DHC “TOPLOFIKATSIA BOURGAS” JSC

New cogeneration power station for combined production of heat and electricity in District Heating Bourgas, Bulgaria

JI Project Design Document

VOLUME 1
Version 2

March, 2006
The Hague

Table of Content

Annexes:

Annex № 1

GENERAL LAYOUT

Annex № 2

TECHNOLOGICAL SCHEMES FOR 100 %, 75 %, 50 % LOADING

Annex № 3

INSTALATION ARANGEMENT MODEL

Annex № 4

THERMAL ENERGY DEMANDS LOAD PROFILE

Annex № 5

THERMAL ENERGY NETWORK

Annex № 6

SINGLE LINE ELECTRICAL SCHEME

Annex № 7

MONITORING MODELS

Annex № 8

MONITORING SCHEME

Annex № 9

MONITORING EUQIPMENT SPECIFICATION

Annex № 10

- STATEMENT FROM THE PEOPLE LIVING IN THE VICINITY OF THE PROJECT SITE

- STATEMENT FROM THE COMPANY “BourgasCvet”, WHICH IS BEEN SUPPLIED WITH HEAT ENERGY FROM DHC BOURGAS

- STATEMENT FROM THE MUNICIPALITY BOURGAS TO MINISTRY OF ENERGY AND ENERGY RESOURCES

- STATEMENT FROM THE ADMINISTRATION OF BOURGAS TO MINISTRY OF ENVIORNMENT AND WATERS

Annex № 11

LETTER FOR NOT NECESSITY OF ENVIORNMETNAL IMPACT ASSESMENT ISUUED BY THE MINISTRY OF ENVIORNMENT AND WATERS

Annex № 12

Financial Statements:

- Prognostication table for costs and revenues
- Payback and IRR calculation without impact JI
- Payback and IRR calculation with impact JI

Annex № 13

PLAN OF COGENERATIONS MAINTENANCES

Annex № 14

ORGANIZATION STRUCTURE AND RESPONSIBILITES – PROJECT TOPLOFIKATSIA BOURGAS JSC

Annex № 15

TRAINING PROGRAM PROJECT TOPLOFIKATSIA BOURGAS JSC

Remark:

All annexes are situated in PDD Volume 2

Abbreviations

Parameters Abbreviations

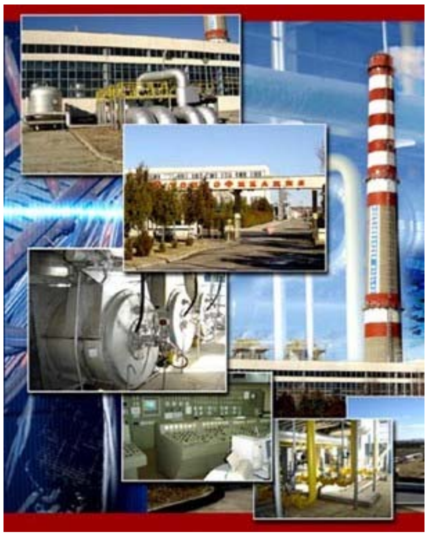
ABE	annual baseline emissions	Kton/y
ABE1	annual baseline emissions from natural gas combustion in boilers	Kton/y
ABE2	annual baseline emissions electricity coming from the grid	Kton/y
h	annual operational hours	h/y
APE	annual project emissions	Kton/y
APE1	annual project emissions from gas combustion in CHP	Kton/y
APE2	annual project emissions from gas combustion in back up boilers	Kton/y
ARE	Total emission reduction from the realization of the Project	Kton/y
Qh	Annual heat production of DHC	TJ/y
Qf	Heat introduced with natural gas fuel annually in boilers	TJ/y
Q_{CHP}	CHP annual heat output	TJ/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	TJ/y
CHP el	CHP net power output capacity	MW_e
LCV	lower calorific value of fuel	GJ/t;GJ/th.c.m
SC	specific consumption of equivalent (conditionally) fuel with low calorific value-LCV = 29,33 GJ/t	kg/GJ
EF el	emission factor for electricity supply by grid	$kgCO_2$/kWh;Kton/TJ
EFel gen	emission factor for electricity generation	$kgCO_2$/kWh; Kton/TJ
EF ng	CO_2 emission factor of natural gas	Kton/TJ
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	
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	

1. Project characteristics

1.1 Project information

1.1.1 Project developer



Company:
Toplofikatsia Bourgas (TB)
District Heating Company
“Lozovo”, North Industrial Area, P.B.O. 642
8000 Bourgas, Bulgaria
Website: www.toplo-bs.com
No. of Employees: approximately 152
BULSTAT: 102011085

Contact person:
Name: Eng. Valio Duchev
Job title: Director
Telephone number: +359 56 871 111
Fax number: +359 56 871 101
E-mail: Valyo_duchev@dhc-bs.com
Web page: www.dhc-bs.com

Corresponder's data (if Supplier is represented by a third party)
Company: Global Carbon BV
2596BA The Hague, Benoordenhoutseweg 23, The Netherlands
Contact person: Erik Saat, Director
Telephone number: +31 70 314 2456
Fax number: +31 70 314 2457
E-mail: saat@global-carbon.com
Internet: www.global-carbon.com

1.2 Project Abstract

The project comprises the design, construction, and operation of a portfolio of eight highly-efficient gas-engines with a total power capacity of 17,82 MWe.

1.2.1 Project Title

"New cogeneration power station for combined production of heat and electricity in District Heating Bourgas, Bulgaria".

1.2.2 Abstract

The project comprises the design, construction and operation for new cogeneration power station for combined production of heat and electricity in District Heating Bourgas including 6 gas engines with a total power capacity of 17,82 MWe (CHP: combined heat and power).
Three of the gas engines will have single output of 3.125 MWe / 3.19 MWth and the other three 2,394 MWth/ 2,814 MWe.
The project will be realized at the premises of city of Bourgas. After the recent process of privatisation DH Bourgas was acquired by the ”NOVAS” 2004 LTD for the amount of 7,8 Million EUR. As a part of the investment program for increasing of the overall efficiency of the DH Company an implementation of cogeneration units is planed. The total investment sum for the cogeneration project is estimated on EUR 9 Million.
The investment will be mainly supported by banks as well as by own funds of the new owner company. After a conservative approach the total emission reductions that will be realised with this project are estimated on 170 000 tones CO_2 for the period before 2008 and 349 000 tones CO_2 in the period between 2008 and 2012. The co-generation station will start operation in 2006.

1.2.3 Project location

The project is located at District Heating Bourgas. The premise of the station is located in west from city of Bourgas. The area covered by DH Bourgas spreads over a territory of 127,000 m2. The distance from the DH to the centre of the city is 7 km and to the suburbs of the city the distance is average 4 km. The DH station is separated from the city with a ring area of agricultural land. The distance from the DH station to the closets located suburb “Lozovo” is 700 meters and to suburb “Dolno Ezerovo” is 2,500 meters.

Bourgas is the fourth largest city in Bulgaria, situated in the South-East part of the country. The city is famous both as an industrial centre and as a tourist centre. It is about 392 km South-East from Sofia.
The location of DH Bourgas is depicted below:

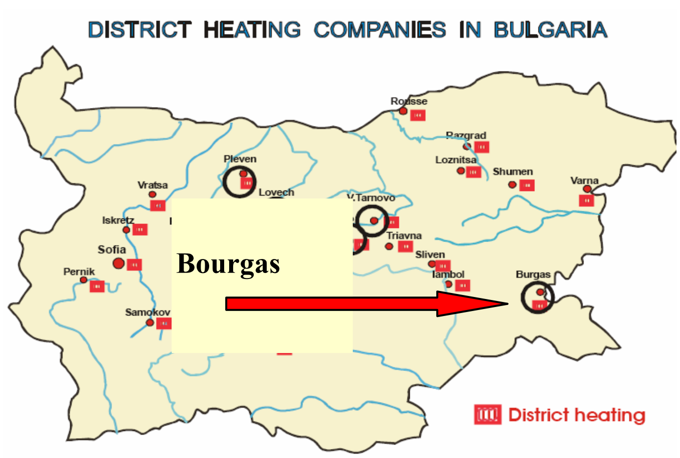


Fig 1. Location of District Heating Station Bourgas

1.2.4 Go decision date, construction works starting and completion date

The final date for go/(no) decision for realization of the project (both phases) is September 2005. The implementation of the project will start in the beginning of 2006. There will be two phases of implementation of the cogeneration units. The first phase will comprise implementation of three gas engines, which construction will start in October 2005 and will finish in March 2006. The execution of the second phase, which comprises another 3 gas engines, which construction will start in October 2005 and will finish in August 2006. The project will be fully implemented only after commissioning of the 6 gas engines, which will happen in September 2006.

Date	DH Bourgas
Go on decision	September 2005

Fig 2. Go decision date

1.3 Background and justification

1.3.1 Background

In the last 15 years the Bulgarian energy sector experienced significant changes. These changes gained a significant momentum in the last five years, during which the new Energy Law Act was adopted by the Bulgarian government. A new policy for the Bulgarian energy sector for the next 15 years was then accepted. The policy is primarily dominated by regulations for accession of Bulgaria into the EU in 2007.
One of the main priorities in the new Energy Law Act is the promotion of cogeneration systems. There are two aspects that support the cogeneration implementation. The National Electrical Company (NEK) is obliged to buy all of the produced electricity at a preferential price. The other advantage is that the operator of a cogeneration power plant can buy natural gas from the national gas supplier at a preferential price. Very few projects have been undertaken yet to implement cogeneration systems due to the related high investments and risky financial investment climate.
The participation of such a cogeneration project in the ERUPT tender would facilitate even more the implementation of the project. What is typical for the few cogeneration projects that were implemented in Bulgaria is that most of them were supported with additional financing through selling the reduced emissions resulting from the projects activity to Western Governments including The Netherlands.

The DHC Bourgas provides service to:

- 29 727 Households connected to the district heating system
- 160 public buildings and firms connected to the district heating system
- 1 Industrial enterprise connected to the district heating system

About 45% of the residents of Bourgas use the services offered by the DHC Bourgas.
The major clients are residential districts “ Slaveikov”, “Izgrev”, ”Zornica”, “Lazur” , “Bratya Miladinovi”.

The present heat supply is based around 4 main gas fired boilers. There are 2 boilers each with a production capacity of 58MW, and two larger boilers each with a capacity of 116MW.There are also 3 gas fired shell and tube boilers that are available to generate steam. Some of the steam is used within the DHC and some is supplied to a local industrial customer. These boilers each have a capacity of 8MW. The length of the hot water network is 119 km.with 877 substations.

In the past several years, the Bulgarian energy sector is undergoing a rapid change, mostly driven by EU accession of Bulgarian projected for 2007. The Ministry of Energy is putting on privatization the energy generation capacity in the country. Several district heating installations, a.o. in the cities of Pleven and Bourgas, have already been privatized. The new owners are mostly companies that have their base in the European Union and that see opportunities in investing in energy generation capacity in Bulgaria because of future growth expectations and profit projections. RWE and EON from Germany and EdF from France are among the companies that invest in the energy sector in Bulgaria. At the same time, the energy market is in the process of liberalization. This means that subsidies for households and industrial users are gradually removed (they are now already almost 100% removed) and prices for energy therefore have increased in will continue to increase. In addition, prices for energy will increase even more when the generation capacity in Bulgaria will be decreased significantly due the decommissioning of the 3rd and 4th blocks of the nuclear power plant. These blocks are decommissioned because they cannot fulfil the strong safety requirements as required by the European Union laws for these types of installations. The factories in Bulgaria that use energy are looking for ways to reduce costs for energy and to maintain the security of supply of energy to their production processes. They start to invest in own generation capacity. Factories that currently produce energy are looking for ways to increase their efficiency to become more competitive in this liberalized and privatized market. The investments that these companies need to make in order to start generating energy or to become competitive are significant.
The investment economics of the CHP portfolio is enhanced by the possibility of selling the reduction of CO2 emissions to the ERUPT programme. At the same time, the Bulgarian government has adopted for the encouragement of investments in combined energy production by compulsory purchasing of the produced electric energy at preferential prices.
The motives for the realization of these CHP projects are based on the analysis of the market situation in the country and the expected reforms in the energy sector with reference to the accession of our country into the EU. The explanation of the background for the projects in this portfolio is divided into 2 parts. First, we will describe the district heating projects in the portfolio, which have similar backgrounds, subsequently we will describe the factories in this portfolio, which have similar backgrounds as well.

1.3.2 History and the problems that this project has to solve

The biggest obstacle that still appears for similar cogeneration projects in Bulgaria is a suitable financing to be found. The banks in the country are still tentative to finance such projects, or on the other hand they are financing under conditions that are not so favourable for the project owners.
Here a key role for the realizations of the projects is playing the additional financing that is secured by selling the reduced CO2 emissions to a potential buyer. The reasons for installing of co-generation system are basically driven by the following problems that the DH Company experienced in the last years:

- The heat energy from DH is still rather expensive and the some of the customers are not using this service anymore.
- Some of the installations are old, low efficient and the network system has lot of leakages. This brings additional losses, and the necessity of further investments.
- There are new efficient criteria that are coming from the EU directives, which bring additional necessity of investment.

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 on to the national grid. This will increase the competitiveness of the DH and will enable the DH to secure the future delivery of energy to its customers.
- Efficient and sustainable heat production from the low carbon fuel natural gas and thus reducing the CO2 emissions in during the energy production.
- Significant reduction of CO2 emissions in the generation of electricity for the national grid compared with the existing situation.

- reduction of the releasing of other harmful gases like: NOx and CO emissions, as a result from using state-of-the-art gas engine combustion technology.

1.3.3 Project Activity

The cogeneration installation will be used for producing of heat and electrical energy. The produced energy will be sold to the residences, municipal and industrial customers of city of Bourgas. DH Bourgas is been fully gasified since 1993 and no additional work on gasification is necessary.
The investment in new CHP at the DH Station will increase the efficiency (by using the heat from the gas engine to make hot water). What is the typical for the DH company is that the energy producing technologies that is used is not high efficient, the operational process is with high level of emissions of different harmful gases and that is already been operational for more then 20 years. With the installation of new technology the DHs will be able to reduce costs and increase competitiveness.
The National Electricity Company (NEK) is obligated to purchase the generated electricity from the CHP against a preferential tariff (Energy law, article 162). Expected prices are at 5 to 6 Eurocents per kWh.

1.3.4 Core business of the project partners and their relations

After the recent process of privatisation DH Bourgas was acquired by the ”NOVAS” 2004 LTD. ”NOVAS” 2004 LTD now owns 100 % of the shares of DH Bourgas. “NOVAS 2004” LTD is registered with № 9559/2004 in accordance with the records of the court of city of Sofia. One of the main activities of the company is construction and maintenance of energy facilities. The company foresees to invest 21 Million EUR in the DHC Bourgas.

The main scopes of activity of DH Bourgas are: heat production, transfer and trade in thermal energy and maintenance and use of the low-pressure gas main infrastructure and boiler units using natural gas. The products and services that DH Bourgas 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. At the premise of DH Bourgas there are 34 buildings used for the purposes of the DH station. There are 29,727 households connected to the district heating system, 160 public buildings and firms and one industrial enterprise: the Pharmaceutical Chemical Company which is located close to the site of the DH. About 45% of the residences of the city of Bourgas use the service offered by DH Bourgas. The major clients are located in the residential districts of “Slaveikov”, “Izgrev”, “Zornica” and “Lazur”.

DH Bourgas holds two licenses for generation and transmission of heat power on the territory of Bourgas city, issued by regional authorities on November 15, 2000. The licenses are granted for a period of 20 years.

1.4 Intervention

1.4.1 Description the GOALS of the project

The described project has several goals that should be reached with the time. These are:
- Keeping the DH Company in a position of a competitive participant on the heat and electricity market.
- Converting the DH Company in a modern energy production facility that fulfils the present environment requirements through sustainable energy production.
- Achieving of energy producing through low emitting of CO_2, using natural gas as a fuel and highly efficient cogeneration technology.
- Realizing a profitable process of generating and selling of heat and electricity to the final customers.
- Fulfilling of the ideas based in the new energy strategy of the country.

1.4.2 Description the PURPOSE of the project

The desired purpose of the project is:
- Keeping the present customers and attracting new to the DH Company.

- Achieving of low emission energy production.
- Implementing of state of the art technology as high efficient cogeneration station.
- Increasing the income form selling of heat and electricity to final customers.

1.4.3 Description the RESULTS of the project

The implementation of the cogeneration station in operation will bring the following results:

- Low emission production of the electricity and heat and especially reducing the amount of the released CO_2.
- Lower usage of fuel during the operational process compared to the conventional methods of separate energy production.
- Achieving of low cost of energy production.
- Achieving of a competitive energy production in the newly created deregulated energy market in Bulgaria.
- Creating of new working positions and educating of the people that will be employed to operate state-of-the art technology.
- Implementing of state-of-the art technology.
- Fulfilling some of the newly developed European Union directives
- Operation of a co-generation system and acquiring of new knowledge related to using such a system. This is essential for Bulgaria, because of the lack of any experience in the field of the co-generation systems.
- Installing of six cogeneration engines three of them with single output of 3.128 MWth/3.00 MWe and the other three with 2.39 MWth/2.814 MWe.

1.4.4 Description the ACTIVITIES of the project

In order the realization of the project to be achieved it is necessary a sequence of activities to be undertaken. In the following table this sequence will be described.

Table 1

Activities	DH Bourgas
1. Feasibility study and final Co-generations choice.	Yes
2. Design, projects coordination, permits issue.	Yes
3. Gasified	Yes
4. Production and supply of the cogenerations	Not specified yet
5. Constructions on site	Yes
6. Installation and adjustment of the equipment	Yes
7. Commissioning	Yes
8. Operation, monitoring, maintenance	Yes

<u>1.5 Detailed project description</u>

1.5.1 Description of the technology and the technical parameters

The implementation of this state of the art technology, which is an alternative of the existing situation, will lead to decreasing the operational costs and increasing the efficiency of the whole operational system for the heat supply to the consumers of DHC Bourgas.

For the execution of the project "Installation for combined production and heat energy at DHC Bourgas" with 17,82 MW electrical and 18,59 MWh heat power" it is foreseen:

- 6 x 16V25SG "WARTSILA" gas engines coupled with AMG710Mm6 "ABB" generators, installation and commissioning;
- The cogeneration installation will be situated at a separate territory within the DHC, north from the Administrative building;
- The natural gas will be supplied from the existing gas-distribution system located at 160 m from the cogeneration station. It is also foreseen the construction of a new gas pipe diversion DN 100 mm starting from gas-distribution system with a nominal pressure 0,6 MPa, which will ensure undependable supply of natural gas and measurement of the cogeneration system consumption;
- It is also foreseen a new heat pipeline, which will be included as circulation circle, part from a return main pipeline. The heat energy received from the cooling systems and the exhaust gases of the gas engines, trough this pipeline will be supplied to the heat network. The water for the cogeneration installation come in from collector N 22 "Return main pipeline" of the heat network from elevation – 3,20 m with a heat pipeline Dn 400 mm. After heating in the cogenerations heat exchangers the water goes back to the collector "Return main pipeline" in a specific point of the elevation – 3,20 m;
- The operating regime is year-round. The necessary thermal load in the heating season will be added from the existing boilers. In the summer season the thermal load for hot water will be covered with optimal chosen number of operating modules.
- The produced electricity, without the auxiliary needs, will be exported to the national electricity system.

The execution of the project will take place in two phases, presented as follow:

Data for the cogeneration modules

Table 2

Technical data	I phase WARTSILA	II phase WARTSILA
Type of module	16V25SG – AMG710 Mm6	16V25SG /* – AMG710Mm6
Rated power [MWe]	3,127	2,814
Heat capacity [MWt]	3,240	2,956
Number of modules	3	3
Efficiency [%]	82	81,6

Each separate cogeneration module includes engine, generator, turbo-compressor, silencer, and heat exchanger for cooling of the oil system, heat exchanger for cooling of the water "jacket", heat exchanger for the exhaust gases, gas regulating system, pumps, armatures, and control system.

The control and the regulation of the technological process of electricity production and heat production in the cogeneration system are automated.

