JOINT IMPLEMENTATION
PROJECT DESIGN DOCUMENT FORM

Name of the Project:

Utilization of Associated Petroleum Gas at the Serginskoye Oil Field

Project Owner:
JSC «Russian Innovation Fuel-Energy Company »
(JSC «RITEK»)

Moscow, 2009

CONTENTS

Annexes

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

Joint implementation project - utilization of associated petroleum gas (APG) at the Serginskoye oil field, Western Siberia, Russia.
PDD Version 4.1, dated August 4, 2009.

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

The project includes utilization of associated petroleum gas (APG) on modern power station (electric power) with the general capacity 7,5 MW on Serginskoye oil field (owner- JSC "RITEK"), Okt'abrsky area, Khanty-Mansijsk Okrug- Yugra, Tyumen oblast, Western Siberia, Russia (Figure 1a). Five Cummins QSV 91G generating units of 1.5 MW of nominal electrical capacity each are installed at the plant. Power plant is designed for APG utilization. Generated electric energy is used by the complex of the basic and supporting equipment on the oil wells and by local housing facilities of the oilfield.

APG at the Serginskoye oil field is obtained during the separation process at the booster pump station (UPN) located next to the new power plant. The APG utilized within the Project was previously flared as shown in Figure 1в. Within the Project, part of the APG is used by the power plant with the remaining APG flared as usual at the stack of the booster pump station. Power needs of the project owner were initially covered from the regional electric grid.

Figure 1. Project Gas Power Plant (GPP), (a), and the associated petroleum gas flaring at Serginskoye oil field (b)
(a) (b)

Exploitation of Serginskoye oilfield began in 1995. Within the Baseline Scenario the growth of power consumption at the oilfield was supposed to be covered by additional acquisition of power. This scenario did not presuppose any additional investment costs.

Still in 2000-2004 the Project Owner considered a number of options of APG utilization that were analyzed and assessed. Partly the refusal from the baseline scenario can be attributed to the innovation profile of the project owner - JSC RITEK within its mother Group LUKOIL. RITEK has been chosen as a testing ground for advanced technological and environmental solutions within the Group, which presupposed additional costs that were spent often regardless of the profitability considerations. Therefore the goal of this project was initially APG utilization and no other goal was possible since it presupposed considerable costs for substitution of the existing power supply system, that could not be considered necessary from either economic or technological viewpoint

One of the legitimate ways of overcoming the financial barriers connected with APG utilization is provided by the expected incentives by the Joint Implementation (JI) mechanism of the Kyoto Protocol..

Carbon revenues were expected in the frameworks of the JI format by the Project Owner since the Kyoto Protocol was signed in 1997 but until September 2003 when the Government Climate Change Commission of Russian Federation has taken the due decisions on the National JI regulation in Russia, these possibilities were not considered as high. After these decisions the chances of receiving carbon revenues have grown substantially, that was taken into consideration by the Project Owner.

The Project has started on the basis of the above mentioned decisions of the Government Climate Change Commission of the RF. With this in mind the related decision was taken on the meeting of the RITEK Technical Board on 25.09.2003 and the development and technical design works have started, later followed by the construction phase (see the Table 2 (b) below).

The related feasibility study was done by the JSC NIPIGazpererabotka research institute (Krasnodar, Russian Federation), contract concluded on 29.09.2003. The preliminary report of this study was issued in December 2003, the final report was ready by May 2004. The project alternatives examined by the Institute combined solution of the problem of APG utilization and electricity generation. The option chosen by the project owner presumed construction of GPP.

The design was performed by the JSC Giprotyumenneftegaz. Commissioning of the full-cycle work on the first block of the power station in Serginskoye to JSC "Zvezda-Energetika" (Saint Petersburg, Russian Federation), contract concluded on 07.06.2007. The job was executed on turnkey basis with the final launching into operation on 06.04.2009.

In addition to the GHG emission reductions, the Project contributes to sustainable development of the host country by promoting the utilization of wasted APG which can be a valuable energy resource. The Project also leads to the reduction of local pollutants such as CH_4, CO, NO_x, through reduced gas flaring and more efficient combustion of the APG by the environmentally friendly low-emission gas engines.

The supplier of APG to the GPP and the user of electric power produced is Project Owner – joint stock company RITEK. The power users are mainly groups of pumping stations, which are maintaining oil reservoir pressure by pumping water into the reservoirs 24 hours a day, and other facilities ensuring oil production and transportation at the oil field. Well-exploiting settlement also consumes power. There are no another potential consumers in the oil-field area.

The basic operating mode for the Power Plant presumes that three units are operating at station (at an average of 80% of total capacity), with the possibility of growth of power output, due to growth of consumption by the production facilities. One unit is reserved to provide peak demand periods, and another one is kept as a reserve capacity. The general electric energy production, taking into account the electric power consumed by GPP for own needs, makes 18300 MWh per year for 2009 with expected growth up to 39200 MWh by 2012. Station own power consumption is regulated in line with Russian National norms (SNIPs), as 20 kWh per every MWh of energy produced. The general own power consumption, thus, makes – 0,3 GWh per year.

Emergency generation provided be diesel-generator with installed capacity 0,28 MW (voltage 0,4 kV). Taking into account uncertainties the related assessment was excluded from the Project boundaries.

The power generated is delivered to transforming station 110/10 kVA, from which it is wired to the oil-field consumers (on the voltage 10 kV).

The Project will contribute to sustainable development of the host country by promoting the utilization of wasted APG which is a valuable energy resource and will reduce CO_2 and CH_4 emissions in two ways:

- Local emissions of CO_2 and CH_4 will be reduced due to increased combustion efficiency in the gas engines compared to the Serginskoye flare,
- Emissions of CO_2 from Tyumen region grid power plants will be reduced as electric production is reduced due to displacement by GPP output.

Estimated total reductions of GHG emissions will be around 26,969 tCO_2- equivalent (tCO_2e) per year and respectively 107,876 tCO_2e within the 2009-2012 crediting period.

A.3. Project participants:

JSC «RITEK» - project owner (investor) and power station operator.
According to the license agreement JSC "RITEK" is the owner of associated petroleum gas.
JSC «RITEK» is responsible for Joint Implementation Project and for implementation of the monitoring plan

Table 1: Project participants

Party involved	Legal entity project participant (as applicable)	Please indicate if the Party wishes to be considered as project participant (Yes/No)
Russian Federation (Host party)	JSC "RITEK"	**No**
Not indicated	-	-

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

The project consists of Gas Power Plant (GPP) with installed capacity of 7,5 MW, and necessary facilities for APG pre-treatment and transportation. Necessary electrical equipment is used for power delivery electricity to the consumers.
A list of key project components is provided in Section A.4.3.

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

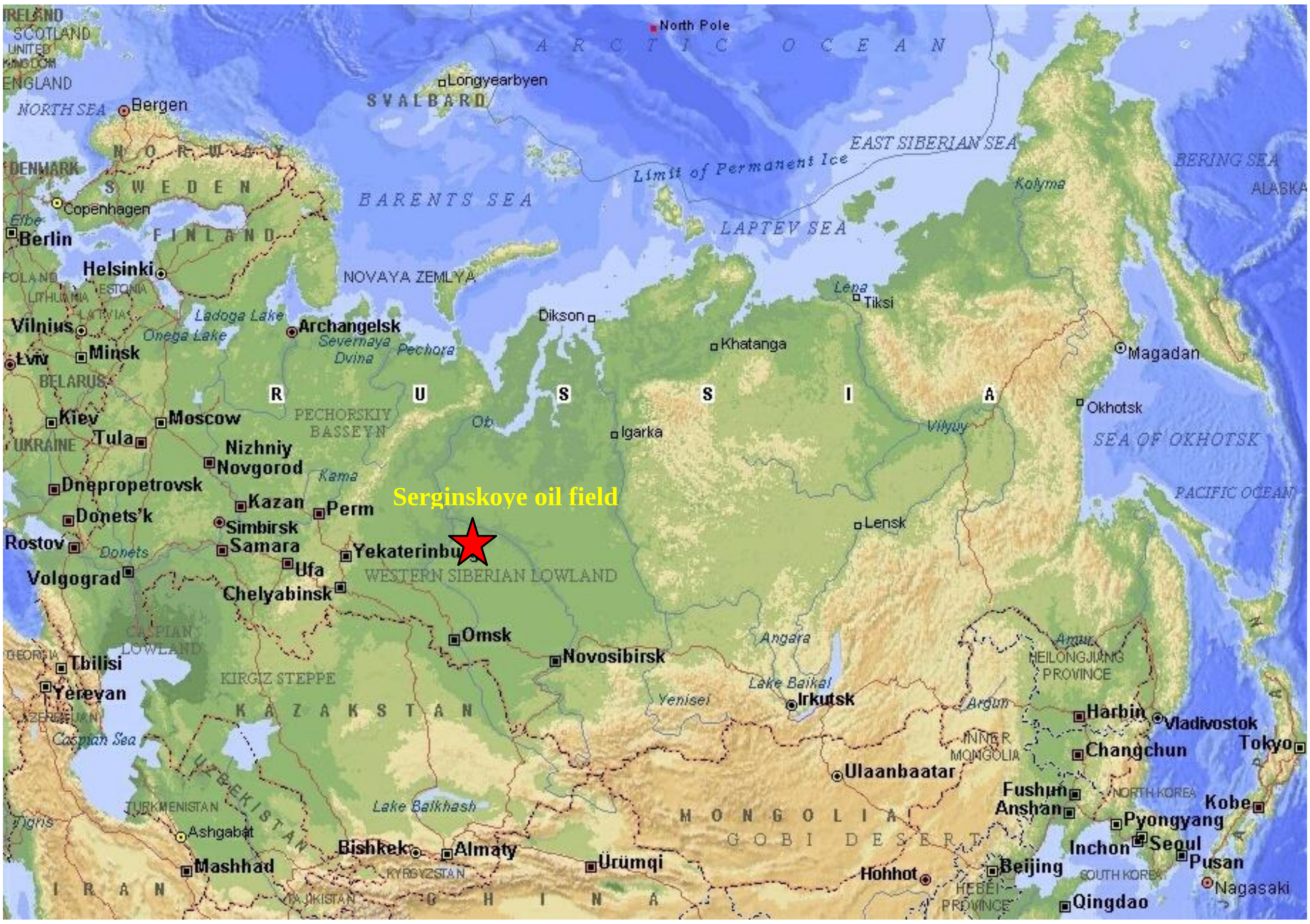
The project is located in Serginskoye county, Okt'abrsky district, Khanty-Mansijsky autonomous Okrug (KhMAO) - Yugra, Tyumen oblast, 2,100 km from Moscow (see fig. 2).
Site latitude - 65°27'56". Site longitude - 65°32'59". Serginskoye oil field located in boggy district, between rivers Ob' and Malaya Sosva.

