JOINT IMPLEMENTATION PROJECT DESIGN DOCUMENT FORM
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SECTION A. General description of the project

A.1. Title of the project:

Reconstruction of Pervomayskaia CHP -14 with installation of combined cycle units.
Sectoral scope: (1) Energy industries (renewable/non-renewable sources)
Version: 01.4
Date: 16/10/2009

A.2. Description of the project:

The purpose of the project is to increase the reliability and quality of the heat and electricity supply system of the residential and industrial sectors of Kirovskiy district and other districts of Saint-Petersburg using modern technology that decreases the environmental pollution including greenhouse gas emissions.

The Pervomayskaia Combined Heat and Power Plant (CHP) -14 began operations in 1957. The installed capacity of the existing CHP-14 is:
Electricity – 330 MW;
Heat – 1773 Gcal/hour (7423 GJ/h).

The Pervomayskaia CHP is a thermal power plant initially designed to run on powdered coal (from Kuznetskyi coal fields) as primary fuel. Currently CHP primarily uses natural gas that is supplied via high pressure gas pipeline.

The baseline scenario is a continuation of the current situation. The baseline scenario is described and justified in Section B.

Project scenario:
The reconstruction project of the Pervomayskaia CHP proposes the installation of three combined cycle units PGU-180 instead of conventional cycle units based on steam turbines. The construction will be done in two stages. The first and second combined cycle units will be constructed during the first stage. The third unit will be completed after the construction of the new high pressure gas pipeline during the second stage. The old CHP units based on two turbines PT-30-90/10, two turbines PT-60-130/13 and one T-50-130-1 would be removed from service except two units with T-50-130-1 steam turbines which will be used as reserve.

The installed capacity of CHP-14 will be 671.2 MW after the completion of the reconstruction. The Pervomayskaia CHP will include 3 combined cycle power plants, each with 190.4 MW installed capacity and two additional steam turbines of 50 MW each. New heat capacity for hot water production after reconstruction will be 1271 Gcal/h (5321 GJ/h). The equipment details are presented in Section A.4.2.

The implementation of the Pervomayskaia CHP reconstruction project will have the following advantages:

- Ensure the adequacy of the heat capacity and the increase of heat loads for the period up to 2015;
- Increased efficiency of electricity generation;
- Improve the cost effectiveness of combined heat and power production (CHP);

Greenhouse gas emissions will be reduced due to the displacement of electricity from the grid produced by fossil fuel power plants by the electricity generated by Pervomayskaia CHP that will produce electricity with lower carbon intensity in comparison with electricity from the grid.

A.3. Project participants:

Party Involved	Legal entity project participant (as applicable)	Please indicate if the Party involved wishes to be considered as project participant (Yes/No)
Russian Federation (Host Party)	• JSC "TGC-1" • ECF Project Ltd	No No
Finland	Fortum Power and Heat Oy	No

JSC "TGC-1" is the leading producer and supplier of electricity and heat power in the North-West region of Russia and the third largest territorial generating company in Russia in terms of installed capacity. It operates 55 power generating stations in four regions of Russia – the City of St Petersburg, Republic of Karelia, Leningrad Region and Murmansk Region. The company's generation assets include thermal, hydroelectric, diesel and co-generation power plants and it has a heating network of 940 km.

The state registration of the company took place on March 25, 2005. TGC-1 began operating on October 1, 2005.

A.4. Technical description of the project:

A.4.1. Location of the project:

The location of the project is shown on the figure 1 below.

A.4.1.1. Host Party(ies):

Russian Federation

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

Leningrad region

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

St. Petersburg

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

The Pervomayskaia CHP is located in the south-west part of St. Petersburg in Kirovskiy district. The CHP-14 location has geographical coordinates of 59°52′21″ north latitude and 30°14′47″ east longitude.

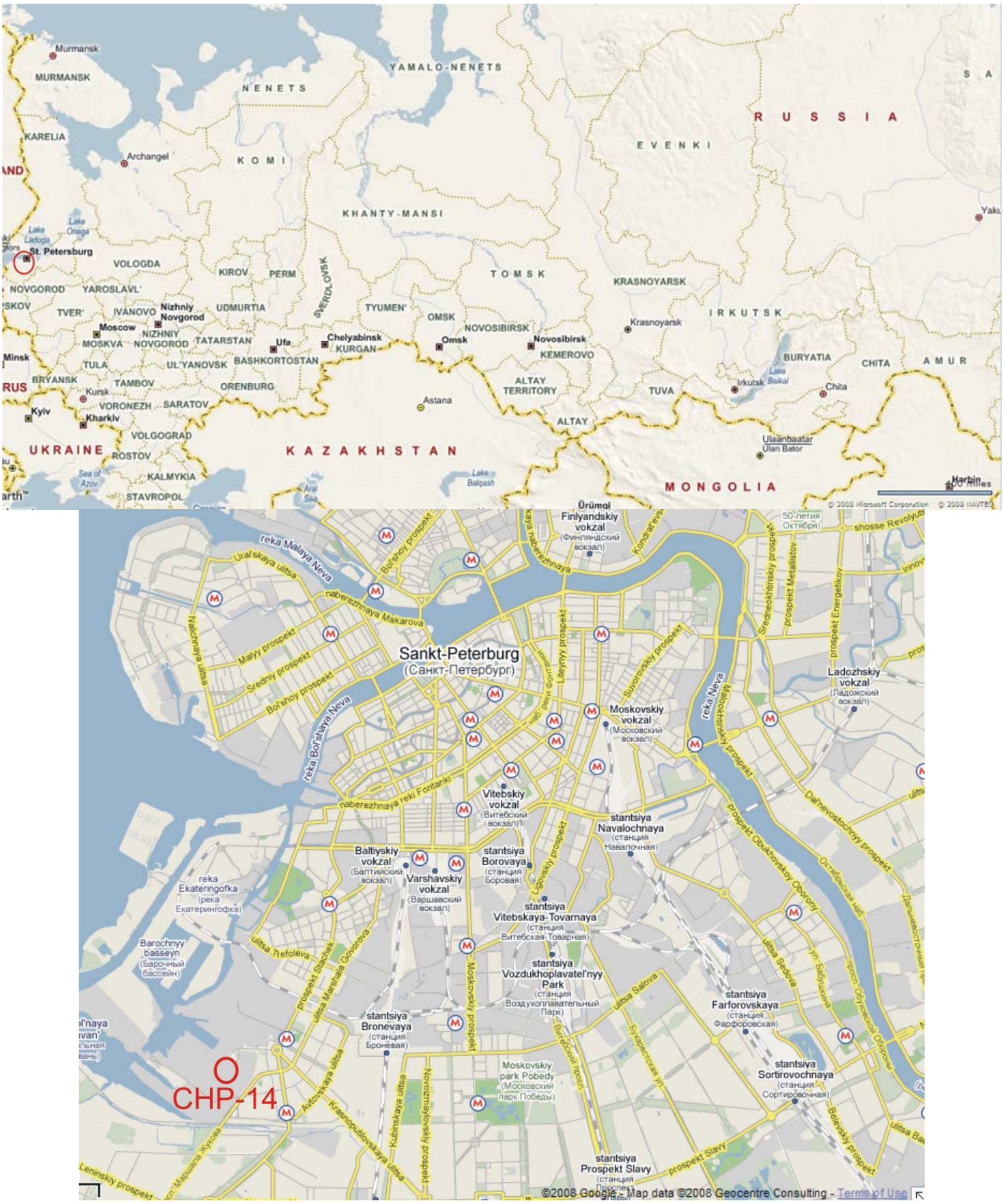

Figure 1. Project location

A.4.2. Technology(ies) to be employed, or measures, operations or actions to be implemented by the project:

The reconstruction of the Pervomayskaia CHP consists of the installation of three sets of PGU-180 that use combined cycle (CC) for power generation.

Each PGU-180 set is made up of the following equipment:

- Two gas turbine units of V64.3A type manufactured by Ansaldo Energia together with WY18Z generator. The main characteristics of V64.3A gas turbine for three operating conditions that are typical for St. Petersburg region are outlined in table 1;
- Two horizontal waste heat boilers (Heat Recovery Steam Generator) to generate steam at two pressures E-99.5/13.5-7.61/0.59-542/210 manufactured by Podolskyi Machinery Construction Plant OJSC;
- One T-50/64-7.4/0.12 condensing steam turbine with bleed manufactured by “Kaluzhskyi Turbine Plant” OJSC, with TZFP-63-2MUZ generator manufactured by Elektrosila OJSC, installed on the single footing with turbine;

Also reconstruction of plant foresees installation new hot water boilers

- Seven hot-water boilers of KV-GM -175-150 type.

Table 1. Main characteristics of gas turbine V64.3A

Characteristic	Ambient temperature, °C		
	-26	-7.8	+15
Capacity on generator terminals, MW	76.35	71.7	65.7
Turbine/generator efficiency, %	35.34	35.23	35.34
Natural gas consumption, m^3/h (at 0°C 0.1013 MPa)	21597	20345	18993

Installed electricity capacity of each PGU-180 set at the ambient temperature of +15°C in condensate mode will amount to 2*65.7+59.0 = 190.4 MW. Guaranteed electricity capacity of PGU-180 set with the ambient temperature of -1.8°C in heat-extraction mode will amount to 2*70.25+47.4 = 187.9 MW.

The PGU sets will work in the regime of base loads.

The system configuration prior to project implementation is shown in Figure 2.

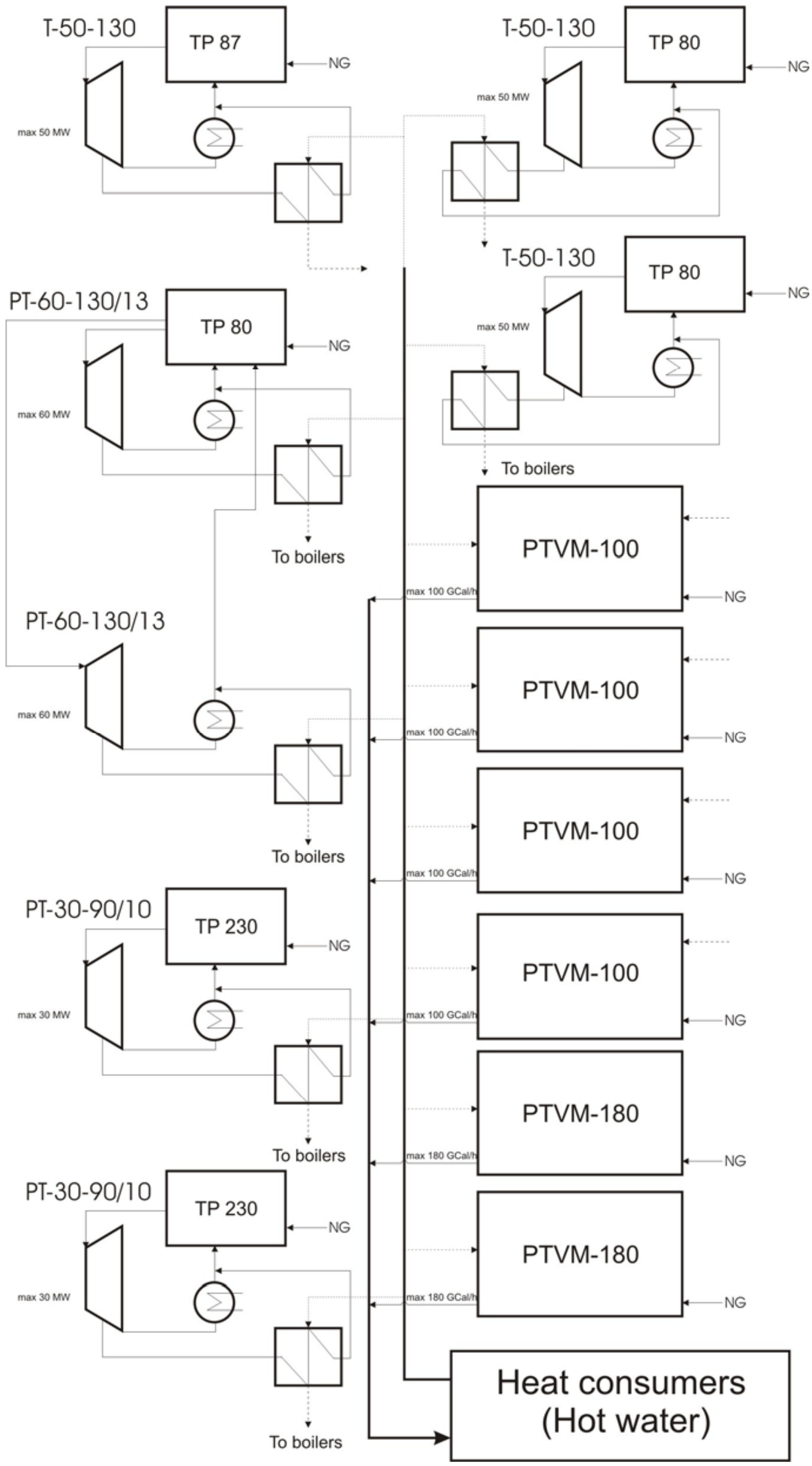

Figure 2. System configuration before project implementation

The situation following project implementation is shown in figure 3. It corresponds to heat and power output at the coldest winter "design" condition: -26 °C ambient temperature. During the heating season the station works according to the heating schedule with maximum electricity generation. Installed heat capacity after reconstruction will constitute 1301.9 Gcal/hour total, out of which 30.9 Gcal/hour heat load is for steam generation and 1271 Gcal/hour is for hot water production. Release of heat from CHP is maintained at a supply temperature of 150/130 °C with return water temperature at 70 °C.

PGU-180 energy blocks work in heat-extraction mode. The remaining heat load is covered by seven hot-water boilers of KV-GM -175-150 type that are installed in the assembled auxiliary building.

During the non-heating season the station provides domestic and service water heating only. This non-heating configuration is shown in Figure 4.

