjusted_OM_EF	tonne/MWh	1,159	1,222	1,150	1,160	1,138		
3.	Average Dispatch Data_OM_EF	tonne/MWh	1,269	1,307	1,231	1,237	1,239		
	HPP included								
1.	Dispatch Data_OM_EF	tonne/MWh	1,144	1,184	1,106	1,160	1,165		
2.	Dispatch Data Adjusted_OM_EF	tonne/MWh	1,065	1,106	1,032	1,067	1,078		
3.	Average Dispatch Data_OM_EF	tonne/MWh	1,101	1,149	1,040	1,073	1,108		
	Fossil Fuels								
1.	Dispatch Data_OM_EF	kg/GJ	106,38	109,57	110,86	111,24	110,03		
2.	Dispatch Data Adjusted_OM_EF	kg/GJ	106,93	109,05	110,68	111,09	109,91		
3.	Average Dispatch Data_OM_EF	kg/GJ	109,43	108,79	109,00	109,47	110,63		
	Forecast								
	Minimum demand	Unit	2006	2007	2008	2009	2010	2011	2012
1.	Total system power generation	GWh	45 051	43 115	44 156	47 490	48 212	51 139	52 291
2.	Total system heat generation	$MW_{th}h$	17 875 519	18 057 503	18 320 175	18 746 936	19 028 565	19 744 974	19 358 651
3.	Total CO2 emissions of power generation	kt/a	28 035,37	31 810,38	31 245,76	33 538,31	33 547,47	33 863,20	31 248,73
4.	Total CO2 emissions of energy transformation	kt/a	34 447,38	38 304,71	37 832,72	40 154,36	40 358,39	40 560,20	37 758,36
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	Dispatch Data_OM_EF	tonne/MWh	1,215	1,158	1,144	1,022	0,984	0,963	0,953
2.	Dispatch Data Adjusted_OM_EF	tonne/MWh	1,154	1,100	1,078	0,956	0,917	0,902	0,899
3.	Average Dispatch Data_OM_EF	tonne/MWh	1,243	1,190	1,146	1,026	0,986	0,974	0,983
	HPP included								
1.	Dispatch Data_OM_EF	tonne/MWh	1,176	1,175	1,110	0,995	0,959	0,940	0,918
2.	Dispatch Data Adjusted_OM_EF	tonne/MWh	1,111	1,102	1,017	0,894	0,858	0,849	0,838
3.	Average Dispatch Data_OM_EF	tonne/MWh	1,138	1,153	1,057	0,947	0,909	0,898	0,889
	Fossil Fuels								
1.	Dispatch Data_OM_EF	kg/GJ	111,997	106,693	106,484	100,340	97,288	95,088	96,152
2.	Dispatch Data Adjusted_OM_EF	kg/GJ	111,976	106,621	106,402	100,566	97,871	95,946	96,570
3.	Average Dispatch Data_OM_EF	kg/GJ	111,622	106,175	106,640	100,646	98,217	96,578	97,026
	Forecast								
	Maximum demand	Unit	2006	2007	2008	2009	2010	2011	2012
1.	Total system power generation	GWh	46 739	43 572	46 588	48 351	49 455	51 368	53 194
2.	Total system heat generation	$MW_{th}h$	20 360 486	19 909 333	20 240 498	21 206 857	22 170 354	23 026 991	23 407 576
3.	Total CO2 emissions of power generation	kt/a	27 152,04	31 508,75	32 821,32	33 044,62	33 387,00	32 807,31	30 531,04
4.	Total CO2 emissions of energy transformation	kt/a	34 405,23	38 713,17	40 181,87	40 770,13	41 342,14	40 706,37	38 615,88
	Baseline Emission Factor - BEF								
	Fossil Fuels								
1.	Dispatch Data_OM_EF	tCO2/MWh	1,204	1,215	1,124	1,014	0,973	0,947	0,884
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,143	1,156	1,059	0,947	0,908	0,884	0,833
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,233	1,252	1,127	1,018	0,977	0,953	0,917
	HPP included								
1.	Dispatch Data_OM_EF	tCO2/MWh	1,158	1,168	1,101	0,990	0,947	0,928	0,865
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,091	1,095	1,006	0,888	0,850	0,834	0,791
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,118	1,144	1,052	0,940	0,899	0,879	0,840
	Fossil Fuels								
1.	Dispatch Data_OM_EF	kg/GJ	109,651	111,991	105,315	100,011	95,929	94,604	93,043
2.	Dispatch Data Adjusted_OM_EF	kg/GJ	109,571	111,876	105,263	100,226	96,498	95,130	93,524
3.	Average Dispatch Data_OM_EF	kg/GJ	109,126	111,908	105,550	100,273	96,821	95,676	94,056