Figure 2.

General view

Of oil field

Figure. 3. **The location of Project** :Okt'abrsky district, Khanty-Mansijsky autonomous okrug (KhMAO) - Yugra



A.4.1.1. Host Party(ies):

Russian Federation

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

The Khanty-Mansijsky Autonomous Region (KhMAO) is situated in the medial part of Russia. It occupies the central part of the West Siberian plain. The capital of the region is the city of Khanty-Mansijsk. KhMAO is a sparsely inhabited area with a population density of 2.8 persons per square km. The total population of 1,488,500 people is spread across 534.8 thousand sq. km. Nearly 86% of the region's population lives in 16 cities.

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

Okt'abrsky district (with centre in town – Okt'abrskoye), Khanty-Mansijsky Okrug (KhMAO) -Yugra, Tyumen region, Western Siberia is one of the smallest districts in the region. It seizes one of the most important centers of KhMAO – Nyagan city.

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

The Okt'abrsky district occupies the central part of the Western-Siberian plain (west part of Khanty-Mansijsky Okrug) and it crosses by the biggest region's river – Ob'. In the north area borders with Berezovsky district, north-east – Beloyarsky district, west – Sovetsky district, south and south-east – Khanty-Mansijsk-city, and Kondinsky district.

The climate of Okt'abrsky district is continental (boreal type) with temperature contrasts forming due to circulation of arctic air masses, north winds in summer, south and south-west all other seasons. Just because of this region famous by unexpected temperature changes, which annual amplitude fluctuations, and very quick season changes (from summer to winter, and from winter to summer).

Average temperature– 3,2 degree below zero, no-frost period can be prolonged from 33 days (minimum) up to 110 days (maximum). Winter - is longest season approximately 200 days. The coldest months are December, January, February. Average temperature at January – 21,9 °C (absolute minimum - 51 °C).
The warmest month is July with temperature nearby 14 °C.

Main rivers of the district are - the biggest in Siberia – Ob'; Chemashyugan, Endyr, Khugot.

The basic rich of Okt'abrsky area is the oil. It has numerous medium-sized oil-fields.

The district is a very important part of national gas transporting system. 17 gas pipelines cross it's territory. The most important are: "Urengoy-Pomary-Uzhgorod", "Urengoy-Centre", "Yamburg- West border".

Ten fuel/energy companies work on the territory of Okt'abrsky area, such as JSC TNK-Nyagan, JSC Surgutneftegas, JSC Archneftegeologiya, JSC RITEK, LLC Sibneft-Yugra, JSC Khantymansijskneftegasgeologiya.

Significant problem is transport scheme. Temporarily settlements can be achieved by the winter's roads (zimniki), in summer by rivers, and between seasons only by helicopters.

A.4.2. Small-scale project type(s) and category(ies):

Type III JI SSC projects that result in emission reductions of less than or equal to 60 kt CO2 equivalent annually. Project category N : other types of small-scale projects (acc.to CMP 2005/8 Add 1 App. B).

A.4.3. Technology (ies) to be employed, or measures, operations or actions to be implemented by the small-scale project:

The 7,5 MW of installed capacity of the Project consists of five 1,538 MW gas-fired reciprocating engines (Cummins QSV 91G). The gas engines are connected with HVS824 electric generators.

The major components of the Technological Solution within the Project design are summarized in Table 2.

Table 2: Project components

Equipment type	Quantity	Parameters	Notes
Power-block			
GPP - QSV 91G Cummins, manufactured by JSC «Zvezda Energetika»	5	1,538 MW_e per unit. efficiency$_э$ 38,2%, estimated expenditure of gas 293 nm cubes/MW	The gas-reciprocating engines are equipped with inner cooling .
Gas power plant automated control system (ACS)	1	ACS includes the control system of each generating unit, the synchronization system of the units and the GPP control system.	The GPP ACS ensures: 1- Operational control of the GPP by automated workstation and monitoring of technological processes at the power generating units, switch gears (10 kV, 0,4 kV, inhouse transformer); 2- Retrospective evaluation of GPP's operation mode; 3- Timely detection of emergency situations with precise indication of the damaged areas.
Transformers 10/0,4 kV	20	10 kV, capacity 63-1000 kWA.	For electricity consumption and for delivery to fiders

Fire fighting and alarm System	2		The Project is implemented in compliance with the existing norms and standards for explosion and fire fighting requirements and ensures operation safety
Communications	1		Radio relay equipment is applied
Emergency diesel-generator	1	0,28 MW, 0,36 kV voltage.	Provides emergency generation (for GPP)
Pre-treatment Block			
Oil-gas separator 1-stage NGS 1,0-2,000-2	1	P=1 MPa, V=25m^3,	The APG treatment plant includes gas separators, pump separators, flare separators, drainage, oil preheater, and the gas pressure control unit, and vias fuel gas to GPP
Oil-Gas separator NGS II-1,0-2400-2	2	P=1 mPa, V=50m^3	
Oil pre-heater PPNT 0,63	1	Q=0,63 Gcal/h	
Finite separator NGS1 -1,0-2400-2	1	P=1 MPa, V=50m^3	
Oil pre-heater PBT	1	Q=1,6 Gcal/h	
Gas separator GS 1-2,5-600-2	1	P=0,5 MPa, V=0,8 m^3,	
Oil pre-heater PPT	1	Q=290 kV	
Gas separator (water separation) NGSV	1	P=0,7 MPa, V=100m^3,	
Water separator NGS1-1,0-2400-2	2	P=1 mPa, V=50m^3	
Flare separator	2	P=1,0 MPa, V=10m^3,	
Drainage tank with pump NV	2	V=50 m^3, P=1MPa	
Gas pre-treatment device	1	Ø=700mm	
Centrifugal pump multi-sectional CNS 38/88	2	Q=38 m^3/h, H=88 m	
Centrifugal pump multi-sectional CNS 38/176	2	Q=38 m^3/h, H=176 m	
Tank-reservoir	2	V=5000m^3	
Water pumping station (CNS)-60/66	1	Q=60 m^3/h, H=66 m	
Flare stack of low pressure	1	Ø=200mm	
Flare stack of high pressure	1	Ø=200mm	
Tank for diesel fuel	1	V=5000m^3	

The main components of the GPP are:
- QSV 91G Cummins gas-reciprocating engines produced by *JSC Zvezda Energetika*,
- alternating-current generators HVS824,
- Fuel gas supply system.

Five (18 cylinders), four stroke, high speed gas engines with electric spark ignition have been chosen, in part, because of their tolerance for lower quality APG-fuel and because of low pollutant emissions in the exhaust gas. The fuel gas supply system of the GPP, including gas pipelines (isolated for leakage minimization) and the APG treatment plant, is designed to support normal operation of the power generating units using APG. Each unit is equipped with a device that switches off fuel supply sources in emergency cases. The fuel gas flow rate at 100% load is 293 nm^3/MW per hour. The fuel gas (APG) is taken from the gas pipeline of the APG treatment plant into the engine's gas mixer where air is added. The mix is then transported by pipe into the turbo-blower. Then, the compressed gas-air mixture goes through the cooler into the fuel suction line that distributes the mixture among the engine's cylinders. Design pressure at the fuel supply inlet is 3.5 Bars with temperatures from 10 to 20 degrees Celsius. The fuel used at the GPP is APG that is separated at the booster pumping station. Minimal CH_4

index without decreasing power is 52 %. APG after separation is divided in three flows with one part directed to the GPP, and the last flared at the existing stack of the booster pumping station.

Before use in gas-engines, APG must be processed at the treatment plant by:

- Drying from dropping liquids while being heated up from +10 to +20°C,
- Reducing pressure from 0,5 MPa to 0,35-0,4 MPa,
- Gas filtration.

No incremental electric use is needed for gas treatment and transport due to the Project. The pressure at which gas comes into the APG treatment plant is sufficient to push it through the system. Heating of the gas is fully covered through use of waste heat from the gas engines.