Principal scheme of a gas engine for such an application is depicted below:

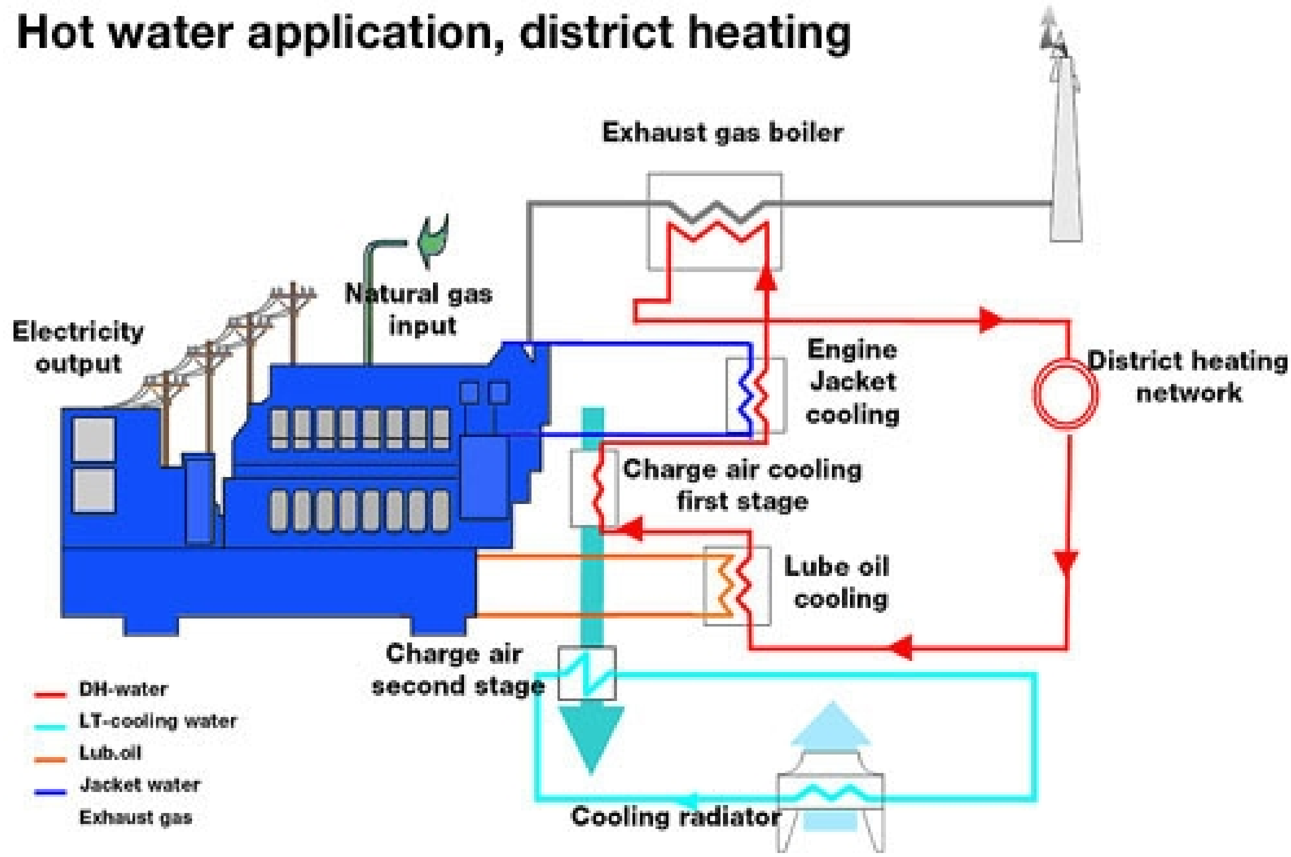


Fig. 3 Principal scheme of cogeneration gas-engine

Principal technological scheme of the module type 16V25SG with technical parameters are provided for 100 %, 75 % and 50 % operating load in **Annex No.2**

Technical parameters for the gas engine:

Table 3

Technical Data	
Producer	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	100m
- humidity	90%
Revolutions [min $^{-1}$]	1000
Number of cylinders	16
Volume of the cylinder [l]	14,7
Fuel Consumption [kJ/kWh]	8760

Technical data for the generator

Table 4

Technical Data	
Producer	ABB Industry OY
Type	AMG710 Mm6
Power	3 900 kVA
Power factor	0,8
Rated voltage	11 kV
Rotation speed	1000 min^{-1}
Frequency	50 Hz
Insulation class	F/F
Protection class	IP 20
Cooling	Self air cooling
Sensors in the stator	2 x 3 PT 100
Voltage adjustment	According AVR, ±5%

Basic technical parameters of the gas engines according to the external conditions and the load of the generator are presented as follow:

I phase

Summer operation mode of the gas engine modules 16V25SG, 50 Hz

Regime	External temperature	Engine load	Electrical power	Thermal power	Fuel heat	Specific heat consumption for electricity production	$ή_e$,	$ή_{th}$,	$ή_{tot}$,
	[^oC]	[%]	[kWe]	[kWt]	[kWt]	[kJ/kWhe]	[%]	[%]	[%]
1	25	96%	3002	3128	7476	8965	40,10	41,90	82,00
2	25	72%	2251	2418	5891	9421	38,20	41,10	79,30
3	25	48%	1501	1654	4266	10232	35,20	38,80	74,00

Winter working regime of a gas engine module type 16V25SG, 50 Hz at 96% load of the engine.

Regime	External temperature	Engine load	Electrical power	Thermal power	Fuel heat	Specific heat consumption for electricity production	$ή_e$,	$ή_{th}$,	$ή_{tot}$,
	[^oC]	[%]	[kWe]	[kWt]	[kWt]	[kJ/kWhe]	[%]	[%]	[%]
1	-1	96%	3002	2534	7476	8965	40,10	41,90	82,00
2	15	96%	3002	2833	7476	8965	40,10	37,90	78,00
3	25	96%	3002	3128	7476	8965	40,10	33,90	74,00

II phase

Winter working regime of a gas engine module type 16V25SG /*, 50 Hz at 96% load of the engine

Regime	External temperature	Engine load	Electrical power	Thermal power	Fuel heat	Specific heat consumption for electricity production	$\acute{\eta}_{e}$,	$\acute{\eta}_{th}$,	$\acute{\eta}_{tot}$,
	[°C]	[%]	[kWe]	[kWt]	[kWt]	[kJ/kWhe]	[%]	[%]	[%]
1	-1	96%	2814	2394	7065	9037	39,73	41,87	81,60
2	15	96%	2814	2677	7065	9037	39,73	37,87	77,60
3	25	96%	2814	2956	7065	9037	39,73	33,87	73,60

Nominal electrical and heat parameters for the efficiency of one gas engine module at different operating loads are presented below:

Load	Electricity produced Ne	Thermal energy produced Q_{th}	□ e	• □ total
[%]	[kWe]	[kWt]	[%]	[%]
100.0%	3127.1	3240.9	40.3%	82.2%
90.0%	2814.4	2955.8	39.7%	81.6%
80.0%	2501.7	2661.1	39.0%	80.5%
70.0%	2189.0	2356.9	38.0%	79.0%
60.0%	1876.3	2043.1	36.8%	77.0%
50.0%	1563.5	1719.8	35.5%	74.5%

Correlation between the ambient temperature and the produced thermal energy from the gas engine modules

	16V25SG – AMG710 Mm6	16V25SG /* – AMG710Mm6
T_{amb},	Thermal energy produced	Thermal energy produced
[°C]	[kWt]	[kWt]
-10.0	2459.4	2324.0
-5.0	2492.5	2355.3
0.0	2546.4	2406.2
5.0	2621.2	2476.9
10	2716.7	2567.1
12	2760.7	2608.7
25	3128.0	2955.8

The sample disposition of the six gas cogeneration modules is depicted in **Annex No. 3**.
The technical staff, which will participate in the installation, commissioning and which will be responsible for the operation and monitoring of the new co-generations installations shall be trained in the phase of commissioning and operation, please see in Annex No. 15: Training Program Project Toplofikatsia Bourgas for more details.

1.5.2 Expected availability of the project

In the table below the preliminary plan is provided for realization of the present project. *Table 5*

		Time frame for realization	
No.	**Activities**	**Phase I**	**Phase II**
1	Start of the project realization	09.2005	09.2005
2	Financing of the project	09.2005 - 12.2005	09.2005 - 12.2005
3	Equipment contracting	09.2005 - 10.2005	09.2005 - 10.2005
4	Detailed project design	09.2005 - 11.2005	09.2005 - 04.2006
5	Construction permit	09.2005 - 11.2005	09.2005 - 11.2005
6	Preparation of the project site	09.2005 - 10.2005	09.2005 - 10.2005
7	Constructing	10.2005 - 04.2006	10.2005 - 08.2006
8	Equipment delivery	11.2005 - 01.2006	11.2005 - 05.2006
9	Installing of the equipment	01.2006 - 03.2006	05.2006 - 07.2006
10	Preliminary tests	03.2006-04.2006	07.2006 - 08.2006
11	Commissioning	03.2006-04.2006	07.2006 - 08.2006
Start of operation		**01.04.2006**	**01.09.2006**

1.5.2.1 Duration of the project activity / Crediting period

Duration of the project activity	
Starting date of the project activity	**01 April 2006**
Expected operational lifetime of the project activity	**15 years, until 01 April 2021**
Length of crediting period	
Starting date of the Crediting period	**01 April 2006**
End date of the Crediting period	**31 December 2012**

1.5.3 Expected capacity factor and project activity level

The expected capacity factor of the cogeneration modules is been defined according to of the observations for operation of similar equipment and the capacity values shown from the equipment producers. The experience from the operation of such type installations shows that the coefficient of annual utilization ratio is over than 95% or 8300 hours. The other important factor influences on the expected capacity of the co-generation modules are the maintenances during the operational life. The preventive maintenance guidelines from the supplier are shown in Annex No. 13: Plan of Co-Generations Maintenances of the PDD. The projected annual operation of the modules is 8021 hours per year or 91.6 %. The capacity of the cogeneration modules installation and the operational regime have been chosen according to the maximal thermal load in the summer season, which is shown in **Annex No. 4**. The additional needs from thermal energy in the winter season are covered by the existing water heating boilers. The basic parameters for production of thermal and electrical energy covering the heat demands, as well as typical parameters of the cogeneration installation, are depicted in the table below.

		Dimensions	**2004**	**2005**	**2006**		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
					Phase I	**Phase II**									
Parameters of the installation including 6 cogeneration modules with a total installed electrical power of 17.823 MWe and total thermal capacity of 18.591 MWt. The electrical power utilization coefficient is 0.891 and for the thermal power is 0.8257. The average annual real power is – electrical -15.918 MWe and Thermal -351 MWt. The annual operation capacity is 8021 hours/annual., LHV of the natural gas – 33.52 MJ/Nm³.															
1	Produced electrical energy	MWhe/a	0	0	96011 66469	 29542	127 670	127 670	127 670	127 670	127 670	127 670	127 670	127 670	127 670
2	Auxiliary needs of the installation	MWhe/a	0	0	2 688		3 575	3 575	3 575	3 575	3 575	3 575	3 575	3 575	3 575
3	Produced thermal energy	MWht/a	0	0	95093 65834	 29259	123 127	123 127	123 127	123 127	123 127	123 127	123 127	123 127	123 127
4	Natural gas consumption	Ths.Nm³	0	0	25 724		34 260	34 260	34 260	34 260	34 260	34 260	34 260	34 260	34 260
Total energy produced from DHC Bourgas															
5	Produced electrical energy	MWhe/a	0	0	96011 66469	 29542	127 670	127 670	127 670	127 670	127 670	127 670	127 670	127 670	127 670
5.1	Electricity for auxiliary needs- total	MWhe/a	6 388	6 524	7 499		7 836	7 772	7 753	7 753	7 753	7 753	7 753	7 753	7 753
5.1.1	DHC plant auxiliary needs without CHP	MWhe/a	5 157	5 214	3 466		2 981	2 933	2 918	2 918	2 918	2 918	2 918	2 918	2 918
5.1.2	Network substations needs	MWhe/a	1 231	1 310	1 295		1 280	1 264	1 260	1 260	1 260	1 260	1 260	1 260	1 260
5.2	Electricity for sale	MWhe/a	0	0	88 512		119 834	119 834	119 917	119 917	119 917	119 917	119 917	119 917	119 917
6	Produced thermal energy	MWht/a	289 933	300 357	297 494		294 669	291 880	291 046	291 046	291 046	291 046	291 046	291 046	291 046
6.1	Thermal energy from the boilers	MWht/a	289 933	300 357	202 401		171 542	168 753	167 919	167 919	167 919	167 919	167 919	167 919	167 919
6.2	Thermal energy from the co-generators	MWht/a	0	0	95093 65834	 29259	123 127	123 127	123 127	123 127	123 127	123 127	123 127	123 127	123 127
6.3	Thermal energy for auxiliary needs	MWht/a	4 675	4 728	4 683		4 638	4 595	4 581	4 581	4 581	4 581	4 581	4 581	4 581
6.4	Heat losses from transport	MWht/a	61400	57 400	57 400		57 400	57 400	57 400	57 400	57 400	57 400	57 400	57 400	57 400
6.5	Thermal energy for sale	MWht/a	285258	295 629	292 811		290 030	287 286	286 464	286 464	286 464	286 464	286 464	286 464	286 464

Table 6

2. Current situation

The thermal source of DHC Bourgas is possessed on territory of 116 dka, located at about 7 km away from Bourgas, at about 700 m away from Lozovo suburb and at 2 500 m away from Dolno Ezerovo. The above mentioned site of DHC Bourgas includes the following units:

- Main building
- Administrative building
- Steam boiler station for internal needs (SBS)
- Workshop for chemical treatment of raw water
- Reservoir area with Heavy Fuel Oil (HFO)
- Auto park
- Workshop for maintenance activities
- Warehouse area.

At the existing situation, DHC Bourgas is licensed for the following activities:

1. Thermal energy production, with License No.Л-023-02/15.11.2000, for the period of 20 years.
2. Thermal energy transport, with License No.Л-024-05/15.11.2000, for the period of 20 years.

At 2005, with Resolution № 33/2005 provided by MoEW, the DHC Bourgas has received, a Complex operation permit of a Fuel installation for thermal energy production with nominal thermal capacity of 372,16 MW.

<u>2.1 Thermal energy</u>

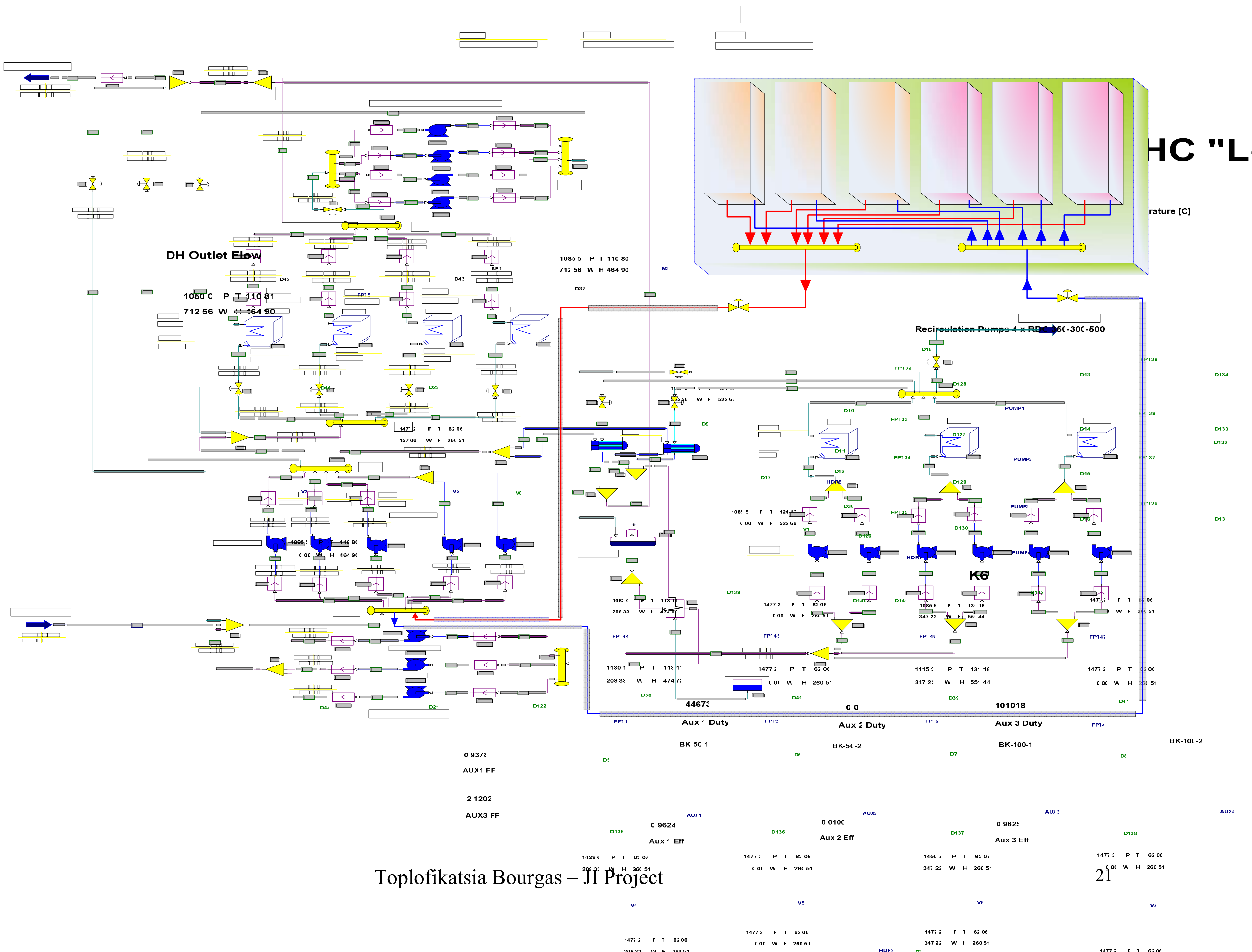
2.1.1. Main equipment for the thermal energy production

The main view of the technological scheme of DHC Bourgas is shown below, as well as the new part of the plant.

It contains six co-generation modules with gas engines, type: 16V25SG/3.127 – 3.127 MWe, and 16V25SG/2.814 – 2.814 MWe

The total installed capacity in the thermal source of the company is 372,16 MW, separated as follows:

- 2 water heated boilers ВК 100 – 116,3 MW
- 2 water heated boilers ВК 50 – 58,15 MW
- 2 steam gas boilers КГ – 12 – 7,56 MW
- 1 steam gas/heavy fuel oil boiler ПКГМ – 12 – 8,13 MW


DH Outlet Flow
K6
Aux 3 Duty
BK-5C-1
BK-5C-2
BK-100-1
BK-10C-2
AUX1 FF
AUX3 FF
Aux 2 Eff
Aux 3 Eff

The steam boilers are installed in the Steam boiler station (SBS), which supplies and satisfies the auxiliary needs of the whole plant. The power capacity of the equipment installed in the SBS, is also included into the total installed power capacity of the thermal source. The steam boilers mainly are used for:

1. Production of superheated steam for auxiliary needs of the plant;
2. Supply of saturated steam during the work of the water heaters with nominal power of 23,26 MW.
3. Superheated steam production for technological needs of the external consumers - “Pharmacy chemicals”-JSC.

All of the boiler equipment in DHC Bourgas has been manufactured by the former boiler-fabrication plant “George Kirkov” - Sofia.

Water heated boilers *Table 7*

Name	Dimension	ВК № 1	ВК № 2	ВК № 3	ВК № 4
Main data					
Type		ВК - 50	ВК - 50	ВК-100	ВК-100
Year of fabrication (last reconstruction)		01.4.1994	01.1.1995	01.6.1994	
Year of commissioning		31.12.1982	31.12.1982	01.2.1989	11.4.2000
Additional data					
Nominal power	[MWt]	58,15	58,15	116,3	116,3
Minimum load	[MWt]	20,35	14,54	40,7	38,3
Average operation pressure	[MPa]	1,4	1,6	1,4	1,4
Inlet/Outlet temperature	[ºC]	70/150	70/150	70/150	70/150
Nominal Efficiency	[%]	86	86	90	90
Fuel type		NG/heavy fuel oil	NG /heavy fuel oil	NG heavy fuel oil	Natural gas (NG)
Working hours till 01.09.2005	[h]	44891	27338	32805	15054
Connection scheme		Collector type	Collector type	Collector type	Collector type

For operation temperature regime keeping up at the inlet of the water heating boilers in usage are 4 (four) pumps, type RDC – 350/300/500- Q = 800 m^3/h, H = 45 m, P = 200 kW, U = 6.3 kW.

Industrial steam boilers

Description	Dimension	КG № 1	КG № 2	PKMG № 3
Type		**КG**-12	**КG**-12	**PKMG** -12
Year of commissioning		31.12.1982	01.1.1982	31.12.1995
Date of last reconstruction		01.12.1995	02.12.1995	-
Steam productivity	[t/h]]	12	12	12
Saturated steam pressure	[MPa]	1,3	1,3	1,4
Saturated steam temperature	[ºC]	194	194	194
Feeding water temperature	[ºC]	104	104	104
Fuel type		Natural gas	Natural gas	Natural gas /heavy fuel oil/
Fuel consumption: - heavy fuel oil	[t/h]	-	-	0,799
- natural gas	[Ths.Nm^3/h]	0,959	0,959	0,959
Efficiency - heavy fuel oil	[%]			88,7
- natural gas	[%]	89,5	89,5	88,9
Operating hours till 01.09.2005	[h]	27324	31911	16171
Efficiency for 2004 - natural gas	[%]	80	80	86,85

Water heaters *Table 8*

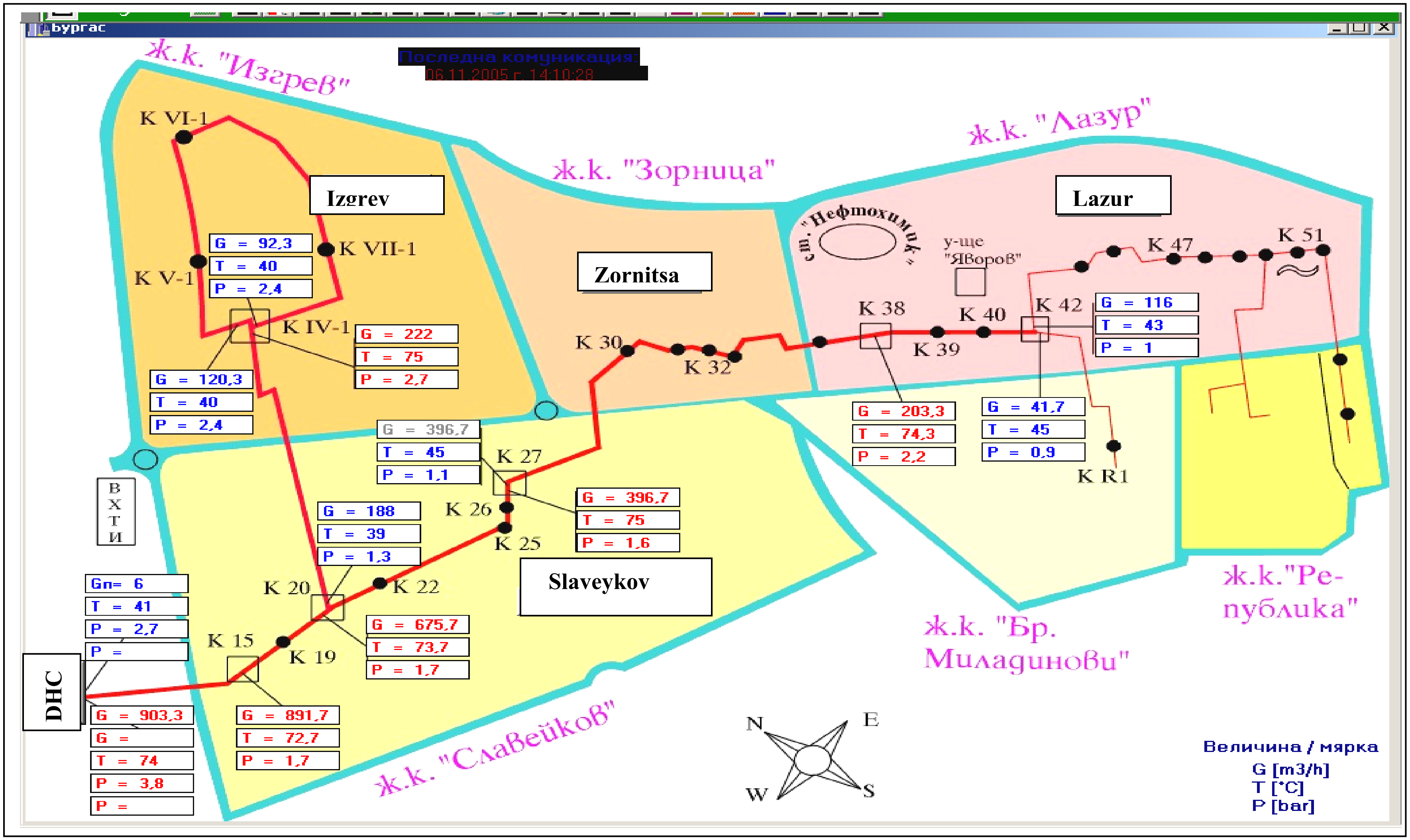
Description	Dimension	Main water heaters	Backup boiler
1. Number		2	0
2. Thermal agent		Saturated steam	
3. Steam pressure	[MPa]	1,3	
4. Heated water parameters			
- inlet temperature	[°C]	40	
- outlet temperature	[°C]	70	
- flow	[m^3/h]	667	
5.Power	[MWt]	23,26	

2.1.2 Thermal network

DHC Bourgas owns the following heat energy transport pipelines:

- First main pipeline DN 700 mm;
- I stage of second main pipeline DN 900 mm.