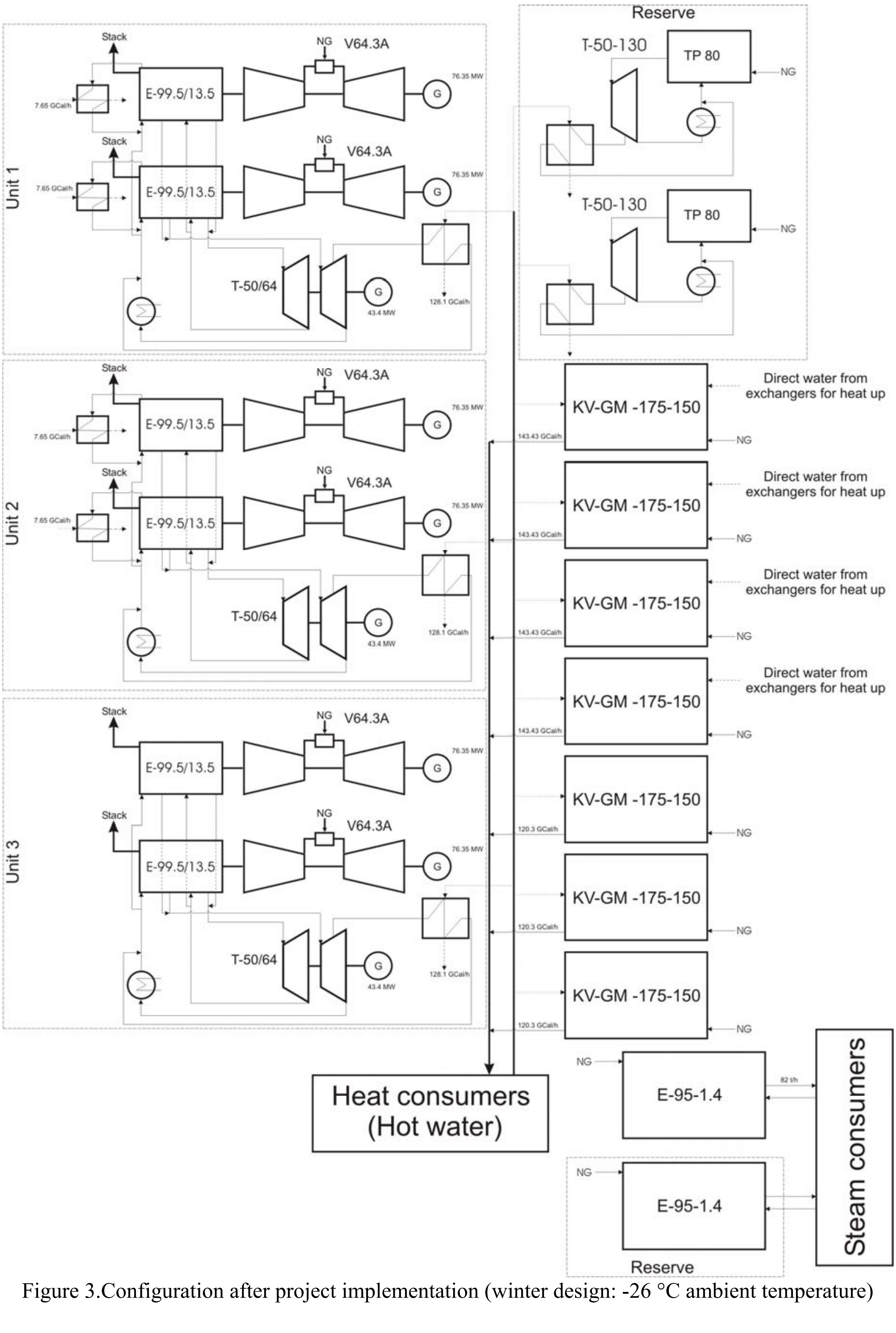

Figure 3.Configuration after project implementation (winter design: -26 °C ambient temperature)

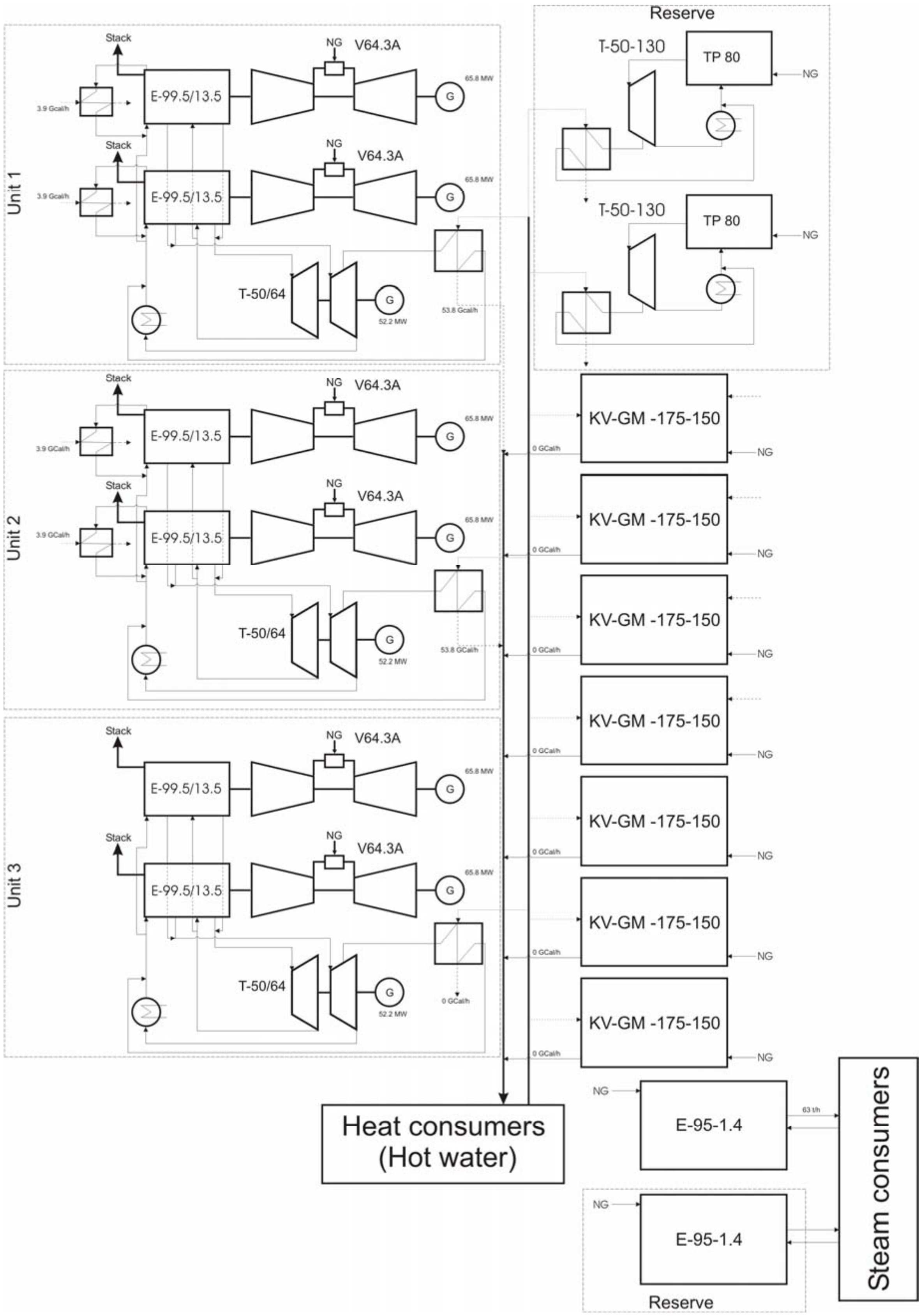

Figure 4. System configuration after project implementation (summer season)

Connected load in steam (constant throughout the year) is released by the steam boiler of E-95-1.4-250GM type (one of two is a back-up).

The release of the generators capacity is maintained through block scheme with 110 kV voltage in 110 kV switchgear. The connection of each generators of the PGU-180 MW block is designed into individual cells of 110 kV switchgear and later into the grid of 110 kV.

Double-wound transformers of TDC-100000/110U1 type of 100 MVA output are designed to be installed in the block of turbo generators of gas turbine units. Double-wound transformers of TDC - 80000/110-UHL1 type of 80 MVA output are designed to be installed in the turbogenerator block of steam turbine units. Turbo generators of gas and steam turbines are connected to the low-voltage winding of two double-wound transformers.

The reconstruction of CHP will be done in four stages. The schedule for the different stages is presented in table 2 and corresponding changes of equipment composition at each stage is shown in table 3.

Table 2: Schedule of reconstruction of CHP-14

Stage	Duration, months	Expected time of stage completion
1st stage	26	January 2010
2nd stage	12	January 2011
3rd stage	18	July 2012
4th stage	22	May 2014

Table 3: Change of existing equipment after completion of each stage

Name	1st stage	#	2nd stage	#	3rd stage	#	4th stage	#
New equipment installed in project scenario								
Gas turbines	V64.3A	2	V64.3A	4	V64.3A	4	V64.3A	6
Steam turbines	T-50/64-7.4/0.12	1	T-50/64-7.4/0.12	2	T-50/64-7.4/0.12	2	T-50/64-7.4/0.12	3
Water boilers					KV-GM -175-150	4	KV-GM -175-150	7
Steam Boilers					E-95-1.4-250GM	2	E-95-1.4-250GM	2
Heat-recovery boiler	E-99.5/13.5-7.61/0.59-542/210	2	E-99.5/13.5-7.61/0.59-542/210	4	E-99.5/13.5-7.61/0.59-542/210	4	E-99.5/13.5-7.61/0.59-542/210	6
Existing equipment kept in project scenario								
Steam turbines	PT-30-90/10 PT-60-130/13 T-50-130-1	2 2 3	PT-30-90/10 PT-60-130/13 T-50-130-1	2 2 3	T-50-130-1	2	T-50-130-1	2
Power boiler	TP 230 TP 87 TP 80	2 1 3	TP 230 TP 87 TP 80	2 1 3	TP 80	2	TP 80	2
Water boilers	PTVM-100 PTVM-180	4 2	PTVM-100 PTVM-180	3 2				

Expected power delivery to the grid and net heat generation after first stage completion (from January 2010) up to the end of the first commitment period of the Kyoto Protocol (2012) is presented in table 4.

Table 4: Expected net power and heat generation in 2010-2012

Year	2010	2011	2012
Power generation, MWh	2 115 222	3 607 698	3 824 650
Heat generation, Gcal	2 373 468	2 859 608	2 859 610

Using combined-cycle (CC) technology for electricity production is not widespread in the Russian Federation. The majority of big power plants are based on single-cycle operation. So the plant reconstruction by installing CC unit will have significantly better performance in comparison with traditional steam-turbine technology.

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

Greenhouse gas emissions will be reduced due to displacement of electricity from the grid produced by fossil fuel power plants that use traditional steam-turbine technology by electricity generated by Pervomayskaia CHP that will produce electricity through combined cycle units with lower carbon intensity in comparison with electricity from the grid.

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

	Years
Length of the crediting period	3 years
Year	Estimate of annual emission reductions in tonnes of CO_2 equivalent
2010	232 683
2011	418 426
2012	453 685
Total estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	1 104 794
Annual average of estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	368 265

A.5. Project approval by the Parties involved:

The project will be approved by the Russian Federation after the approval of the Russian procedure for the registration of JI projects.

The Parties' Letter of Approval will be received later.

SECTION B. Baseline

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

At present time there are no approved CDM methodologies applicable to establish the baseline, and determine baseline and project emissions for the proposed project activity. Accordingly being guided by principles stated in *Decision 9/CMP.1*, *Appendix B*, we present a new baseline methodology based on existing CDM methodologies and CDM methodology tools.

The CDM methodologies considered in new methodology are listed below with a brief description of their limitations with respect to the proposed project activity.

AM0029 (“Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas”) is applicable to new natural gas combined cycle (NGCC) power plants that only produce electricity. The proposed project involves the use of some existing equipment as well as the installation of new NGCC equipment. Moreover, the proposed project would produce both electricity and heat. Thus AM0029 is not applicable for the proposed project.

AM0061 (“Methodology for rehabilitation and/or energy efficiency improvement in existing power plants”) is not applicable where new equipment is added.

AM0062 (“Energy efficiency improvements of a power plant through retrofitting turbines”) is not applicable where cogeneration is involved.

ACM0007 (“Baseline methodology for conversion from single cycle to combined cycle power generation”) is only applicable when the initial state was a gas turbine or internal combustion engines, and that the original equipment remains operational after project implementation. Neither is the case here. The initial state here was the use of steam turbines. Moreover, most of the existing steam turbines would be removed in the project scenario.

Given that no existing approved CDM methodology is applicable to the proposed project, we develop a new methodology, partially based on the above AMs and the following methodological tools:

- “Combined tool to identify the baseline scenario and demonstrate additionality”,
- “Tool to calculate the emission factor for an electricity system”

In the following text, we describe the methodological procedure step by step, followed by its application to the specific project.

Applicability

The proposed new methodology is applicable to project activities that implement rehabilitation measures in an existing fossil fuel fired cogeneration plant for and the purpose of enhancing its energy efficiency. The following conditions apply:

- The project activity plant supplies electricity to the electricity grid and heat to consumers through a heat distribution centre.
- The project activity is implemented in an existing cogeneration plant and involves its reconstruction. The installed power and/or heat generation capacity may increase as a result of the project activity.
- Only rehabilitation measures which require capital investment and improve efficiency (as per the definition above) shall be included. Regular maintenance and housekeeping measures cannot be included in the proposed project activity;

- All major equipment in use prior to project implementation (boilers, turbines, generators, and heat exchangers) should have a remaining life that is equal to or exceed the proposed crediting period. Thus the current equipment could supply electricity and heat for the duration of the proposed crediting period.
- The lifetime of any new equipment installed should also equal or exceed the proposed crediting period.
- The project is limited to the case where natural gas is the main fuel used both before and after project implementation. Because of supply interruptions and other problems, it is permissible to use other fuels in the project scenario, taking into consideration additional emissions from such fuel use.

The proposed methodology is **not** applicable to:

- Greenfield cogeneration plants;
- Captive cogeneration plants that produce heat and power for in-house consumption.

In addition, the applicability conditions included in the tools referred to above apply.

The proposed project meets all the applicability conditions specified above, as well as those relevant to the Tools used.

The basic fuel used on Pervomaiskaia CHP is natural gas. Liquid gas turbine fuel and residual fuel oil are used as reserve fuel. Note that since these fuels have higher emissions factor compared to the main fuel, natural gas, any use of the reserve fuels would increase project emissions, and reduce emissions reductions. This is therefore conservative.

Procedure for estimating remaining lifetime of the existing equipments

The following approaches are used to estimate the remaining lifetime of the existing equipments, i.e. the time when the existing equipments would need to be replaced/rehabilitated in the absence of the project activity:

(a). The typical average technical lifetime of the different type of equipments may be determined taking into account common practices in the sector and country (e.g. based on industry surveys, statistics, technical literature, etc.);

(b). The practices of the responsible company regarding replacement/rehabilitation schedules may be evaluated and documented (e.g. based on historical replacement records for similar equipments).

The time of replacement/rehabilitation of the existing equipments in the absence of the project activity should be chosen in a conservative manner, i.e. the earliest point in time should be chosen in cases where only a time frame can be estimated and should be documented.

The baseline established below assumes continuation use of the installed equipment in spite of the fact that this equipment reached its depreciation stage. In the Russian Federation the time for depreciation of equipment of various stages is estimated and approved. In accordance with power strategy of Russia[1] the 50 % of all capacities of thermal power stations and hydro power stations of Russia will wear out their resource (reach its depreciation stage) by 2010. However by 2010, the equipment upgrade on power station blocks that reached its depreciation stage (worn its resource) will not have time to take place. The further prolongation of equipment use requires an individual approach for each block. In particular that such prolongation is possible on CHP - 14 anticipates that the reconstruction project will leave two extraction turbines and boilers in a cold reserve. Individual prolongation of equipment depreciation time

1 http://stra.teg.ru/lenta/energy/1108 (Rus)

(lifetime) in accordance with publication[2] equals to 1.35-1.5 of its initial duration (economic life), i.e. in our case for the blocks installed on CHP - 14 it is 77-110 thousand working hours or more. This approximately equals to 10-15 years of operation.