Figure. 4 Block of QSV 91G Cummins

Electrical Interconnection Systems
The GPP includes the following electrical equipment:

- 5 generators;
- 10& 0,4 kV gears;
- 110/10/0,4 kV transformers;
- in-house transformer substation with 0.4 kV distributor switch gear (for self consumption)

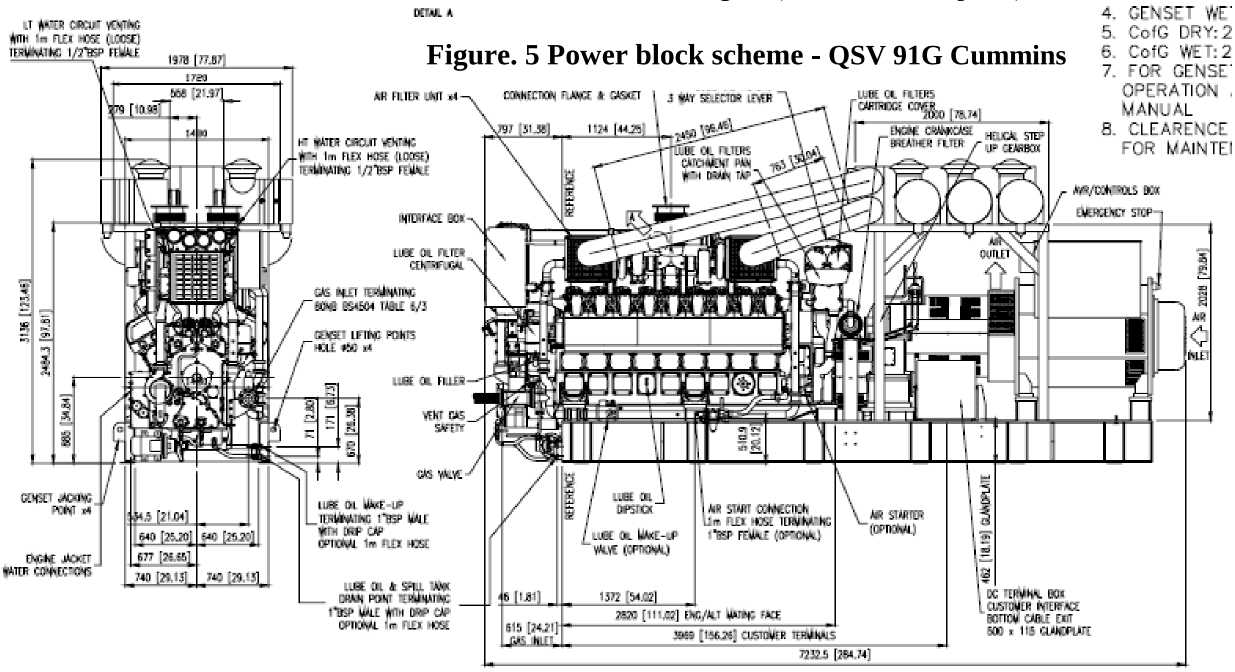


Figure. 5 Power block scheme - QSV 91G Cummins

Delivery of the electricity to power consumers is provided from transforming station, voltage 10 kV. Total annual consumption from the given substation is estimated as 18.300 MWh/year, with presupposed growth up to 39.200 MWh in 2012. Own power consumption of the station is approximately 0,3 GWh/year. Power supply for own needs is provided from external feeders on voltage 360 V. Electricity delivering in external grid metering on transforming station on voltage - 110 kV. Losses connect with transmission by 10 kV cable line taking into account.

Delivery of the electric power is carried out by 10 kV cables to the related transformers and facilities. The average distance to local consumers 0,2-12 km. In case of emergency switch-off of a gas supply system, or in other cases of absence of gas in APG processing facilities, consumers will be supplied from emergency diesel-generator. Transition to emergency operation of work in GPP occurs in case of critical pressure drop in the gas pipeline.

In case of GPP transition to work the emergency diesel fuel the emissions are calculated according to the actual expense of fuel and nameplate data on received emissions.

As electric power transfer occurs on low voltage grid, it assumes rather high level of losses. The existing national norms (that may be considered obsolete) presume 2% losses for high voltage grids, and 9% losses for low-voltage grids in Russia, regardless of the distance for power transmission. High voltage grids of "Tyumenenergo" presumes 5-6 % losses (depends upon circumstances). Necessary to notice that mentioned figures include also commercial losses. Energy auditing and metrology is necessary for an estimation of practical losses. At the state level works on metrology have started in 2005, and will be possibly finished in 2016. Therefore using the existing norms for the assessment of losses may seem to be the only legitimate way for their estimation.

Besides, as the GPP works in an autonomous mode, the regime of operation of the power facilities may be characterized as (rather) unstable sinusoid mode, that results in is, decrease of cos φ, and in respective growth of losses.

Figure 6 represents technological scheme and monitoring point locations for the Project facilities: gas pre-treatment block, GPP. The description of the monitoring points is provided in Table 3 following the diagram.

Figure 6: General scheme of the Project

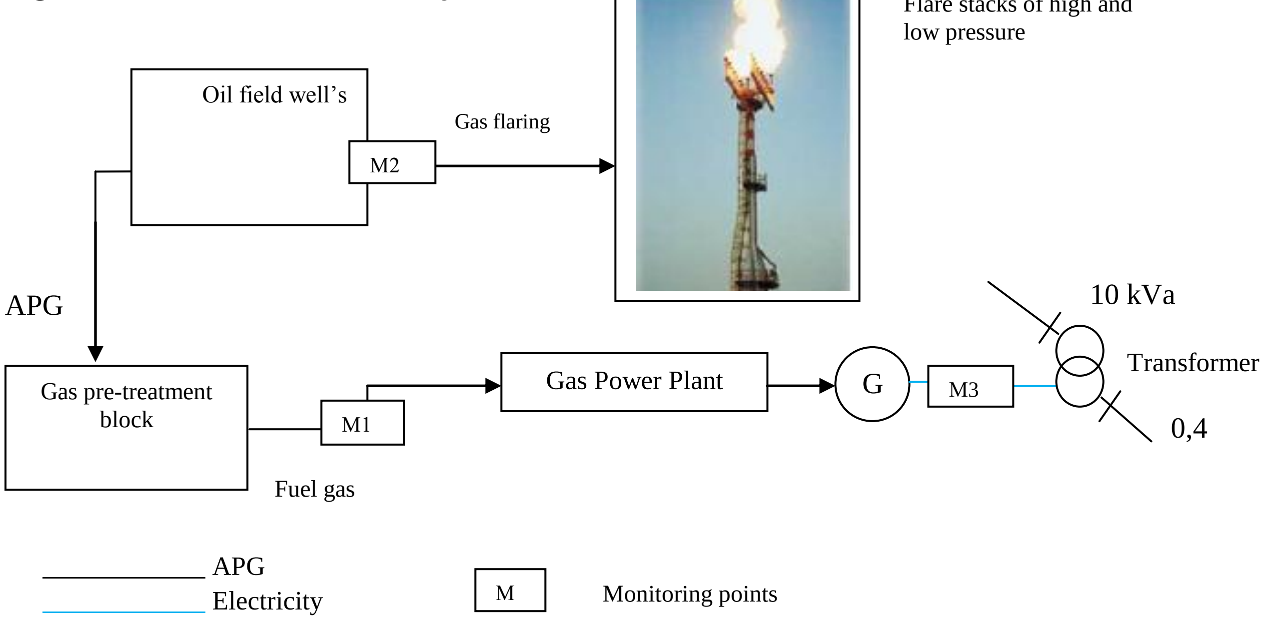


Table 3: Description of monitoring points

Monitoring Point	Location	Parameters to monitor	Quantity | year	Metering equipment
M1	Gas pre-treatment block station	Gas volume explicated in normal cubic meters	About 9,2 mln. cubic meters (2010)	Flowmeter Dymetic - 5221, Dymetic - 2721
M2	Flare stack	Flaring on a stack	Actual volumes	Flowmeter,

		superfluous gas volume and pressure		chromatograph
M3	Feeders on GPP	Electricity delivery	31500 MWh (2010)	Electricity counter SET 4TM03.01

Table 2. (b) Project schedules

#		2003		2004				2005				2006				2007				2008-09		
				Quarters				Quarters				Quarters				Quarters				Quarters		
1	Decision on business plan elaboration on GPP 25.09.2003																					
2	Business planning GPP																					
3	Corporate approval																					
4	Design project of GPP																					
5	GPP construction																					
6	Complex commissioning, 06.04.09																					

A.4.4. Brief explanation of how the anthropogenic emissions of greenhouse gases by sources are to be reduced by the proposed small-scale project, including why the emission reductions would not occur in the absence of the proposed small-scale project, taking into account national and/or sectoral policies and circumstances:

In the baseline scenario a significant amount of APG will continue to be flared annually at the Serginskoye booster pumping station. In the Project scenario, the related volume of APG is captured and burns in the installed gas engines to supply electric power in annual amounts ranging from 18300 MWh (2009) to 39200 MWh (2012) to support pumping requirements for the Serginskoye oil field. In the baseline scenario, the related amount of electricity will continue to be purchased from the regional grid power plants which are powered by natural gas and APG from other oil fields .

Consumption of electricity from external grid assumes (in any case) additional losses on transmission, which in frames of present Project will be minimized.