The main view of the heat network pipelines is shown as follows:


Бургас
Последна комуникация:
06.11.2005 г. 14:10:28
ж.к. "Изгрев"
ж.к. "Зорница"
ж.к. "Лазур"
Izgrev
Zornitsa
Lazur
Slaveykov
K VI-1
K VII-1
K V-1
K IV-1
G = 92,3
T = 40
P = 2,4
G = 222
T = 75
P = 2,7
G = 120,3
T = 40
P = 2,4
G = 396,7
T = 45
P = 1,1
K 27
K 26
K 25
G = 396,7
T = 75
P = 1,6
G = 188
T = 39
P = 1,3
K 30
K 32
K 38
K 39
K 40
K 42
K 47
K 51
K R1
ст. "Нефтохимик"
у-ще "Яворов"
G = 116
T = 43
P = 1
G = 203,3
T = 74,3
P = 2,2
G = 41,7
T = 45
P = 0,9
ВХТИ
Gп= 6
T = 41
P = 2,7
P =
DHC
K 20
K 22
K 15
K 19
G = 675,7
T = 73,7
P = 1,7
G = 903,3
G =
T = 74
P = 3,8
P =
G = 891,7
T = 72,7
P = 1,7
ж.к. "Славейков"
ж.к. "Бр. Миладинови"
ж.к."Ре-публика"
N
E
W
S
Величина / мярка
G [m3/h]
T [°C]
P [bar]

For the hot water transport, through the heat transport network are used five network pumps of two types.

The technical data of these pumps are shown as follows: *Table 9*

No.	Description	Dimension	CN 1000-180	KRHA 300/660/40 A - 019
1.	Number		3	2
2.	Flow	[m3/h]	1000	900
3.	Total head	[MPa]	1,8	1,5
4.	Electrical motor power	[kW]	630	710
5.	Electrical motor voltage	[kV]	6.3	6.3
6.	**Operation modes**			
	Summer mode		1	
	Network water temperature /by temperature graph/ - inlet/outlet	[°C]	40/70	
	Feeding water pressure - inlet/outlet	[MPa]	0,32/0,5	
	Feeding water flow	[M^3/h]	798	
	Winter mode		1	1
	Network water temperature /by temperature graph/ - inlet/outlet	[°C]	70/150	70/150
	Feeding water pressure - inlet/outlet	[MPa]	0,32/0,65	
	Feeding water flow	[m^3/h]	2069	

The network pumps are controlled by Frequency Inverters. The total length of the heat transport network is 120,374 m, from which 12,288 m are previously isolated and are installed without channels. The heat transport network is in good condition, taking into consideration the following indicators, as a fact:

- Looses of hot water flow - 5 - 8 m3/h at normative value of 26,3 m3/h;
- The transport thermal looses are 57000 - 58000 MWh annually, which is around 20% from the total quantity of the produced from DHC thermal energy.

The thermal energy transfer equipment includes 881 residential substations, from which:

- with plates heat exchangers - 320 units
- with pipes heat exchangers - 561 units.

All of the residential sub-stations are equipped with heat measuring devices and regulators for heating and for the residential-hot-water supply. Several actions for increasing of the efficiency of the process of heat transfer (to be over 95 %) from the substations, through laying-down of new heat insulation of the pipes or recovering of the damaged insulation.

The installed equipment in 2002, financed by the program 3739BUL and the equipment installed with help of an investment program of the DHC will let decreasing of the heat losses and the expenses for the hot water transportation. The heated suburbs of city of Bourgas are “Slaveikov”, “Izgrev”, “Zornica”, “Bratia Miladinovi”, “Republica” and “Lazur”.

The heat networks of the different regions in Bourgas are presented in **Annex No.5**

The pipelines from the heat transport network are possessed – by air installing 11800 m, by channels installing 101800 m and by installing without channels 4800 m. The heat transportation capabilities of the different transport heat main pipelines are shown in the table below:

Table 10

No.	Name of the heat transportation main pipeline	Symbol	Length [m]	Flow	Pressure
				[t/h]	[MPa]
1.	First City heat main pipeline	DN 700	17502	0 – 3200	Pмах. - 1.6 P rat. – 0,5
2.	Second City heat main pipeline	DN 900	2197	0 – 6000	P max - 1,6 P rat. – 6,5

The hydraulic adjustment and the heat supply control are performed centralized in the DHC plant.
The thermal power capacity provided by the heat transport network is shown in the table below:

Table 11

No.	Negotiated thermal power capacity	Dimension	2003	2004
1.	For heating	[MW]	191.76	192.26
2.	For household hot water	[MW]	67.74	67.74
3.	**Total**	**[MW]**	**259.5**	**260**

2.1.3 Thermal energy production

The annual thermal loads, given per 3 months period, separated from 01.10.2004 till 30.09.2005 with a single winter season in the mentioned time period (2004-2005yr) and a single summer season (2005yr) are presented in **Annex No. 4**.

The data for the produced thermal energy, for the consumed thermal energy for auxiliary needs and the energy which was sold to the consumers during 2003 and 2004 are presented in the table below:

Table 12

No.	Parameters	Dimension	2003	2004
1.	Produced thermal energy	[MWht]	335 594	289 933
2.	Auxiliary needs	[MWht]	5 077	4 675
		[%]	1,51	1,61
3.	Thermal energy for sale	[MWht]	330 517	285 258
4.	Thermal looses - total	[MWht]	70 035	61 400
5.	Sold thermal energy	[MWht]	260 482	223 858

The data showing the type of the thermal looses through the heat transport network are presented in the table below:

Table 13

No.	Parameters	Dimension	2003 y.	2004 y.
1.	Thermal looses - total	[MWht]	70 035	61 400
		[%]	21,19	21,52
2.	From radiation	[MWht]	66 280	57 633
		[%]	20,05	20,20
3.	From leakages	[MWht]	3 755	3 767
		[%]	1,14	1,32

The sold thermal energy assessment during 2003 and 2004 is presented in the table below:

Table 14

No.	Parameters	Dimension	2003 y.	2004 y.
1.	Sold thermal energy	[MWht]	260 482	223 858
	- Industrial steam	[MWht]	309	235
	- Household Hot Water (HHW)	[MWht]	103 390	101 815
	- Heating	[MWht]	156 783	121 808
2.	Annual day-degrees	-	1 935	1530
3.	Heating power [Qth]	[MW]	182,9	183,4
4.	$k = \dfrac{24 * q * V}{Q_{от}^{изч}}$	[1/K]	0,443	0,4341
5.	Total heated volume	[m^3]	5 832 506	5 870 379
6.	Specific heat consumption of $1m^3$ heated volume for 1◦ K temperature gradient [q]	[W/(m^3.K)]	0,577	0,5651

The sold thermal energy distribution by the type of the consumers, shown in percentages is presented as follows:

Table 15

No.	Parameters	Dimension	2003	2004
1.	Sold thermal energy	[%]	100	100
2.	a/ household consumers	[%]	81	80,5
3.	б/ public consumers	[%]	19	19,5
	- budget supported	[%]	13	13,5
	- commercial needs	[%]	6	6
4.	в/ commercial needs (steam)	[%]	0	0

The sold thermal energy distribution by the type of the consumer, shown in values is presented as follows:

Table 16

No.	Parameters	Dimension	2003 г.	2004 г.
1.	Sold thermal energy	[MWht]	260 482	223 858
2.	a/ household consumers	[MWht]	211 792	180 049
3.	б/ public consumers	[MWht]	48 381	43 574
	- budget supported	[MWht]	33 978	30 339
	- commercial needs	[MWht]	14 403	13 235
4.	в/ commercial needs (steam)	[MWht]	309	235

The forecast data for the production and consumption development of thermal energy, including the produced by the co-generation units thermal energy, which is the scope of this project, are presented in point 1.5.3 above.

2.2 Electrical energy

The Single-line scheme of the electricity supply system of DHC Bourgas is presented in **Annex No. 6.** The electricity supply is taking place through two existing electrical lines form the National Electrical Company (NEK) with a voltage of 110 V. Two electrical three-winding transformers with voltage of 110/21/6.3 kV and power of 25 MVA each. The switch gear - 6.3 kV is positioned at the sub-station of DH Bourgas. The bus-bar system is sectioned. The plant is supplied with electricity by:

- At the direct side - 6.3 kV for the motors of the recirculation and network pumps.
- At the side - 0.4 kV with the help of transformers 6.3/0.4 kV- 3 units each 1000 kVA and 2 units each 630 kVA. Presently in the operational process is included one transformer of 1000 kVA, and the others are in stand-by regime.

The co-generation installation foreseen in the project include generators having an output voltage - 2 units each 2.814 MWe of 6.3 kV and 4 units / 3 x 3.128 MWe + 1 x 2.814 MWe/ voltage 11 kV. The export of the produced electricity for sale to NEK will take place with the help of three windings transformer 110/11/6.3 kV, 25 kVA directly to side 110 kV. The DHC auxiliary needs are covered from the two modules with power 2.814 KWe on side 6.3 kV.

2.3 Fuel supply

2.3.1 Natural gas

The main fuel type used in DHC Bourgas is natural gas. The gas pipeline from Gas Distribution Station (GDS) to Gas Distributional Point (GDP) – DHC Bourgas is separated of two sections Φ 426 x 9 mm with length of 2 km and Φ 377 x 10 mm with length of 5 km. The working pressure is 1,2 MPa, and the maximal consumption of the consumption-measuring line is 50 000 Nm3/h. It is completely underground-constructed with having four cross points at river Aitos, at the rail-way Sofia-Bourgas, motor way close to village of Refinery " Lukoil" to Dolno Ezerovo and a motor way – Refinery " Lukoil" "Bourgas". There is a cathode protection system with a single cathode station. The Anode zero-grounding is been projected to be operational for 20 years at average annual current 2,3 A. At the entrance of the GDP is been constructed a crane-equipment system with stopping armatures having electrical local and remote control. The GDP is foreseen to reduce the incoming pressure (from the out-coming gas distribution pipeline) in the range of 0,95–1,2 MPa of 0,17 MPa. The flow capacity is up to 44 000 Nm^3/h. The gas-transportation equipment is defined into two groups:

<u>I</u>st <u>group – Regulation group</u>

There are foreseen three regulation lines, each with flow capacity from 22,000 Nm^3/h, two operational and one in stand-by regime. The pressure regulators are having a securing system for low and high pressure after the regulator and with implemented quick-acting stopping flap.

<u>II</u>nd <u>group – Measuring group</u>

The Measuring group consists of three lines:

1. DN 700 mm with ranges for measuring – Q = 5000 - 16000 Nm^3/h
   Q = 14000 - 44000 Nm^3/h
2. DN 250 mm with ranges for measuring – Q = 4000 - 22000 Nm^3/h
3. DN 150 mm with ranges for measuring – Q = 700 - 5000 Nm^3/h

The measurement of the consumed quantities of natural gas is taking place with measuring diaphragms. The points used for measuring of the consumption of natural gas include the following equipment:

1. Programmable computer for calculation of the consumption of natural gas type "DART II", produced by the company "Honeywell" USA,
2. Converter of pressure type 7MF1000-DE31-IBDI, produced by "SIEMENS" – Germany,
3. Converter of the pressure difference, produced by the company "Honeywell" USA
4. Resistance thermometer – explosive-protected.
5. Diaphragm chamber type having implemented condensate-settled.

Located inside there is a natural gas low pressure 0,17 MPa pipeline, for supply of the steam and water heating boilers. The energy installations are equipped with all of the necessary devices. The measurement of the quantity consumed natural gas for one day is taking place through the installed in the GDS device for measurement of the natural gas consumption (owned of "BULGARGAS"), checked and marked from licensed authorities, as for a controlling hour is selected 8:00 o'clock in the day. The data for the daily consumed quantity of natural gas are receive every day through a secured permanent telephone connection with the GDS, where the information is recorded in paper form.

2.3.2 Liquid fuels

For back-up fuel is been used heavy fuel oil, produced by "Lukoil-Neftochim" – Bourgas. The reservoir park consists of 2 units heavy fuel oil reservoirs with volume of 5000 m^3 and one unit naphtha reservoir with volume of 2000 m^3. The keeping of the reserve boiler fuel is been secured from heavy-fuel-oil / naphtha utility, situated very close to the reservoirs.

Fuel utility *Table 17*

Description	Dimension	Value
1. Type and capacity of the fuel utility		
- Naphtha - 1 reservoir	[m^3]	1 x 2000
- Heavy-fuel-oil - 2 reservoirs	[m^3]	2 x 5000
2. Gas regulated point**:**		1
Ist group – Regulation group:		
a) Regulating lines	[Pcs.]	3
- Passing through capacity of one line	[m^3/h]	22000
- Regulator for pressure with protection for low and high pressure after the DN 100 mm	[mm]	100
- Rated pressure	[MPa]	1,2
- Inlet pressure	[MPa]	0,95 - 1,2
- Outlet pressure	[MPa]	0,17
IInd group – Measuring group:		
- DN 150 mm with range	[Nm^3/h]	700 - 5000
- DN 250 mm with range	[Nm^3/h]	4000 - 22000
- DN 700 mm with range	[Nm^3/h]	5000-16000 14000-44000

2.4 Process water supply

The DHC Bourgas is using water from two sources:

- From the city potable water supply network with maximum capacity of 150 m^3/h;
- Two deep boreholes with maximum capacity of 63 m^3/h.

The raw water is been treated chemically in a separate unit. The purpose of this unit is production of softened water for compensating of the losses of the network water from leakages, as well as for own needs steam production. The equipment has been fully replaced during 1996 y and in the same year is mounted and implemented an automated softening installation SFBH 2004 by “EURO WATER”, with a capacity of 63 m^3/h. A reservoir for drainage water with volume of 400 m^3, a pumping station and an automatic mechanical filter for pre-cleaning of the water from the boreholes are available at the site. The boreholes water is used only for process needs and for the purposes of soft water producing.

Chemical purification of the water *Table 18*

Description	Dimension	
Softening installation SFBH 2004 by “EURO WATER”	number	1
1. Productivity	m^3/h	63
2. Parameters of the softened water based on the basic passport date – hardness	MgE/l	0,04

Waste water cleaning

Type of the equipment	Dimension	
I. Local		
- Septic pit	number	2
- Neutralization pit, V = 232 m3	number	2
- Separating shaft	number	2
- Mud-oil collector	number	1
II.. “Waste water” Pumping station – transfers waste water to WWTP - Bourgas	number	1

2.5 Measurements

The consumed electricity measurements are performed by electro meters for commercial measurement at side of 6.3 kV. On the plant site of DHC-Bourgas JSC, the installed flow meters are shown below as follows:

Steam measurements *Table 19*

Steam measurement	Type	Accuracy rate	Measurement range	Measurement error
I. Heat pipeline				
a) Saturated steam flow meter	“Autarkon”, “DANFOSS” company	1%	0 – 2,88 t/h	1%
a) Consumption measurement device	Whirlwind flow meter № 23 891/1 DN 50 PN 40	1%	0 – 80 m3/h	1%
b) Temperature measurement	Thermo-converter Pt 1000	1%	0 – 200 oC	1%
c) Pressure measurement	-	-	-	-

Condensate measurement

The fabrication installation of “Pharmacy chemicals”-JSC, which is the single consumer of superheated steam, is not sending back a condensate, so respectively, it is not necessary these value to be measured.

Hot water measurement *Table 20*

Hot water measurement	Type	Accuracy range	Measurement range	Measurement error
City hot water system of Bourgas Ist main pipeline	DN 700			
a) Hot water flow meter	EMAJ “DANFOSS”	0.5 % to Δt = 1 ^{0}C	Flow: to 10 000 m^3 Temperature: 0 – 200 ^{o}C	
- Temperature measurement device	Pt 100, Converter: TRN – 2 WR3	1,0 %	Min and Max.: 0 – 150^{o}C	1,5 %
- Consumption measurement device	SONOFLO 3100/1000 Ultrasound – DN 700	1 %	Min and Max: 0 – 3300 m^3/h	0,05 – 1,65 %
a) Pressure measurement devices	CH 40011 FO.6	0,6 %	Min and Max.: 0 – 16 bar	0,1 %
City hot water system of Bourgas IInd main pipeline	DN 700			
a) Hot water flow meter	EMAJ - DANFOSS	0,5 % to Δt =1 ^{o}C	Flow: to 10000 m^3 Temperature: 0 – 200 ^{o}C	
- Temperature measurement device	PT 100, Converter: TRN – 2 WR3	1,0 %	Min and Max.: 0 – 150^{o}C	1,5 %
- Consumption measurement device	SONOFLO 3100/1000 Ultrasound – DN 700	1.0 %	Min and Max.: 0 – 4320 m^3/h	0,003 – 1,46
b) Pressure measurement devices	CH 40011 FO.6	0,6 %	Min and Max.: 0 – 16 bar	0.1 %

Additional water measurement

Additional water source	Type	Accuracy range	Measurement range	Measurement error
Water from Dearator				
a) Hot water flow meter	“SONOCAL” DANFOSS	0.5%	Min - 0,4 m3/h Nom - 40 m3/h Max - 80 m3/h	0,5 %
- Temperature measurement device	Pt 500 – 2 numbers	0,5%	-40 ^{o}C – 250 ^{o}C	0,5%
- Consumption measurement device	SONO 2500	0.5%	Nom 40 m3/h	0.5%

The hot water transport system is controlled by 57 measurement points. These points measure and transfer the collected data of the flow, the pressure and the temperature of the hot water to the central information and control system.

2.6 Control system

Two information and control systems are connected and used in DHC Bourgas. The hydraulic adjustment and the parameters of the outlet hot water settings are controlled from the central plant control system. The regulation is executed on the basis of quality – quantity regulation in accordance with the external meteorological conditions. The local regulation in the residential sub-stations is taking place from the regulation devices for heating and hot water.

- **DHC computer control information system, "MIUS".**
  The system includes the Water heating boilers No.1, No.2, No.3, No.4 and other main measurements. The main functions which this system executes are as follows:
  - Parameters visualization and local control of each water heating boiler;
  - Local power regulators, enabling the automatic temperature control of the feeding network water, as well as, night reduce of the temperature in definite time period;
  - Main station parameters visualization, control of regulating armatures, start of network and recirculation pumps. Power regulator for the water heating boilers load distribution on the base of preliminary settled outgoing hot water temperature;
  - Parameters archiving and graphics visualization;
  - Automatic print out of the shift lists.

- **Computer information system for meteorological data and hot water network parameters, "MIS"**
  This system includes four meteorological stations and the hot water network. The main functions of this system are as follows:
  - Measurement, calculation and archiving the received data from the four meteorological stations. Sending the collected information in special concentrators through a radio-telemetry channel;
  - Calculation of the incoming for transport hot water temperature in accordance with the schedule $t_{schedule}$ and the flow of the network water in accordance with the schedule $G_{schedule}$ based on consolidated methodology for correction of the regime for heat supply;
  - Collecting, archiving and visualization of data, about the pressure, temperature and flow parameters in 57 measurement control points from the hot water network.
  - The thermal loads calculation of different suburbs.
  - Sending the collected information in special concentrators through a radio-telemetry channel.

3 Greenhouse gas sources and project boundaries

3.1 Flowcharts

Flowchart of current delivery system with it's the main components and their connections.

DHC Bourgas produce only heat, which supply by net delivery system in the city of Bourgas

The heat deliverable system uses the following boilers situated in the plant in current situation:

- Hot water produced boilers:

2 x WK100 (capacity 2 x 116,3 MW);

2 x WK 50 (capacity 2 x 58,15 MW).

- Steam produced boilers (saturated steam):

2 x KG 12 (capacity 2 x 7,56 MW) – using natural gas as a fuel;

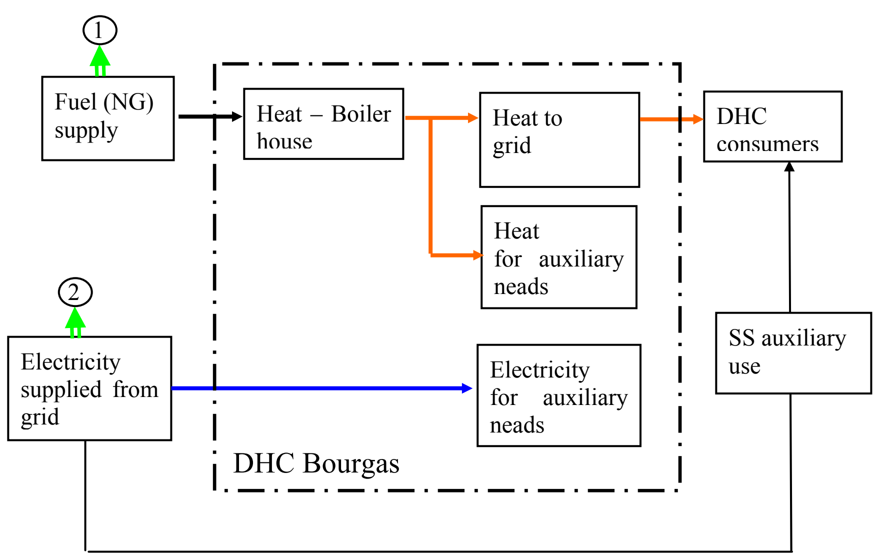
1 x PKGM (capacity 1 x 8,13 MW)

From the total production of heat from the boilers part is used as heat for auxiliary needs for DHC Plant and the rest is coming to the heat grid.