Procedure for the identification of the most plausible baseline scenario and assessment of additionality

For the selection of the most plausible baseline scenario and assessment of additionality, use the latest version of the "Combined tool to identify the baseline scenario and demonstrate additionality". Version 02.2. is used here.

Description and application of these tool presented in section B.2

Normally, a baseline methodology determines baseline emissions first followed by project emissions. In this case, the baseline scenario must match the heat and electricity output of the project scenario and provide the same amount of heat and power with the baseline technology. Therefore, for this project, we first consider Project emissions.

Project emissions

The project activity is power and heat generation using PGU-180 combined cycle units. Old CHP units and boilers, as well as peak load boiler will be used during the construction period. So combustion of natural gas (as primary fuel) in gas turbines to generate electricity and heat is main source of emissions. Also project foresees combustion of natural gas (as primary fuel) and residual fuel oil (as reserve fuel) in peak load boilers. The CO_2 emissions from project activity (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} \cdot COEF_{f,y}$$

where:

$FC_{f,y}$: = the total volume of natural gas or other fuel '*f*' combusted in the project plant or other startup fuel (m^3 or similar) in year(s) *y*

$COEF_{f,y}$: = the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and obtained as:

$$COEF_y = NCV_{f,y} \cdot EF_{CO_2,f,y} \cdot OXID_f$$

where:

$NCV_{f,y}$: = the net calorific value (energy content) per volume unit of fuel *f* in year *y* (GJ/m^3 or similar) as determined from the fuel supplier;

$EF_{CO2,f,y}$: = the CO_2 emission factor per unit of energy of fuel *f* in year *y* (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

$OXID_f$: = the oxidation factor of fuel *f*.

Baseline emissions

The reconstructed plant or additional unit can change heat and power output of plant. Moreover heat and power output depends on power deficit or excess in region, number of heat consumers, ambient temperatures etc. So there is considerable uncertainty relating to which type of other power and heat generation is substituted by the power and heat generation of the project plant.

[2] http://www.rosteplo.ru/Tech_stat/stat_shablon.php?id=692 (Rus)

Baseline emissions are those emissions that are associated with the production of heat and electricity that are identical to the output of the project CHP plant. Baseline emissions are determined by emissions from existing CHP equipment for generating heat and power to their limit. Then additional emissions are from fuel use in boiler for excess heat requirement in project scenario and/or emissions in the grid for excess power demand. The calculation of baseline emissions is therefore based on different emission factors for different quantities of electricity and heat generated. As represented in figure 5, the following cases are differentiated:

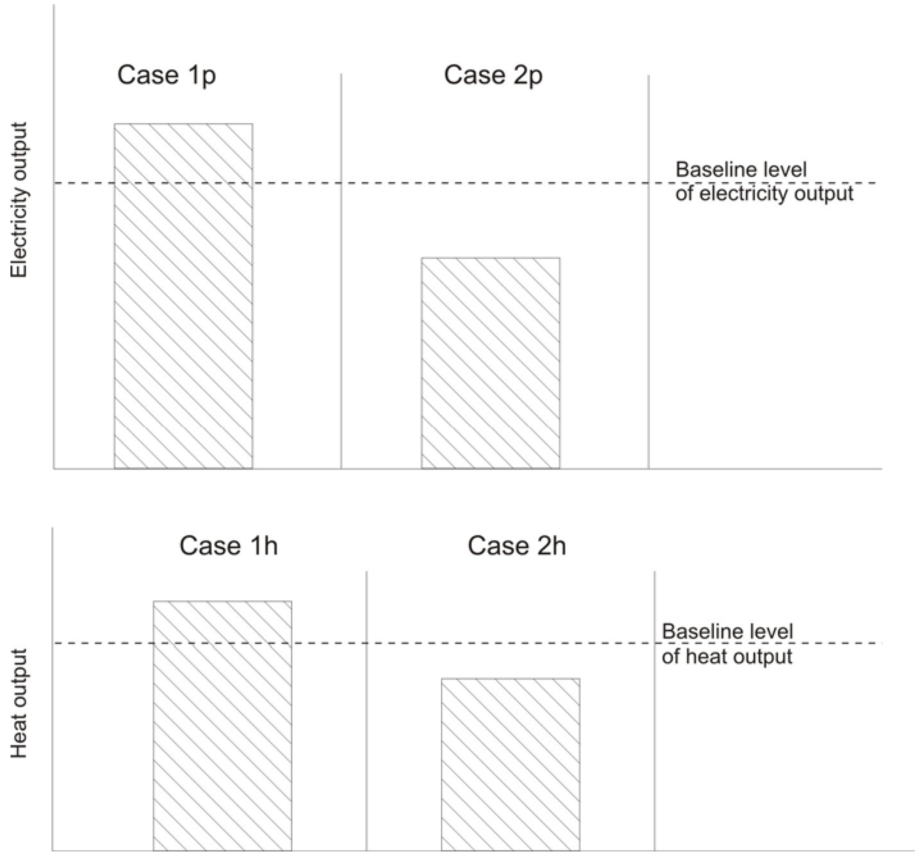

Figure 5. Baseline cases

The any combination of cases 1p, 2p, 1h, 2h are possible. Determine the baseline level of electricity output. The conservative approach is used to determine baseline of power output. We cannot separate fuel in CHP only for heat and only for electricity generation. Therefore the comparison of fuel uses for historical level of heat and electricity output from CHP uses to determine baseline level.

$$P_{BL,grid}E + H_{BL,boiler}E \geq CHP_{hist}E$$

where

$P_{BL,grid}E$: = the CO_2 emission (tCO_2) from electricity grid in equivalent of historical level from CHP;

$H_{BL,boiler}E$: = the CO_2 emission (tCO_2) from heat generation in equivalent of historical level from CHP;

$CHP_{hist}E$: = the CO_2 emission (tCO_2) from CHP for heat and electricity generation at historical level.

If this inequality is *true* then as limit of baseline power generation uses maximum of historical electricity generation at the plant. And all historical level of fuel consumption and heat generation also corresponds to this year of electricity generation.

$$EG_{BL,\lim} = EG_{CHP,\max,hist,yh};\ HG_{BL,\lim} = HG_{CHP,yh};\ FC_{BL,\lim} = FC_{CHP,yh}$$

where
$EG_{BL,lim}$: = the limit of baseline electricity generation (MWh or similar);
$EG_{CHP,\ max,hist,yh}$: = the maximum level of historical electricity generation (MWh or similar) in the year *yh*;
yh: = is year of the maximum historical electricity generation;
$HG_{BL,lim}$: = the limit of baseline heat generation (GJ or similar);
$HG_{CHP,\ yh}$: = the heat generation (GJ or similar) that corresponds to the year *yh*;
$FC_{BL,lim}$: = the limit of baseline fuel consumption (m^3 or similar);
$FC_{CHP,\ yh}$: = the fuel consumption (m^3 or similar) that corresponds to the year *yh*.

If the inequality is *false* then as limit of baseline power generation uses minimum of historical electricity generation at the plant. And all historical level of fuel consumption and heat generation also corresponds to this year of electricity generation.

$$EG_{BL,\lim} = EG_{CHP,\min,hist,yh};\ HG_{BL,\lim} = HG_{CHP,yh};\ FC_{BL,\lim} = FC_{CHP,yh}$$

where
$EG_{BL,lim}$: = the limit of baseline electricity generation (MWh or similar);
$EG_{CHP,\ min,hist,yh}$: = the minimum level of historical electricity generation (MWh or similar) in the year *yh*;
yh: = is year of the minimum historical electricity generation;
$HG_{BL,lim}$: = the limit of baseline heat generation(GJ or similar);
$HG_{CHP,\ yh}$: = the heat generation (GJ or similar) that corresponds to the year *yh*;
$FC_{BL,lim}$: = the limit of baseline fuel consumption (t.c.e. or similar);
$FC_{CHP,\ yh}$: = the fuel consumption (t.c.e. or similar) that corresponds to the year *yh*.

Emission from the electricity grid ($P_{BL,grid}E$) in equivalent of historical level from CHP calculated as follow:

$$P_{BL,grid}E = EG_{CHP,hist} \cdot EF_{grid,CM,y}$$

where
$EG_{CHP,\ hist}$: = average historical electricity generation (MWh or similar) for the last 3 years;
$EF_{grid,CM,y}$: = the baseline emission factor (tCO_{2e}/MWh) for the UES of Russia electricity grid is calculated as a combined margin (CM) emission factor, consisting of the combination of operating margin (OM) and build margin (BM) emission factors according to the methodological tool version 01.1 "Tool to calculate the emission factor for an electricity system".

Emission from the boilers ($P_{BL,grid}E$) in equivalent of historical level from CHP calculated as follow:

$$H_{BL,grid}E = \frac{HG_{CHP,hist}}{\eta_{boiler}} \cdot EF_{CO_2,NG} \cdot OXID_{NG}$$

where

$EF_{CO2,NG}$: = CO_2 emission factor per unit of energy of natural gas (tCO_2/GJ) as determined based on national average fuel data, if available, otherwise IPCC defaults can be used;
η_{boiler} : = efficiency of the boilers that generates heat in equivalent of historical quantity, determines in conservative way;
$HG_{CHP,\ hist}$: = average historical heat generation (GJ or similar) for the last 3 years;
$OXID_{NG}$: = the oxidation factor of natural gas.

Emission from CHP plant ($CHP_{hist}E$) for heat and electricity generation at historical level;

$$CHP_{hist}E = FC_{t.c.e.,hist} \cdot COEF_{NG}$$

where:
$FC_{t.c.e.,hist}$: = the annual average fuel consumption in tons of coal equivalent (t.c.e.) combusted in the CHP during the last 3 years;
$COEF_{NG}$: = the CO_2 emission coefficient (tCO_2/m^3 or similar) for natural gas and obtained as:

$$COEF_{NG} = NCV_{t.c.e.} \cdot EF_{CO_2,NG} \cdot OXID_{NG}$$

where:
$NCV_{t.c.e.}$: = the net calorific value (energy content) of t.c.e. (GJ/t.c.e.).

Define baseline emission BE for the following cases:
a) 1p+1h; 1p+2h

$$BE = FC_{BL,\lim} \cdot COEF_{NG} + EF_{grid,CM,y}\left(EG_{P,y} - EG_{BL,\lim}\right) + \frac{\left(HG_{P,y} - HG_{BL,\lim}\right)}{\eta_{boilers}} EF_{CO_2,NG} \cdot OXID_{NG}$$

b) 2p+1h; 2p+2h
The decreasing of electricity output also can lead to decreasing of heat generated in heating cycle and may increase heat output from peak load boilers. If decreasing of electricity generation will happen in summer season heat generation in heating cycle may not changes. Taking into account this uncertainty the conservative decreasing of fuel consumption is used to obtain baseline emissions.

$$BE = FC_{BL,\lim} \cdot COEF_{NG} \frac{EG_{P,y}}{EG_{BL,\lim}} + \frac{\left(HG_{P,y} - HG_{BL,\lim}\right)}{\eta_{boilers}} EF_{CO_2,NG} \cdot OXID_{NG}$$

where
$EG_{P,y}$: = the electricity (MWh or similar) generated by project plant in year *y*;
$HG_{P,y}$: = the heat (GJ or similar) generated by project plant in year *y*.

For determination of the combined margin (CM) emission factor $EF_{grid,CM,y}$ the methodological tool used version 01.1 “Tool to calculate the emission factor for an electricity system”. The CM emission factor is calculated as the sum of operating margin (OM) and build margin (BM) emission factors multiplied by corresponding weightage coefficients. The data for CM calculation are obtained from statistical forms 6-TP.

STEP 1. Identify the relevant electric power system.

The relevant electric power plant is UES of Russia (see Section B.3).

STEP 2. Select an operating margin (OM) method.

Simple operating margin method can be used since for UES of Russia low-cost/must-run resources constitute less than 50 % of total grid generation. For UES of Russia the installed capacity of low-cost/must-run resources (nuclear and hydro) is 69.8 GW (31.9%), and of fossil fuelled plants with industrial power plants 149.2 GW (68.1%).

Ex-ante option is chosen to calculate CEF.

STEP 3. Calculate the operating margin emission factor according to the selected method.

The simple OM emission factor is calculated as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_{i,m} EG_{m,y} \cdot EF_{EL,m,y}}{\sum_{m} EG_{m,y}}$$

Where:
$EF_{grid,OMsimple,y}$ - the simple OM CO_2 emission factor in year y (tCO_2/MWh);
$EG_{m,y}$ - the net electricity generated and delivered to the grid by power plant/unit *m* in year *y* (MWh);
$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh).
m - all power plants/units serving the grid in year *y* except low-cost/must-run power plants/units;
i - all fossil fuel types combusted in power plant/unit m in year *y*;
y - the three most recent years for which data is available.

STEP 4. Identify the cohort of power units to be included in the build margin (BM).

The cohort of five plants and units that were built most recently are presented in Annex 2 Table 6.

STEP 5. Calculate the build margin emission factor.

The simple BM emission factor calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_{m} EG_{m,y} \cdot EF_{EL,m,y}}{\sum_{m} EG_{m,y}}$$

Where
$EF_{grid,BM,y}$ - the build margin CO_2 emission factor in year y (tCO_2/MWh);
$EG_{m,y}$ - the net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh);
$EF_{EL,m,y}$ - the CO_2 emission factor of power unit m in year y (tCO_2/MWh);
m - power units included in the build margin;
y - most recent historical year for which power generation data is available.

STEP 6. Calculate the combined margin (CM) emission factor.

The baseline emission factor is represented by the combined margin emission factor and calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \cdot w_{OM} + EF_{grid,BM,y} \cdot w_{BM}$$

Where:
$EF_{grid,CM,y}$ - the combined margin CO_2 emission factor in year y (tCO_2/MWh);

$EF_{grid,BM,y}$ - the build margin CO_2 emission factor in year y (tCO_2/MWh);
$EF_{grid,OM,y}$ - the operating margin CO_2 emission factor in year y (tCO_2/MWh);
w_{OM} - the weightage of the operating margin emission factor (%);
w_{BM} - the weightage of the build margin emission factor (%);
Whele the default values were used for w_{OM}=0.5 and for w_{BM}=0.5.