GHG emission reductions, that will be included in the calculation of the emission reductions due to the Project, will occur in two locations (see table 4):

- Reductions at the Serginskoye field will occur because the captured APG that was previously flared will be combusted in the gas engines with much higher efficiency than it is in the local flare. This will generate the emission reductions due to the combustion of the unburned fraction of the APG that was previously directly escaping into the atmosphere from flare stack.
- Reductions will also occur at the marginal grid power plants in the Tyumen region because of the electric production that is displaced by GPP electric production.

Table 4: Ex ante emission reduction estimates (for 2010)

Items	Units	Baseline Emissions (index b)	Project Emissions (index p)
APG flared/combusted	1000 $м^3$	9,230	9,230
Complete combustion of APG	tCO_2	21539	27543
Unburned APG in terms of tCH_4	tCH_4	765	-

Unburned APG in terms of tCO_{2e}	tCO_2	16071	-
Total local emissions	tCO_2	37610	27543
Substituted Grid Power Plants emissions	tCO_2	17493	-
Total emissions	tCO_{2e}	55102	27543

Flare combustion is less efficient than more tightly controlled combustion in gas engines (and modern furnace). However, there are no international standardized methods of precisely calculating such emissions from readily available data. Therefore, calculations of the methane emissions from flaring of APG captured and utilized by the Project is based on the "Methodology of calculation of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks" developed by St-Petersburg Institute St-Petersburg Institute for the Air Protection (NII Atmosfera) and endorsed by state committee for environmental protection – "Goskomekologiya", Decree # 199 of 08.04.1998 as the appropriate basis for reporting hazardous emissions from flaring of APG.

NII Atmosfera methodology is the most widely accepted approach used by the Russian oil and gas industry. It provides all relevant parameters, algorithms and measurement requirements to calculate the emissions of hazardous substances (including methane emissions) that are accounted in the project baseline as a result of the incomplete combustion of the APG. The calculation of methane emissions is based on the following parameters:

- Technical parameters of the stack and characteristics of APG (flow rate, composition, density) and of the APG components (density, molecular mass, adiabatic index, carbon mass content, etc).
- The mode of APG combustion (subject to non-black firing test). The non-black firing test is implemented to determine the quantity of methane emissions vented into atmosphere due to low combustion efficiency of the flare (under-firing). Black-firing mode refers to under-firing to a degree that flare emissions contain significant soot and under-fired hydrocarbon emissions, including methane. The methodology provides default factors for the emission rates for both non-black firing and black-firing combustion. These factors are the integral part of the approved methodology and were established on the basis of the program of on-field measurements for the industrial flare stacks in Russian oil and gas industry.

Current national policies provide minimal incentives to oil producers in Russia to use APG more efficiently or to reduce flaring. The main obstacles for APG flaring reduction projects in Russia are as follows (see also the Section B.1 of the PDD):

- Regulated prices for APG at the entry of gas processing plants are too low to encourage development of new APG transport and processing facilities. These prices remained non-revised from their 2001 level until 2008 at the range of 2.8 to 17 USD/1000 m^3 depending on liquids content. With the free pricing introduced formally the problem of low price did not disappear due to the advantages of the buyers (gas processing plants) due to their location.

Hence, the Project, even within the most favorable circumstances (maximal world oil prices, low APG prices), cannot be assessed as commercially viable; according to the calculations of its commercial profitability below, it generates net operational losses due. Calculations for this period show that NPV for the project remains negative for the whole 20-years' period average -6.465.000 EUR. With this in mind we may conclude that the Project is financially unattractive for the Owner.

- High investment costs and inadequate returns of APG utilization projects compared to other highly profitable alternatives for the oil companies. The facilities for the utilization of the APG were usually not integrated in the oil field production schemes and may imply a construction of the new infrastructure for collection, treatment, and transport of the APG. These investments tend to be uneconomic for remote oil fields with limited local energy needs and long distances to the gas processing facilities or consumption markets. The oil companies also face structural barriers such as limited access to the existing gas transmission infrastructure and low prices for the APG negotiated with the transmission companies or gas processing facilities.
- Low environmental fees for the emissions of polluting substances during APG flaring. According to Amendments to the Governmental Decree of 12.06.2003 # 344, issued on July 2005, the fee rate for methane emissions contained in APG flared by stationary sources is 250 rubles (about 10 US dollars) per ton of methane. Mentioned fee rate was applied for basic investment analysis. This level of environmental payments does not

imply any significant impact on the investment decisions of the oil companies. Since January 1, 2012 fee rate will increased considerably in accordance with the RF Government Decree # 7 of 08.01.2009.

- Small electricity generation (power plants with installed capacity – 7,5 MW determines as "small generation") depending from free market. Large consumers are not interested to work with them and generated electricity sells by catchpenny prices. The same concerns the second part of electricity tariff – on power.

Taking all this into account, including local specifics, e.g. : absence of GPP *operating* experience by the Project owner (present GPP already generating electricity on RITEK's oil-fields managed by outsourcing entities), high investment costs of the project, relatively high operation costs, the Project cannot be considered as economically attractive for the Owner. Therefore its implementation in the mode described above can be explained only by its environmental importance, including intentions to reduce the emissions of GHG.

The total estimated greenhouse gas emission reductions to be achieved by the proposed project – 107876 tonnes of CO2 equivalent over the period 2009-2012.

A.4.4.1. Estimated amount of emission reductions over the crediting period:	
Length of the crediting period	**4 years**
Year	**Estimate of annual emission reductions in tonnes of CO_2 equivalent**
2009	16011
2010	27559
2011	30010
2012	34296
Total estimated emission reductions over the crediting period (tonnes of CO2 equivalent)	107876
Annual average of estimated emission reductions over the crediting period (tonnes of CO_2 equivalent)	26969

A.4.5. Confirmation that the proposed small-scale project is not a debundled component of a larger project:

Present project has much in common with other projects implemented and implementing by RITEK on other oilfields such as Sredne-Khulymsk and Vostochno-Perevalnoye. All of them targeted on APG combusting in gas power plants equipped with gas-engines. They have approximately the same technical, juridical, economical solutions and sometimes common external factors. Moreover, basically projects connected with further development of company were approved by the corporate "Programme of associated petroleum gas utilization in 2008-2011" for 12 oilfields.

But at the same time it is necessary to note that:

- the biggest project on Sredne-Khulymsk consisting of two parts presumes annual emission reductions due to utilization of APG in GPP at level ≈100000 tCO_2e. And it assumes definition of the project as a *large scale* and essentially different from the others.
- similar project on Vostochno-Perevalnoye oil field also differs from present one. Especially it concerns the baseline. On Serginskoye oil-field, baseline was predetermined by emissions from APG combustion and emissions connected with generation of power consumed by the old-field. Generation of electric power on GPP was economically not the most efficient decision in a view of presence of rather cheap electric power from "Tyumenenergo" high voltage grids. Vostochno-Perevalnoye has initially used powertrains combusting crude-oil. Additionally the project boundary of Serginskoye project is at minimum ca. 400 km distance from the project boundary of the closest similar project – Vostochno-Perevalnoye.

In this case project of utilization of APG on Serginskoye oil-field cannot be considered as a debundled component of a larger project.

A.5. Project approval by the Parties involved:

All necessary approvals will be obtained later in accordance with Decree #332 of the Russian Government of May 28, 2007.

SECTION B. Baseline

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

This section defines and justifies the selected baseline scenario following the Annex B of the JI Guidelines and the JISC "Guidance on criteria for baseline setting and monitoring". The baseline is established on a project-specific basis using two main steps:

- By identifying and listing alternatives to the project activity on the basis of conservative assumptions and taking into account uncertainties;
- By identifying the most plausible alternatives considering relevant sectoral policies and circumstances and other key factors that may affect a baseline. The screening of the alternatives is based on analysis of the technological and economic considerations, as well as on the prevailing practices.

Step # 1. List alternatives to the project activity that can be a baseline scenario.

The decision making context of the Project includes two entities:

- Project owner, which operates the Serginskoye oil field, has flares the APG before the Project.
- the GPP, receiving gas from gas pre-treatment block, generate electricity for own consumption of the oil field.

The APG produced at the Serginskoye oil field can be treated in the following possible ways by Owner or with involvement of a third party:
1. Continuation of 100% APG flaring at the Serginskoye booster pumping station with electricity used oil-field at production facilities coming from the grid. This is the business-as-usual scenario (also for RITEK till 2009).
2. The proposed Project - reduction of APG flaring installation of the GPP - electricity generation, for the local needs using the APG.
3. The GPP Project could be developed on the base of gas turbine technology instead of four-stroke reciprocating engines.
4. The GPP Project could be of a smaller or larger scale in case if it could be commercially viable.
5. Reduction of APG flaring and re-injection of APG into oil wells.
6. Reduction of APG flaring and delivery of APG by the Project owner to the gas processing plants for conversion to dry gas, LPG, or condensate for downstream utilization, or delivery of the APG to the gas transmission pipelines.

These options cover all of the alternatives for baseline identification that are listed in CDM methodology AM0009, for example. The comparison of AM0009 alternatives and the list above is as follows:

Table 5: The comparison of AM0009 alternatives and the possible alternatives to the Project activity

AM0009 Alternatives	Options considered as possible alternatives to the Project activity
Release of APG to atmosphere (Venting)	Not considered
Flaring at the Project site	Option 1
On-site APG utilization	Options 2 through 4
Injection into oil reservoir	Option 5

Transportation, processing, distribution to end users	Option 6

Venting is not an acceptable option for this project because it is not legal under Russian regulations. Therefore, this is not a plausible future scenario.