In current situation, the deliverable electricity system use electricity from grid for auxiliary needs as follow:

- Electricity for auxiliary needs for the DHC Plant;
- Electricity for auxiliary needs for the Substations in the city.

The flow chart of current situation is presented on fig. 3.1



1 – CO_2 emissions (combustion in boilers)
2 – CO_2 missions (electricity from grid)

Fig. 3.1 Flowchart of current situation

Flowchart of the project with its main components and their connections.

After project implementation, the base heat and all electricity loads for auxiliary needs in the DHC Plant will be covered by CHP, except the auxiliary needs for electricity in the substations, situated in the city. The rest of electricity, produced by CHP, minus electricity for auxiliary needs of the DHC Plant and CHP itself will be supplied to electricity grid. The existed boilers will cover heat pick demand – back up boilers. Heat demand and auxiliary heat needs in the DHC plant are not influenced by the project implementation. The flow chart of co-generation system is presented on fig. 3.2.

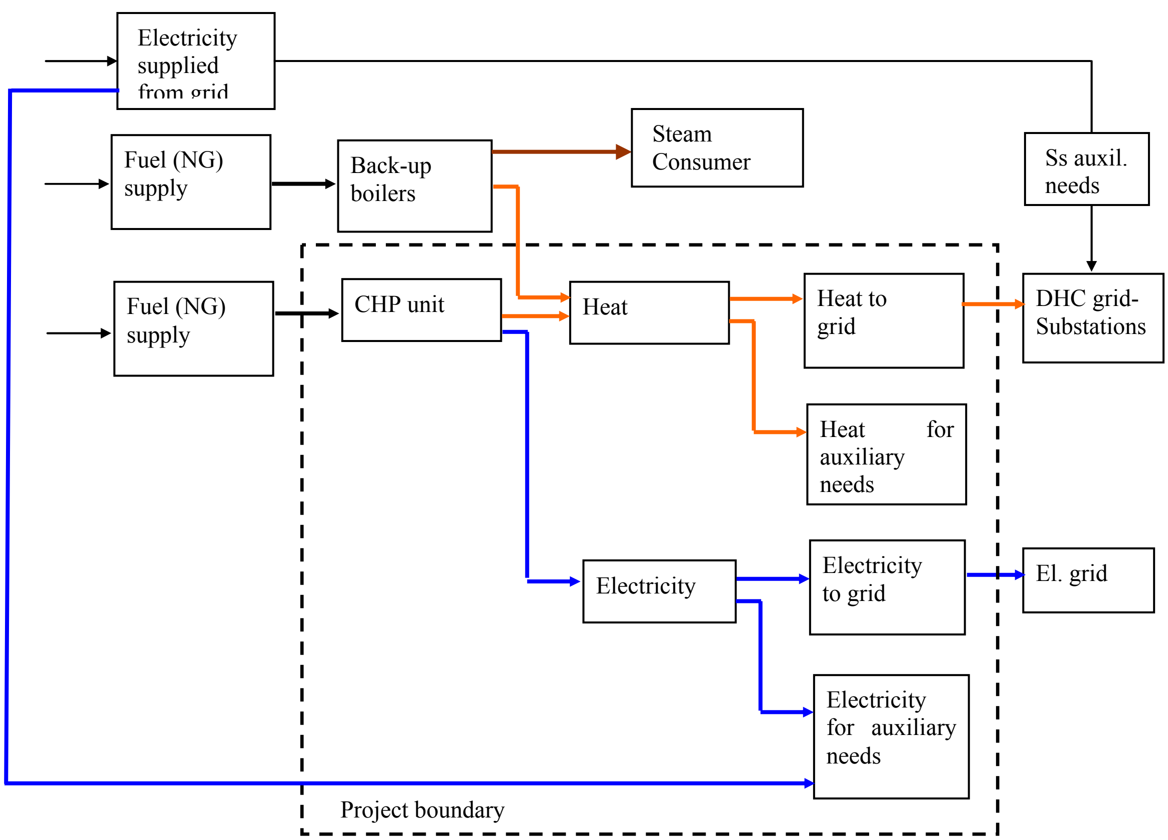


Fig. 3.2 Flowchart of co-generation system

3.2 Direct and Indirect Emissions

According to the project boundary (described below), the Project and Baseline emissions, both On-site and Off-site are as shown in Table 3.1 below:

Remark: Emissions related to activities to produce, transport or deliver the fuel are not taken into account, because they are small compare to the project emissions reduction and it is impossible to monitor them.

The Project and Baseline emissions, both On-site and Off-site are as shown in the table 3.1:

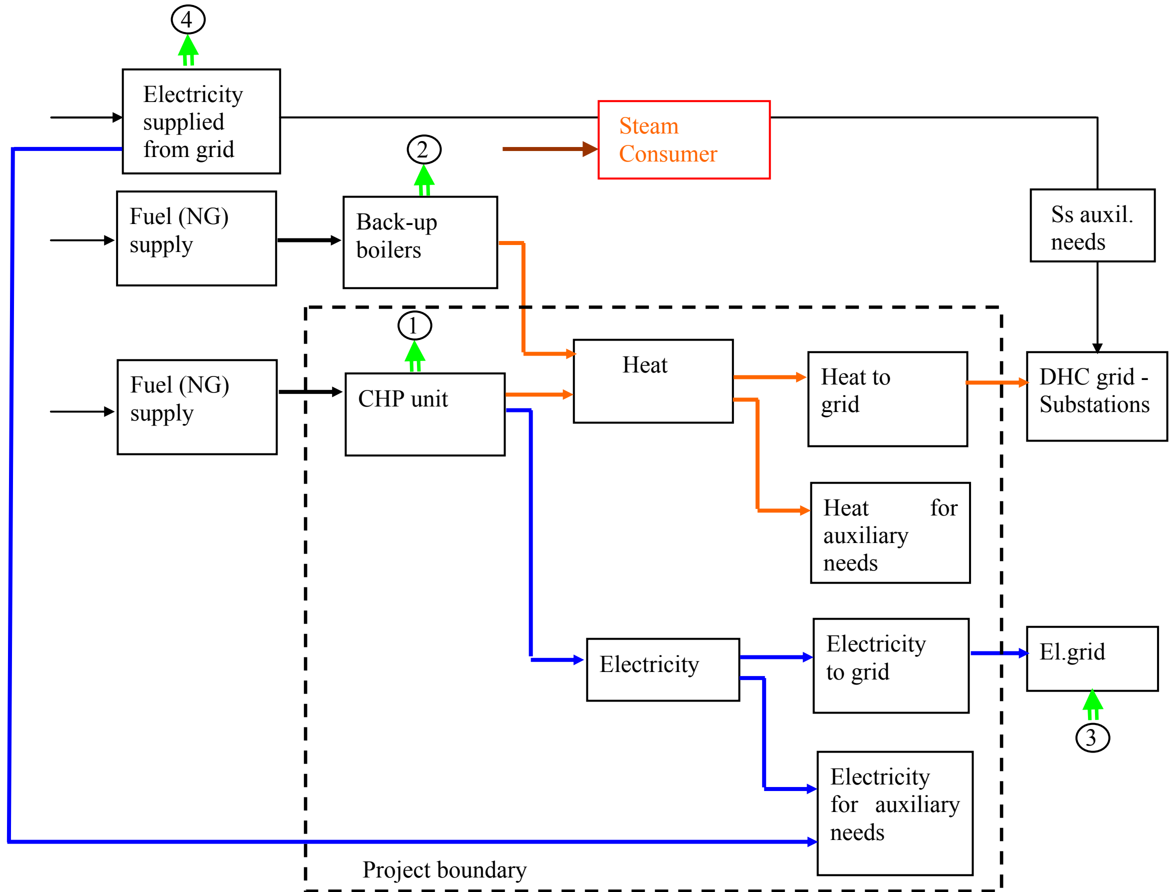
Table 21.

On-site emissions			
Project	**Current situation**	**Direct or indirect**	**Include or exclude**
CO_2 emissions from NG combustion in CHP		Direct	Include
	CO_2 emissions from NG combustion in boilers	Direct	Include
Off-site emissions			
Project	**Current situation**	**Direct or indirect**	**Include or exclude**
CO_2 emissions from NG combustion in back - up boilers		Direct	Include
	CO_2 emissions from electricity grid	Direct	Include
CO_2 avoided emissions to Electricity grid		Indirect	Include

3.3 Project boundaries

The project is the installation of CHP whose input is natural gas from gas pipeline, and whose outputs are electricity and heat supplied to the electricity and heat grids. Heat produced by CHP will cover the base load of heat demand. Electricity produced by CHP will cover the auxiliary needs in the DHC Plant and in the CHP itself and the rest will go to the grid. Electricity produced by CHP minus auxiliary needs for CHP will substitute in the grid the same quantity of generated electricity somewhere in Bulgaria. The auxiliary needs for electricity in the substations in the city will be covered by the grid in the same way as before realization of the CHP Project. Although the project will be installed at the DHC Plant site, the project boundary is strictly the CHP.

Project boundaries for natural gas fired in CHP are given below:



1 – Direct on-site CO_2 emissions (combustion in CHP)
2 – Direct off-site CO_2 emissions (combustion in back up boilers)
3 – Indirect off-site CO_2 avoided emissions (electricity to grid)
4 – CO_2 missions (electricity from grid)

Fig. 3.3 Flowchart of the Project boundary (the dashed line indicates the system boundary)

The cogeneration system is sized to provide base load heat to the grid and the back up boilers will cover the relevant peak load. The back up boilers are outside of the Project boundary as they already existed, but the CHP and the heat, supplied to the grid in the DHC Plant (presented as HEAT, HEAT TO GRID, HEAT FOR AUXILIARY NEEDS in Fig. 3.2 and Fig. 3.3) are inside the Project boundary for the following reasons:

- The CHP will be installed thanks to the Project;
- The Heat, supplied to the grid in the DHC Plant has to be adjusted for the implementation of the CHP.

The Steam production is not influenced by realization of the CHP project as well as the hot water grid is different from the steam grid. That is why the steam is produced by the back up boilers and the realization of steam supply to the grid is not within the project boundary. The Heat meters at the outlet of the DHC Plant for hot water and steam, coming to the relevant grid are different. Both are commercial devices

According to baseline scenario the demand of electricity for auxiliary needs in the DHC Plant and CHP itself during the monitoring period will be covered with part of the produced electricity from the CHP, and the rest will substitute electricity produced elsewhere in the grid. During realization of the Project, the CHP will produce electricity covering entirely auxiliary needs in DHC Plant and the rest of the electricity production will be sold to the grid. If the CHP, for some reasons, will not be in operation, the existing electricity supply

system from the grid will cover those auxiliary needs. For this reason a new electro-meter has to be installed with possibilities to measure electricity in two directions – from the DHC to the grid and vice versa.
Thus, the system does not meet all of the heat demand of the DHC grid, but meet the whole electricity for auxiliary needs of the DHC Plant and CHP itself with part of the produced electricity by CHP. The auxiliary needs for electricity in the substations in the city will be covered by the grid in the same way as before the realization of the CHP project. So these auxiliary needs are excluded from baseline and Project scenario. The auxiliary needs for CHP installation in the DHC Plant are not included in the base line scenario, as they do not exist before the realization of the CHP Project.
Prior to project installation DHC Bourgas acquires all of electricity for auxiliary needs from the power grid and meets all of its heat requirements with natural gas acquired from the ng pipeline.
Once the project (CHP) is installed, DHC acquires the remaining heat demand by existing boilers (further named back up boilers) in the DHC Plant with natural gas from ng pipeline and entirely electricity for auxiliary needs in the Plant. The remaining produced electricity from CHP (electricity produced by CHP minus electricity for auxiliary CHP needs) will substitute in the grid produced electricity elsewhere. Auxiliary electricity needs in the substations in the city will be covered by the grid in the same way as before realization of the Project. That means that emissions, caused by electricity for auxiliary substations needs in the city are not taken into account both in the base line and project scenario.
Thus the baseline is determined by fuel purchases from ng pipeline, that are avoided or offset as a result of heat supplied from CHP to the DHC located at the project side, but outside the project boundary plus remaining heat demand and the whole produced by CHP electricity (minus electricity for CHP auxiliary needs), which if the project will not executed will be produced somewhere and distributed in the same grid

4. Key Factors

4.1 Internal key factors

4.1.1 Variability of the thermal load

The variability of the thermal loads leads to variability in the efficiency. The production of the cogeneration equipment will therefore depend on the season. In the winter season the cogenerations will perform at maximum output whereas in the summer season the production is depending on the actual heat requirements. Normally the decreasing of the load leads to decreasing of the efficiencies of the boilers and cogeneration sets. The existing heating facility at DH Bourgas has limited flexibility to adapt their production to the demands while keeping efficiency at acceptable levels, but this will be increased by the installation of the project.

4.1.2 Activity level

The long-term outlook for Bulgaria is related to the accession to the European Union and can be considered very positive. The Bulgarian economy is in period of growing with appreciable and stable rate of positive development. The district heating facility will focus on cost reductions in order to maintain competitiveness with alternatives heat sources for customers. As described below, growth levels for the district heating company will be moderate to small.

4.1.3 Availability of working capital

In general the facilities has a continuous shortage of working capital. The facility has been making operational losses during the past years. Due to the history of the factory and in general of the Bulgarian economy, the balance sheet of the company is not in good shape. There is little working capital, and in most cases short/long term debt instead.

However, in this period of significant growth of the Bulgarian economy companies have difficulties matching the production increase with the increasing demand. The lack of working capital restricts them in to invest in production expansion, efficiency projects and other structural reforms to increase capacity and competitiveness. This leads to a vicious circle where the lack of performance will result in loss of customers, resulting in even less availability of working capital.

4.1.4 Technical expertise

The facility has no expertise with the construction and operation of cogeneration facilities. The Western type gas engine technology is new to the country and only one similar cogeneration project at Biovet in Peshtera is currently under construction. The management and the technical personnel at DH Bourgas will need extensive training on operation and maintenance of the equipment. Although this is a risk to the envisaged operational performance, the technology supplier will be able to educate DH Bourgas in the basics of operating and maintaining the equipment.

4.2 External key factors

4.2.1 Legislative development

The legal and institutional framework for the energy sector in Bulgaria is set out in the Energy Act (amended as of March 5, 2004), Energy Efficiency Act (effective as of March 5, 2004) and the regulations for their application. These acts have been developed on the basis of the EU requirements as Bulgaria is expected to enter into the EU as of 2007. These two fundamental Acts regulate public relations in the energy sector with regard to state governance, regulation and efficient use of energy and energy sources, as well as the rights and obligations of legal entities in conducting activities in production, import, export, transfer, distribution and sale of electricity, heating energy and natural gas, enhancing energy efficiency and encouraging the use of renewable energy sources. According to the EU commission, Bulgaria has several challenges to realize in order to confirm the path towards accession in 2007. According to the latest report[1] on developments within the energy sector in Bulgaria, the country is making good progress in its legislative alignment and in its preparation to the internal energy market. The restructuring and privatisation of the energy sector is progressing well but particular efforts are still needed to improve energy efficiency and the use of renewable energy. Bulgaria must continue to respect its commitments on nuclear safety, notably as regards closure commitments for certain units of the Kozloduy nuclear power plant, and to ensure a high level of nuclear safety in its installations."

Chapter XI part I and Part II of the above mentioned Energy Act concerns primarily the encouragement of energy production based on renewable energy sources (RES) and combined energy production (CHP). According to Art. 162 of this act, upon the commissioning of the installations, the surplus produced electric power will by compulsory purchased at preferential prices. The producers of thus produced energy will be issued green certificates for the produced and sold by them energy from 01.01.2006 (Regulation for certification of the origin of electric power generated by renewable and/or combined generation sources, issuance of green certificates and their trading-2004). These prices are set by the State Energy and Water Regulatory Commission (www.dker.bg). And are determined on a yearly basis depending on international standard fuel prices and on determined prices for the energy sector for sales of electricity and heat. The price determination of heat supply and electric power and natural gas are also determined by the DKER. The prices are determined on a case by case basis depending on revenue requirements of the companies and / or on certain incentive parameters such as efficiency increases realized by the generation companies.

[1] http://europa.eu.int/comm/enlargement/report_2004/

4.2.2 Sectoral reform projects

A key issue in Bulgaria's accession to the EU is the requirement for the early closure of Nuclear Kozloduy units 3 and 4. Based on the negotiations between Bulgaria and the EU, the decommissioning of Kozloduy units 3 and 4 (commissioned in 1980 and 1982, respectively) are expected by the end of 2006[2]. Due to the expiry of the service life of some facilities and the restrictions posed by the Directive 2001/80/EC that sets Permission Emission Standards, the following TPP generating capacities will be decommissioned:

1."Maritsa Iztok 3" TPP – updating of 4 blocks of 210 MW each with sulphur filter installations, investment value 518 million Euro. EURO, completion term 36 months, end of 2012;

2. "Maritsa Iztok 1" TPP – construction of replacement facilities, i.e. 2 blocks of 330 MW each with sulphur filter installations, investment value 1056 million Euro. EURO, end if 2010;

3. "Maritsa Iztok 2" TPP – updating of 4 blocks of 150 MW each with sulphur filter installations and of 2 blocks of 210 MW each, investment value 230 million. EURO, projected for 2014;

The high costs of the quoted investments for the reforms of the energy sector will inevitably lead to a price hike for the conventionally produced electric power. This will make the investments for the construction of the CHP station economically more feasible.

About 1700 MW of new capacities will be constructed during this time, and the Least-Cost Development Plan (see also Chapter 6) 2004¬2020 includes the commissioning of the following projects:

- New TPP burning indigenous lignite – 600 MW, 2009/2010.
- Tsankov Kamak HPP – 80 MW, 2009
- Rousse East TPP Unit 3 – 110 MW, 2006/2007
- CCGT in DHSs Zemliane and Lulin – each of 65 MW, 2009
- CCGT in DHS Sofia – 100 MW, 2008
- Nuclear Belene NPP – 1000MW, 2011/2012.

Some of the existing large energy generation plants, such as TPP Varna, will also start to improve their efficiencies by implementing large scale rehabilitation programmes.

1 http://europa.eu.int/comm/enlargement/report_2004/

2 www.doe.bg; Bulgarian Ministry for Energy and Energy Resources

4.2.3 Economic, demographic and social factors

The forecasts of electricity demand in the country directly and indirectly imply the macro-economic growth forecast for Bulgaria. The most frequently investigated macro-economic indicators influencing electricity demands are:

- o Gross Domestic Product (GDP) and its structure
- o Development of the GDP structure by major branches: industry, agriculture, services
- o Inflation rate
- o Population
- o Electric power price
- o Per capita income by current and comparable prices

The forecast macro-economic parameters for Bulgaria up to the year 2007 (General National Plan for the Economic Development of Bulgaria until 2007), according to the State Agency for Economic Analyses and Prognoses[3] are the following:

- Inflation rate - 3.5 to 5.5 %
- Unemployment rate – 12%, see also: http://www.aeaf.minfin.bg

[2] www.doe.bg; Bulgarian Ministry for Energy and Energy Resources

[3] http://www.aeaf.minfin.bg/en/publications.php?l=2&c=107

The envisaged GDP growth for the period up to 2020 according to the Ministry of Economy[4] is projected as follows:

GDP 2003-2020

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate of GDP Growth	4,3%	5,6%	5,3%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,0%	5,0%	4,5%	4,0%

DH Bourgas is included with reference to the quoted development rates for the country's economy and the projected growth for the DH is similar.

4.2.4 Fuel prices and availability

The efficiency and payback potential of the investments for this project are mainly determined by the prices of natural gas in the long term. The only official forecast on the fluctuation of the gas prices up to the year 2015 has been published in the "REVIEW OF THE ENERGY SECTOR AND THE ENVIRONMENT" in November 2001 by the World Bank team with the cooperation of the Ministry of Energy and Energy Resources. According to this forecast, the gas prices can be expected to fluctuate according to basic and pessimistic scenarios, as shown on the table below. In order to facilitate the analysis, the table has been supplemented by the current prices for the years 2000, 2003, 2004 and the beginning of 2005.

Table 22

Scenario	Actual [USD /1000N m³]					Expected [USD/1000N m³]			
In years	**1999**	**2000**	**2003**	**2004**	**2005**	**2000**	**2005**	**2010 г.**	**2015**
Main	92,60	118,2	128,5	129,8	157	129,95	79,92	74,61	74,61
Pessimistic	92,60	118,2	128,5	129,8	157	147,25	138,98	142,29	150,67

The table shows that the expected price for natural gas in Bulgaria is projected at 150 BGN/10^3Nm3. Using the exchange rate of 2001, this is 144 Euro/10^3Nm3.
Investigations at one of the biggest natural gas distributors Overgas, reveals a price outlook for industrial users for the period 2006-2012 at 179 Euro/10^3Nm3. (Source: PDD, REDUCTION OF GREENHOUSE GASES BY GASIFICATION, in Varna Municipality, JI Project Design Document, ERUPT 5)

The analysis of the gas prices shows that the forecast of their future fluctuations is very difficult and depend on the following external variables:

- USD / EUR (BGN) exchange rate
- International market standard prices for oil and gas.
- Price setting by the DKER and potential policy adjustments.

Recent increase of international prices for oil have also led to a price spike for natural gas sold by Bulgargaz of more than 18% according to various newspapers in Bulgaria[5]. When this increase is applied to the existing outlook from 2001, prices increase to 166 Euro/10^3Nm3.

For calculations in this PDD we take for conservatism a price of 144 Euro/10^3Nm3.

[4] www.mi.government.bg/

[5] http://www.sofiaecho.com/article/bulgaria-experiences-additional-price-increases/id_12440/catid_5

4.2.5 Capital availability

The climate on the Bulgarian credit market is improving every year as a result of the stabilization of the country's economy, but still remains risky. The investment climate is expressed in a credit rating, which is BB- for Bulgaria.
There is no tradition for the financing of energy efficiency projects in the energy sector in Bulgaria. Normal interest rates for credits (including fees and commissions) provided in Bulgaria vary within the range of 12% to 15%[6] primarily depending on the size of the credit and the projected payback time, and the corresponding future cash flow projections of the company that requires the loan. Most of the credit provided is for short term 3 to 5 years, with a gratitude period of 1 year. The loan share does generally cover not more than 65% of the investment and the lending institutions require a credit guarantee for about 150% of the loan. Some municipal loans offer smaller interest rates of about 7%.
Credit lines from EBRD and World bank or grants from the Kozloduy International Fund are in most cases needed to fund loans to big investments with average risk profiles.