Leakage
Leakages in project are associated with increased fuel use at the plant. At the same time leakage will decrease because of reduced fuel use in other power plants in the grid.

$$LE_{CH_4,y} = GWP_{CH_4} \cdot \left(\begin{array}{l} \left(\sum_f FC_{f,y} \cdot EF_{f,upstream,CH_4} - FC_{BL,\lim} \cdot EF_{NG,upstream,CH_4} \right) NCV_{t.c.e.} - \\ -\left(EG_{P,y} - EG_{BL,\lim} \right) \cdot EF_{BL,upstream,CH_4} \end{array} \right)$$

where
$LE_{CH4,y}$: = leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_{2e};
GWP_{CH4}: = global warming potential of methane valid for the relevant commitment period;
$EF_{f,upstream,CH4}$: = emission factor for upstream fugitive methane emissions from production, transportation and distribution of fuel *f*. It is obtained from the table 2 of CDM methodology AM0029;
$EF_{BL,upstream,CH4}$: = emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project site, as defined below:

$$EF_{BL,upstream,CH_4} = 0.5 \cdot \frac{\sum_{i,k} FF_{i,k} \cdot EF_{k,upstream,CH_4}}{\sum_i EG_i} + 0.5 \cdot \frac{\sum_{j,k} FF_{j,k} \cdot EF_{k,upstream,CH_4}}{\sum_j EG_j}$$

$FF_{j,k}$: = quantity of fuel type k combusted in power plant j included in the build margin
$EF_{k,upstream,CH4}$: = emission factor for upstream fugitive methane emissions from production of the fuel type k in t CH_4 per PJ fuel produced
i: = plants included in the operating margin
j: = plants included in the build margin
EG: = electricity generation in the plant i or j (MWh/yr)

In accordance with methodology AM0029 where total net leakage effects are negative ($LE_y < 0$), project participants should assume $LE_y = 0$.

Emission Reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y$$

where;
ER_y ; = emission reductions in year y (tCO_2e/yr);
BE_y ; = baseline emissions in year y (tCO_2e/yr);
PE_y ; = project emissions in year y (tCO_2/yr);
LE_y ; = leakage emissions in year y (tCO_2/yr).

Not monitored data:

Data / Parameter:	*Remaining lifetime of the power equipments*
Data unit:	Years
Description:	Time when the existing equipment would need to be replaced in the absence of the project activity.
Time of determination/monitoring	
Source of data (to be) used	Project activity
Value of data applied (for ex ante calculations/determinations)	10
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Determined as per the procedure for estimating remaining lifetime of the existing equipments described in PDD Section B.1 p. 13.
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$EG_{CHP, max,hist,yh}$
Data unit:	MWh
Description:	Maximum level of net historical electricity generation by the CHP plant at the project site.
Time of determination/monitoring	
Source of data (to be) used	On-site measurement, statistical data
Value of data applied (for ex ante calculations/determinations)	Historical data presented in Annex 2 Table 4.
Justification of the choice of data or description of measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$EG_{CHP, min,hist,yh}$
Data unit:	MWh
Description:	Minimum level of net historical electricity generation by the CHP plant at the project site.
Time of determination/monitoring	
Source of data (to be) used	On-site measurement, statistical data
Value of data applied (for ex ante calculations/determinations)	724903.6 (Historical data presented in Annex 2 Table 4.)
Justification of the choice of data or description of measurement methods and	

procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	yh
Data unit:	
Description:	Year that uses to establish baseline level of fuel consumption, electricity and heat generation at baseline CHP.
Time of determination/monitoring	
Source of data (to be) used	Calendar
Value of data applied (for ex ante calculations/determinations)	2005
Justification of the choice of data or description of measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$HG_{CHP, yh}$
Data unit:	GJ
Description:	Annual net heat generation that corresponds to the year yh;
Time of determination/monitoring	
Source of data (to be) used	On-site measurement, statistical data
Value of data applied (for ex ante calculations/determinations)	1714800
Justification of the choice of data or description of measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$FC_{CHP, yh}$, $FC_{t.c.e.,hist}$
Data unit:	t.c.e.
Description:	Annual and average fuel consumption that corresponds to the year
Time of determination/monitoring	
Source of data (to be) used	Statistical data
Value of data applied (for ex ante calculations/determinations)	574102
Justification of the choice of data or description of	

measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	η_{boiler}
Data unit:	Non dimensional
Description:	Efficiency of boilers
Time of determination/monitoring	
Source of data (to be) used	Data from supplier
Value of data applied (for ex ante calculations/determinations)	93.5%
Justification of the choice of data or description of measurement methods and procedures (to be) applied	In accordance to the information of design document the boiler efficiency not exceed 93.5%
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	GWP_{CH4}
Data unit:	tCO_2/tCH_4
Description:	Global warming potential of methane valid for the relevant commitment period
Time of determination/monitoring	Once for the commitment period
Source of data (to be) used	IPCC Second Assessment Report ("1995 IPCC GWP values"). Refer to FCCC/CP/1997/7/Add.1 Page 31 item 3.
Value of data applied (for ex ante calculations/determinations)	21
Justification of the choice of data or description of measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data and parameters monitored

Data / Parameter:	$EG_{P,y}$
Data unit:	MWh
Description:	Net quantity of electricity generated by the project activity plant in year *y*
Time of determination/monitoring	Continuous
Source of data (to be) used	On-site measurement

Value of data applied (for ex ante calculations/determinations)	2010: 2 115 222; 2011: 3 607 698; 2012: 3 824 650
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Use energy meters. The consistency of metered net heat generation should be cross-checked with receipts from sales (if available) and the quantity of fuels fired.
QA/QC procedures (to be) applied	Cross check measurement results with invoices for sale of electricity if relevant.
Any comment:	

Data / Parameter:	$HG_{P,y}$
Data unit:	Gcal
Description:	Total quantity of heat generated by the project plant in year *y*
Time of determination/monitoring	Continuous
Source of data (to be) used	On-site measurement
Value of data applied (for ex ante calculations/determinations)	2010: 2 373 468; 2011: 2 859 608; 2012: 2859610
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The consistency of metered net heat generation should be cross-checked with receipts from sales (if available) and the quantity of fuels fired.
QA/QC procedures (to be) applied	Cross check measurement results with invoices for sale of electricity if relevant.
Any comment:	

Data / Parameter:	$FC_{f,y}$
Data unit:	t.c.e.
Description:	Total quantity of fuel *'f'* consumed by the project activity plant in the year *y*
Time of determination/monitoring	Continuously
Source of data (to be) used	On site measurement, statistical data
Value of data applied (for ex ante calculations/determinations)	NG consumption: 715 892; 1 048 141; 1086160 Residual oil: 209 749; 305 739; 316600 Turbine fuel: 4 150; 11 066; 11 066
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Use mass or volume meters
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$FF_{j,k}$
Data unit:	Mass or Volume units

Description:	Total quantity of fuel *'f'* consumed by the plant included in the project boundary
Time of determination/monitoring	yearly
Source of data (to be) used	Statistical data
Value of data applied (for ex ante calculations/determinations)	Total Fuel consumption of plants presented in Annex 2 Table 5.
Justification of the choice of data or description of measurement methods and procedures (to be) applied	
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$EF_{CO2,f,y}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor per unit of energy of fuel *'f'*
Time of determination/monitoring	Monthly, yearly
Source of data (to be) used	Fuel supplier, measurements by the project participants, regional or national default values, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Chapter 2.
Value of data applied (for ex ante calculations/determinations)	Natural Gas: 56.1 Turbine fuel: 71.5 Residual oil: 77.3
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Measurements should be undertaken in line with national or international fuel standards
QA/QC procedures (to be) applied	
Any comment:	Time of determination depends on source

Data / Parameter:	$NCV_{f,y}$
Data unit:	GJ/mass or volume units
Description:	Weighted average net calorific value of the of fuel *'f'* consumed by the plant in the year *y*
Time of determination/monitoring	monthly
Source of data (to be) used	Supplier-provided data
Value of data applied (for ex ante calculations/determinations)	Natural Gas: 33 461 Turbine fuel: 42 675 Residual oil: 40 533
Justification of the choice of data or description of measurement methods and procedures (to be) applied	The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
QA/QC procedures (to be) applied	Verify if the values under are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006

	IPCC Guidelines for National Greenhouse Gas Inventories. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in should have ISO17025 accreditation or justify that they can comply with similar quality standards.
Any comment:	

Data / Parameter:	$OXID_f$
Data unit:	
Description:	Total quantity of fuel *'f'* consumed by the plant included in the project boundary
Time of determination/monitoring	yearly
Source of data (to be) used	IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied (for ex ante calculations/determinations)	1
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (table 1.4) the oxidation factor equal 1
QA/QC procedures (to be) applied	
Any comment:	

Data / Parameter:	$EF_{f,upstream,CH4}$
Data unit:	tCH_4/PJ
Description:	Fugitive CH_4 upstream emission of fuel "*f*"
Time of determination/monitoring	yearly
Source of data (to be) used	Methodology AM0029
Value of data applied (for ex ante calculations/determinations)	Natural Gas, tCH_4/PJ: 921 Coal, tCH_4/kt: 0.8 Residual oil, tCH_4/PJ: 4.1
Justification of the choice of data or description of measurement methods and procedures (to be) applied	Default value suggested by the methodology AM0029, Table 2.
QA/QC procedures (to be) applied	
Any comment:	

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

Step 1. Indication and description of the approach applied

As mentioned in section B.1. The Version 02.2 of the "Combined tool to identify the baseline scenario and demonstrate additionality" is used here.

The Tool has an applicability condition:
"Methodologies using this tool are only applicable if all potential alternative scenarios to the proposed project activity are available options to project participants."

The proposed project would meet this condition, since all plausible alternatives are options available to the project participants.

The Toll comprises four Steps:
Step 1. Identification of alternative scenarios;
Step 2. Barrier analysis;
Step 3. Investment analysis (if applicable);
Step 4. Common practice analysis.

Each Step of the Tool is briefly described below and applied to the project activity. For a full description of the Tool, please see http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-02-v2.2.pdf.

Step 2. Application of the approach chosen

Step 1: Identification of alternative scenarios

This Step serves to identify all alternative scenarios to the proposed CDM project activity(s) that can be the baseline scenario through the following Sub-steps:

Step 1a: Define alternative scenarios to the proposed CDM project activity

Identify all alternative scenarios that are available to the project participants and that provide outputs or services with comparable quality, properties and application areas as the proposed CDM project activity.

These alternative scenarios shall include:

- The proposed project activity undertaken without being registered as a CDM project activity;
- All other plausible and credible alternative scenarios to the project activity scenario, including the common practices in the relevant sector, that deliver outputs or services (e.g. electricity, heat or cement) with comparable quality, properties and application areas, taking into account, where relevant, examples of scenarios identified in the underlying methodology;
- If applicable, continuation of the current situation and, where relevant, the "proposed project activity undertaken without being registered as a CDM project activity" undertaken at a later point in time (e.g. due to existing regulations, end-of-life of existing equipment, financing aspects).

The alternative(s) to the proposed project activity are listed below:

A.1	The proposed project activity not undertaken as a JI project activity.
A.2	The continuation of power and heat generation in the existing cogeneration plant at the project site, with the same technology and configuration, without retrofitting till its remaining operational lifetime. The heat output would be the same as in the historical case, determined by the maximum heat output capacity of the existing CHP plant. The power output would be the same as in the historical case, with the remaining power (difference between project power output and this power output) to be supplied by the interconnected power grid.
A.3	The continuation of power and heat generation in the existing CHP plant and the installation of **new** cogeneration units with technology similar to the existing one. The new capacity addition would be such that the total heat output would be the same as in the proposed project activity.

	Thus, no boiler would be needed to supply increased heat demand in the future, unlike the previous scenario. The CHP capacity addition would also increase electricity output. If the total electricity output (existing + new CHP plant) is lower than the power output in the project scenario, then the excess electricity would be supplied to the grid. If the total power output (existing + new) is below that of the project scenario, then the difference would be purchased from the power grid, as in A.2 above. However, this scenario will consume higher amount of fossil fuel compared to the project activity since the existing technology (e.g. a technology that is common practice in the country) has lower efficiency than that of the project activity

The Tool continues with:

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

All above mentioned alternatives are in compliance with the existing legislation and regulation requirements of the Russian Federation.

Step 2: Barrier analysis

Sub-step 2a: Identify barriers that would prevent the implementation of alternative scenarios

In the following discussion, we describe the barriers facing the proposed project activity.

Barrier of regulatory mechanism for price establishing

At present, the electricity sector in the Russian Federation is beginning its first steps towards an unregulated market, and it is no certain that a fully market-oriented electricity sector will be functional in the near future. Present tariffs usually are not able to fully compensate investment in power generation. Moreover, taking into account regulatory character of origin it can lead to time delay for compensation fuel price change rate[3]. Regulatory function in the Russian Federation is performed by the Federal Tariff Service[4]. The situation with prices for heat generation is the same except that there is no move to establish a market orientation for heat supply. So the current regulatory structure leads to unpredictable economics for investment in power sector, and does not promote increasing the installed power capacity in the Russian Federation.

Investment barrier

TGC-1 is at present constrained to reduce investment into renovation of existing installed capacities. It is shown that company does not have enough resources.

Outcome of Step 2a:

The above analysis shows that barriers would prevent investments in power and heat supply, as is necessary for scenarios A.1 and A.3.

Sub-step 2b: Eliminate alternative scenarios which are prevented by the identified barriers

[3] http://www.e-apbe.ru/analytical/doklad2005/doklad2005_3.php (Rus)

[4] http://www.fstrf.ru/eng

A.1 and A.3 are eliminated from possible baseline scenario. The scenario *A.2* does not require investments and changes in work of Pervomaiskaia CHP-14, and therefore remains as the only viable baseline scenario not subject to barriers.

Outcome of Step 2b: Only alternative A.2 is not prevented by barriers.

Since only one alternative scenario** A.2 **is not prevented by any barrier, and this alternative is not the proposed project activity undertaken without being registered as a JI project activity, then this alternative scenario is identified as the baseline scenario.

Step 3: Investment analysis

The Tool states:

"This Step serves to determine which of the alternative scenarios in the short list remaining after Step 2 is the most economically or financially attractive. For this purpose, an investment comparison analysis is conducted for the remaining alternative scenarios after Step 2. If the investment analysis is conclusive, the economically or financially most attractive alternative scenario is considered as the baseline scenario."

Since only one alternative was determined in step 2 that is not prevented by barriers this step is not needed.

Step 4. Common practice analysis

The thermal power stations using simple cycle for electricity generation dominate power generation in Russia. Presently only few units of power plants of Russia use combined cycle for power generation. The installed capacity of combined cycle power plants in Russia adds up to only 2 % of the total installed capacity of thermal power stations. Until now, these were pilot projects with the main purpose to try new technologies. One of the recently implemented projects –Ivanovskie PGU with gas and steam turbines manufactured in the Russian Federation – was implemented as a testing facility. The previously implemented projects were with foreign turbines.

All projects with combined cycle completed up to now had significant support from Russian monopolist RAO UES. After privatization, the company does not have such possibilities as RAO UES.

As all steps are successfully completed, therefore the proposed project activity is additional.

Step 3. Provision of additionality proofs

The reference to proof barrier of regulatory mechanism presented above. The decision for changing of investing was accepted at committee of directors of "TGC-1" from 19/09/2008

B.3. Description of how the definition of the project boundary is applied to the project:

Project boundary

The spatial extent of the project boundary includes the project power plant and all power plants connected physically to the electricity system that the JI project power plant is connected to.

The electrical power system is the complex of jointly working power plants and networks with common mode of operation and centralized dispatching control. Several jointly working power systems connected together form the power pool system. The term “Consolidated Energy System” (CES) is accepted in Russia. It means several energy systems with common mode of operation and centralized dispatching control. The major part of the energy systems of Russia are integrated into the Unified Energy System of Russia, which includes 6 Consolidated Energy Systems: the Centre, Mid-Volga, Ural, North-West, South and Siberia. The Far East Consolidated Energy System operates segregated from the Unified Energy System of Russia. The geographical boundaries of the CESs mentioned are presented below (Fig. 6).