Options 3 and 4 test technical Project variants to provide robust assessment of which options are the most plausible future developments that involve on-site electric generation.

Re-injection and downstream processing are the alternatives available to the RITEK as owner of the APG without the project, and complete the list of possible options to be considered.

Step # 2. Identifying of the most plausible alternatives considering relevant sectoral policies and other key factors that may affect a baseline.

<u>1. Continuation of APG flaring at the Serginskoye booster pumping station and electricity supplies of RITEK production facilities from the grid (and partly from diesel-generators)</u>.

The specific feature of the oil field is the proximity of the APG sources and the oil field facilities to the GPP. All customers also (pumping and other facilities) are located within 0,3 -12 km from GPP. Existing transforming station provides present consumption of oil-field.

Installation of additional diesel-generators is suitable only for small consumption. At the same time diesel-generator is the most expensive kind of generation.

Since 2003, (after adoption of the new State Law on Energy Sector Reform) the country is experiencing growth of prices for power that gave an additional reason for the Owner to develop in-house generation facilities, though this factor is not felt in the Tuymen region as it is in Central Russia, since the local supplier-Tuymenergo-is one of the cheapest power producer in Russia.. Currently, economic incentives are insufficient to attract most oil companies to efficiently use APG. No tax for APG flaring is imposed on oil companies. The only payments oil companies are required to make are the environmental fees for emissions of the polluting substances (i.e. methane) into the atmosphere. These fees are extremely modest compared to the investment costs required to productively utilize the APG. The current methane fees for flared APG per barrel of oil produced are less than 1.0% of the sales price of a barrel of oil. Thus, methane fees for flaring will have no major influence on decisions regarding oil production and related APG output, even with the perspective of their rise in accordance with the Government Decree # 7 of January 8, 2009, taken into account.

In this context , from 53- 55 billion m^3 of APG produced annually in Russia, about 45% is purchased by gas processing plants, 26% is utilized at the oil fields, and more than 25% is flared. A similarly low rate of utilization of the APG is observed in the KhMAO.

Oil producers in this region can earn very high returns on investment, expanding oil production and are much more likely to allocate funds to production rather than to less financially attractive APG utilization facilities. According to the head of the Gas and Natural Resources Department of neighboring Khanty-Mansijsk Autonomous Okrug, the payback on investment in oil production tends to be less than one year. No APG utilization projects are likely to offer a similar return.

In addition to the overall sectoral circumstances, the following project-specific arguments suggest that continued flaring at the Serginskoye field is a highly probable future scenario through 2012 and beyond as long as current economic and regulatory conditions prevail:

- Traditionally problem of power supply on this oil field was effectively solved by diesel-generators, or electricity from grid. First variant ensured operatively new equipment with generation. Second one – chargers minimization. Electricity in region still is the cheapest in the country, less then in the central-European part more than 2,5 times.
- There is gas processing plant of APG in Nyagan (at distance 27 km), but no available networks in the immediate vicinity to the Serginskoye oil field. No plans exist to construct them in future. Nyagan's plant (rather small and connected to main gas pipe-line) already has enough gas, that usually deliveries by long-term contracts. Construction of new pipe-line to plant will make Project owner dependent from the plant. Last one will dictate prices on APG.
- The technological solution in oil mining at the Serginskoye oil field presumes use of water to maintain pressure for oil extraction. Additional investments are needed to replace water with APG for injection; this option was considered by the Project Owner on the business planning phase (2001-2005) as the remote perspective,

going beyond the Project timeframe. Thus, possibility of further APG flaring exists, and can be considered as an alternative to the Project.

2. The proposed Project presuming the reduction of APG flaring, construction of the GPP and power & heat generation for the local needs using the APG, that is currently implemented by the Project Owner.

It should be noted that the Project Owner already possesses the experience of on-site electric generation at some oil fields, for example on Sredne-Khulymsk oil field. However, in this case the choice has been made, taking into account the local specifics, namely the absence of access to external grids. In this case the Power plant operates in an independent mode, and power supply of each well is provided by the cable-lines that are connected with power distribution facilities of the GPP.

Within the investment analysis approach and cost assessment provided in Section B.2 (Investment analysis sub-section), the total Investment cost for the Project Owner is estimated at 6,14 million Euro). High specific investments were presumed from the very beginning, because the infrastructure expenses were defined as top-priority. At the moment of commissioning total consumption of oil-field doesn't provide even 50% from installed capacity.

The project at existing costs is below the threshold of profitability existing for the first class borrowers for crediting period - project planning (7 years for a full recovery at 14 % annual) and even below the zero rate of NPV.. This clearly demonstrates that the project is not economically attractive to the Initiating party. The possibility exists for the Initiating party to compensate a part of the Project costs by using the Kyoto mechanisms, namely the Joint Implementation. This opportunity was considered at a stage of business planning of the Project.

Due to revenues from sales of GHG emissions reduction for roughly 0,8 million Euro during 2009-2012 the economic parameters of the project improve. But it does not allow the project to reach the level of profitability.

All this gives ample ground for conclusion, that the Project is additional from the financial point of view and in no case can be attributed to the business-as-usual scenario. Project Owner did not have sufficient economic reasons to investments in the Project, and Project implementation was not considered to be economically efficient alternative.

3. The installation of gas turbines instead of gas engines for power generation using APG.

This alternative was not considered by the Project Owner as technologically realistic, though the turbine solution had some advantages, including smaller size and smaller costs for MW installed. Still, the Project Owner explored this option and rejected the gas turbine technology for the following reasons:

- The efficiency of gas turbines (GT) is (usually) not higher than 32%, compared to 38-40% for Cummins engines operating at full load. Steam-gas cycle (that can raise total efficiency) is appropriate when the GPP has possibility to deliver power to external networks. But since it is not so, and internal consumption is characterized by significant fluctuation in demand, the gas turbines seems to be not inappropriate for this.
- The climate of Western Siberia is harsh with severe winters and warm summers. The temperature varies from - 40°C through + 20-25°C, and these changes do affect the GT efficiency that drops by 15-20%. On the contrary, Cummins has a high degree of resistance against the temperature changes, keeping its efficiency parameters high and steady.
- A Cummins engine can be started up and halted without limitation. Starts and halts do not affect the length of service of the engine. As for the GT, the situation is different; 100 starts of the GT reduce its service life by 500 hours.
- The service life until the overhaul for a GT is 20,000 - 30,000 hours, whereas for a Cummins engine it is 60,000 hours.
- Specific equipment costs, fuel consumption rates and O&M expenses for GT in this size range are higher than those for a Cummins.

Based on these findings, development of the Project with gas turbines replacing the gas engines is not more attractive than the Project as proposed. If the Project, as proposed, does not offer competitive returns, the gas turbine variant will certainly not be attractive. The GT alternative is not a plausible future scenario for the Project since the Cummins option proves to be more efficient and reliable.

4. Construction of larger GPP with increase in quantity of utilized APG and sales of a part of the electric power to external consumers.

The larger size option presumes competition with local power networks that appears to be not realistic.

There is no enough APG and dynamics (according to developed project "NIPIGaspererabotka") shows that APG volume will increase only till 2012, and after that debit slowly decreases. By that moment the APG resources may cover up to 75-80% of the GPP production capacity.

That is why such variant of Project development – as construction of larger GPP is not applicable.

5. Reduction of APG flaring and re-injection into the oil reservoirs.

Re-injection of associated petroleum gas into oil reservoirs is one of the methods to increase oil extraction, as it helps maintain reservoir pressure. APG injection as an option was considered by the Project Owner on the business planning phase (2000-2004) as the remote perspective, going beyond the Project timeframe. At the Serginskoye water injection system is operating efficiently; this system includes a group of pumping stations that are constantly pumping the water into the oil reservoirs. These stations consume the power delivered by the GPP within the Project.

Given the considerable costs invested by the Project Owner in water injection infrastructure, taking into account local hydrology, climate and the low cost of water used for this purpose, the APG re-injection can not be considered as economically attractive alternative for the Project Owner. Still, possibility of re-injection of APG in reservoir is now being considering by Project's owner (as a technological experiment), but perspective of commercial use of this technology is distant and is definitely outside the Project timeframe.

There were only few precedents (three) all over CIS with realization of so-called cycling-process (gas injection in oil well) – Novotroitzkoye oilfield (Ukraine), Kukmol and Aryskum (Kazakhstan). Due to achieved results efficiency of such technological decision still looks unconvincing (from the economic point of view), including also potential revenues from ERU sails. The reason – is very high energy chargers necessary to provide enough pressure on the well's mouth.

Therefore, this option can not be considered a plausible future scenario.