4.2.6 Permits

In accordance with the provisions of Paragraph. I, Art. 39 of the Energy Act, the production of electric and thermal power is subject to licensing. In addition to the above, in accordance with the provisions of Regulation for Certification of the Origin of Electrical Power generated from Renewable and /or Combined Generation Sources – 2004, a certificate of origin will also have to be obtained. The certificate of origin, is a base for obtaining the green certificates trading. The market of green certificates will be open from 01.01.2006.
The licensing and the obtaining of the certificate of origin are foreseen to be achieved during the end phase of construction or around commissioning of the CHP project.

[6] http://www.eva.ac.at/(en)/publ/pdf/bul_energietage_eea2_e.pdf

5. Additionallity Test

Note: Demonstration of additionality has been based on EB 16 guidance "Tool for the demonstration and assessment of additionality"

Step 0: Preliminary screening

a) The project has not yet been implemented and therefore the starting date of the JI project activity falls after 1 January 2000. The start of the JI project activity is projected at the end of 2005. In absence of a JI Supervisory Committee the project cannot be forwarded for registration yet;

b) The incentive of JI is being considered since beginning of 2004 when the CEO of Toplofikatsia Bourgas, Mr Rusev, contacted SenterNovem for potential participation in the ERUPT 5 programme[7]. This is finally demonstrated by the PIN which was made in the beginning of September 2005 and which as sent to the Bulgarian Ministry of Environment (MOEW) to apply for a Letter of Endorsement. In this PIN the project owner states its interest to obtain the JI incentive for their envisaged project activity.

5.1 Step 1: Identification of alternatives to the project activity

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

There are two realistic alternatives (or alternative scenarios) for the project activities:
Alternative I: Cogeneration 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 activities or alternatives undertaken. In this alternative the factory would continue to purchase electricity from the regional grid and would continue to generate thermal energy from existing sources. Maintenance costs will be made to maintain the old equipment into operation until and beyond 2012.

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

Alternative I :
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 (NEC) 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. The producers of thus produced energy will be issued green certificates for the produced and sold by them energy from 01.01.2006 (Regulation for certification of the origin of electric power generated by renewable and/or combined generation sources, issuance of green certificates and their trading-2004).
In addition to this 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.

[7] Evidence is sent to the Validator

Alternative II:
The plant has all necessary licenses to operate the existing equipment. There are no laws under development that prevent operating of the existing equipment nor the purchasing of electricity from the grid.

5.2 Step 2: Investment analysis

Sub-step 2a: Determination of analysis method
The project, 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 facility owner 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.
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: Application of 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's 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[8] 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 neighboring 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 neighboring Ukraine with B+. This means that business circumstances a still more comparable to Eastern European standards then 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.
In the commercial sector loans of several millions of Euros are not a tradition in Bulgaria[9].

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).

[8] www.standardandpoors.com

[9] See www.eva.ac.at/publ/pdf/**bul_energietage_eea2_e**.pdf

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 Unicredit 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 maximumized at 3 million Euro) and restricted on payback time (maximum 3 years) while interest rates for project financing vary between 10 to 13%. See also:
http://www.aeaf.minfin.bg/en/interest_rate/interest_rates_04_2005_en.php
Individual discussions big banks in Bulgaria confirm the focus on payback time rather than IRR. The discussions with Bulbank confirm the payback requirements to be as much as 5 to maximum 6 years[10]. 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. The payback requirements are based on their experience with large Bulgarian businesses which have a solid underlying cash flow and substantial assets. For smaller companies payback times can go up to 7 years or higher.
Bulbank is one of the biggest banks in Bulgaria and can count almost all of the large businesses to their customers. The bank had assets worth more than 3.6 billion BGN in 2004[11].
Energy efficiency funds made available through these banks by the EBRD for projects in the energy sector and industry offer somewhat better conditions[12].
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. For reasons of conservatism, we apply a payback benchmark of **6 years** to the project.

Sub-step 2c: Calculation and comparison of financial indicators
When we include all costs for equipment and services, all revenues from the generation of heat and electricity, excluding revenues from carbon credits, but including and all other related costs for installing and operating the project activities, the payback time estimated at 7 years, see Annexes.
Sub-step 2d: Sensitivity analysis
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. Within the sensitivity analysis the evidence will be given of the robustness of the investment analysis. 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.
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 complete calculation tables are added in the annexes to this PDD.

The calculation results are shown in the diagram below:

[10] Evidence sent to validator

[11] http://www.bulbank.bg/bb/about/ar2004en.pdf

[12] See www.eva.ac.at/publ/pdf/**bul_energietage_eea2_e**.pdf

Elec. price	Payback	Payback	Payback	Payback
10	>5	>5	>8	>7
5	>5	>6	7	8
2	>6	7	8	10
0	7	7	8	**10**
Gas price	**0**	**2**	**5**	**10**

Table 23

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 than described in the tables, but from the tables it becomes clear that the impact of the increase of the electricity price on project is not so significant, the impact of the increase of the gas price has more impact. This is mainly due to the large consumption of DH Bourgas for cogeneration.

It is important to acknowledge that in reality an increase in gas price will always involve an increase in electricity price. Therefore the outcomes in the upper left and lower right side of the tables should be ignored. The sensitivity analysis further shows that the projects payback time never falls below the acceptable 6 years payback time as required by commercial lending institutions. 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.

5.3 Step 3: Barrier analysis

Sub-step 3a: Identification of barriers preventing 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.

In the commercial sector loans of several millions of Euros are not a tradition in Bulgaria[13]. 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).

For the energy sector, financing institutions and banks are averse of project financing 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 in 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.

Equity barrier:

- Equity constraints at investing companies

[13] See www.eva.ac.at/publ/pdf/**bul_energietage_eea2_e**.pdf

DH Bourgas has been making considerable losses in the past years. Therefore, there is a big constraint on equity available for investments. The new owner of DH Bourgas has certain priorities in spending equity on investments over all of there investments and therefore equity available for investing in DH Bourgas is limited. Given the bad revenue history of average companies in the energy sector, in general companies are very low on equity available for considerable investments such as this one.

Technological barriers:

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

At DH Bourgas there is no experience with the operation and maintenance of the described technology of gas engines with heat recovery boilers. In Bulgaria, there are only a few comparable projects in the country and 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, who are inexperienced and untrained.

Sub-step 3b: Explanation that barriers would not prevent implementation of the other alternatives

Alternative II would not involve any large investment, other than small maintenance costs, since it is a continuation of the existing situation.

Alternative I does not represent a change from the existing situation, so no barriers are experienced.

5.4 Step 4: Common practice analysis

Sub-step 4a: Analysis of other activities similar to the proposed project activity

Although there are many business ideas identified in recent studies by for example the EBRD[14] or the EVA from Austria[15], almost no Western type cogeneration system has been actually really installed in Bulgaria. There are a few investment projects under way in the industrial and energy sector various stages of development such as a CHP at Biovet pharmaceutical factory[16] which will install the first western type gas turbine and heat recovery boiler in Bulgaria and a CHP investment project under construction at Toplofikatsia Varna. These projects are all JI projects and are therefore excluded from this common practice analysis, since only non-JI projects should be included here.

Small cogeneration for industry and district heating is totally 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: Discussion of similar options that are occurring

Since similar projects are hardly observed in Bulgaria, there is no basis for an analysis of similar activities.

5.5 Step 5: Impact of JI registration

The incentive of JI registration is discussed in the form of an ERPA with the Dutch ERUPT program. This governmental tender program has a deadline of January 16, 2006 and offers the following payment options:

- 50% prepayment of the value of the carbon contract paid after closing the ERPA and commissioning of the project activities.
- Payment of the rest of the contract on verification report and delivery of the emission reductions at the end of each delivery year.

The impact of JI registration on payback time and equity requirements is depicted below. We assume an equity percentage of 40%, which is higher than the 10 to 30% equity requirements for most Western financing markets.

14 http://projects.bv.com/ebrd/profiles/Bulgaria.pdf

15 http://www.eva.ac.at/publ/pdf/bul_study.pdf

16 http://www.senternovem.nl/carboncredits/projects/eru0433.asp

Parameter	Unit	Without JI	With JI	Difference
Payback	Yr	7	5	-2
Equity	Mill Euro	2,8	1,8	-1,1

Table 24

For the project activity the carbon revenue brings the payback time within the required 6 years to be eligible for financing.

Step 5b: Impact on the identified barriers

Investment barrier

The additional JI revenue helps to improve the payback time of the project and therefore it increases the changes for the companies to obtain significant more project capital for the investment.

Equity barrier

Thanks to the 50% prepayment of the contract value in the construction period of the projects, the amount of equity to be provided from the company into the investment is considerably lower.

Technological barrier

Western type technology is much more expensive than Eastern European technology. Therefore the JI revenue enables the company to invest in gas engines, which are fairly new to the country of Bulgaria.

5.6 Step 6: Conclusion

The JI incentive leads to reduction of the payback time within required limits, it involves a reduction of the required equity for project capital, which helps to overcome the investment barrier. In addition, the JI incentive helps to improve the cash flow of the project, which make them less sensitive to price increases for fuel. Also the JI incentive helps the projects to foresee in technological expertise from abroad, which was otherwise not possible because the total costs of the project would increase payback time above acceptable level by financing banks.

The above-mentioned impact of JI leads to the conclusion that the project activity is additional.

6. Identification of the most likely baseline scenario ad the associated GHG

The major risks to the baseline stability are connected with normal operation of the equipment in DHC Bourgs in the whole operation period. These risks are shown in the table below with their possible influences. Part from the risks for the project and their influences to the baseline is determinated in Chapter 4 "Key factors", as well as in the Business plan.

No	Risks	Possible Impact	Conclusion
1.	Decreasing the thermal energy production because of: 1*) reduction of the consumers; 2*) increasing of the energy efficiency of the households.	For 1*): both in winter and summer season this would not influence the amount of the reduced emissions from the project; the only effect would be reducing of the operation of the cogeneration in the summer. For 2*): in the winter season it would lead to reduction of operation of the cogeneration, which would not lead to decreasing of the amount of the reduced emissions. In the summer season this would not have any effect over the operation of the cogeneration system.	The two scenarios will lead to a negative effect on the whole project and the baseline. The decision of this problem is in the extension of the thermal network and including new consumers, additional investments will be necessary in this case.
2.	Decreasing of the annual availability of the equipment due to: - the reliability of the equipment - maintenance quality	Decreasing of emission reductions is in direct dependence from the damage factor of the equipment.	The conclusion is: - choice, contract and delivery of good quality equipment; - maintain required quality of the spare parts and consumables. - trained maintenance personal with good qualification. - Reliable diagnostic and good planning of the maintenance overhauls. It is also foreseen that the CHP will be connected to the existing central controlling system.
3.	Problems with the supply of natural gas fuel.	Decreasing of emission reductions is in direct dependence from the interruptions.	In this case the cogenerations would stop and the emission reductions would decrease. The back-up boilers have the possibility to work with HFO fuel that will decrease the losses of the factory and the supply of heat water to the households.

Description of formulae used to estimate emissions by sources of GHG of the baseline

Since the project boundary is the proposed CHP, there are no emissions within the project boundary in the baseline case. Baseline emissions can be comprised in the following two components:

- **CO_2 combustion** corresponds to ng that would have been used for covering the whole heat demand during the investigated period for every year.
- **CO_2 electricity –** emission associated with the electricity that would have to be purchased from the power grid if the CHP did not provide electricity to the DHC Plant for auxiliary needs plus the rest of produced by CHP electricity, which substitute 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 CHP Project realization

.

Annual baseline GHG emissions – ABE1 from ng combustion in boilers for production of heat, covering annual heat demand of the DHC is calculated as follow:

$ABE1 = Qf * EFng$, Kton CO_2/y

where: Qf is heat introduced with natural gas fuel annually in boilers, TJ/y

$Qf = Qh * Sc * 29{,}33/1000$, TJ/y

EFng = 0,0561, Kton/TJ – emission factor for combustion of natural gas (data from PDD guide)

where: Qh is annual heat demand for DHC Plant, (data from DHC), TJ

Sc is specific consumption of equivalent (conditionally) fuel with low calorific value-LCV = 29,33 GJ/t, kg/GJ (for heat producing boilers in Bourgas Sc = 126 kg/MWh = 35 kg/GJ)

Sc is the ratio of the quantity By [kg] of so called equivalent fuel per produced heat Qh [GJ] from the boilers. It is estimated as follow:

$By*29{,}33 = B_{NG}*Q_{i,NG}^{r} = Qf;$

$By = B_{NG}*Q_{i,NG}^{r}/29{,}33;$

$Sc = By/Qh.$

where: B_{NG} [th.nm^3] – quantity of NG combustion for production of heat in boilers Qh;

$Q_{i,NG}^{r}$ is the low calorific value of NG;

There is a strong relationship between boiler efficiency η and Sc on the base of:

$Qf = Qh/\eta = Sc*29{,}33*Qh/1000$, or:

$1/\eta = Sc*29{,}33/1000$; and finaly:

$\eta = 34{,}1/Sc$ and $Sc = 34{,}1/\eta$;

where Sc is in [kg/GJ]

Annual baseline GHG emissions – ABE2 from electricity coming from grid is calculated as follow:

$ABE2 = Wel,s * EFel$, Kton CO_2/y

where: $Wel,s = Wel – Wa_{,CHP}$, MWh/y

W el - electricity produced by CHP annually, MWh/y (data from DHC)

$W\ a_{,CHP}$ - auxiliary needs for CHP itself, MWh/y (data from DHC and CHP)

W el,s - electricity production from CHP, which will substitute generation of electricity elsewhere in the power grid, MWh/y;

EFel – calculated emission factor for Bulgarian Power grid. Description and calculation of emission factor for Bulgarian power grid are presented in chapter 5.1 to5.7

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

ABE = ABE1 + ABE2 , Kton CO_2 /y

Estimation of the baseline GHG emissions without realization of the project

The estimated baseline emissions without realization of the project are resented in table B.

6.1 The Bulgarian Electricity Sector

6.1.1 Short History of the Bulgarian Electricity Sector

The Bulgarian electricity sector was dominated by the vertically integrated state-owned Natsionalna Elektricheska Kompania (NEK) until its unbundling in 2000. NEK has been converted to a transmission company with a single buyer division, transmission system maintenance division, hydro power plants enterprise, and dispatch centre (Operator of the power transmission system: National Dispatch Centre NDC). The NDC, in its capacity as a specialized unit of NEK EAD, performs the functions of real time dispatching of the electric power system of Bulgaria. Its main assignment is to guarantee reliable and economic operation of the Bulgarian electric power system. Bulgaria is dependent on imports for 70% of its energy supplies. With virtually no supplies of oil and small reserves of gas, Bulgaria has had to pay for energy in hard currency at world market prices, resulting in less reliable supplies or price fluctuations. The installed capacity of the Bulgarian power system in 2004 was 12.331 MW. A historical summary of installed electricity generating capacity in the Bulgarian EPS is shown in the following table.

Installed Electricity Generation Capacity							
	Unit	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Hydroelectric	MW	2.839	2.839	2.839	2.839	2.838	2.838
Nuclear	MW	3.760	3.760	3.760	3.760	2.880	2.880
Geothermal/Solar/Wind/Biomass	MW	0	0	0	0	0	0
Conventional thermal	MW	6.487	6.477	6.412	6.477	6.613	6.613
Total Capacity Installed	**MW**	**13.086**	**13.076**	**13.011**	**13.076**	**12.331**	**12.331**

Table 26: Installed Capacities 1999-2004

An historical summary of Bulgarian electricity net generation and net consumption is shown in the following table.

Bulgarian Electricity Generation and Consumption							
	Unit	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Net Generation	**GWh**	**34.298**	**36.887**	**39.618**	**38.595**	**38.428**	**37.598**
hydroelectric	GWh	2.934	2.881	2.021	2.708	3.276	3.246
nuclear	GWh	14.529	18.449	18.237	18.949	16.040	15.596
geo/solar/wind/biomass	GWh	0	0	0	0	0	0

conventional thermal	GWh	16.835	15.557	19.360	16.938	19.112	18.756
Net Consumption*	**GWh**	**25.522**	**25.486**	**25.800**	**25.312**	**26.430**	**26.359**
Imports	GWh	1.670	964	1.092	2.040	1.283	741
Exports	GWh	3.627	5.584	8.017	8.335	6.772	6.620
Net Exports	**GWh**	**1.957**	**4.620**	**6.925**	**6.295**	**5.489**	**5.879**

*Final consumption in the country

Table 27: Electricity Generation and Consumption

The following figure gives an overview on the Electric Power Sector in the Republic of Bulgaria

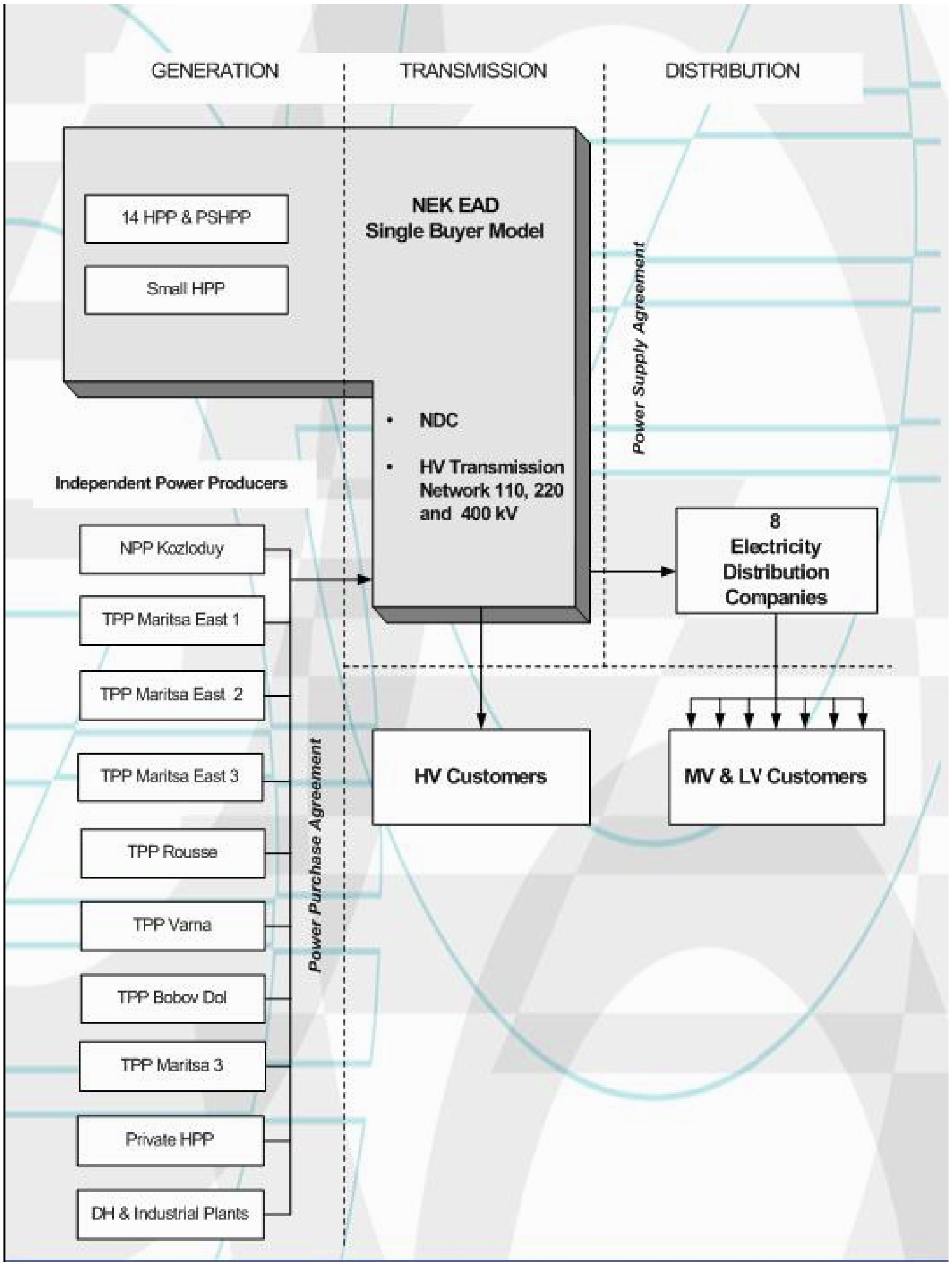


Fig. 4: Bulgarian Electric Power Sector

Source: NEK - EAD

Over the past 6 years, the Bulgarian electricity net generation has increased by 10%, with a peak in 2001. In accordance with the Bulgarian government's commitments to the European Union and as confirmed by a decision of the Bulgarian Council of Ministers, units No1 and No2 of Kozloduy NPP were disconnected from the Bulgarian EPS at the end of 2002. As a result the net generation from nuclear sources decreased in 2003. Bulgaria is a major exporter of electricity, supplying power to Turkey, Greece, Yugoslavia, Macedonia, and Albania. In 2004 Bulgaria exported about 6.620 GWh, with the majority of the exported electricity going to Turkey.

6.1.2 Current status of the Bulgarian Electricity Sector

1.) Generating Capacities

In 2004, the Bulgarian EPS had a total of 12.331 MW installed generating capacities consisting of:

	Installed Capacities 2004		*Available Capacities 2004*	
Category	**MW**	**%**	**MW**	**%**
Thermal Power Plants	6613	53,6%	5015	52,7%
Nuclear Power Plants	2880	23,4%	2700	28,4%
Hydro Power Plants and Pumped-Storage HPPs	2838	23,0%	1800	18,9%
Total	**12331**	**100%**	**9515**	**100%**

Table 28: Installed and Available Generation Capacities 2004

Source: NEK - EAD

4,740 MW of the thermal power plants are public utilities, 880 MW are co-generation plants which have the main purpose of supplying heat to towns, and 993 MW are co-generation plants that belong to large industrial enterprises. Thermal power plants (52,7%) and nuclear generation (28,4%) dominated the available generation capacities.