Figure 6: The Unified Energy System of Russia

Since the project is implemented in the CES of North-West the project boundary shown schematically in fig. 6 includes 6 consolidated energy systems: the Centre, Mid-Volga, Ural, North-West, South and Siberia (UES of Russia).

The spatial extent of the project boundary as defined above is shown in Figure 6. This expanded project boundary takes into consideration that power generated at the project CHP plant and supplied to the grid would displace generation elsewhere in the grid in meeting demand. There is a smaller project boundary that encompasses the physical, geographical site of the cogeneration plant, and is applicable to both the baseline and project scenarios. We consider all GHG emissions within this smaller boundary in detail to determine baseline and project scenarios. Emissions from other power plants are also considered in order to determine the overall emissions in the two scenarios.

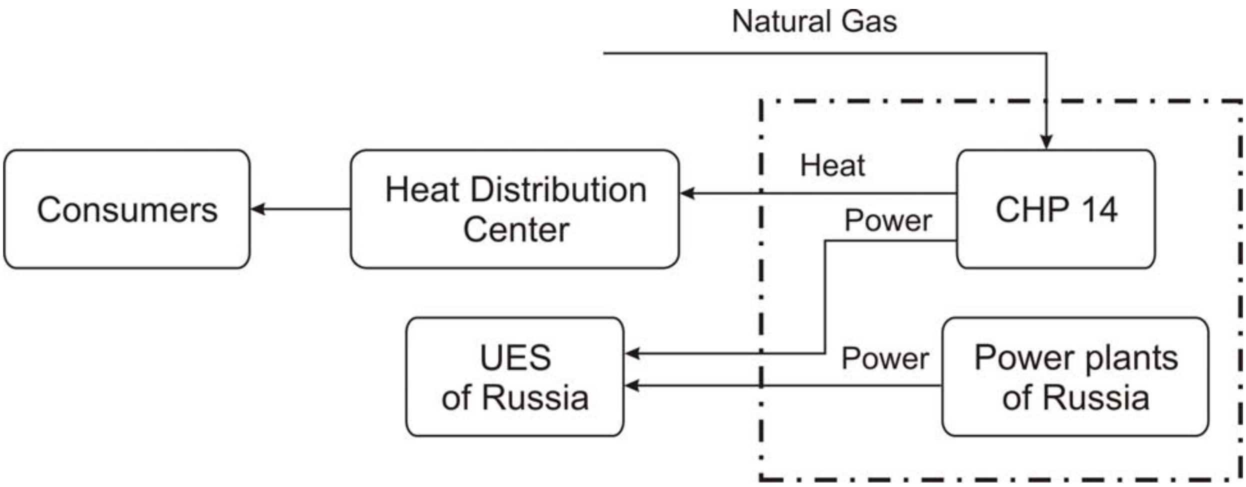

Figure 7: Project Boundary, including the project plant and all power plants in the interconnected power grid, which is the Unified Energy System (UES).

The emissions sources and gases included in (or excluded from) the project boundary are listed below.

	Source	Gas	Included	Justification / Explanation
Baseline	Emissions due to the combustion of fossil fuels for heat and electricity production in the CHP plant at the project site considered in the baseline scenario.	CO_2	Yes	CO_2 is the main emission source
		CH_4	No	Minor Source
		N_2O	No	Minor Source
	Emissions due to the combustion of fossil fuels for electricity production in power plants connected to the grid in the baseline scenario.	CO_2	Yes	CO_2 is the main emission source
		CH_4	No	Minor Source
		N_2O	No	Minor Source
Project Activity	Emissions due to the combustion of fossil fuels for heat and electricity production in the CHP plant at the project site considered in the project scenario.	CO_2	Yes	CO_2 is the main emission source
		CH_4	No	Minor Source
		N_2O	No	Minor Source
	Emissions due to the combustion of fossil fuels for electricity production in power plants connected to the grid in the project scenario.	CO_2	Yes	CO_2 is the main emission source

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

Date of baseline setting: 28/4/2009

The following entities set the baseline:
• **MGM International Ltd** (not project participant)
Tel: +38 044 2792435
e-mail: JIprojects@mgminter.com
• **Energy Carbon Fund (see Annex 1)**

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

07/09/2007 (Beginning of main building construction)

C.2. Expected operational lifetime of the project:

30 years

C.3. Length of the crediting period:

2 years, 9 months.

The starting date of the crediting period is 01/04/2010.

The status of emission reductions or enhancements of net removals generated by JI projects after the end of the first commitment period may be determined by any relevant agreement under the UNFCCC.

The second crediting period will be within agreement but not exceed life time of existing equipment at CHP-14.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

The monitoring plan includes the measurement, maintenance, recording and calibration tasks that should be performed to fulfill the requirements of the selected monitoring methodology and guarantee traceability in emission reduction calculations. The main steps of the monitoring plan are described below.

The primary parameters to be monitored during the crediting period of the project activity are listed below and described above in section B. Other parameters will be calculated using the primary parameters.

For project emissions:

$FC_{f,y}$ - annual fuels *f* consumption in project activity in year *y*;
$NCV_{f,y}$ - net calorific value of fossil fuel type *f* in year *y*;
$EF_{CO2,f,y}$ - emission factors for fuels *f* used in the project activity in year *y*;
$OXID_f$ - the oxidation factor of fuel *f.*

For baseline emissions:

$EG_{P,y}$ - electricity supplied to the grid from CHP-14 after project implementation in year *y*;
Electricity will be monitored using electricity meters which will be maintained and calibrated according to QA/QC procedures. Cross check with electricity sale bills will be performed on a monthly basis.
$HG_{P,y}$ - heat generation by CHP – 14 delivered to the heating system in year *y*.
Heat supplying will be monitored using electricity meters which will be maintained and calibrated according to QA/QC procedures.

Monitoring of parameters used in the calculation of baseline and grid-connected emission factor

The combined margin emission factor ($EF_{grid,CM,y}$) is fixed for the first crediting period using the ex-ante option. To calculate the operating margin emission factor according to the simple method (Option A) the following parameters should be determined only once for the crediting period for the used ex-ante data vintage (for 3 years). The parameters used to calculate $EF_{grid,CM,y}$ are:

Information to clearly identify the plant;
Identification of the plants included in the build margin and the operating margin during the relevant time year(s);
i - the fuel types used;

$FC_{i,m,y}$ - amount of fossil fuel type *i* consumed by power plant/unit *m* per year *y;*

$NCV_{i,y}$ - net calorific value of fossil fuel type *i* in year *y;*
$EF_{CO2,i,y}$ - CO_2 emission factor of fossil fuel type *i* in year *y;*
$EG_{m,y}$ - net electricity generated and delivered to the grid by power plant/unit *m* in year *y.*

Also for the establishing baseline the following parameter and data should be monitoring once for the crediting period.
$EG_{CHP, max,hist,yh}$- the maximum level of historical electricity generation (MWh or similar) in the year *yh*;
$EG_{CHP, min,hist,yh}$- the minimum level of historical electricity generation (MWh or similar) in the year *yh*;
Remaining lifetime of the power equipments;
$HG_{CHP, hist}$- average historical heat generation (GJ or similar) for the last 3 years;
$FC_{t.c.e.,hist}$- the annual average fuel consumption in tons of coal equivalent (t.c.e.) combusted in the CHP during the last 3 years;
$EG_{CHP, hist}$- average historical electricity generation (MWh or similar) for the last 3 years;
$\eta_{boilers}$ - efficiency of boilers at Pervomaiskaia CHP;
GWP_{CH4}- global warming potential of methane valid for the relevant commitment period.

Data management system

A person will be appointed by the project owner to take responsibility for data handling, preparing monitoring reports of greenhouse gas emission reductions and collecting the data for emission reduction verification. (See Section D.3.)

Verification

The verification of project emission reductions will be done annually. The project owner should be responsible for preparing documentation for verification by the Accredited Independent Entity (AIE).

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

This Option 1 is chosen for this project.

D.1.1.1. Data to be collected in order to monitor emissions from the project, and how these data will be archived:								
ID number *(Please use numbers to ease cross-*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/	Comment

referencing to D.2.)							paper)	

The table D.1.1.1. is left blank on purpose since the data to be collected are presented in the tables of Section B.1.

D.1.1.2. Description of formulae used to estimate project emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

$$PE_y = \sum_f FC_{f,y} \cdot COEF_{f,y}$$

where:

$FC_{f,y}$: = the total volume of natural gas or other fuel '*f*' combusted in the project plant or other startup fuel (m^3 or similar) in year(s) *y*

$COEF_{f,y}$: = the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and obtained as:

$$COEF_y = NCV_{f,y} \cdot EF_{CO_2,f,y} \cdot OXID_f$$

where:

$NCV_{f,y}$: = the net calorific value (energy content) per volume unit of fuel *f* in year *y* (GJ/m^3 or similar) as determined from the fuel supplier;

$EF_{CO2,f,y}$: = the CO_2 emission factor per unit of energy of fuel *f* in year *y* (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

$OXID_f$: = the oxidation factor of fuel *f*.

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

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

The table D.1.1.3. is left blank on purpose since the data to be collected are presented in the tables of Section B.1.

D.1.1.4. Description of formulae used to estimate baseline emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

$$P_{BL,grid}E + H_{BL,boiler}E \geq CHP_{hist}E$$

where

$P_{BL,grid}E$: = the CO_2 emission (tCO_2) from electricity grid in equivalent of historical level from CHP;
$H_{BL,boiler}E$: = the CO_2 emission (tCO_2) from heat generation in equivalent of historical level from CHP;
$CHP_{hist}E$: = the CO_2 emission (tCO_2) from CHP for heat and electricity generation at historical level.

If this inequality is *true* then as limit of baseline power generation uses maximum of historical electricity generation at the plant. And all historical level of fuel consumption and heat generation also corresponds to this year of electricity generation.

$$EG_{BL,\lim} = EG_{CHP,\max,hist,yh};\ HG_{BL,\lim} = HG_{CHP,yh};\ FC_{BL,\lim} = FC_{CHP,yh}$$

where

$EG_{BL,lim}$: = the limit of baseline electricity generation (MWh or similar);
$EG_{CHP, max,hist,yh}$: = the maximum level of historical electricity generation (MWh or similar) in the year *yh*;
yh: = is year of the maximum historical electricity generation;
$HG_{BL,lim}$: = the limit of baseline heat generation (GJ or similar);
$HG_{CHP, yh}$: = the heat generation (GJ or similar) that corresponds to the year *yh*;
$FC_{BL,lim}$: = the limit of baseline fuel consumption (m^3 or similar);
$FC_{CHP, yh}$: = the fuel consumption (m^3 or similar) that corresponds to the year *yh*.

If the inequality is *false* then as limit of baseline power generation uses minimum of historical electricity generation at the plant. And all historical level of fuel consumption and heat generation also corresponds to this year of electricity generation.

$$EG_{BL,\lim} = EG_{CHP,\min,hist,yh};\ HG_{BL,\lim} = HG_{CHP,yh};\ FC_{BL,\lim} = FC_{CHP,yh}$$

where

$EG_{BL,lim}$: = the limit of baseline electricity generation (MWh or similar);
$EG_{CHP, min,hist,yh}$: = the minimum level of historical electricity generation (MWh or similar) in the year *yh*;

yh: = is year of the minimum historical electricity generation;
$HG_{BL,lim}$: = the limit of baseline heat generation(GJ or similar);
$HG_{CHP,\,yh}$: = the heat generation (GJ or similar) that corresponds to the year *yh*;
$FC_{BL,lim}$: = the limit of baseline fuel consumption (t.c.e. or similar);
$FC_{CHP,\,yh}$: = the fuel consumption (t.c.e. or similar) that corresponds to the year *yh*.

Emission from the electricity grid ($P_{BL,grid}E$) in equivalent of historical level from CHP calculated as follow:

$$P_{BL,grid}E = EG_{CHP,hist} \cdot EF_{grid,CM,y}$$

where
$EG_{CHP,\,hist}$: = average historical electricity generation (MWh or similar) for the last 3 years;
$EF_{grid,CM,y}$: = the baseline emission factor (tCO_{2e}/MWh) for the UES of Russia electricity grid is calculated as a combined margin (CM) emission factor, consisting of the combination of operating margin (OM) and build margin (BM) emission factors according to the methodological tool version 01.1 “Tool to calculate the emission factor for an electricity system”.

Emission from the boilers ($P_{BL,grid}E$) in equivalent of historical level from CHP calculated as follow:

$$H_{BL,grid}E = \frac{HG_{CHP,hist}}{\eta_{boiler}} \cdot EF_{CO_2,NG} \cdot OXID_{NG}$$

where
$EF_{CO2,NG}$: = CO_2 emission factor per unit of energy of natural gas (tCO_2/GJ) as determined based on national average fuel data, if available, otherwise IPCC defaults can be used;
η_{boiler} : = efficiency of the boilers that generates heat in equivalent of historical quantity, determines in conservative way;
$HG_{CHP,\,hist}$: = average historical heat generation (GJ or similar) for the last 3 years;
$OXID_{NG}$: = the oxidation factor of natural gas.

Emission from CHP plant ($CHP_{hist}E$) for heat and electricity generation at historical level;

$$CHP_{hist}E = FC_{t.c.e.,hist} \cdot COEF_{NG}$$

where:
$FC_{t.c.e.,hist}$: = the annual average fuel consumption in tons of coal equivalent (t.c.e.) combusted in the CHP during the last 3 years;
$COEF_{NG}$: = the CO_2 emission coefficient (tCO_2/m^3 or similar) for natural gas and obtained as:

$$COEF_{NG} = NCV_{t.c.e.} \cdot EF_{CO_2,NG} \cdot OXID_{NG}$$

where:
$NCV_{t.c.e.}$: = the net calorific value (energy content) of t.c.e. (GJ/t.c.e.).

Define baseline emission BE for the following cases:
a) 1p+1h; 1p+2h

$$BE = FC_{BL,\lim} \cdot COEF_{NG} + EF_{grid,CM,y}\left(EG_{P,y} - EG_{BL,\lim}\right) + \frac{\left(HG_{P,y} - HG_{BL,\lim}\right)}{\eta_{boilers}} EF_{CO_2,NG} \cdot OXID_{NG}$$

b) 2p+1h; 2p+2h
The decreasing of electricity output also can lead to decreasing of heat generated in heating cycle and may increase heat output from peak load boilers. If decreasing of electricity generation will happen in summer season heat generation in heating cycle may not changes. Taking into account this uncertainty the conservative decreasing of fuel consumption is used to obtain baseline emissions.

$$BE = FC_{BL,\lim} \cdot COEF_{NG} \frac{EG_{P,y}}{EG_{BL,\lim}} + \frac{\left(HG_{P,y} - HG_{BL,\lim}\right)}{\eta_{boilers}} EF_{CO_2,NG} \cdot OXID_{NG}$$

where
$EG_{P,y}$: = the electricity (MWh or similar) generated by project plant in year *y*;
$HG_{P,y}$: = the heat (GJ or similar) generated by project plant in year *y*.