6. Delivery of APG to gas processing plants or to a gas transporting pipeline.

Implementation of this scenario is an unlikely due to following reasons:

- APG delivery to the nearest gas processing plant located in the city of Nyagan at a distance of 27 km from Serginskoye oil field requires huge investments, of many millions. For example construction of 1 km of the gas pipeline could cost 1,0-1,5 million €. Thus the total cost of the gas pipeline would require an investment of 30 to 40 million €. The volumes of AP gas available at the oil field are definitely not enough to guarantee a pay-off of such a project.
- Construction of a new gas processing plant at this site would also be excessively expensive. Based on available data, we can assume that construction of a gas processing plant for a comparable volume of APG would cost 28-40 million euros. The Serginskoye APG has an attractive composition due to significant fraction of gas liquids. This fraction (20% of APG volume) can be effectively sold on the market. But remaining part of APG - methane - can be transported from the oil field only in the liquefied form. However there is no necessary infrastructure for liquefied gas transportation in Russia. The necessary national technical regulation (TU) for this type of gas transporting is not developed yet, and this presents an additional problem, especially taking into the related hazard effects of methane. Thus, the economic benefits of such option are not obvious.
- There is a gas pipeline (main – "Urengoy – Uzhgorod", "Yamburg-West Border") nearby to oil field location that belongs to JSC "Gazprom". However access to them and perspective of their use for APG sales, are not clear due a number of constraints. APG from Serginskoye oil field can not be delivered to gas transporting pipelines without preprocessing needed to change it in accordance with pipeline transportation standards - GOST for natural gas. Even with this done, the supply to the gas transmission pipelines of Gazprom could face barriers due to the risk of facing limited access to the gas transmission infrastructure, taking into account the lack of free capacities in Gazprom system.

In addition, Gazprom generally accepts to pay a low price for the APG that may not be enough to cover the costs needed to develop the related infrastructure for gas collection, treatment and transportation. And above all, additional gas volumes from an outside producer being injected in the Gazprom transport system at the Gazprom "key gas producing region", actually means decrease of revenues of state monopoly. All this reduces chances of this similar scenario of APG treatment practically to zero.

Conclusion:

Based on above considerations, the only option can be regarded as plausible and credible candidate for the baseline scenario at this site:

• Option 1: Continuation of APG flaring at the Serginskoye oil field with power needed by the Project Owner delivered from the local grid operator.

Data/Parameter	$V_{F,y}$
Data unit	Nm^3
Description	Volume of the total recovered gas measured at point M1, after pre-treatment, during the period *y*
Time of determination/monitoring	Monthly
Source of data (to be) used	Flow meter
Value of data applied (for ex ante calculations/determination)	9230000 nm^3 (2010)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Measurements effectively show volume of APG that would be flared in frames of baseline. It is typical procedure using for settlements between Project's owner and GPP's exploiting company (Zvezda Energetika).
QA/QC procedures (to be) applied	Volume of gas will be completely metered with regular calibration of metering equipment. The measured volume should be converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement.
Any comment	-
Data/Parameter	Vi
Data unit	(%)
Description	Composition, of recovered gas measured at point M1, after pretreatment, during the period *y*
Time of determination/monitoring	Once a month
Source of data (to be) used	Measurement providing by authorized company
Value of data applied (for ex ante calculations/determination)	Vi (shown below)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Basic figures for calculations meters by authorized company on its chromatograph, at the junction point and at exit from pre-treatment block. Annual figures will be the APG volume weighted averages of twelve-times a year figures.
QA/QC procedures (to be) applied	**QA**: measurements are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of State Office for Metrology and Standardization
Any comment	-
Data/Parameter	Gen El.
Data unit	MWh
Description	Electricity supply to consumers at Serginskoye oil-field on voltage 10 kV, and electricity supplied for self consumption 0,4 kV.
Time of determination/monitoring	Monthly
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	31,500 MWh (2010)
Justification of the choice of data	Electric meters are installed at the 10 kV (0,4 kV) in-door switch gears,

or description of the measurement methods and procedures to be applied	data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; - **QC**: periodic calibration by the regional representatives of the State Office for Metrology and Standardization
Any comment	-
Data/Parameter	EF
Data unit	tCO_2/MWh
Description	Emission factor for grid connected plants
Time of determination/monitoring	Annually
Source of data (to be) used	Official site Tyumenenergo of Regional Energy Committee
Value of data applied (for ex ante calculations/determination)	0,522 (CO_2/MWh)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Emission factor for grid connected plants periodically calculates on the base of official data from GPP located in the region.
QA/QC procedures (to be) applied	Typical procedure in national power generation sector. Calculations providing by authorized specialists.
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 small-scale project:

To demonstrate that the proposed JI SSP will reduce the GHG emissions below those that would have occurred in the absence of the project, two steps are implemented:
• Step #1: Investment analysis of the Project based on calculation on NPV (net present value) for the Project.
• Step#2: Comparison of the GHG emissions that would occur due to the project activity and in the baseline scenario.

Step #1. Investment analysis of project without carbon revenues

The investment analysis is performed to assess the additionality of the Project. This analysis is based on calculation on NPV (net present value) for the Project giving a detailed vision of the degree of its financial attractiveness to the Project and taking into consideration the investment costs, operation costs, amortization and other parameters referring to expenses, including the discount taken at the rate of 14% (rate applicable to the first rate corporate borrowers at the major banks at the stage of the corporate decision making on the Project).

• *Annual revenues* for Serginskoye oil-field project are calculated based on the amount of money saved due to substation of power acquisition from the local grid operator as the result of GPP generation. The base here is the price to be paid to the power supply company for the amount of power to be substituted by the power generation by GPP. The tariffs for power were taken as 0,24 EUR/KWh – the average existing tariffs with the local grid operator Tyumenenergo for 2008.
• *Annual costs* for RITEK are calculated on the base of servicing fees to be paid to the company executing the technical servicing of the GPP. According to the respective concluded contract, it equals EUR 665.000 p/a, with the first servicing year starting on April 6 (that is reflected in the related table – see below)
.
Taken into account was also the amortization rate taken as 10%. With all the above costs and revenues taken at the level specified above, the Project shows negative profitability for the whole of its lifetime ending in 2028.

Investment Analysis for the Project – NPV calculations for 2007-2028 Part 1

Years	years		1	2	3	4	5	6	7	8	9	10	11
Years	years		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Investments	Euro	6140000	3684000	2456000									
Share of equipment	%	60%											
Discount	%	14%											
Annuity	Euro												
GPES production	MWh				18300	31500	34300	39200	39200	39200	39200	39200	39200
Electric energy to cover electric needs	MWh				18300	31500	34300	39200	39200	39200	39200	39200	39200
Total elecrric energy from the grid	MWh				18300	31500	34300	39200	39200	39200	39200	39200	39200
Tariff	Euro/MWh		24	24	24	24	24	24	24	24	24	24	24
Electric energy cost ('revenue)	Euro		0	0	439200	756000	823200	940800	940800	940800	940800	940800	940800
Amortization	%	10%											
Amortisation	Euro	10%	221040	368400	368400	368400	368400	368400	368400	368400	368400	368400	368400
Operation cost	Euro		0	0	495000	665000	665000	665000	665000	665000	665000	665000	665000
Project cost	Euro	27227440	3905040	2824400	863400	1033400	1033400	1033400	1033400	1033400	1033400	1033400	1033400
Cash (revenue - cost)	Euro	-9215440	-3905040	-2824400	-424200	-277400	-210200	-92600	-92600	-92600	-92600	-92600	-92600
IRR													
NPV													

Investment Analysis for the Project – NPV calculations for 2007-2028 Part 2

Years	years		12	13	14	15	16	17	18	19	20	21	22
Years	years		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Investments	Euro	6140000											
Share of equipment	%	60%											
Discount	%	14%											
Annuity	Euro												
GPES production	MWh		39200	39200	39200	39200	39200	39200	39200	39200	39200	39200	39200
Electric energy to cover electric needs	MWh		39200	39200	39200	39200	39200	39200	39200	39200	39200	39200	39200
Total elecrric energy from the grid	MWh		39200	39200	39200	39200	39200	39200	39200	39200	39200	39200	39200
Tariff	Euro/MWh		24	24	24	24	24	24	24	24	24	24	24
Electric energy cost ('revenue)	Euro		940800	940800	940800	940800	940800	940800	940800	940800	940800	940800	940800
Amortization	%	10%											
Amortisation	Euro	10%	368400	368400	368400	368400	368400	368400	368400	368400	368400	368400	368400
Operation cost	Euro		665000	665000	665000	665000	665000	665000	665000	665000	665000	665000	665000
Project cost	Euro	27227440	1033400	1033400	1033400	1033400	1033400	1033400	1033400	1033400	1033400	1033400	1033400
Cash (revenue - cost)	Euro	-9215440	-92600	-92600	-92600	-92600	-92600	-92600	-92600	-92600	-92600	-92600	-92600
IRR													
NPV		-6 464 988											

Even at the end of the Project lifetime the revenues cannot exceed costs , and the NPV for the Project period is as low as – 6.465.000. With this degree of financial unattractiveness the Project can by no means be a part of Business-As-Usual scenario for the Project Owner.

Sensitivity Analysis
Sensitivity Analysis is added for the conservativeness reasons to confirm the robustness of the financial additionality of the Project. The sensitivity is tested against the dynamics of tariffs for power to be aquired by the Project Owner from the external grid. The first scenario presumes - 20% fall of tariffs and shows the following project economics : with these conditions the project becomes still less attractive for the Project Owner, with the NPV reaching -7.358.000 EUR.
In the second scenario, presuming tariff rise by 20% the Project still remains unattractive from the financial viewpoint with NPV at the level of – 5.572.000 EUR. In this connection the project can be described as economically unreasonable for the Owner.

Analysis of the impact of the regulatory norms of the Russian Federation introduced after the date of baseline setting. On January 8, 2009 the Government of the RF has issued a decree # 7 ” On the measures of stimulation of the reduction of atmospheric air pollution by the by-products of associated petroleum gas flaring on stacks” that sets starting from 1.01.2012 a considerably higher payment rates for APG flaring above the prescribed norm of 5%. Analysis of impact of this regulation shows that supposed that for the whole amount of the APG flared within the baseline, that is considered to be above the prescribed norm with the respective payment rate, the annual baseline expenses within this scenario will grow by EUR 37.000. This will bring down the NPV slightly up, but no more then 6-7% depending upon the scenario chosen from the above ones. This gives a reason to conclude that the new regulation produces no sizeable effect upon the financial attractiveness of the baseline and financial disadvantage of the project for the Owner.