The **available capacity** of the existing power generating resources, however, is considerably lower than their installed capacity and amounts to about 9,515 MW. This difference compared to the installed capacity is mainly caused by the following factors:

- Due to economic reasons, district heating plants do not operate at their total installed capacity, but only at the level corresponding to the heat load in combined electricity and heat generation, which amounts to **about 460 MW.**
- After privatization, the existing industrial co-generation plants considerably decreased their available capacity due to closure of companies and decrease of the heat load. Thus, out of 993 MW installed capacity in the large industrial plants, currently their available capacity is **about 400 MW**.
- The HPP (Hydro Power Plants) and PSHPP together participate in covering the maximum load in the system during a moderately humid year with **1,800 MW** total capacity.
- Part of the installed capacity of the existing thermal power plants cannot be reached due to wear of their facilities. Thus, of 4,740 MW of installed capacity in large thermal power plants, the available capacity is **about 4,155 MW** (or 12,3% less).

The age structure of thermal power plants and nuclear units shown in the table below is very similar to that of other European countries and demonstrates the need for rehabilitation. Investments in rehabilitation will also take place in the Bulgarian energy sector in the coming years.

Age Structure of Power Plants						
	over 35 yrs.	**31-35 yrs.**	**26-30 yrs.**	**21-25 yrs.**	**16-20 yrs.**	**below 15 yrs.**
TPPs	24,8%	17,4%	12,7%	25,5%	10,9%	8,7%
District heating TPPs	59,0%	0,7%	19,2%	6,0%	15,2%	0,0%
On-site TPPs	41,2%	33,0%	1,0%	12,4%	5,0%	7,4%
NPPs	0,0%	0,0%	0,0%	30,6%	34,7%	34,7%

Table 29: Age Structure of Bulgarian Power Plants

Source: NEK - EAD

2.) Transmission Infrastructure

Bulgaria's high-voltage power transmission network consists of transmission lines of 750 kilovolt (kV), 400 kV, 220 kV, and 110 kV; step-down substations; one 400 kV switching station; and medium and low voltage distribution networks that supply the industrial, public and residential customers. The system of 400, 220 and 110 kV lines, which has a total length of about 14.427 km, operates in a ring mode. The 750 kV-line runs along a total distance of 235.4 km from Varna in Bulgaria to Isaccea in Romania (85 km on Bulgarian territory), and it is operated at 400 kV.

An overview of Bulgaria's high-voltage electricity grid system is shown in Figure 2.

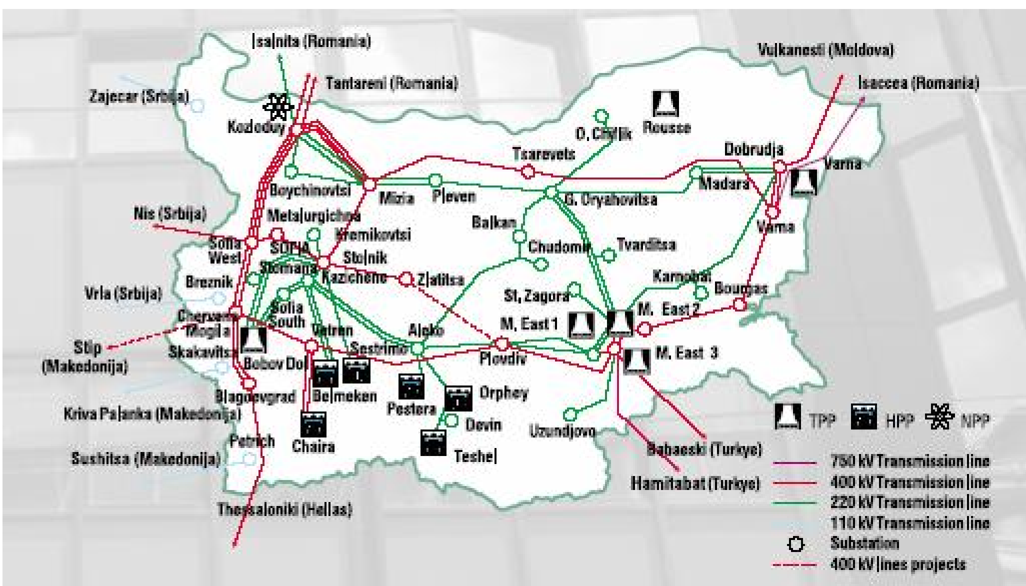


Figure 5: **Bulgaria's High-Voltage Electricity Transmission System**

Source: NEK - EAD

6.2 Bulgarian Electricity Demand Forecast

6.2.1 Background

The latest Least Cost Development Plan of the Bulgarian power sector for the period 2004-2020 was published in April 2004, and it is used as a reference in this PDD. It reflects the latest forecast macro-economic data for the Republic of Bulgaria, developed by the Economic Analyses and

Forecasts Agency (EAFA) in 2004, as well as the considerable changes that have occurred in the structure of the electricity sector in the recent years. The plan is based on the national priorities and principles of market integration. It implies the requirements for a stable economic growth and adequate way of living under the expected conditions of national economy growth. The Bulgarian forecast of generation requirements for the power system is prepared by NEK. A number of scenarios have been worked out for the electricity sector development in the country until 2020. All scenarios are developed by taking into account the same energy fuel price forecast, which are based on the forecasts from the scenario by the International Energy Agency -*World Energy Outlook 2000*. Out of these scenarios, 2 scenarios have been identified as most likely to represent the future development of electricity demand in Bulgaria. These scenarios have been named “Minimum” and “Maximum” and are described in the following chapter.

6.2.2 Minimum and Maximum Scenarios

NEK’s forecasts involve the so-called “maximum” and “minimum” scenarios. The main difference is the assumption on the rate of improvement of energy efficiency that the Bulgarian economy would achieve over time.

1.) Macro-economic Determinants

The forecasts of **electricity demand** in the country directly and indirectly imply the macroeconomic growth forecast for Bulgaria. The most frequently investigated macro-economic indicators influencing electricity demands are:

- Gross Domestic Product (GDP) and its structure
- Development of the GDP structure by major branches: industry, agriculture, services
- Inflation rate
- Population
- Electric power price
- Per capita income by current and comparable prices

The envisaged rates of GDP growth in the period under consideration are as follows:

GDP 2003-2020

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate of GDP Growth	4,3%	5,6%	5,3%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,5%	5,0%	5,0%	4,5%	4,0%

Table 30: GDP 2003 -2020

Source: State Agency for Economic Analyses and Prognoses

2.) Electricity Demands

The total electricity demand forecast for Bulgaria consists of the following forecasts:

2.1) public sector demand
2.2) household sector demand
2.3) house consumption of power plants
2.4) transmission and distribution losses
2.5) electric power export

2.1) Public sector demands
For the public sector electricity demand forecast, the macro-economic development data for Bulgaria as well as forecasts of electricity intensity by sectors of the economy (Industry, Services, and Agriculture and Forestry) are used.

All assessments made by local and foreign macro-economists show that the GDP electricity intensity in Bulgaria is several times higher compared to West European countries. So, a policy that improves this factor will be a major priority in the economic development in the forthcoming years.

The following table shows a forecast of electricity intensity for electric power consumed in the public sector with respect to the GDP.

Electricity Intensity per GDP		
Phases	**Minimum Scenario**	**Maximum Scenario**
	kWh/BGL	**kWh/BGL**
2002 -2005	from 1,27 to 0,99	from 1,27 to 1,01
2006 -2010	0,83	0,84
2011 -2015	0,69	0,73
2016 -2020	0,63	0,69

Tab. 31: Electricity Intensity 2002 – 2020

Source: NEK - EAD

2.2) Household sector demand
For the household sector electricity demand forecast, the input data are: population forecast, household income forecast, electricity price forecast, and the forecast of electric power saving in the households.
In order to forecast the electricity demand of the households, the following function is applied:

$E = \alpha + \beta I + \gamma P + \delta N$, with a multiple correlation factor R = 0.9987.

E – average household electricity demand;
I – average household income;
P – average household electricity price;
N – number of households.

The sum of the public sector and household sector electricity demand forecasts forms the end-consumer electricity demand forecast.

2.3) House consumption by power plants, transmission and distribution losses
In the next step, a forecast of house consumption by power plants as well as the transmission and distribution losses is made. For this purpose, the period 1990-2003 was analysed and it was found that electric power consumption for the house load of power plants will be 10-10,5% of the gross

electricity production. Furthermore, the transmission and distribution losses were found to be very high, reaching 18% of distributable electric power. The decrease of process losses in the future is one of the main methods of reducing electricity intensiveness in Bulgaria.

2.4) Electric power exports

The final element in the electricity demand forecast is the export of electricity. In the Least Cost Development Plan, an annual export of 5000 GWh is assumed until the end of 2006. At the end of 2006, two units in the Kozloduy NPP will be decommissioned in order to comply with EU recommendations. Hence, it is assumed that 1500 GWh of electricity will be exported annually after 2006.

3.) Electricity gross demand forecast

The Electricity Gross Demand Forecast for the country is equal to the sum of forecasts for final electricity consumption in the public sector and in the households plus the forecasts for auxiliaries of the power plants and T&D losses. The following table shows the electricity demand forecast:

Year	2000	2005	2010	2015	2020	2000 - 2020
Minimum scenario Growth,%	36307	36 990 0.4%	40 260 1.3%	43 750 1.7%	48 870 2.2%	1.5%
Medium scenario Growth,%	36307	37 650 0.7%	40 630 1.5%	45 100 2.1%	51 540 2.7%	1.8%
Maximum scenario Growth,%	36307	37 650 0.7%	40 990 1.7%	46 440 2.5%	54 190 3.1%	2.0%

Tab. 32 Bulgarian Electricity Gross Demand Forecast , GWh

Source: NEK - EAD

These analyses demonstrate the increasing trend of electricity demand in Bulgaria, except for a decrease after the year 2006 due to the decommissioning of Kozloduy NPP. Furthermore, the assumptions lead to different electricity demands in the different scenarios. This forecast is illustrated by the following figure.

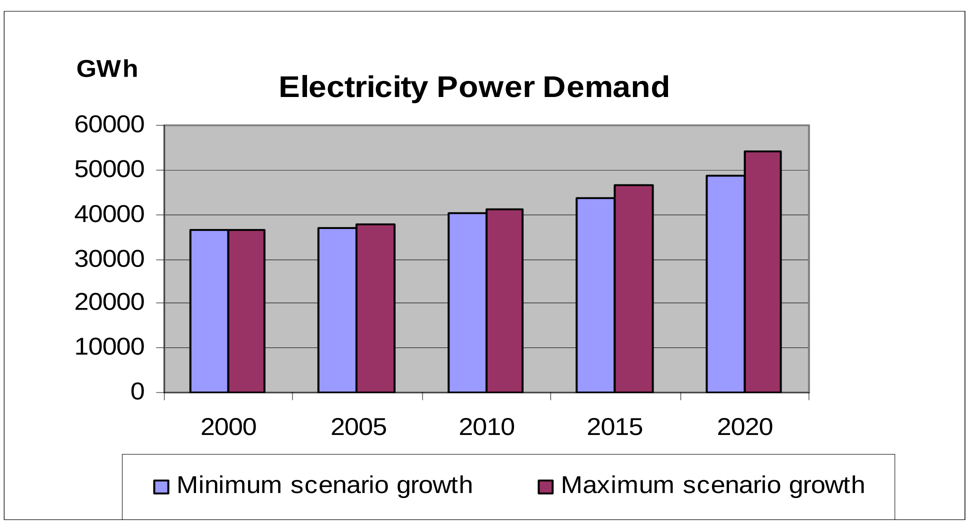


Fig. 6: **Bulgarian Electricity Demand 2000 – 2020**

The Minimum scenario reports an electricity demand of 36.307 GWh in 2000 and 48.870 GWh in 2020, which means an increase of about 34,6%. During the same period, the Maximum scenario shows an increase of the electricity demand from 36.307 GWh to 54.190 GWh (55,7%).

3.) Electricity Imports / Exports

The Bulgarian Electric Power System has established stable connections with the electricity systems of the neighbouring countries. The Government Energy Policy envisages development of Bulgaria as a regional electricity supplier. The Bulgarian EPS is already part of the UCTE, which will result in expansion of the export possibilities of the system. For the period up to 2006, annual exports of 5.000 GWh have been assumed. After 2006, the annual exports will be decreased to 1.500 GWh due to the decommissioning of the nuclear power plant Kozloduy (units 3 and 4). The analysis of the electric power systems development in the **Balkan countries** and the possibilities for electricity import from countries outside the Region after the year 2005 shows the following exports and imports in the Balkan region:

Exports / Imports

Country	Import	*Export*
	GWh	GWh
Albania	1000	-
Bosnia & Herzegovina	-	2000
Serbia	-	1000
Montenegro	4000	-
Macedonia	1000	-
Croatia	8000	-
Romania	-	5000
Greece	3000	-
Turkey	6000	-
Non-Balkan countries	-	6000
Total	**23000**	**14000**

Table 33: Balkan Countries Export and Import

Source: NEK - EAD

The expected shortage of electricity is 9,000 GWh. Over the next decade, electricity demand in the Balkan region is expected to increase by approx. 130 TWh. In conclusion, if Bulgaria manages to rehabilitate its capacities soon and completes its investment program in the electricity sector, it could establish itself significantly in the region with the expected energy deficiencies after 2010.

6.2.3 Decision on the Baseline scenario

The analysis of the future electricity demand shows that there is quite a difference in the additional electricity consumption in the 2 scenarios. While in the Minimum scenario there will be an increase in demand of about 9,063 GWh between 2000 and 2020, the increase demand will be about 14,383 GWh in the Maximum scenario for the same time period.

This difference between the 2 scenarios will of course have an influence on the marginal load and most probably also on the Least Cost Development Plan. So a decision has to be made as to which scenario will be used for the further analyses.

The demand increase in the Minimum scenario between 2000 and 2020 is about 21,9%, whereas in the Maximum scenario the demand increase in this time period is estimated to be 34,8%, thus requiring more electric capacity.

Power plants currently on the margin are mainly coal-fired power plants with rather low efficiencies. When demand is increased, the following scenarios are possible:

- Existing plants will have a higher load factor, which increases overall efficiency of the plants and therefore also decreases the specific CO_2 emission factor per MWh.
- New plants will be built to cover additional demand. Options for new plants will mainly include coal-and gas-fired units, which have lower specific CO_2 emission factors than the existing coal fired power plants.

These potential developments show the tendency that a higher demand will lead to lower specific CO_2 emission factors for the marginal plants.
In order to be conservative in the assumptions in this baseline scenario, the Maximum scenario is taken as a basis for the further calculations.

6.3 Development prospects of generating capacity extension

6.3.1 Decommissioning of capacities

The integration of Bulgaria into the European Union is a high priority in the program of the Bulgarian government. A key issue in Bulgaria's accession to the EU is the requirement for the early closure of Kozloduy units 3 and 4. Based on the negotiations between Bulgaria and the EU, the decommissioning of Kozloduy units 3 and 4 (commissioned in 1980 and 1982, respectively) are expected by the end of 2006.

Due to the expiry of the service life of some facilities and the restrictions posed by the Directive 2001/80/EC that sets Permission Emission Standards, the following TPP generating capacities will be decommissioned:

1. Maritsa 3 TPP – in the end of 2015
2. Brikel TPP – in the end of 2010
3. Bobov Dol TPP – Unit 1 in 2008, Unit 2 in 2011 and Unit 3 in 2014

6.3.2 Commissioning of capacities

The period 2007-2010 is crucial to the Bulgarian EPS, especially if Kozloduy units 3 and 4 are decommissioned before a new nuclear unit is commissioned. About 1700 MW of new capacities will be constructed during this time, and the Least-Cost Development Plan 20042020 includes the commissioning of the following projects:

New TPP burning indigenous lignite – 600 MW, 2009/2010.

- Tsankov Kamak HPP – 80 MW, 2009
- Rousse East TPP Unit 3 – 110 MW, 2006/2007
- CCGT in DHSs Zemliane and Lulin – each of 65 MW, 2009
- CCGT in DHS Sofia – 100 MW, 2008

- Belene NPP – 1000MW, 2011/2012.

Furthermore, following measures are listed in the Least-Cost Plan for preserving the level of electricity supply security and creating new generating capacities:

- Increased share of electricity output from renewable energy sources;
- Rehabilitation of TPPs that will continue to operate after 2010;
- Preservation of the share of nuclear energy in the overall energy balance through construction of new nuclear capacities;
- Increased share of co-generation plants;
- Reduction of transmission and distribution losses;
- Gasification of households to replace consumption of electric power, fuel oil and coal for heating by natural gas.

6.3.3 Rehabilitation

Instead of constructing new capacities, rehabilitation of existing power plants is one way to provide electric capacity for the future. The rehabilitation of large TPPs in Bulgaria should fulfil the following general requirements:

- Facilities and machines operational life extension by at least 15 years.
- Energy cycle efficiency improvement.
- Increase of the energy units' gross electric power.
- Increase of the availability and the manoeuvrability of the energy units.
- Meeting the technical requirements for the units operation within the UCTE Electric Power System.
- Meeting of all legislative requirements for environmental safety and operation of the energy capacities.

The TPP rehabilitation projects differ by scope and envisaged refurbishment and take into account the condition and the operational life of the machines and the equipment in the different power plants. The following table gives an overview on the rehabilitation program in the Bulgarian electricity sector.

Electricity Sector Rehabilitation Program				
			Available Capacity	**Available Capacity**
Rehabilitation Program	**Fuel**	**Period**	**existing**	**new**
			MW	**MW**
TPP Varna	steam coal	2007-2013	1200	1260
TPP Maritsa Iztok #2 part 150 MW	lignite	2005-2007	540	610
TPP Maritsa Iztok #2 part 200 MW	lignite	2009-2012	800	840
TPP Maritsa Iztok #3	lignite	2003-2006	800	840
TPP Rousse (condensate plant)	steam coal	2005-2006	100	200
PSHPP Chaira	hydro	2007-2009	420	630

Table 34: Rehabilitation Program -Baseline Scenario *Source: NEK - EAD*

6.4 Baseline Scenarios (Least Cost Development Plan)

6.4.1 Introduction to the Baseline Scenario

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

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

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

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;

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;

To be project-based or standard oriented;

To consider uncertainty. 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 validator and by the stakeholders.

Besides, the Baseline selection shall be substantiated.

There is a restriction upon the choice of a Baseline composition method for projects under CDM, but not for JI 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 Marrakech 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, and the preferences of Carbon Credit buyers, respective the parties to the Contract, the Baseline author's experience, etc.

6.4.2 Methodological Approaches to Baseline Determination

For the baseline determination the CDM methodology ACM0002 has been chosen. Below you will find the application of this baseline methodology to the Project

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

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 scenario 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. Because 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 scenario.

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 modelling 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., Basic Carbon Emission Factor /BCEF/ determined in tons of CO_2/GWh).

The multi-project approach is launched because; using 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 scenario 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.

6.4.3 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 15MWe, 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.

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 hydropower (about 50%) is large within the power system of Bulgaria.

2.) Mean specific emissions less Nuclear, Pumped-Storage and Hydropower 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 Hydropower 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.

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.

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.) 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.

6.5. Baseline Determination and Computation of the Baseline Emission Factor (BEF)

6.5.1 Mean specific emissions (all plants included)

The scenario enables determination of the mean specific emissions and the corresponding BEF 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 BEF and, respectively, reduction of CO_2 emissions in a Joint-Implementation Project, because the operation of nuclear power plants and, are not influenced by the implementation of such projects.

6.5.2 Mean Specific Emissions (less NPP and HPP)

The scenario 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 Hydropower Cascades 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 hydropower capacities of the system (HPP or gas-fired combined-cycle power plant over 15 MW).

6.5.3 Mean Specific Emissions for Each Load Category

This approach is not considered in detail because it requires BEF 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.

6.5.4 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.

6.5.5 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.

6.6 Selection of Baseline Scenario 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 IRP Model provides and coordinates an extended "Tool Box" of included resource planning opportunities including chronological demand and source simulation, computer-aided development of resource strategies, decision analysis and complete impact forecasts from all angles.

6.7 Baseline Scenarios

6.7.1 Electricity supply in the Baseline scenario

When combining electricity demand, current structure of electricity supply and options for capacity extension/rehabilitation, the IRP Manager Model delivers as an output the Least-Cost Development Plan for the Bulgarian electricity system.

The following list summarizes the main assumptions for the Least-Cost Development Plan:

Electricity demand of the country: will increase from 42.850 GWh in 2005 to about 44.465 GWh in 2012 (+3,8%).

Decommissioning:

- Units No. 3 & 4 of Kozloduy NPP by end of 2006;
- TPP Brikel by the end of 2010;
- TPP Maritsa 3 by the end of 2012;
- In Bobov Dol TPP, one coal-fired unit will be decommissioned in 2008, a second one in 2011, and a third one in 2014.

Commissioning:

- HPP Tsankov Kamak, 80 MW, in 2009;
- New TPP burning indigenous lignite, 600 MW, in 2008/2009;
- Expansion of cogeneration PPs, 130 MW, in 2009;
- New NPP Belene, 1000 MW, 2012.

Rehabilitation:

- TPP Varna
- TPP Maritsa Iztok #2 part (150MW)
- TPP Maritsa Iztok #2 part (210MW)
- TPP Maritsa Iztok #3
- TPP Rousse
- The power generation of the pumped storage hydro power plant Chaira will increase due to the Yadenitsa reservoir project, which foresees the construction of an additional lower compensation basin by 2010.

The computations of the IRP Manager Model report the following generations per power plant in the years 2005 to 2012 are shown in file: < Baseline Study DHS Bourgas 24.11.2005 rev 1. xls >. The calculations are detailed in a spreadsheet attached in **Annex No**. The Excel spreadsheet shows the available capacities, generation, heat rates, carbon contents and the emission factors on an annual basis. The gross heat rate and net calorific values are based on average figures for the years 2000-2004.

The Bulgarian Least-Cost Development Plan reports the following new power plants in the period 2005 to 2012.

Electricity Sector			
New Capacities 2005-2012	**Fuel**	**Year of Commissioning**	**Capacity MW**
Expansion of cogeneration PPs	nat. gas	2008	130
New TPP burning indigenous lignite	lignite	2008-2009	600
New NPP	nuclear	2010-2012	1.000
HPP Tsankov Kamak	hydro	2009	80
Total			1.810

Table 35: Commissioning of New Capacities – 2005-2012 *Source: NEK - EAD*

6.7.2 CO2 emissions in the Baseline scenario

The CO_2 emissions in the Baseline scenario per plant and year for the time span 2005-2012 are shown in the file: < Baseline Study DHS Bourgas 24.11.2005 rev 1.xls >. Total baseline emissions are calculated by multiplying the annual plant specific power generation with corresponding specific emission factors. In the period 2008 to 2012, total baseline CO_2 emissions caused by the Bulgarian electricity sector are around 134.376 kilotons CO_2. The significant CO_2 emission reductions in 2009 are the result of the decommissioning of Unit 1 of TPP Bobov dol, the rehabilitation works on TPP Varna decreasing power generation, and the commissioning of HPP Tsankov Kamak in 2009. The CO_2 emission reductions in 2012 are due to the commissioning of a 1000 MW nuclear power plant in 2012. Plant specific emission factors and detailed computations are in the file <Baseline Study DHS Bourgas 24.11.2005 rev 1.xls>.