For determination of the combined margin (CM) emission factor $EF_{grid,CM,y}$ the methodological tool used version 01.1 “Tool to calculate the emission factor for an electricity system”. The CM emission factor is calculated as the sum of operating margin (OM) and build margin (BM) emission factors multiplied by corresponding weightage coefficients. The data for CM calculation are obtained from statistical forms 6-TP.

STEP 1. Identify the relevant electric power system.

The relevant electric power plant is UES of Russia (see Section B.3).

STEP 2. Select an operating margin (OM) method.

Simple operating margin method can be used since for UES of Russia low-cost/must-run resources constitute less than 50 % of total grid generation. For UES of Russia the installed capacity of low-cost/must-run resources (nuclear and hydro) is 69.8 GW (31.9%), and of fossil fuelled plants with industrial power plants 149.2 GW (68.1%).

Ex-ante option is chosen to calculate CEF.

STEP 3. Calculate the operating margin emission factor according to the selected method.

The simple OM emission factor is calculated as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_{i,m} EG_{m,y} \cdot EF_{EL,m,y}}{\sum_{m} EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,y}$ - the simple OM CO_2 emission factor in year y (tCO_2/MWh);

$EG_{m,y}$ - the net electricity generated and delivered to the grid by power plant/unit *m* in year *y* (MWh);

$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh).

m - all power plants/units serving the grid in year *y* except low-cost/must-run power plants/units;

i - all fossil fuel types combusted in power plant/unit m in year *y*;

y - the three most recent years for which data is available.

STEP 4. Identify the cohort of power units to be included in the build margin (BM).

The cohort of five plants and units that were built most recently are presented in Annex 2 Table 6.

STEP 5. Calculate the build margin emission factor.

The simple BM emission factor calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where

$EF_{grid,BM,y}$ - the build margin CO_2 emission factor in year y (tCO_2/MWh);
$EG_{m,y}$ - the net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh);
$EF_{EL,m,y}$ - the CO_2 emission factor of power unit m in year y (tCO_2/MWh);
m - power units included in the build margin;
y - most recent historical year for which power generation data is available.

STEP 6. Calculate the combined margin (CM) emission factor.

The baseline emission factor is represented by the combined margin emission factor and calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \cdot w_{OM} + EF_{grid,BM,y} \cdot w_{BM}$$

Where:

$EF_{grid,CM,y}$ - the combined margin CO_2 emission factor in year y (tCO_2/MWh);
$EF_{grid,BM,y}$ - the build margin CO_2 emission factor in year y (tCO_2/MWh);
$EF_{grid,OM,y}$ - the operating margin CO_2 emission factor in year y (tCO_2/MWh);
w_{OM} - the weightage of the operating margin emission factor (%);
w_{BM} - the weightage of the build margin emission factor (%);
Whele the default values were used for w_{OM}=0.5 and for w_{BM}=0.5.

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

This Option 2 is not used in the project.

D.1.2.1. Data to be collected in order to monitor emission reductions from the project, and how these data will be archived:

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

This option is not used in the project.

D.1.2.2. Description of formulae used to calculate emission reductions from the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

This option is not used in the project.

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

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

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

The table D.1.3.1. is left blank on purpose since the data to be collected are presented in the tables of Section B.1.

D.1.3.2. Description of formulae used to estimate leakage (for each gas, source etc.; emissions in units of CO_2 equivalent):

Leakages in project are associated with increased fuel use at the plant. At the same time leakage will decrease because of reduced fuel use in other power plants in the grid.

$$LE_{CH_4,y} = GWP_{CH_4} \cdot \begin{pmatrix} \left(\sum_f FC_{f,y} \cdot EF_{f,upstream,CH_4} - FC_{BL,\lim} \cdot EF_{NG,upstream,CH_4} \right) NCV_{t.c.e.} - \\ -\left(EG_{P,y} - EG_{BL,\lim} \right) \cdot EF_{BL,upstream,CH_4} \end{pmatrix}$$

where

$LE_{CH4,y}$: = leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_{2e};

GWP_{CH4}: = global warming potential of methane valid for the relevant commitment period;

$EF_{f,upstream,CH4}$: = emission factor for upstream fugitive methane emissions from production, transportation and distribution of fuel *f*. It is obtained from the table 2 of CDM methodology AM0029;

$EF_{BL,upstream,CH4}$: = emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project site, as defined below:

$$EF_{BL,upstream,CH_4} = 0.5 \cdot \frac{\sum_{i,k} FF_{i,k} \cdot EF_{k,upstream,CH_4}}{\sum_i EG_i} + 0.5 \cdot \frac{\sum_{j,k} FF_{j,k} \cdot EF_{k,upstream,CH_4}}{\sum_j EG_j}$$

$FF_{j,k}$: = quantity of fuel type *k* combusted in power plant *j* included in the build margin

$EF_{k,upstream,CH4}$: = emission factor for upstream fugitive methane emissions from production of the fuel type *k* in t CH_4 per PJ fuel produced

i: = plants included in the operating margin

j: = plants included in the build margin

EG: = electricity generation in the plant *i* or *j* (MWh/yr)

In accordance with methodology AM0029 where total net leakage effects are negative ($LE_y < 0$), project participants should assume $LE_y = 0$.

D.1.4. Description of formulae used to estimate emission reductions for the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y$$

where;
ER_y ; = emission reductions in year y (tCO_2e/yr);
BE_y ; = baseline emissions in year y (tCO_2e/yr);
PE_y ; = project emissions in year y (tCO_2/yr);
LE_y ; = leakage emissions in year y (tCO_2/yr).

D.1.5. Where applicable, in accordance with procedures as required by the host Party, information on the collection and archiving of information on the environmental impacts of the project:

In accordance with Federal Governmental Body "RosTechNadzor" requirements the information about emission into the air recorded and kept in "Form #2-TP (Air)"[5].

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:

Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.

The section D.2. is left blank on purpose since relevant QA/QC procedures are presented in the table of Section B.1.

D.3. Please describe the operational and management structure that the project operator will apply in implementing the monitoring plan:

The monitoring plan will be implemented by the OJSC "TGC-1" to ensure that the project emission reductions during the crediting period are verifiable. Monitoring plan for the project activity includes the details of the operation and management of the project activity during the crediting period and the measurement of the parameters in baseline and project scenarios that will be used to calculate actual emission reductions. The basic management structure is shown below in the fig. 8.

[5] http://www.rosnadzor.nnov.ru/zakon/2tpvoz.doc

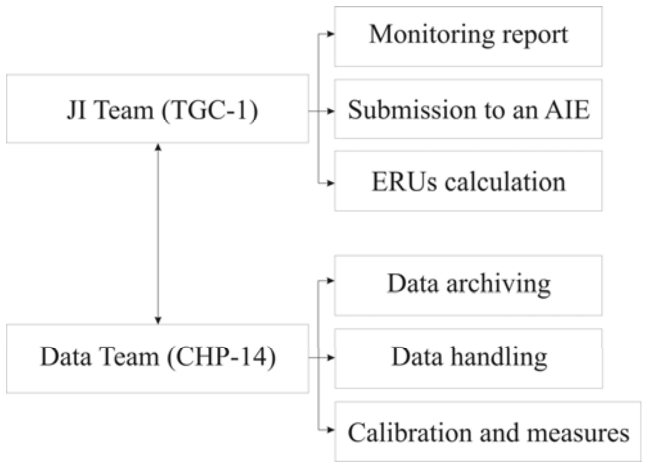

Figure 8: The management structure

The management and operational structure for monitoring of the project activity is as follows. The project owner will set up a JI Team to take charge of preparing and archiving monitoring reports, checking obtaining data, support validation process. Also TGC-1 establishes personnel (Data team) who will be responsible for data support of JI Team at CHP 14. The monitoring plan does not foresee any additional measures. All data collects from measurement equipment that will install with project implementation and standardized form of data handling are used. The personnel of CHP-14 are responsible for calibration and maintenance of measurement equipment in accordance with national rules and standards and providing measurement of parameters. The project owner will organize the training of personnel for providing monitoring plan management and support of ERUs verification procedures.

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

The following entity established the monitoring plan:
Energy Carbon Fund (see Annex 1)
MGM International Ltd (not project participant)
Tel: +38 044 2792435
e-mail: JIprojects@mgminter.com

SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

The project activity is electricity and heat generation using natural gas as primary fuel and gas turbine fuel as reserve fuel. Residual oil is also used for peak load boilers and old CHP units

Table 6: Project GHG emissions

Year	2010	2011	2012
PE_y, tCO_2/year	1 660 916	2 439 142	2 526 257

E.2. Estimated leakage:

Table 7: GHG leakage emissions

Year	2010	2011	2012
LE_y, tCO_2/year	-129 503	-268 730	-288 985

In accordance with methodology AM0029 where total net leakage effects are negative ($LEy < 0$), project participants should assume $LEy = 0$. So ***LEy=0*** tCO_2e/yr.

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

Table 8: The sum of project GHG emissions and leakage (taken to be zero)

Year	2010	2011	2012
PE_y,+ LEy tCO_2/year	1 660 916	2 439 142	2 526 257

E.4. Estimated baseline emissions:

Table 9: Baseline GHG emissions

Year	2010	2011	2012
BE_y, tCO_2/year	1 893 599	2 857 567	2 979 942

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

Table 10: GHG emission reductions

Year	2010	2011	2012
BE_y, - PE_y,+ LEy **tCO_2/year**	232 683	418 426	453 685

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

Year	Estimated project emissions (tonnes of CO_2 equivalent)	Estimated leakage (tonnes of CO_2 equivalent)	Estimated baseline emissions (tonnes of CO_2 equivalent)	Estimated emission reductions (tonnes of CO_2 equivalent)
2010	1 660 916	0	1 893 599	232 683
2011	2 439 142	0	2 857 567	418 426
2012	2 526 257	0	2 979 942	453 685
Total (tonnes of CO_2 equivalent)	6 626 315	0	7 731 108	1 104 794

SECTION F. Environmental impacts

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

The analysis of the environmental impacts of the project performed in project design documentation in section “Environment protection”[6].

From the environmental impact stand point of view, the presented analyses in the assessment indicates the reduction of CHP anthropogenic impact after a reconstruction comparing to existent situation.

CHP environmental impact includes atmospheric air, water environment, as well as waste disposal Contamination of atmosphere, caused by the CHP - 14 emissions after the reconstruction reduces according to all calculation parameters, including in part of gross emissions and on the ground level concentrations in residential territory.

When fuel oil (especially high-sulphurous) is used, current atmosphere pollution substantially increases, and when taking into account a background there is an exceeding of sanitary norms on nitrogen dioxide and combination of nitrogen and sulphur dioxides. It is recommended to limit the use of fuel oil (as a contingency fuel) to 5 %.
The impact on water bodies after the reconstruction is practically eliminated, because all discharges (waste waters) of the CHP are collected by the sewage system. Production waste water are refined its own high-efficient wastewater treatment facilities. The pipe bend chart of rain and melted waters after the reconstruction are designed to be collected (with the separation into rain and oil-containing discharges) with the subsequent refining on the designed wastewater treatment facilities. After cleaning the repeated use of purified sewages is foreseen.

Domestic discharges are directed into the centralized city sewage system with the subsequent refining on the municipal wastewater treatment.

The water consumption and subsequent discharge volumes after the reconstruction will reduce due to the application of the efficient cooling systems and repeated use of the cleared waters.

After a reconstruction the amount of generated solid waste at the power station considerably will decrease, mainly due to the exclusion of coal ash and stone breed crow-bar accumulation volumes in coal that constitute s more than 96 % of all production waste.

Most waste (no less than 85 %) is not higher than fourth class of danger. Waste is transferred mainly external (off-site) organizations. The only temporary accumulation is foreseen in the specially equipped places on industrial territory site.

The influence on the flora and fauna is practically absent, because the designed object is located on the existent industrial site.

Reconstruction of CHP - 14 will not result in vegetation development failure and deforestation, as well it will not lead to worsening of the hydrological mode of water bodies, relief and surface discharge parameters.

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[6] Reconstruction of Pervomaiskaia CHP (CHP-14) OJSC TGK-1“Nevskiy” branch. Environment protection, OJSC “Company EMK-Engineering”, Moscow, 2008

As the project reduces contaminant emissions, therefore the project does not have transboundary impact.

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

On the basis of material presented to the AIE it was concluded that there is no significant impact on the environment.

SECTION G. Stakeholders' comments

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

The stakeholders' comments on the "Reconstruction of Pervomayskaia CHP -14 with installation of combined cycle units" will be compiled after obtaining responses from environmental competent authorities.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

Organisation:	OJSC "TGC-1"
Street/P.O.Box:	Marsovo Pole
Building:	1
City:	St. Petersburg
State/Region:	
Postal code:	191186
Country:	Russian Federation
Phone:	+7 (812) 494 3606
Fax:	+7 (812) 494 3477
E-mail:	office@tgc1.ru
URL:	http://www.tgc1.ru
Represented by:	Valery Nikolayevich Rodin
Title:	
Salutation:	
Last name:	Rodin
Middle name:	Nikolayevich
First name:	Valery
Department:	
Phone (direct):	+7 (812) 494-30-18; +7 (812) 494-31-22
Fax (direct):	+7 (812) 4943477
Mobile:	
Personal e-mail:	office@tgc1.ru

Organisation:	ECF Project Ltd
Street/P.O.Box:	Krzhizhanovskogo street
Building:	7, building 2
City:	Moscow
State/Region:	
Postal code:	109004
Country:	Russia
Phone:	
Fax:	
E-mail:	ecf@energyfund.ru
URL:	http://www.carbonfund.ru/home/
Represented by:	Gleb Anikin
Title:	Mr.
Salutation:	
Last name:	Anikin
Middle name:	Vladislavovich
First name:	Gleb
Department:	
Phone (direct):	+7 495 748 79 60
Fax (direct):	+7 495 748 79 60
Mobile:	
Personal e-mail:	anikingv@energyfund.ru

Organisation:	Fortum Power and Heat Oy
Street/P.O.Box:	Keilaniementie / P.O. Box 100,
Building:	1
City:	Espoo
State/Region:	
Postal code:	00048
Country:	FINLAND
Phone:	+358104528900
Fax:	
E-mail:	
URL:	
Represented by:	Evgenia Tkachenko
Title:	Development director
Salutation:	Mrs.
Last name:	Tkachenko
Middle name:	
First name:	Evgenia
Department:	Fortum Service
Phone (direct):	+7 922 639 41 73
Fax (direct):	
Mobile:	+7 922 639 41 73
Personal e-mail:	Evgenia.tkachenko@fortum.com

Annex 2

BASELINE INFORMATION

The combined margin emission factor was determined to estimate baseline emissions for the UES of Russia in accordance with the "Tool to calculate the emission factor for an electricity system". In Table 1 of Annex 2, the groups of fossil fuel power stations of the UES of Russia (except CES of East) are presented.