Emissions reduction (ERU) sales within the Project can add to its attractiveness in terms of return on investments within the Project line; a possibility also exists to increase incomes of the company by revenues from ERU sales in the post-Kyoto period, after 2012. It is worth noticing, that incomes from the sales of reductions will raise attractiveness of the Project for the Owner and will create a precedent which can be further repeated by the other oil companies in KhMAO.

The Project is one of the first in the region, directed to utilization of associated petroleum gas for power generation.

Nowadays, as the State is shaping its strategy in APG treatment the Project can be assessed as one conforming with best environmental standards and approaches, that can be reflected in this strategy as an effective way to minimize the anthropogenous pressure on environment in the oil-producing regions.

Step #2. Comparison of the GHG emissions that would occur due to the project activity and in the baseline scenario
The previous section demonstrates that the most probable option in the absence of the JI project is the continued flaring of 9,23 million m^3 of APG that the JI project would have used for electric and heat generation. Given this baseline scenario, baseline and project emissions of GHG can be compared as follows:

Table 8: Baseline and project scenario emissions (as per 2010)

Comparative Item	**Units**	**Baseline scenario**	**Project scenario**
APG flared/combusted	1000 m^3	9,230	9,230
Complete combustion of APG	tCO_2	21539	27543
Unburned APG in terms of tCH4	tCH_4	765	-
Unburned APG in terms of tCO2e, *(c*21)*	tCO_2	16071	-
Total Local Emissions	tCO_2	37610	27543

Power (electricity) from grid	MWh	31500	-
Emissions of CO_2 from grid plants	tCO_2	17493	-
Total emissions CO_{2eq}	tCO2	55102	27543

Calculations based on representative historical data show that the Serginskoye flaring is performed in black-firing mode and that the APG produced here is ≈70% methane (by volume). The detailed NII Atmosfera calculation methodology then indicates that flaring of 9,23 million m^3 per year (on the representative 2010) of APG at oil field will lead to emissions of 765 tCH_4 due to under-firing and 21,539 tCO_2. Conversion of CH_4 to CO_2e using an IPCC global warming potential factor of 21 then indicates baseline local emissions due to flaring of 37,610 tCO_2e.

The Project supplies 31500 MWh of electricity p/a (data for 2010) for local consumption on the Serginskoye oil field. CO_2 emissions from grid power plants for this amount of power within the baseline are estimated as 17,493 tonnes per year. The grid emission factor has been developed using the elements of the Combined Margin approach defined by the "Tool to calculate the emission factor for an electricity system" and is estimated at 0.522 tCO_2/MWh (see Annex 2 "Baseline Study"). The simple operating margin emission factor is 0.531 tCO_2/MWh and the build margin emission factor based on the most recent five power plants is 0.517 tCO_2/MWh. All power plants in the Tyumen grid are fired with natural gas or APG and operate at average gross efficiencies of 39% to 40%. Delivery losses and grid plant station demands have been estimated conservatively at about 11% of gross grid generation

Total baseline emissions are then 37,610+17,493 = 55,102 tCO_2e per year.

Combustion of APG in the gas engines is much more efficient than in flare. The project uses the approach from the previously approved CDM methodology AM0009 version 2 and assumes full oxidization.

$PE,y = (Vy*Py) * Wcarbon,A,y *44/12$

Where:
Vy – volume of APG to be flared
Py – density of APG

Thus, 9924 (tAPG) * 0,756 (cAPG) * 44/12 = 27543 tCO_2

Total Project CO_2e emissions: 27,543 tCO_2e

The estimate of annual reductions in GHG emissions is then 55,102 – 27,543 = 27,560 tCO_2e

While the NII Atmosfera methodology for calculating flare emissions is widely recognized as the standard for the Russian oil and gas industry, it relies centrally on the chemical composition of the APG being burned and on continued operation of the flare in black-firing mode. Since the gas engines within the Project have been specifically designed for the APG of Serginskoye, the long term purchase contract includes clear specifications of fuel composition and GPP staff regularly monitors compliance with these specifications. No significant variations in fuel composition are anticipated during the period from 2009 to 2012 (Project crediting period) although this will be monitored monthly and emission reductions will be tied to composition of the fuel actually received.

As discussed in the Annex 3, the black-firing test depends on the physical dimensions of the flare stack, the volume, adiabatic index, molecular mass and temperature of the APG being flared, and the discharge velocity of the flared gas. Since the flaring will continue within the Project, the necessary data for this test will be provided on a regular basis. However, some significant changes in the mode of operation of GPP may require reconstruction of the stacks. Since there is no significant motivation for RITEK to change the mode of operation of the flare or to invest in reconstruction, it is assumed that black-firing mode will continue. GPP will provide monthly dated photographs of the flare as evidence that no major reconstruction has occurred. In that case, the assumption of continued black-firing is appropriate. If significant reconstruction does occur, GPP will request the necessary data from the Project Owner to determine whether black-firing is still the appropriate. Future flare reconstruction is considered highly improbable.

The Project reroutes APG that flows to the flare in the baseline through the gas treatment plant, the gas engines (furnaces) and ultimately through the gas engine stacks. Obviously this Project routing offers some opportunities for emissions due to leakages and/or accidents in the delivery, cleaning and combustion of APG.

However, the Project APG pipeline is only 0,5 km. It was built according to the modern standards, including those for isolation. Therefore, leaks have been ignored to assure that emission reduction estimates are on a conservative basis.

Common Practice. Actually there was a number of projects implemented in Russia since 2004 in APG utilization and some of them took place in the region with roughly similar conditions as Serginskoye project with the same goal of substitution of the power previously acquired from the local grid operator. These projects included i.a. :

	Oil-field	Region	Project owner	Brief description
1	Yuzhno-Myldzhensk oil-field	KhMAO	JSC Russneft	GPP consists of 3 engines GE-Jenbacher 0,88 MW each. Annual APG utilization 5 mln.m3. Commissioned in 2007.
2	Yarayner oil-field	YaNAO	JSC Gazprom-Neft	Commissioned in 2005 GPP engines Cummins -QSV91G with total installed capacity 6,58 MW (5*1,35).
3	Maiskoye oilfield	Tomsk	Imperial Energy	Commissioned in 2007 Station «ENERGO-П6160/6,3KH30», 6160 KW capacity, APG utilization over 9 mln ncm. p/a
4	Igolsko-Talovoye oilfield	Tomsk	Tomskneft (JSC Rosneft)	Commissioned in 2004 Gas turbine station, 24 MW capacity

The difference between the above mentioned examples and situation with Serginskoye oil-field is on the financial side of the project. Though the above mentioned projects as well as Serginskoye project were targeted to substitute the power from the external grid by the power from APG utilization, there are reasons to presume that the financial conditions of the above group of projects must have differed from those of the Serginskoye project. With the low profitability of APG utilization project generally acknowledged as a problem in average the projects of APG utilization with power generation provide for sustainable development of oil-field as a key result, but the issue of additional revenues is generally questioned.

. Still, with the analysis of local practice it becomes clear that for the projects of this type the exact degree of financial appropriateness for the project owner may vary from one project to another, affecting the related decision making of the Project Owners. Though the financial details of the projects mentioned above are not available for public access, and it is not possible to give the exact comparison of the financial situation of each respective project, one can assume that these projects were considered appropriated for implementation by the Project Owners for a number of reasons. In some cases better attractiveness was reached by lower operating costs, the savings generated by the Project Owner's own staff that is used to run the equipment instead of the specialized operator company (it should be noted that the servicing costs within the Serginskoye project are considered as high by Russian standards, since the GPP operation has been commissioned to the equipment supplier, with costs of EUR 665.000 p/a). In some cases the projects enjoyed status of technological innovation experiment, supported by the budget, e.g. the one at the Igolsko-Talovoye oilfield, that tested the new technological solution of use of the ex-defence helicopter turbines of for power generation on the base of APG utilization.

Still, one more consideration may be treated as a proof of better financial attractiveness of the said projects compared with the Serginskoye project. This consideration is the stance of the owners of the related Projects towards the opportunities of additional financing with the help of Kyoto protocol, that may be instrumental in easing the financial burden of each respective Project for the owner. The above mentioned projects have not been developed as JI projects and no attempts to attract additional financing within the Kyoto protocol framework were made by the project owners, that cannot be perceived otherwise than as a sign, demonstrating the appropriateness of the financial conditions of these projects fro the owners. In case of Serginskoye, the situation is different, with the Project Owner actively searching additional financing within Kyoto protocol, trying to ease the financial burden caused by the APG utilization project.