6.7.3 Determination of Baseline Emission Factor according to Baseline Scenario

The forecast power balances obtained by merit order dispatching are used to develop the Baseline scenario. The scenario itself was developed using the ACM0002 Methodology, "Consolidated Baseline Methodology for Grid-Connected Electricity Generation from Renewable Sources" of UNFCCC CDM – Executive Board.

The Power Plants are classified in 4 main categories according to there merit order and operating costs computed by IRP Model:

- Operating Margin Power Plants;
- Build Margin (BM):
  - Existing BM Power Plants:
  - Future BM Power Units and Plants;
- Least Cost Power Plants;
- Must-run Power Plants.

Dispatch data computed by IRP Model incorporated in Baseline Minimum and Maximum Scenarios are use as input data for modelling of the relevant Operation Margin Emission Factor (OM_EF) in the applied determination methodology. OM_EF is determined in 3 methods with/without Hydropower Cascades:

- **Dispatch Data OM_EF** - is the generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost and must-run power plants;
- **Dispatch Data Adjusted OM_EF** - is a variation on the previous method, where the relevant power sources (including imports) include a fraction (λ) of least-cost/must-run power plants. For determination of (λ) is plotted the load duration curve for certain year and with a horizontal line across load duration curve such that the area under the curve (MW times hours) equals the total generation (in MWh) from least-cost and must-run power plant generation. The intersection of the horizontal line plotted and the load duration curve plotted gave the number of hours (out of the total of 8760 hours) to the right of the intersection. This is the number of hours for which low-cost/must-run sources are on the margin. If the lines do not intersect, it may conclude that low-cost/must-run sources do not appear on the margin and (λ) is equal to zero. Lambda (λ) is the calculated number of hours divided by 8760.
- **Dispatch Data Average OM_EF** - is the generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including Build Margin Power Plants.

The determination of **Build Margin emission factor (BM_EF)** as the generation-weighted average emission factor of a sample of power plants, consists of either the 5 most recent, or the most recent 20% of power plants built or under construction, whichever group average annual generation is greater (in MWh);

In order that the scenario can be as complete as possible, 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 Baseline Emission Factor determination.

The findings for BEF are given in the following Table 11. For further determination of Project Scenario will be use the most conservative BEF which is received of Baseline Maximum Scenario when Dispatch Data Adjusted Method is implemented.

	Forecast Minimum demand	Unit	2005	2006	2007	2008	2009	2010	2011	2012
1.	Total system power generation	GWh	44 324	45 051	43 115	44 156	47 490	48 212	51 139	52 291
2.	Total CO2 emissions of power generation	kt/a	27 407,61	28 035,37	31 810,38	31 245,76	33 538,31	33 547,47	33 863,20	31 248,73
3..	Total CO2 emissions of energy transformation	kt/a	33 747,07	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	tCO2/MWh	1,227	1,215	1,158	1,144	1,022	0,984	0,963	0,953
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,166	1,154	1,100	1,078	0,956	0,917	0,902	0,899
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,256	1,243	1,190	1,146	1,026	0,986	0,974	0,983
	HPP included									
1.	Dispatch Data_OM_EF	tCO2/MWh	1,183	1,176	1,175	1,110	0,995	0,959	0,940	0,918
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,118	1,111	1,102	1,017	0,894	0,858	0,849	0,838
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,144	1,138	1,153	1,057	0,947	0,909	0,898	0,889
	Fossil Fuels									
1.	Dispatch Data_OM_EF	kg/GJ	110,719	111,997	106,693	106,484	100,340	97,288	95,088	96,152
2.	Dispatch Data Adjusted_OM_EF	kg/GJ	110,697	111,976	106,621	106,402	100,566	97,871	95,946	96,570
3.	Average Dispatch Data_OM_EF	kg/GJ	110,571	111,622	106,175	106,640	100,646	98,217	96,578	97,026
	Forecast									
	Maximum demand	Unit	2005	2006	2007	2008	2009	2010	2011	2012
1.	Total system power generation	GWh	44 417	46 739	43 572	46 588	48 351	49 455	51 368	53 194
2.	Total CO2 emissions of power generation	kt/a	27 455,70	27 152,04	31 508,75	32 821,32	33 044,62	33 387,00	32 807,31	30 531,04
3..	Total CO2 emissions of energy transformation	kt/a	34 843,81	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	1,212	1,204	1,215	1,124	1,014	0,973	0,947	0,884
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,151	1,143	1,156	1,059	0,947	0,908	0,884	0,833
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,242	1,233	1,252	1,127	1,018	0,977	0,953	0,917
	HPP included									
1.	Dispatch Data_OM_EF	tCO2/MWh	1,170	1,158	1,168	1,101	0,990	0,947	0,928	0,865
2.	Dispatch Data Adjusted_OM_EF	tCO2/MWh	1,105	1,091	1,095	1,006	0,888	0,850	0,834	0,791
3.	Average Dispatch Data_OM_EF	tCO2/MWh	1,132	1,118	1,144	1,052	0,940	0,899	0,879	0,840
	Fossil Fuels									
1.	Dispatch Data_OM_EF	kg/GJ	110,268	109,651	111,991	105,315	100,011	95,929	94,604	93,043
2.	Dispatch Data Adjusted_OM_EF	kg/GJ	110,262	109,571	111,876	105,263	100,226	96,498	95,130	93,524
3.	**Average Dispatch Data_OM_EF**	**kg/GJ**	110,599	109,126	111,908	105,550	100,273	96,821	95,676	94,056

Table 36: Baseline Emission Factor

Baseline Study DHS Bourgas 24.11.2005 rev 1.xls>

7. GHG Project emissions

7.1 Estimation of the heat and power rate in the project boundary

The CHP installation is designed with electricity capacity of 17,82 MWe and heat capacity of 18,59 MWth by means of mounting of 6 unit CHP modules of the firm WARTSILA – Finlandia type 16V25SG. The installation will be executed on 2 phases:

- I phase – 3 x WARTSILA 16V25SG during April 2006;
- II phase – 3 x WARTSILA 16V25SG during August 2006

Data for CHP modules

Technical data	I phase WARTSILA	II phase WARTSILA
Type	16V25SG – AMG710 Mm6	16V25SG – AMG710Mm6
El. capacity, MWe	3,127	2,814
Heat capacity, MWth	3,240	2,956
Number of modules	3	3
Efficiency %	82	81,6

Table 37

- The base load heat during heating season will be covered by CHP modules and the pick heat demand will be covered by existed boilers, working as back up boilers;
- The heat demand during summer season will be covered by CHP modules by means of optimum number of chosen CHP modules;

Technological parameters of the CHP engine WARTSILA type 16V25SG with installation as a function of the load rate and ambient conditions are presented in the following table:

I phase

1. Summer regime WARTSILA type 16V25SG, 50 Hz

Regime	Ambient temperature, ^oC	Load rate, %	Ne, kWe	Qth, kWth	Fuel heat, kW	Spec. heat for generation of el. enery kJ/kWhe	$ή_e$, %	$ή_{th}$, %	$ή_{общ}$, %
1	25	96%	3002	3128	7476	8965	40,10	41,90	82,00
2	25	72%	2251	2418	5891	9421	38,20	41,10	79,30
3	25	48%	1501	1654	4266	10232	35,20	38,80	74,00

2. Winter regime WARTSILA type 16V25SG, 50 Hz at 96% load rate of the engine.

Regime	Ambient temperature, ^oC	Load rate, %	Ne, kWe	Qth, kWth	Fuel heat, kW	Spec. heat for generation of el. enery kJ/kWhe	$ή_e$, %	$ή_{th}$, %	$ή_{общ}$, %
1	-1	96%	3002	2534	7476	8965	40,10	41,90	82,00
2	15	96%	3002	2833	7476	8965	40,10	37,90	78,00
3	25	96%	3002	3128	7476	8965	40,10	33,90	74,00

II phase
2. Winter regime WARTSILA type 16V25SG, 50 Hz at 90% load rate of the engine.

Regime	Ambient temperature, °C	Load rate, %	Ne, kWe	Qth, kWth	Fuel heat, kW	Spec. heat for generation of el. enery kJ/kWhe	ήe, %	ήth, %	ήобщ, %
1	-1	90%	2814	2394	7065	9037	39,73	41,87	81,60
2	15	90%	2814	2677	7065	9037	39,73	37,87	77,60
3	25	90%	2814	2956	7065	9037	39,73	33,87	73,60

- Produced electricity from CHP will cover the auxiliary needs of DHC Plant - Bourgas and the rest sent to the power grid.
- Annual operational hours 8021 h/y
- On the base of this assumption, DHC Bourgas prepare annually prognoses data after realization of the Project for:
  - Total heat production of DHC plant;
  - Heat produced by CHP;
  - Heat produced by back up boilers;
  - Electricity produced by CHP;
  - Electricity for auxiliary needs;
  - Natural gas fuel consumption for CHP

  are presented in Tabl. P below

7.2 Estimation of GHG emissions in the project boundary

Estimation of GHG emissions in the project boundary are estimated on the base of DHC prognoses data for heat and electricity production from CHP and back up boilers.

Annual GHG project emissions – ApE1 from ng combustion in CHP for production of heat, covering base load heat demand and entirely power demand for auxiliary needs of the DHC plus electricity to the grid is calculated as follow:

$$ApE1 = QF_{CHP}*EFng\ ,\ Kton\ CO_2/y$$

where: QF_{CHP} is heat introduced with natural gas fuel annually in CHP, TJ/y (DHC data)
EFng = 0,0561, Kton/TJ – emission factor for combustion of natural gas (data from PDD guide)

Annual GHG project emissions – ApE2 from ng combustion in back up boilers:

$$ApE2 = (Qh-Q_{CHP}) * EFng,\ Kton\ CO_2/y$$

where: Qh is annual heat demand for DHC Plant, (data from DHC), TJ,
Q_{CHP} is annual heat production from CHP (data from DHC), TJ
EFng = 0,0561, Kton/TJ – emission factor for combustion of natural gas (data from PDD guide)

Total annual GHG project emissions, ApE, are given by**:**

$$ApE = ApE1 + ApE2 + ApE3,\ Kton\ CO_2/y$$

The results from calculation of the project emissions are presented in Tabl.P

8. Estimation of GHG emission reduction from the Project

The differences:

ARE = ABE-ApE

between total GHG emissions per year of the baseline scenario (Table B) and the project total GHG annual emissions (Tabl P) and for AAUs (1^{st} July to 31^{st} December 2007) and ERUs (1^{st} January 2008 to 31^{st}December 2012) are also presented in Tabl. R

AAUs = SUM {ARE (1^{st} April to 31^{st} December 2007)}
ERUs = SUM {ARE (1^{st} January 2008 to 31^{st}December 2012)}

REPORTING FORM FOR A BASE LINE STUDY FOR A CHP PROJECT

Table B. Calculation of the baseline emissions - case: separate generation of heat and electricity

B		Unit	2006		2007	2008	2009	2010	2011	2012	Average in 2008-2012	Level of precision
			Phase I	Phase II								
	Electricity for auxiliary needs - total (DHC data)	MWh	6154		6556	6508	6493	6493	6493	6493	6496	
	DHC Plant auxiliary needs (DHC data)	MWh	3466		2981	2933	2918	2918	2918	2918	2921	
	Electricity for auxiliary CHP needs	MWh	2688		3575	3575	3575	3575	3575	3575	3575	H
			1861	827								
B2	Heat consumption for auxiliary needs in DHC Plant (DHC data)	TJ	17		17	17	16	16	16	16	17	H
	Heat production											
B3	Heat produced by sources on site	TJ	1071		1061	1051	1048	1048	1048	1048	1048	H
B4	Spec.consumption of comparable fuel with LCV=29,33 GJ/t (DHC data)	kg/MWh	126		126	126	126	126	126	126	126	H
B5	Specific consumption of comparable fuel with LCV=29,33 GJ/t	kg/GJ	35.00		35.00	35.00	35.00	35.00	35.00	35.00	35	H
B6	On-site fuel use	TJ	1099		1089	1079	1076	1076	1076	1076	1076	H
B7	CO2 emission factor of heat from sources on site (PDD guide)	Kton/TJ	0.0561		0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0	H
	Electricity production											
B8	Electricity produced by CHP (DHC data)	MWh	96011		127670	127670	127670	127670	127670	127670	127670	H
			66469	29542								
B10	Electricity coming from grid for auxiliary DHC Plant needs	MWh	3466		2981	2933	2918	2918	2918	2918	2921	H
B11	CO2 emission factor of electricity from grid	Kton/MWh	0.001085		0.001095	0.001006	0.000888	0.00085	0.000839	0.000796	0.00088	H
	Direct on-site emissions											
B12	Emission from existed boilers heat production	Kton	61.67		61.09	60.51	60.34	60.34	60.34	60.34	60.37	H
	Direct off-site emissions											
B13	Electricity coming from grid for DHC Plant for auxiliary needs	Kton	3.76		3.26	2.95	2.59	2.48	2.45	2.32	2.56	H
B14	Electricity from grid,substituted electricity from CHP elsewhere	Kton	97.49		132.62	121.89	107.61	103.00	101.67	96.46	106	H
			67,49	29,00								
B15	**Total emission**	**Kton**	**162.93**		**196.97**	**185.35**	**170.53**	**165.82**	**164.45**	**159.12**	169	H

REPORTING FORM FOR PROJECT STUDY AND EMISSION REDUCTIONS, Table P. Estimation of the project emissio

P		Unit	2006	2006 Phase I	2006 Phase II	2007	2008	2009	2010	2011	2012	2008-2012	precision
P1	Natural gas fuel consumption for CHP (DHC data)	Th.c.m	25724	17809	7915	34260	34260	34260	34260	34260	34260	34260	H
P2	On-site fuel use from CHP	TJ	862	597	265	1148	1148	1148	1148	1148	1148	1148	H
P3	CO2 eq. emission factor of fuel used	Kton/TJ	0,0561			0.0561	0,0561	0,0561	0,0561	0,0561	0,0561	0,0561	H
	Heat production												
P4	On-site heat production (DHC data)	TJ	1071			1061	1051	1048	1048	1048	1048	1048	H
	Heat consumption for auxiliary needs in DHC Plant	TJ	17			17	17	16	16	16	16	17	H
P5	Heat produced by CHP (DHC data)	TJ	342	237	105	443	443	443	443	443	443	443	H
P6	Heat from other sources -back up boilers (DHC data)	TJ	728,6			617.6	607,5	604,5	604,5	604,5	604,5	605	H
P7	Fuel consumption from other sources-back up boilers	TJ	748,0			633.9	623,6	620,5	620,5	620,5	620,5	621	H
P6	CO2 eq. emission factor of heat from other sources on site	Kton/TJ	0,05610			0.05610	0,05610	0,05610	0,05610	0,05610	0,05610	0	H
	Electricity production												
P8	On-site electricity auxiliary consumption for DHC Plant (DHC data)	MWh	3466			2981	2933	2918	2918	2918	2918	2921	H
	On-site electricity for auxiliary CHP needs	MWh	2688	1861	827	3575	3575	3575	3575	3575	3575		
P10	Electricity produced by CHP (DHC data)	MWh	96011	66469	29542	127670	127670	127670	127670	127670	127670	127670	H
P11	Electricity coming to grid	MWh	89856	62208	27648	121115	121163	121178	121178	121178	121178	121175	H
P12	CO2 eq. emission factor of electricity from grid	Kton/MWh	0,00109			0.001095	0,00101	0,00089	0,00085	0,00084	0,0008	0,000876	H
	Direct on-site emissions												
P13	CHP	Kton	48,4	33,51	14,89	64.4	64,4	64,4	64,4	64,4	64,4	64,4	H
	Direct off-site emissions												
P14	Back up boilers	Kton	42,0			35.6	35,0	34,8	34,8	34,8	34,8	34,8	H
	Indirect off-site emissions												
	CO_2 avoided emissions to Electricity grid	Kton	101,3	70,13	31,17	135.9	124,8	110,2	105,5	104,1	98,8	108,7	H
P15	**Total project emissions**	Kton	90,3			100.0	99,4	99,2	99,2	99,2	99,2	99,3	H

Table R. Estimation of emission reduction

		Unit	2006	2007	2008	2009	2010	2011	2012	2008-2012	precision
R1	**Base line emissions**	Kton	**162,93**	**196.97**	**185,35**	**170,53**	**165,82**	**164,45**	**159,12**	169,05	H
R2	**Project emissions**	Kton	**90,3**	**100.0**	**99,4**	**99,2**	**99,2**	**99,2**	**99,2**	99,3	H
R3	**Total emission reduction**	Kton	**72,60**	**96.99**	**85,94**	**71,30**	**66,58**	**65,22**	**59,88**	69,78	H
R4	**TOTAL reduction during monitoring period AAUs**	Kton	**169,58**								H
R5	**TOTAL reduction during monitoring period ERUs**	Kton					**349**				H

9. Monitoring Plan

Considering the project boundaries, the following data / parameters need to be monitored in order to estimate the project and baseline emissions, and the emission reductions:

- Natural gas quantity, used by the CHP installation; in Nm^3;
- Natural gas quantity, used by the Steam and Water heating boilers; in Nm^3;
- Heavy fuel oil (HFO) and natural gas used for the back up boilers, in tons;
- Thermal energy produced by the CHP installation, in MWht;
- Steam energy sold to external consumers, in MWh;
- Thermal energy produced by the back up boilers (Water heating and Steam), in MWh;
- Net electricity provided to the national electricity network (NEC), in MWh_e;
- The efficiency of the existing boilers in the plant, which heat output, will be reduced from the quantity produced by the co-generation installation, in %;
- Thermal energy (steam and hot water) consumed for auxiliary needs in DHC station, in MWh_e
- The consumed electrical energy for auxiliary needs of DHC from the network, in MWh_e.
- The consumed electrical energy for auxiliary needs of CHP, in MWh_e.
- The produced electrical energy from CHP for DHC auxiliary needs, in MWh_e

The methane emissions from the burning process are excluded from the monitoring data as insignificant < 0,1 %. For this data assessment it is necessary a precise measurement equipment to be used. Also it is necessary to be assessed the natural gas emissions by any delivery leakage (on-side and off-side for the project boundaries), again using the standard emissions factors. This project includes only the suggested co-generation installations and as a result by this project execution, there are even emissions changes outside the scope of this project. However, the assessment of these emissions does not require an additional data to be monitored and collected. These emissions assessment is made by the data collected from the monitoring, which are specified below in this document and the parameters, which left unalterable during the project execution. The same procedure is foreseen for the emissions reduction calculations, described in chapter 6.

The monitoring methodology and the monitoring activities organization, includes as follows:

- The measurement data that will be monitored continuously on a daily basis for normal operation or malfunctioning. This will be done by the personnel in charger of the Central Network Monitoring Station;
- The Central Network Monitoring Station will collect and visualize the dates from all measurement devices and will export them on a daily and monthly basis in MS-Excel spreadsheet reports;
- The consumed thermal energy (of hot water) for auxiliary DHC needs will be measured from 4 devices of electronical flow meters and will be archived in reports one time of month.
- The consumed thermal energy (of steam) for auxiliary DHC needs, will be calculated every month on the base of the difference between the measured total produced steam from the steam boilers and the consumed steam from the external consumers. The measurements and the calculations will be archived in reports one time of month.
- The used template for reporting and the period at which the data will be reported are in accordance with table 9.1;
- The periodical check of the accuracy of the measurement devices will be done by nationally authorized laboratories every year. The periodical validations and the results from these checks will be stored in paper and digital stored journals;
- The measurement devices will only operate when in the possession of Calibration certificates, Quality certificates, Ex certificates and Water resistance certificates from the suppliers of the devices.

- The measurement devices will be with Certificate for calibration, Certificate for quality, Certificate for Ex, Certificates for IP and electromagnetic compatibility.

The Project manager and the Measurement manager will be responsible for the organization and the execution of these activities. The technical staff will receive special education from the equipment suppliers of the devices, to operate the equipment of the monitoring system and to perform the required measurements.
DHC Bourgas JSC is in application process to obtain certification under ISO 9001.
The full measurements requirements as described above will be implemented in a separate part of the detailed operational design for the project.

9.1 Monitoring methodology

For monitoring, collection, registration, visualization, archiving, reporting of the monitored dates and periodical checking of the measurement devices are responsible the measurement team from 5 people and its manager M-r Minko Dimitrov. The authorisations 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 storage 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
The dates for the recording periods, archive type and archive data storage time are shown in the table No. 38 in point 9.1.2.

9.1.1 Baseline Monitoring Methodology

The emission reductions from DHS Bourgas JI Project are based on the power generation of electricity and heat of new co-generation Units. The electricity power generation of Bourgas JI Project displaces power generated by other dispatchable units in the Bulgarian EPS. The heat recovery of co-generation Units displaces heat generation of the existing water heating boilers (back-up boilers).

Based on the hourly dispatch order NDC prepares reports of the Bulgarian EPS, in particular the marginal power Unit and the specific emission factors. The information required to perform the monitoring in the project is thus made available by NDC to the project operator DHS Bourgas.

Conservative Approach of the Monitoring Plan

The methodology for the monitoring and the calculation of the emission reductions is based on metered parameters and real time dispatch data for the Bulgarian EPS. This reduces the likelihood that the monitoring will lead to an overestimation of the emission reductions. In addition, the project does not claim emission reductions from emissions associated with the production and transportation of the fossil fuels used in the marginal plants. Also, the lifetime of the project will significantly exceed the crediting period.

For these reasons, the calculated emission reductions are seen as conservative figures with no tendency to overestimate the emission reduction generated by DHS Bourgas JI Project throughout the crediting period.

Operational and monitoring obligations

The Project Operator (DHS Bourgas) of the co-generation Units JI Project must fulfill certain operational and data collection obligations in order to ensure that sufficient information is available to calculate emission reductions in a transparent manner and to allow for a successful verification of these emission reductions. The operational obligations of the Project Operator are to ensure that all reasonable steps to maximize the generation of the Co-generation facilities are taken.