Table 1 of Annex 2: Structure of the UES of Russia

Structure of the UES of Russia								
#	CES	Plant	2005		2006		2007	
			$EF_{EL,m,y}$, tCO_2/GWh	Electricity, mln kWh	$EF_{EL,m,y}$, tCO_2/GWh	Electricity, mln kWh	$EF_{EL,m,y}$, tCO_2/GWh	Electricity, mln kWh
1	2	3	4	5	6	7	8	9
1	Center	Belgorodskaya CHPP	649.6	94.5	619.5	88.0	549.6	120.0
2	Center	Gubkinskaya CHPP	653.2	81.8	635.1	83.4	619.8	77.7
3	Center	Voronezhskaya CHPP-1	708.2	754.0	691.6	756.9	693.0	716.7
4	Center	Kurskaya CHPP-1	567.8	879.3	560.2	781.1	539.4	750.2
5	Center	Kurskaya CHPP-4	666.5	9.1	613.7	11.4	611.3	6.6
6	Center	Lipeckaya CHPP-2	567.3	1669.9	620.0	1522.1	618.2	1555.3
7	Center	Eleckaya CHPP	759.8	36.0	759.5	45.2	717.2	44.7
8	Center	Dankovskaya CHPP	737.3	29.3	776.3	32.7	770.2	30.9
9	Center	Orlovskaya CHPP	513.1	1212.9	493.5	1200.7	480.1	1154.3
10	Center	Livenskaya CHPP	573.5	39.5	689.8	39.8	760.6	30.7
11	Center	Ryazanskaya TPP	696.0	6244.5	730.0	7366.8	702.8	7802.3
12	Center	TPP-24 (Moscow)	528.4	1439.8	522.9	1675.0	523.7	1750.4
13	Center	Dyagilevskaya CHPP	519.7	414.6	528.5	416.6	532.7	425.7
14	Center	Smolenskaya TPP	600.7	1992.1	714.1	2213.3	617.8	1944.1
15	Center	Smolenskaya CHPP-2	486.2	1647.2	476.2	1453.6	480.2	1555.5
16	Center	Dorogobuzhskaya CHPP	743.0	228.5	680.6	168.3	619.0	108.6
17	Center	Bryanskaya TPP	836.7	184.0	876.1	66.9	857.8	109.0
18	Center	Klincovskaya CHPP	677.6	30.7	632.6	32.8	690.0	32.0
19	Center	Kaluzhskaia CHPP-1	1088.0	32.7	1060.5	26.9	958.2	21.8
20	Center	Tambovskaya CHPP	585.5	894.1	578.7	925.7	545.1	823.4
21	Center	Kotovskaya CHPP-2	671.9	220.9	673.7	179.7	649.8	138.7
22	Center	Cherepetskaya TPP	1136.0	2341.5	1097.1	3099.4	1115.1	2931.5
23	Center	Schekinskaya TPP	591.1	1641.7	587.6	1838.4	591.5	1733.4
24	Center	Novomoskovskaya TPP	688.2	573.1	697.4	423.0	761.5	439.5
25	Center	Aleksinskaya CHPP	706.2	289.8	768.5	214.4	758.7	181.6
26	Center	Pervomajskaya CHPP	605.8	379.7	593.1	393.0	655.0	329.7
27	Center	Efremovskaya CHPP	576.6	281.3	637.3	280.5	586.0	327.9
28	Center	Dzerzhinskaia CHPP	601.5	1586.0	555.6	2447.3	538.1	2133.4
29	Center	Nizhegorodskaya TPP	579.4	605.1	559.0	628.7	556.4	605.8

30	Center	Igumnovskaya CHPP	1338.6	164.8	1253.0	147.9	1291.2	105.8
31	Center	Novogorkovskaya CHPP	660.2	866.8	630.3	820.6	636.9	739.3
32	Center	Sormovskaya CHPP	657.5	1113.7	617.2	1181.3	597.1	1132.4
33	Center	Vladimirskaya CHPP-2	509.2	1968.7	508.0	1923.3	501.4	1861.0
34	Center	Kashirskaya TPP-4	647.0	5858.1	711.5	6274.6	671.7	6033.2
35	Center	Shaturskaya TPP-5	736.0	4252.3	694.8	4412.2	655.5	4555.2
36	Center	GES-1 im.Smidovicha	571.1	298.4	566.5	294.1	641.0	312.0
37	Center	TPP-3 im.Klassona	734.3	118.6	761.7	151.1	720.6	148.1
38	Center	CHPP-6 [Moscow]	855.6	27.2	869.5	27.9	926.3	23.7
39	Center	CHPP-8 [Moscow]	548.2	2694.7	554.6	2885.7	553.6	2673.5
40	Center	CHPP-9 [Moscow]	523.7	1353.0	518.4	1230.4	523.5	1225.6
41	Center	CHPP-11 [Moscow]	497.0	1781.8	515.2	1917.9	509.9	1935.3
42	Center	CHPP-12 [Moscow]	501.8	2456.2	493.5	2397.4	497.6	2569.9
43	Center	CHPP-16 [Moscow]	525.9	2132.8	529.1	2174.5	526.0	2120.5
44	Center	CHPP-17 [Moscow]	768.4	486.6	752.4	542.8	774.8	678.0
45	Center	CHPP-20 [Moscow]	497.7	3619.6	520.1	4104.2	511.2	4006.2
46	Center	CHPP-21 [Moscow]	429.6	8225.2	429.7	8348.1	436.0	8471.6
47	Center	CHPP-22 [Moscow]	519.1	7836.7	534.6	8485.8	505.7	8020.8
48	Center	CHPP-23 [Moscow]	448.3	8366.3	458.8	8647.8	455.3	8388.6
49	Center	CHPP-25 [Moscow]	463.0	8093.8	465.8	8314.9	471.2	8617.7
50	Center	CHPP-26 [Moscow]	442.0	7834.6	444.5	8550.4	438.2	8088.4
51	Center	CHPP-27 [Moscow]	431.8	1120.4	425.8	1161.7	411.1	1364.8
52	Center	CHPP-28 [Moscow]	526.4	84.4	526.1	83.0	518.3	77.7
53	Center	Ivanovskaya CHPP-1	491.7	42.2	459.1	44.8	413.7	53.6
54	Center	Ivanovskaya CHPP-2	706.6	513.4	726.1	536.2	747.9	530.2
55	Center	Ivanovskaya CHPP-3	506.7	923.0	507.5	953.1	513.5	1066.1
56	Center	Yaroslavskaya CHPP-1	617.8	374.2	643.2	394.4	620.3	401.9
57	Center	Yaroslavskaya CHPP-2	620.5	734.7	638.2	734.3	578.0	810.0
58	Center	Yaroslavskaya CHPP-3	557.8	1104.0	574.2	1097.0	543.6	1158.4
59	Center	Konakovskaia TPP	607.6	6297.0	630.6	8149.3	606.8	8200.3
60	Center	Tverskaya CHPP-1	810.5	56.5	815.1	55.3	886.1	46.5
61	Center	Tverskaya CHPP-3	463.5	765.4	475.1	972.7	458.4	851.4
62	Center	Tverskaya CHPP-4	607.3	351.1	630.6	356.5	600.4	357.7
63	Center	Vyshnevolockaya CHPP	853.9	14.1	850.6	13.1	846.9	14.2
64	Center	Kostromskaya TPP	499.2	11630	515.9	12359	501.5	12964
65	Center	Kostromskaya CHPP-1	754.9	94.2	782.1	92.3	736.3	77.6
66	Center	Kostromskaya CHPP-2	500.1	970.4	510.6	966.8	491.1	929.4
67	Center	Sharinska CHPP	1224.8	31.3	1327.6	26.2	1240.6	20.3
68	Center	Cherepoveckaya TPP	752.6	2467.9	894.5	3026.7	876.7	3174.3
69	Center	Vologodskaia CHPP	684.4	78.0	690.6	80.5	672.3	82.4
70	North-West	Arhangel'skaya CHPP	661.4	1397.6	684.7	1460.4	701.3	1739.3
71	North-West	Severodvinskaya CHPP-2	715.7	711.1	720.3	484.6	711.6	629.7
72	North-West	Severodvinskaya CHPP-1	998.2	747.0	1019.7	1028.3	1045.2	957.7
73	North-West	Petrozavodskaya CHPP	438.9	785.6	436.7	803.8	446.9	867.2
74	North-West	Leningradskaya CHPP-5	691.4	137.8	549.2	338.7	427.3	1002.8

75	North-West	Leningradskaya CHPP-7	536.5	523.5	518.8	553.4	507.7	539.5
76	North-West	Vyborgskaya CHPP-17	496.8	1014.5	539.3	1046.9	511.1	1016.1
77	North-West	Dubrovskaya CHPP-8	761.8	278.0	766.5	245.0	748.0	247.3
78	North-West	Pervomajskaya CHPP-14	650.6	724.9	609.3	758.6	596.3	900.4
79	North-West	Avtovskaya CHPP-15	529.8	1237.8	579.7	1176.9	570.5	1260.2
80	North-West	CHPP-21	464.1	2207.3	488.3	2000.4	472.2	2013.1
81	North-West	Yuzhnaya CHPP-22	464.3	2733.1	473.1	2615.8	442.6	2720.3
82	North-West	Kirishskaya TPP	571.9	5660.3	609.1	6911.2	566.9	6258.9
83	North-West	Severo-Zapadnaya CHPP	415.5	2616.0	406.6	3323.9	377.5	3313.3
84	North-West	Vorkutinskaya CHPP-1	1341.1	87.1	1347.2	96.5	1353.8	95.4
85	North-West	Vorkutinskaya CHPP-2	1195.1	982.4	1187.1	1039.1	1212.8	970.2
86	North-West	Intinskaya CHPP	889.4	49.0	1124.8	44.5	1124.0	41.0
87	North-West	Pechorskaya TPP	534.7	2994.3	538.6	3273.9	536.0	3446.2
88	North-West	Sosnogorskaya CHPP	624.7	1600.4	630.7	1445.4	626.7	1424.5
89	North-West	Apatitskaya CHPP	919.9	369.4	919.6	368.7	901.7	357.8
90	North-West	Murmanskaya CHPP	1298.0	14.5	1233.9	16.5	1061.1	19.0
91	North-West	Novgorodskaya CHPP-20	608.9	757.8	616.2	685.1	620.9	720.2
92	Middle Volga	Joshkar-Olinskaya CHPP	475.3	998.8	474.2	925.3	481.5	938.7
93	Middle Volga	Saranskaya CHPP-2	525.2	1435.6	543.9	1443.3	531.7	1357.9
94	Middle Volga	Alekseevskaya CHPP-3	699.2	6.6	715.1	6.3	1026.3	2.6
95	Middle Volga	Bezymyanskaya CHPP	559.4	753.2	587.1	779.1	628.1	720.0
96	Middle Volga	Novokujbyshevskaya CHPP-1	643.4	437.9	652.1	466.3	648.5	483.5
97	Middle Volga	Novokujbyshevskaya CHPP-2	705.8	884.7	720.3	993.7	714.9	923.7
98	Middle Volga	Samarskaya CHPP	533.6	1880.1	529.5	2001.6	500.5	1918.0
99	Middle Volga	Syzranskaya CHPP	578.3	750.0	560.5	849.7	539.7	662.7
100	Middle Volga	Tol'yattinskaya CHPP	557.3	2314.7	566.8	2533.5	573.8	2398.1
101	Middle Volga	CHPP of VAZ	498.2	4624.6	512.3	4772.5	502.1	4671.6
102	Middle	Samarskaya TPP	654.8	175.3	635.7	174.1	639.0	172.9

	Volga							
103	Middle Volga	Kuzneckaya CHPP-3	533.8	6.5	518.1	10.5	542.7	11.8
104	Middle Volga	Penzenskaya CHPP-1	511.8	1657.0	511.7	1599.4	504.5	1451.4
105	Middle Volga	Penzenskaya CHPP-2	617.4	44.3	619.5	36.2	608.0	37.4
106	Middle Volga	Ul'yanovskaya CHPP-1	487.7	1633.5	477.2	1534.6	486.2	1565.3
107	Middle Volga	Ul'yanovskaya CHPP-2	489.3	1341.6	486.9	1042.9	495.1	1056.1
108	Middle Volga	Novocheboksarskaya CHPP-3	472.2	832.0	485.9	856.9	520.5	1064.6
109	Middle Volga	Cheboksarskaya CHPP-1	426.3	19.3	428.4	20.5	437.6	21.2
110	Middle Volga	Cheboksarskaya CHPP-2	445.4	1121.5	455.2	1216.9	479.5	1332.9
111	Middle Volga	Balakovskaya CHPP-4	555.1	1463.8	562.7	1341.0	541.9	1294.2
112	Middle Volga	Saratovskaya TPP	626.0	195.5	578.4	198.2	617.0	195.4
113	Middle Volga	Saratovskaya CHPP-2	606.2	809.0	636.7	709.5	605.9	732.4
114	Middle Volga	Saratovskaya CHPP-5	478.8	1885.2	482.4	1846.9	465.1	1788.2
115	Middle Volga	Engel'skaya CHPP-3	566.4	401.3	619.6	510.3	599.0	482.1
116		Saratovskaya CHPP-1	676.0	40.5	709.5	37.1	684.2	37.5
117	Middle Volga	Zainskaya TPP	562.9	9027.0	572.0	9196.2	559.3	8917.8
118	Middle Volga	Nizhnekamskaya CHPP-1	483.0	2946.3	495.3	3315.4	483.7	3170.3
119	Middle Volga	Naberenochelninskaya CHPP	464.0	3689.2	483.7	4178.9	464.2	4081.6
120	Middle Volga	Nizhnekamskaya CHPP-2	494.0	1180.8	505.7	1098.2	486.7	1291.4
121	Middle Volga	Kazanskaya CHPP-2	509.6	738.4	584.3	797.5	528.9	830.1
122	Middle Volga	Kazanskaya CHPP-3	512.2	1452.6	519.8	1533.6	516.5	1617.6
123	Middle Volga	Urussinskaya TPP	748.9	338.4	761.4	305.2	745.2	319.3
124	Middle Volga	Kazanskaya CHPP-1	508.5	599.3	507.0	670.3	512.2	850.3
125	South	Astrahanskaya CHPP-2	684.3	643.1	696.2	510.4	682.7	518.1
126	South	Astrahanskaya TPP	556.2	2083.6	572.1	1892.7	563.9	2124.3
127	South	Volgogradskaya TPP	741.5	187.4	683.5	172.7	653.7	164.3
128	South	Volgogradskaya CHPP-2	558.0	773.1	554.4	815.6	532.3	783.4
129	South	Volgogradskaya CHPP-3	629.9	707.1	649.5	793.2	582.6	826.0
130	South	Volzhskaya CHPP-1	577.9	1926.6	576.7	1323.4	552.7	1225.7
131	South	Volzhskaya CHPP-2	509.3	850.8	524.6	936.7	511.8	946.0
132	South	Kamyshinskaya CHPP	555.9	190.3	562.0	198.8	532.8	188.9