Annex 3: MONITORING PLAN

The parameters, mentioned in section D “Setting of the monitoring plan” – table D.1.1.1. “Project emissions” and table D.1.1.3. “Baseline emissions” will be collected by the monitoring team and the project emissions, baseline emissions and emission reduction will be calculated in the **Excel sheets presented below as “Monitoring models DHC Pleven and DHC V.Tarnovo”.**

Note: monitoring sheets will be used both for DHC Pleven and DHC V.Tarnovo:

MONITORING MODELS DHC PLEVEN AND DHC VELIKO TARNOVO

1. Data to be monitored - from table 1 to 11.
(the numeration corresponds to Section D of the PDD)

2. Calculation of baseline emissions - table 12.

3. Calculation of project emissions - table 13.

4. Calculation of emission reductions - table 14.

TABLE 1 - QUANTITY OF NG USED BY THE NEW CHP - 1000 nm3							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total (1000 Nm3)	0	0	0	0	0	0	0

TABLE 2 - QUANTITY OF NG USED BY THE EXISTING SWB - 1000 nm3							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total (1000 Nm3)	0	0	0	0	0	0	0

TABLE 3 - QUANTITY OF NG USED BY THE DHC - 1000 nm3							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total (1000 Nm3)	0	0	0	0	0	0	0

TABLE 4 - QUANTITY OF HFO USED BY THE DHC - tonnes							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	0	0	0	0	0	0	0

TABLE 5 - LCV OF USED NG - MWh/1000nm3							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Average	0	0	0	0	0	0	0

TABLE 6 - LCV OF USED HFO - MWh/tonne							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Average	0	0	0	0	0	0	0

TABLE 7 - ELECTRICITY BY THE NEW CHP TO THE GRID - MWh/y							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	0	0	0	0	0	0	0

TABLE 8 - HEAT FROM DHC TO THE GRID - MWh/yr							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	0	0	0	0	0	0	0

TABLE 9 – CAHO (HEAT OUTPUT TO COVERING HEAT DEMAND) - MWh/yr							
Month	2006	2007	2008	2009	2010	2011	2012
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	0	0	0	0	0	0	0

TABLE 10 – EFFICIENCY OF THE SWB						
2006	2007	2008	2009	2010	2011	2012

TABLE 11 - EF of BG grid - tCO2/MWh							
	2006	2007	2008	2009	2010	2011	2012

TABLE 12 - BASELINE EMISSIONS									
Parameter	Dim.	Reference	2006	2007	2008	2009	2010	2011	2012
Bng	000m3/y								
LCV ng	MWh/000m3	Table 5							
EF ng	tCO2/MWh		0.202	0.202	0.202	0.202	0.202	0.202	0.202
ABE 1	tCO2/y								
Wel,s	MWh/y	Table 7							
EF grid	tCO2/MWh	Table 11							
ABE 2	tCO2/y								
ABE	tCO2/y								

TABLE 13 PROJECT EMISSIONS									
Parameter	Dim.	Reference	2006	2007	2008	2009	2010	2011	2012
Q ng	000m3/y	Table 3							
EF ng	tCO2/MWh		0.202	0.202	0.202	0.202	0.202	0.202	0.202
APE	tCO2/y								

TABLE 14 EMISSION REDUCTIONS - tCO2/yr						
2006	2007	2008	2009	2010	2011	2012