The operator must integrate the monitoring requirements and the calculation of the emission reductions into the operational procedures for the co-generation in JI Project. In particular, the Operator has to install the electronic workbook. In order to avoid errors based on data transfer, maximum automation of the workbook is desired. The implementation of the monitoring system and the calculation of the emission reductions is subject to review and approval at the verification.

The DHS Bourgas JI Project Electricity Power Generation Worksheets

The calculation of the DHS Bourgas electricity generation is based on Worksheet 1. DHS Bourgas, the Project Operator reports the net generation of the co-generation Units on a hourly basis. The data is obtained from the metering system at the power station and will be stored automatically in a database. To transfer data from the database to the Worksheet, data will be transformed in the corresponding formats and will be transferred by email from the DHS to the person responsible for the Workbook.

Worksheet 1 – DHS Bourgas Power Generation
shows the Excel spreadsheet used for generation data acquisition.

	A	B	C	D	E	F	G	H	I	J	K	...	Z	AA
1	DHS Bourgas Power Generation Worksheet						Year:		Month:					
2			Hour											
3	Day		0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	...	23:00	Total
4	1	MWh												sum(C4:Z4)
5	2	MWh												sum(C5:Z5)
6	3	MWh												sum(C6:Z6)
...	...	MWh												
34	31	MWh												sum(C34:Z34)
35	Total Month	MWh												sum(AA4:AA34

Worksheet 1 – DHS Bourgas Power Generation

Emission Factor Worksheet

Each thermal power plant has its own specific emission factor according to its specific energy consumption, efficiency and type of fuel. In order to determine the plant specific emission factors (EF) each power plant in the Bulgarian EPS is given a numerical code. Emission factors are required for all marginal and next marginal plants and are reported on a monthly basis.

The specific heat rates are manually calculated for each month at each TPP. The carbon contents are measured accordingly. Until the 10th of the following month NDC will receive the calculated plant specific emission factors for each month. The data is transferred via Email.

	A	B	C
1	**Emission Factors**	**Year:**	
		Month:	
2	**Power Station**	**Code**	**Emission Factor**
3			**tCO2/GWh**
4	TPP Bobov dol	1	EF1
5	TPP Varna	2	EF2
6	TPP Maritsa Iztok #1	3	EF3
7	TPP Maritsa Iztok #2 part (150MW)	4	EF4
8	TPP Maritsa Iztok #2 part (210MW)	5	EF5
9	TPP Maritsa Iztok #3	6	EF6
10	TPP Maritsa 3	7	EF7
11	TPP Rousse (condensate plant)	8	EF8
...			
34	New TPP burning imported coal	34’	EF34
35	New Combined Cycle PP	35’	EF35
36	New TPP burning lignites	36’	EF36
37	Zemliane GTCC	37’	EF37
38	Luilin GTCC	38’	EF38
39	Sofia GTCC	39’	EF39

Worksheet 2 – Emission Factors

- EF: Emission Factor

If monthly emission factors are not available, NDC will report annual plant specific emission factors. In the absence of actual emission factors, the most recent emission factors for corresponding types of power plants published by the Intergovernmental Panel on Climate Change will be used.

Marginal and next Marginal Plant Worksheet

This worksheet records the available capacity and the actual generation of the marginal plant. All required information is provided by the National Dispatch Center (NDC). A similar worksheet is applied for reporting the next marginal plants.
All required data will be stored in the SCALA database and can be transferred easily to Microsoft Excel. The data transfer will be arranged via Email.

	A	B	C	D	E	F	G	H	I	...	AA	AB
1	**Marginal Plant Worksheet**				**Year:**		**Month:**					
2					**Hour**							
3	**Day**				**0:00**	**1:00**	**2:00**	**3:00**	**4:00**	**...**	**22:00**	**23:00**
4	**1**	**Marginal Plant**	Name (Code)		PC							
5			Capacity	MW	CMP							
6			Generation	MWh	GMP							
7			Emission Factor	tCO2/GWh	SVERWEIS(E4,'Emission Factor'!B4:C39,2)							
8	**2**	**Marginal Plant**	Name (Code)									
9			Capacity	MW								
10			Generation	MWh								
11			Emission Factor	tCO2/GWh								
...												
110	**31**	**Marginal Plant**	Name (Code)									
111			Capacity	MW								
112			Generation	MWh								
113			Emission Factor	tCO2/GWh								

Worksheet 3 – Marginal Plant

The worksheet includes the name/code of the marginal power plant, the amount of energy generated by the marginal power plant and the available capacity at the marginal power plant on an hourly basis. The emission factors reported in Emission Factor Worksheet 2 will complete this worksheet.

- PC: Plant Code
- CMP: Available Capacity Marginal Plant
- GMP: Generation Marginal Plant

Dispatch without the Project and the Emission Reduction Calculation Worksheet

Based on the data collected in Worksheets 1-3 the following worksheet will answer the question what would happen without the implementation of DHS Bourgas JI Project and in particular the emission reduction occurred through the implementation of the co-generation Units in DHS Bourgas.

The methodology described in the Baseline Scenarios (least cost dispatch analysis) assumes that the plants running at the margin (with the highest cost) will be the first to be replaced. Without the implementation of the DHS Bourgas JI Project the marginal plant (and in some cases the next marginal plant) would increase its generation by the same quantity, DHS Bourgas is generating in this hour.

	A	B	C	D	E	F	G	H	...	AB	AC
1	**Dispatch w/o DHS Bourgas Worksheet**				**Year:**		**Month:**				
2					**Hour**						
3	**Day**				**0:00**	**1:00**	**2:00**	**3:00**	**...**	**23:00**	**Total**
4	**1**	**DHS Bourgas**	Generation	MWh	GVC						
5		**Marginal Unit**	Capacity	MW	CMP						
6			Generation	MWh	GMP						
7			Incremental Generation	MWh	IF(E4<(E5-E6),E4,(E5-E6))						
8			Emission Factor	tCO2/MWh	EFMP						
9			Emission Reduction	tCO2.	E7*E8						
10		**Next Marginal Unit**	Capacity	MW	CNMP						
11			Incremental Generation	MWh	E4-E7						
12			Emission Factor	tCO2/MWh	EFNMP						
13			Emission Reduction	tCO2	E11*E12						
14		**Total**	**Emission Reduction**	**tCO2**	**E9+E13**						SUM(E14:AB14)
...	**...**	**...**									
345		**Total Month**	**Emission Reduction**	**tCO2**							**SUM(M4:M344)**

Worksheet 4 – Emission Reduction Calculation

Usually the available additional capacity of the marginal power unit should be sufficient to cover DHS Bourgas power generation. Therefore the emission reductions will be equal the electricity generated by the co-generation Units multiplied by the specific emission factor of the marginal power unit. The calculation of the incremental generation of the marginal power unit is shown in cell *E7* in the worksheet above. If the marginal unit change his place for certain reason as first margin unit during an hour, the residual generation *(E4-E7*) will be generated by the next marginal plant. The incremental generation of the next marginal plant is shown in cell *E11*, which is simply DHS Bourgas power generation minus the incremental generation of the marginal power unit. Finally the emission reduction is calculated as a binomial formula. The summation of the incremental generation of the marginal plant *(E7)* times the plant specific emission faction *(E8)* and the incremental generation of the next marginal plant *(E11)* times the specific emission factor *(E14*) will result in the emission reductions achieved through the implementation of DHS Bourgas JI project. The calculation of the emission reductions is done on an hourly basis and results in the daily emission reduction as shown in cell *AC14*. Due to the fact that DHS Bourgas monitoring plan is based on a monthly reporting period, the total monthly emission reduction is calculated in cell *AC345*.

GVC: Total Generation DHS Bourgas JI Project
CMP: Capacity Marginal Plant
GMP: Generation Marginal Plant
EFMP: Emission Factor Marginal Plant
CNMP: Capacity Next Marginal Plant
EFNMP: Emission Factor Next Marginal Plant

Cumulative CO2 Emission Reduction Worksheet

Once work on the monthly Workbook is complete, the Project Operator transfers the total amount of emission reductions to the appropriate cell (according to the month and year) of the Cumulative CO_2 Emission Reduction Worksheet.

	A	F	G	H	I	J	K	L
1	**Cumulative Emission Reduction Worksheet**							
2		**2008**	**2009**	**2010**	**2011**	**2012**	**Total 2008-2012**	**Total**
3		GHG Emission Reduction	GHG Emission Reduction	GHG Emission Reduction	GHG Emission Reduction	GHG Emission Reduction	GHG Emission Reduction	GHG Emission Reduction
4	**Month**	tCO2	tCO2	tCO2	tCO2	tCO2	tCO2	tCO2
5	**January**							
6	**February**							
...								
15	**November**							
16	**December**							
17	**Total**	**SUM(F5:F16)**	**SUM(G5:G16)**	**SUM(H5:H16)**	**SUM(I5:I16)**	**SUM(J5:J16)**	**SUM(F17:J17)**	SUM(B17:J17)

Worksheet 5 - Cumulative CO_2 Emission Reductions

The Cumulative CO_2 Emission Reduction Worksheet adds the monthly CO_2 emission reduction figures up to produce annual GHG emission savings (see Table 5). The example only shows the years 2008 to 2012.

Data Transfer and Storage

As mentioned, once the operator has completed the monthly workbook, it must be saved as the auditable record for any entity wishing to verify the emissions reductions achieved by the project. The operator must do this each month, building up a series of monthly workbooks. In addition, the operator must maintain a paper trail of all relevant documentation and measurements and of the monthly signed off workbooks.

When calculating the figures of the next months, the operator takes the previous months workbook, deletes the input data on the DHS Bourgas Workbook, enters the new months parameters, transfers the new monthly CO_2 emissions reduction to the Cumulative CO_2 Emission Reduction Worksheet and then saves the new workbook under a new name and date.

9.1.2 Brief description of Monitoring methodology at DHS Bourgas

This project includes construction of a co-generation installation (CHP), using natural gas in a thermal source, in which, the thermal energy is produced in water heating boilers (BK 1...4), and is using electrical energy for auxiliary needs (AN) from the national electricity network. After the project completion, the thermal energy for domestic hot water supply will be produced by a combined production of thermal and electrical energy from CHP-modules. The generated electricity will satisfy the auxiliary needs of the DHC and the remaining part will be exported into the state energy system. The monitoring and the confirmation plan are based on records of the used quantity natural gas in the co-generation installation, the electrical and thermal energy supplied from the co-generation system to the plant. The data will be collected on monthly base for the project development lifetime period and the credit period (5 years). The emission from the greenhouse gases (GHG) following the project execution are defined by three supervised parameters.
The project emissions mainly include CO_2 emissions from the burning process of natural gas in the co-generation installation. There is an insignificant quantity of methane emissions (assessed as insignificant and excluded from supervision) and emissions from nitride oxide during the natural gas burning process. These quantities are insignificant and are assessed by the standard emission factors, shown in IPCC. 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 aren't valuated, cause of their insignificant quantity. Considering the project scope, to install a co-generation installation in DHC Bourgas, the following data/parameters need to be monitored:

- Natural gas consumed by the co-generation installation, in Nm^3;
- Natural gas consumed by the water heated and steam boilers, in Nm^3;
- Consumed "back up" fuel (HFO), in tons;
- The consumed thermal energy (steam an hot water) for auxiliary needs, in MWh;
- Net electricity provided to the national electricity network, in MWh;
- The electricity consumed for auxiliary needs of DHC from the network, MWh;
- Net thermal energy provided by the co-generation installation to the heat supply network, in MWh;
- Total net thermal energy provided by the DHC to the heat supply network, in MWh;
- Total net steam quantity produced by the steam boilers, in MWh;
- The steam sold to the external consumers, in MWh;
- The efficiency of the water heated boilers in the thermal source, in %.
- The consumed electrical energy for auxiliary needs of CHP, in MWh.
- The produced electrical energy from CHP for DHC auxiliary needs, in 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 document. The model requirements are to enter the monitored parameters as an input data, so it will automatically calculates simultaneously the project and the base line emissions, for each year after the project commissioning.
The electronic worksheets should be filled up with information by the project manager and also the inspector personnel, through the whole time length of the project.
The base line emissions depends of the thermal energy and electricity production of the co-generation system and are determined by the input data in the model, which also determine the emissions reduction which are obtained as a result of the project execution. The personnel responsible for the monitoring should fill up the electronic worksheets monthly. The model automatically calculates the annual sum and respectively the emissions reduction from the greenhouse gases obtained as a result of the project execution of the co-generation system. The model contains different electronic worksheets series with various functions:

Electronic worksheet – Input data:

- *Natural gas consumption;*
- *Electricity provided by the plant co-generation installation to the National Electricity Company (NEC);*
- *The thermal energy provided by the plant co-generation installation to the heat supply network;*
- *Thermal energy for auxiliary needs of DHC*;
- *The total thermal energy provided by the DHC to the heat supply network;*
- *Consumed electricity for auxiliary needs;*
- *The efficiency coefficient of the water heated and steam boilers;*
- *The caloric of the main and the "back up" fuel.*

Electronic worksheet - calculations:

- *Project emissions;*
- *Electricity production base line;*
- *Thermal energy production base line.*

Electronic worksheet - Results:

- *Emissions reduction of CO_2.*

9.1.3 Assumptions used in the methodology

No	Data type	Symbol	Dimension	Measured (м), calculated (c), assessed (e)	Recording period	%	Archive type (digital copy / hard copy)	Archive data storage
1	Quantity of consumed natural gas by - CHP; - Steam boilers; - Water heating boilers.	V_{NG}	Nm^3	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
2	Quantity of consumed "back up" fuel (HFO)	m_{HFO}	t	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
3	Electricity from the co-generator to NEC	E_{CHP}	MWh e	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Electronic worksheet - 7 years
4	Thermal energy from CHP to the network	Q_{CHP}	MWht	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
5	Total generated thermal energy toward the network. Steam and Hot water	Q_{DHC}	MWht	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
6	Total generated thermal energy for auxiliary needs. Steam and Hot water	Q_{AN}	MWht	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
7	Total electricity for auxiliary needs - 110 kV from NEC; - 6 kv from CHP; - 0.4 kV for CHP.	E_{AN}	MWh e	m	Monthly	100%	Hard copy (Record) Electronic worksheet	Electronic worksheet - 7 years
8	Efficiency coefficient Existing boilers	η_{SG}	-	m	Yearly	100%	Hard copy (Record) Electronic worksheet	Hard copy (Record) - 1 year Electronic worksheet - 7 years
9	Low heat value	LHV	$KCal/Nm^3$	m	Monthly	100%	Hard copy (Record)	Hard copy (Record) – 1 year

Table 38 Data to be collected in order to monitor the emissions from the project activities, and how these data will be archived

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	High	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

Table 39 Quality control (QC) and quality assurance (QA) procedures to be performed for the data monitored

9.2 Potential strengths and weaknesses of this methodology

Since, there is still none an approved specialized methodology by UNFCCC for such projects, the strengths and the weaknesses of this methodology need to be evaluated, regarding its own contribution.

The strengths of this methodology are as follows:

- Simple and easy to use, based on data, which should be collected during the project execution by measuring and recording the thermal and electrical productivity of the co-generating installation and the consumed quantity natural gas. It is fully comparable with the emissions calculations of the base line.
- The base line emissions are automatically defined in the model by electronic tables, based on the continuous control of the data from the thermal and electrical energy production from the co-generating system and by the periodical measurement of the industrial boilers efficiency.
- The model allows an automatic calculation of the emissions reduction from the greenhouse gases, taken into consideration the exposed above in the document and also the entered as an input data spent natural gas in the co-generation installation.

There are not known any weaknesses in this methodology.

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.

The monitoring model is presented below in **Annex No.7**. The measurement point schemes for the monitoring are presented in **Annex No.8.** In **Annex No.9** is presented the monitoring equipment specifications, detail separated by the monitoring system positions. In Annex No. 15 “Training Program Project Toplofikatsia Bourgas” is presented the plan for training of the monitoring personne in commissioning period and the period of operation”.

10. Stakeholder comments

With reference to the planned construction of the cogeneration gas powered installations at Topofikatsia Bourgas, the Municipalities, the Ministries and Agencies, the neighbouring companies, the people living in the vicinity of the projects sites, and the involved banks were informed in detail of the planned projects. The goals and the expected advantages for the realization and operation of the projects were explained in detail. The environmental effects from the project were also discussed. Various opinions and comments were heard with reference to the realization and operation of the installations.
In general the comments of the stake holding parties in general can be considered positive.
Enclosed in this chapter are a brief summary of the comments of several interested parties on the realization and operation of the projects. The individual letters expressing the opinions of the stakeholders are attached in Annexes No.10, No.11, No.12

The letters included in the above mentioned Annexes are presenting the positive attitude of different institutions and stakeholders. A short summary of each letter is presented bellow.

STATEMENT FROM THE PEOPLE LIVING IN THE VICINITY OF THE PROJECT SITE (Annex 10)

Quote:
“We as representatives of the of the local residence people, highly appreciate the implementation of state of the art cogeneration station at the territory of DHC Bourgas. We support the idea, because this project would decrease the pollution the area and would make the service provided by the DHC more affordable to us.”

STATEMENT FROM THE COMPANY “BourgasCvet”, WHICH IS BEEN SUPPLIED WITH HEAT ENERGY FROM DHC BOURGAS (Annex 11)

Quote:
“We as a company that uses your service are highly interested in the sustainable and more economically effective of energy production that would result from the described project. Our economical progress is dependable from the way that you use to supply us with energy. We consider that the construction of such cogeneration plant would bring only positive effect for all of the interested parties”

<u>STATEMENT FROM THE MUNICIPALITY BOURGAS TO MINISTRY OF ENERGY AND ENERGY RESOURCES (Annex 12)</u>

<u>Quote:</u>
"Dear Sirs, the steps undertaken from DHC Bourgas for construction of a cogeneration station are highly appreciated and supported from the Environmental Branch of the World Bank as well as some Environmental protection organizations like "Eco Links" from USA. I consider that the realization of the project would bring only positive effects over the Municipality of Bourgas, through reducing of the released emissions and sustainable energy production."

11. Environmental impact

<u>11.1 General</u>

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 Report Assessment (AEIR).

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 already has submitted the required documents for the elaboration of this assessment to the Environmental Impact Inspection District located in the town of Bourgas 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).

The following documents have been submitted:

I Information for correspondence with the investor

1. Name, Project Idea Note, residence, citizenship – a physical person, head office and unique identity number of a corporation.
2. Full post address
3. Telephone, fax, e-mail
4. Person for correspondence

II Characteristics of the investment proposal

1. Proposal's summary
2. Proving the necessity of investment proposal
3. Connection with other existing approved with organization or other type of plan activities.
4. Detailed information for examined alternatives.
5. The building site, including the necessary area for temporary activities during the construction.
6. Main processes descriptions (under catalogue data).
7. Scheme of new or already existing road infrastructure.
8. Activity programme, including those of construction, operation and stages of closing, restoration and subsequent usage.
9. Suggested methods for construction.
10. Forecast for use of natural resources during construction and operation.

11. Refuses that are expected to be generated – types, quantities and ways of treatment.
12. Information on discussed measurements and precautions for reduction of negative effects on the environment.
13. Other activities, connected with the investment proposal (for instance building material output, new water-supply system, output and energy transferring, residential building, treatment of sewage).
14. Necessity of other licenses, connected with the investment proposal.

III Site of the investment proposal

1. Plan, mapping and photos, showing the boundaries of the investment proposal, giving information about physical, natural and anthropogenic characteristics, as well information about near-situated elements from the National ecological net.
2. Existing land users and their adaptation to the building site or site trace of the investment proposal and future planned land users.
3. Zoning and land use in accordance with already approved plans.
4. Sensitive territories, including sensitive zones, vulnerable zones, protected zones, sanitary-guarded zones and others such as the National ecological net.
5. Detailed information about all discussed alternatives for the sites and the individual situations.

IV Characteristics of potential affecting influences

A brief description of the possible influences in chronological with the realization of the investment proposal:

1. Effects on people and their health, land use, material assets, atmospheric air, the atmosphere, water, soil, landscape, natural objects, mineral diversity, biological diversity and its elements and protected territories of single and group monuments, as well the expected effects from natural and anthropogenic substances and processes, different kinds of refuse and its location, risky energy resources – noises, vibrations, radiations and some genetic modified organisms as well.
2. Influence upon the elements from the National ecologic net, including elements located near the object of the investment proposal.
3. Type of the effects (direct, indirect, secondary, cumulative, momentary, middle- and long-lasting, permanent or temporary, positive or negative).
4. Effect range – geographical area; concerned population; residential sites (name, type – a town, a village, a resort, a number of population and others).
5. Duration, frequency and possible changing of the impacts.
7. Precautions and measurements that are necessary to be included in the investment proposal, connected with prevention or avoidance, reduction or compensation of considerable negative impacts upon the environment.
8. Global characteristics of the expected impacts.

11.2 EIA analysis

A brief environmental impact analysis after the model of the country based extended environmental impact analysis of the four separate sub-projects making up the co-generation portfolio has been done. In general types and ranges of environmental influences were assessed after their impact on air, water and land, people and borders. Also indicate mitigation measures, if applicable, have been described briefly.

This assessment was elaborated in cooperation with the environmental officers of DHC Bourgas. The responsible person is: Tanya Ducheva

	DHC Bourgas
1. Influence over the people and their health.	The influence is defined as a positive. There is a reduction of the emissions in the regions a state-of-the art cogeneration technology will be used for energy production
2. Influence over the elements that are part form the National ecological network.	Due to the project implementation the amount of the emissions locally will increase. However this would not influence negatively to the environment and the local people, because the released emissions will be in accordance with environmental requirement and with the Bulgarian legislation.
3. Type of influence	
3.1 Emissions in the air.	Direct, permanent, less negativity in comparison with the current situation.
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	Incidentally possibility to appear.

the water.	
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. In accordance with Bulgarian Regulation No.2 / 98 the norm of NOx is 250 mg/m³, the emission of J620GC is 500 mg/m³. After conversion of O_2 to 5 % the real quantity is 444 mg/m³. The gas engines will be completed with special filters for decreasing of the level to less than 250 mg/m³.
6.2 Influence on the water.	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 cogenerations are deposited in special containers. The containers are situated inside of special closed sites. The level of the noise outside of the containers (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 four projects are not situated close to international border areas and there will not be any influence over the borders.

Communication with the Regional Inspections for the Environment that an Assessment of the Environmental Impact is depicted in Annex No.11.