133	South	Kaspijskaya CHPP	736.7	29.2	684.3	21.9	765.7	23.5
134	South	Mahachkalinskaya CHPP	583.9	47.0	611.9	35.8	590.8	48.3
135	South	Krasnodarskaya CHPP	604.3	4680.7	600.4	4814.6	599.5	4824.6
136	South	Volgodonskaya CHPP-1	535.8	12.9	602.6	11.8	637.4	5.6
137	South	Volgodonskaya CHPP-2	544.5	1578.0	565.3	1162.6	525.4	922.3
138	South	Kamenskaya CHPP	-	-	-		688.5	0.1
139	South	Rostovskaya CHPP-2	490.4	768.3	492.9	709.6	480.1	650.3
140	South	Stavropol'skaya TPP	552.9	8285.2	555.6	9492.3	553.0	9384.2
141	South	Kislovodskaya CHPP	596.5	18.5	621.5	20.8	597.8	23.1
142	South	Nevinnomysskaya TPP	571.8	5722.9	568.1	6103.6	569.0	5905.2
143	Ural	Kirovskaya CHPP-1	632.8	36.6	619.1	37.8	651.8	31.4
144	Ural	Kirovskaya CHPP-3	665.0	466.6	676.9	551.0	665.3	547.5
145	Ural	Kirovskaya CHPP-4	562.6	1173.7	652.3	1223.2	632.8	1267.7
146	Ural	Kirovskaya CHPP-5	502.9	2028.4	546.8	2060.7	539.9	2154.5
147	Ural	Kurganskaya CHPP	575.7	1247.8	581.4	1686.8	586.5	1667.1
148	Ural	Iriklinskaya TPP	534.9	8178.9	557.3	8729.3	547.9	9721.6
149	Ural	Sakmarskaya CHPP	507.9	2091.1	500.9	1980.6	494.6	2057.5
150	Ural	Kargalinskaya CHPP	518.4	1232.9	497.8	1297.3	497.0	1294.2
151	Ural	Orskaya CHPP	519.7	950.3	540.0	931.3	549.8	1039.8
152	Ural	Mednogorskaya CHPP	478.3	14.3	498.4	8.6	486.5	9.3
153	Ural	Bereznikovskaya CHPP-10	659.6	112.5	642.6	135.1	637.7	131.6
154	Ural	Bereznikovskaya CHPP-2	703.4	360.4	746.8	369.5	700.9	492.7
155	Ural	Bereznikovskaya CHPP-4	688.3	135.5	660.9	162.4	670.9	49.8
156	Ural	Zakamskaya CHPP-5	634.0	215.2	658.3	357.4	649.0	317.8
157	Ural	Kizelovskaya TPP-3	743.9	94.3	793.4	135.0	804.9	144.0
158	Ural	Permskaya TPP	496.6	12437	495.8	12420	495.6	13832
159	Ural	Permskaya CHPP-13	639.2	70.3	635.8	72.1	628.2	73.3
160	Ural	Permskaya CHPP-14	602.0	1654.3	617.6	1405.6	611.8	1409.0
161	Ural	Permskaya CHPP-6	597.6	245.7	617.4	236.5	598.8	241.7
162	Ural	Permskaya CHPP-9	549.7	2109.3	560.8	2141.7	559.5	2091.2
163	Ural	Chajkovskaya CHPP	565.2	842.7	598.5	755.0	614.8	1199.3
164	Ural	Yajvinskaya TPP	595.9	3453.5	595.9	3850.9	588.3	4067.8
165	Ural	Bogoslovskaya CHPP	1112.6	443.1	1094.8	451.2	1119.8	429.7
166	Ural	Verhne-Tagil'skaya TPP	763.2	6107.2	744.0	6347.5	733.3	6801.6
167	Ural	Kachkanarskaya CHPP	469.5	177.9	491.1	166.2	507.0	149.0
168	Ural	Krasnogorskaya CHPP	985.2	330.2	1065.6	354.9	1045.4	349.0
169	Ural	Nizhneturinskaya TPP	792.7	1367.1	847.2	1618.6	838.0	1681.4
170	Ural	Novo-Sverdlovskaya CHPP	465.3	2231.3	475.6	2527.8	462.8	2447.1
171	Ural	Pervoural'skaya CHPP	592.8	192.5	600.2	193.2	593.4	182.2
172	Ural	Reftinskaya TPP	949.4	16865	948.9	18050	956.3	15543
173	Ural	Sverdlovskaya CHPP	636.1	190.7	643.0	181.4	642.2	182.1
174	Ural	Serovskaya TPP	971.3	2872.8	1094.3	2986.8	1053.2	2850.8
175	Ural	Sredneural'skaya TPP	507.5	6345.5	507.4	6203.3	506.3	6865.4
176	Ural	Nizhnevartovskaya TPP	509.3	9062.3	507.5	11219	503.6	11329

177	Ural	Surgutskaya TPP-1	533.7	21896	531.9	23023	532.0	23340
178	Ural	Surgutskaya TPP-2	502.5	31086	500.0	32038	502.2	33493
179	Ural	Tobol'skaya CHPP	526.7	2086.0	530.7	2305.1	560.9	2590.2
180	Ural	Tyumenskaya CHPP-1	483.4	2627.1	461.8	3112.9	452.4	3282.2
181	Ural	Tyumenskaya CHPP-2	480.4	3975.4	482.8	4835.7	489.7	5124.4
182	Ural	Urengojskaya TPP	708.2	156.4	705.3	159.3	701.4	176.9
183	Ural	Izhevskaya CHPP-1	564.7	309.4	558.9	310.2	551.9	322.9
184	Ural	Izhevskaya CHPP-2	460.0	1975.2	474.1	1963.0	475.9	2050.9
185	Ural	Sarapul'skaya CHPP	699.2	52.5	715.9	50.9	709.4	51.9
186	Ural	Argayashskaya CHPP	703.8	1289.7	761.7	1167.4	792.7	1146.7
187	Ural	Troickaya TPP	1059.4	4505.8	1039.7	8358.1	1017.2	8380.4
188	Ural	Chelyabinskaya TPP	584.7	285.8	588.4	269.4	583.0	274.9
189	Ural	Chelyabinskaya CHPP-1	703.5	432.0	686.1	416.8	666.9	426.8
190	Ural	Chelyabinskaya CHPP-2	570.2	1964.6	583.2	1910.5	567.7	1987.3
191	Ural	Chelyabinskaya CHPP-3	424.7	1377.4	429.2	1231.0	478.9	2342.2
192	Ural	Yuzhnoural'skaya TPP	828.8	5450.1	812.0	5120.7	791.8	4974.0
193	Ural	Karmanovskaya TPP	535.3	10701	528.2	10533	527.3	10420
194	Ural	Ufimskaya CHPP-1	541.9	257.5	524.1	246.2	524.6	258.6
195	Ural	Ufimskaya CHPP-2	500.7	2523.4	494.5	2597.9	506.6	2890.9
196	Ural	Ufimskaya CHPP-3	647.0	333.7	628.1	351.0	613.0	378.4
197	Ural	Ufimskaya CHPP-4	558.3	1081.2	558.5	1206.3	603.0	1208.6
198	Ural	Priufimskaya CHPP	626.1	971.6	584.2	999.3	602.7	1063.5
199	Ural	Sterlitamakskaya CHPP	560.0	1311.3	533.1	1652.2	553.2	1501.2
200	Ural	Novo-Sterlitamakskaya CHPP	547.9	1296.4	536.2	1361.6	523.1	1397.6
201	Ural	Salavatskaya CHPP	669.9	806.4	671.6	821.4	619.4	839.4
202	Ural	Novo-Salavatskaya CHPP	530.2	1778.3	545.4	1868.9	551.2	1936.9
203	Ural	Kumertauskaya CHPP	863.4	605.9	865.1	683.5	896.3	718.3
204	Siberia	Barnaul'skaya CHPP-1	1143.5	22.1	1167.8	10.2	1181.9	11.5
205	Siberia	Barnaul'skaya CHPP-2	1173.9	955.4	1259.3	962.1	1151.6	1003.8
206	Siberia	Barnaul'skaya CHPP-3	869.9	1496.6	880.6	1493.0	916.4	1631.0
207	Siberia	Gusinoozerskaya TPP	1004.0	3067.9	1023.9	3156.4	1031.3	3785.8
208	Siberia	Ulan-Ud`enskaya CHPP-1	989.8	315.0	995.6	270.3	987.1	248.1
209	Siberia	Berezovskaya TPP	1046.1	6222.4	1021.1	6503.5	1013.8	8045.3
210	Siberia	Kanskaya CHPP	809.6	64.2	824.9	59.2	1073.1	44.0
211	Siberia	Krasnoyarskaya TPP-2	1149.9	3216.4	1129.0	3378.1	1129.2	4260.6
212	Siberia	Krasnoyarskaya CHPP-1	1011.8	1845.9	995.5	1663.0	1017.6	1774.1
213	Siberia	Krasnoyarskaya CHPP-2	821.6	2281.3	824.6	2152.3	837.6	2067.4
214	Siberia	Minusinskaya CHPP	923.8	402.5	902.6	358.2	944.0	405.0

215	Siberia	Nazarovskaya CHPP	1125.7	5824.2	1129.8	4030.4	1143.0	4943.0
216	Siberia	Belovskaya TPP	947.0	6564.3	946.3	6258.7	955.4	6450.2
217	Siberia	Zapadno-Sibirskaya CHPP	943.6	2815.4	926.8	2855.7	985.3	3061.5
218	Siberia	Kemerovskaya TPP	822.9	2069.9	878.4	108.8	880.6	2091.6
219	Siberia	Kemerovskaya CHPP	868.0	107.5	930.7	108.8	921.1	101.7
220	Siberia	Novokemerovskaya CHPP	917.3	1556.0	980.3	1424.9	982.5	1524.5
221	Siberia	Kuzneckaya CHPP	966.2	483.2	974.5	415.3	933.9	459.1
222	Siberia	Tom'-Usinskaya TPP	1045.0	7240.4	1041.3	7614.1	1054.0	7402.8
223	Siberia	Yuzhno-Kuzbasskaya TPP	1215.1	1726.3	1210.3	1546.4	1202.6	1760.7
224	Siberia	Omskaya CHPP-3	606.3	1195.9	607.2	1198.2	601.7	1095.3
225	Siberia	Omskaya CHPP-4	963.5	1474.3	1012.7	1352.3	1029.8	1245.9
226	Siberia	Omskaya CHPP-5	945.2	2395.7	856.5	2686.0	908.6	2902.4
227	Siberia	Tomskaya TPP-2	629.1	1269.9	616.4	1273.6	650.1	1100.8
228	Siberia	Tomskaya CHPP-3	460.9	646.3	470.5	654.6	458.0	574.6
229	Siberia	Abakanskaya CHPP	895.4	911.8	850.4	820.2	925.5	918.6
230	Siberia	Priargunskaya CHPP	1434.4	55.2	1463.1	46.6	1466.1	36.7
231	Siberia	Haranorskaya TPP	1019.7	1665.8	987.7	1812.9	982.7	2146.4
232	Siberia	Chitinskaya CHPP-1	1180.6	2351.6	1201.9	1981.7	1166.6	1644.4
233	Siberia	Chitinskaya CHPP-2	1422.0	12.2	1457.9	6.3	1451.1	6.9
234	Siberia	Sherlovogorskaya CHPP	1429.2	41.1	1432.0	39.4	1430.4	36.7
235	Siberia	CHPP-9(CHPP-)1	1386.5	471.5	1321.5	476.5	1401.8	428.0
236	Siberia	CHPP-9	846.8	1082.3	825.6	1241.6	828.1	1152.8
237	Siberia	CHPP-10	1042.5	861.0	986.7	1794.1	996.8	2024.0
238	Siberia	CHPP-3(CHPP-5)	1564.9	13.7	1559.3	29.6	1553.3	15.2
239	Siberia	CHPP-12	1566.0	7.5	1457.6	10.3	1447.6	11.1
240	Siberia	CHPP-11	842.3	777.6	832.8	794.6	839.7	787.3
241	Siberia	CHPP-16	1321.3	30.7	1306.5	38.6	1307.7	37.3
242	Siberia	Novo-Irkutskaya CHPP	773.9	1529.8	763.2	1776.9	765.9	1837.6
243	Siberia	Ust'-Ilimskaya CHPP	831.2	833.6	809.6	926.0	849.9	1132.4
244	Siberia	Novo-Ziminskaya CHPP	885.5	555.3	871.7	791.5	924.4	797.4
245	Siberia	Irkutskaya CHPP-6	857.6	756.1	827.0	886.8	839.7	873.0
246	Siberia	Bratskie TS (CHPP-7)	1343.0	2.4	1327.8	4.3	1143.5	27.5
247	Siberia	Novosibirskaya CHPP-5	815.0	6033.7	786.5	5675.9	789.2	5521.3
248	Siberia	Novosibirskaya CHPP-4	767.2	1153.4	663.0	1159.9	586.4	1100.9
249	Siberia	Novosibirskaya CHPP-3	806.1	1480.6	778.4	1568.2	751.6	1444.9
250	Siberia	Novosibirskaya CHPP-2	1566.0	929.5	1457.6	927.8	1446.2	887.9
251	Siberia	Barabinskaya CHPP	1191.4	114.5	1110.0	105.9	944.9	83.2

Table 2 of Annex 2: Operating margin CO_2 emission factor

Year	**2005**	**2006**	**2007**

Weighted average CO_2 emission factor, tCO_2e/MWh	0.63963	0.64333	0.63933

Weighted average operating margin of CO_2 emission factor is **0.64077** tCO_2e/MWh.
To calculate build margin of CO_2 emission factor five most recently built power plants were selected.

Table 3 of Annex 2: Build margin of CO_2 emission factor

#	Plant	Start-up Year	up to 2006		2006	
			Electricity, $MWh*10^{-3}$	$EF_{EL,m,y}$, tCO_2/MWh	Electricity, $MWh*10^{-3}$	$EF_{EL,m,y}$, tCO_2/MWh
1	2	4	7	8	9	10
1	Sochinskaya TPP	2004	396.91	0.4604	483.84237	0.4398
2	GTU "Luch"	2005	26.85	0.3926	318.326	0.3790
3	OJSC Kaliningradskaya CHPP-2	2005	262.974	0.4427	2468.138	0.4309
4	Tyumen PGU-190/220 st. No.1	2004	77834	0.4372		
5	Nizhnevartovskaya TPP (block No.2, 800 MW)	2003	4289654	0.4883		
Weighted average CO_2 emission factor						**0.4873**

The baseline CO_2emission factor is the average combined CO_2 emission factor which equals **0.56406 tCO_2/MWh.**

Table 4 of Annex 2: Historical data

Year	2005	2006	2007	Average
Electricity output, MWh	724903.6	758568.1	900384.1	601609.7
Heat generation, Gcal	1714800	1992300	1913700	794618.6
Fuel consumption, t.c.e.	574102	599320	631407	1873600

Table 5 of Annex 2: Total fuel consumption of power plants included in project boundary

Year	2005	2006	2007
Natural Gas, kt.c.e.	159830.8	163376.5	167634.6
Coal, kt.c.e.	43092.65	47300.66	45995.77
Residual oil, kt.c.e.	5682.495	7699.466	4460.257

Annex 3

MONITORING PLAN

See Sections B. and D. of the present PDD.

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