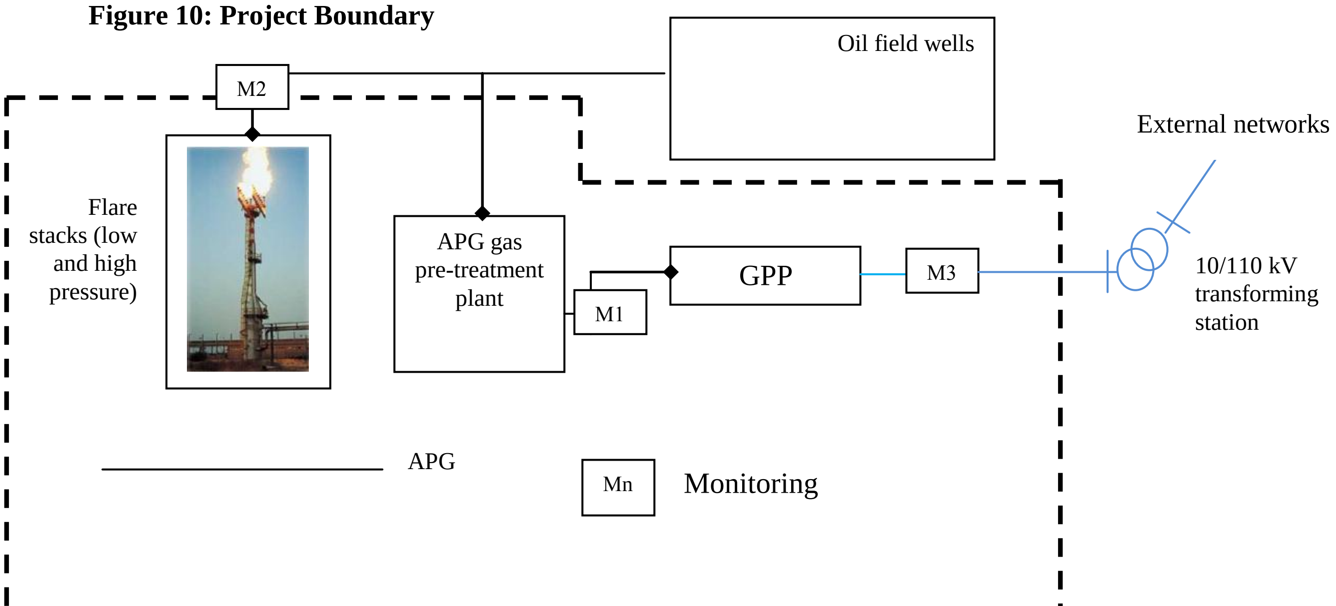
Summarizing the additionality considerations, it should be repeated that in the baseline scenario, electric power for the local needs of the Serginskoye oil field would be provided by grid power plants. Within the Project APG flaring at the Serginskoye oil field would be considerably reduced. The new GPP combustion process is much more environmentally friendly than flaring and reduces the methane emissions into the air. As shown by the economic efficiency analysis, the Project itself is not the most attractive option for the Project Owner from the financial point of view. Therefore, it may be stated that the Project corresponds to the additionality requirements, since it is definitely not a part of the baseline scenario and reduces the GHG emissions below those that would have occurred in the absence of the project.

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

The project boundary encompasses the following Project components (see figure 10):
- GPPs including auxiliary facilities such as the electrical cables, etc;
- Local grid (low voltage) - distribution system, transforming station;
- Flare stacks (high and low pressure) at the Serginskoye booster pumping stations;
- The APG treatment plant (providing fuel-Gas) and the emergency diesel generator;
- Equipment for APG transmission onto GPP (gas pipeline and pumping stations);
- Complex of metering equipment.

All components are directly under control Project owner (operator). Access to metering equipment (including certification, exploitation and calibration) is enjoyed solely by the Operator with the exception for the relevant state authorities.

Figure 10: Project Boundary



Electricity

Project boundary

The table below specifies Emissions sources included into the Project boundary.

Emissions sources included into the Project boundary.

	Sources	Gas	Included	Justification/ Explanation
Baseline	Flaring of associated gas	CO2	Yes	Main source of emissions in the baseline within any APG utilization project
		CH4	Yes	Source of emissions in the baseline
		N2O	No	Assumed negligible
	Consumption of other fossil fuels by grid power company in place of the recovered gas	CO2	Yes	Source of emissions in the baseline within any APG utilization project
		CH4	No	Assumed negligible due to negligible amounts
		N2O	No	Assumed negligible due to negligible amounts

	Sources	Gas	Included	Justification/ Explanation
Project activity	Emissions from recovered APG combustion within power generation at the GPP	CO2	No	Main source of emissions in the project scenario within any power-generation APG utilization project
		CH4	No	Assumed negligible due to negligible volumes
		N2O	No	Assumed negligible due to negligible volumes

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 the baseline study 21/11/2008

Name of person(s)/entities determining the baseline:

LLC «Sigma International»
Moscow, Russian Federation
Tel. +7 (495) 7753232
Fax +7 (495) 7753232
e-mail: sigma@effort.ru

LLC «Sigma International» is not Project participant

The baseline was determined under the guidance of approved methodology CDM AM 0009

SECTION C. Duration of the small-scale project / crediting period

C.1. Starting date of the small-scale project:

July 12, 2001

C.2. Expected operational lifetime of the small-scale project:

20 years (240 months) starting from 06.04.2009

C.3. Length of the crediting period:

45 months (3 years 9 months) starting on 06.04.2009

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

The Project will contribute to sustainable development of the host country by promoting the utilization of a wasted energy resource and will achieve two goals:

- Reducing CH_4 emissions due to more complete APG combustion in gas engines relative to APG flaring;
- Substitution of grid power generation to power from GPP with more efficient engine and reduced GHG emissions.

At present, no approved CDM monitoring methodology that would allow estimating CH_4 emissions mitigation from APG flaring reduction projects is available. On the other hand, the “Methodology of calculation of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks” developed by the Saint-Petersburg Scientific Research Institute for Protection of Atmosphere (NII Atmosfera) endorsed by State Committee for Environmental Protection (GosKomEcologiya) is designed for practical usage when estimating such emissions during APG flaring. This methodology is widely used by Russian oil and gas sector in calculations of hazardous atmospheric emissions.

Therefore, modalities relating to CH_4 emission reductions estimation contained in the methodology of NII “Atmosfera” are used in the monitoring plan of this Project. Estimation of CO_2 reductions due to the displacement of electricity generation from grid power plants uses the “Tool to calculate the emission factor for an electricity system” for the calculation of the Combined Margin emission factor on the basis of the Operating and Build Margin factors. Accordingly, the monitoring plan includes the elements of the “Tool to calculate the emission factor for an electricity system” used for the Project:

- The simple OM emission factors are calculated *ex-ante* using the full generation-weighted average for the most recent 3 years for which data are available at the time of PDD submission;
- The Build Margin emission factor is calculated *ex-ante* based on the most recent information available on GPP (technical data) and on plants already built for sample group *m* at the time of PDD submission. The sample group consists of five power plants that have been built most recently.

D.1.1.1. Description of formulae used to estimate project emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

The equations used to calculate Project emissions are summarized in Table 10 below.
The project uses the approach from the previously approved CDM methodology AM0009 version 2 and assumes full oxidization.

$PE_{,y} = (V_y * P_y) * W_{carbon,A,y} * 44/12$

where:
PE,y - the baseline emissions during the period y in tons of CO2 equivalents.
Vy - volume of gas recovered from the oil field during the period *y*, explicated in (000) ncm.
Py - density of APG, kg/ncm.
Wcarbon,A,y - the average content of carbon in the gas recovered during the period y.
The methane content in the gas W*carbon,A,y* is determined from Table 11, 1.

Table 10: Project emissions calculation equations

1- Annual emissions from GPP

PE1	1	2	3	4	5	6=1*2*3*4/5
	Mass amount of APG flared	Carbon mass fraction in APG		Molecular mass of CO2	Molecular mass of C	Total CO2 emissions project
	M APG	σ c_APG	*Scalar*	*μ CO2*	*μ C*	*ECO2_combustion project*
Units	T	% mass		kgCO2/mole	kgC/mole	tCO2
GPP	9924	75,68992405	0,01	44	12	27542,6

2- Emissions from emergency diesel generator

PE2	1	2 IPCC Factor	3=1*2
	Electricity by emergency diesel generator	Emissions factor for electricity by diesel generator	Total emissions _emergency diesel generator
	Emgen_fuel	*Diesel fuel EF*	*Emgn_CO2*
Units	MWh	tCO2/MWh	tCO2
	0	0,2626	0

3- Total Project emissions

PE3	1 from PE1	2 from PE2	3=2+1
	Total emissions from APG_project	Total emissions_emergency diesel generator	Total emissions project
	ECO2e_APG_project	*Emgn_CO2*	*ECO2e_total_project*
Units	tCO2e	tCO2	tCO2
	27543	0	27543

Thus, total project emissions 27,543 tCO2e per year.

As explained in Section B.2, emissions based on leakages and/or accidents are likely to be greater in the baseline delivery of APG to the flare than they will be in the operation of the new GPP. Therefore, potential leaks and accident emissions in the Project scenario have been ignored to assure that the emission reduction estimates are based on conservative assumptions.

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

Baseline emissions at the Serginskoye flare are calculated using equations *BE2* through *BE6* below in combination with *BE1* as shown in Table 11.
Color coding distinguishes inputs which will be monitored each year (yellow); inputs that will be stipulated upfront as constants (green) and calculated values (blue).

Columns (6) in equation *BE4* and column (1) in equation *BE3* are parameters that are specified in the using methodology for calculating emissions from flaring of APG in Russia. The factors shown assume that the Serginskoye flare will continue to operate in black-firing mode. The monitoring plan addresses the photo evidence that will support this assumption going forward. The key input parameters for future years will be the volume of APG used by the GPP (column (1) in equation *BE5),*

Table 11: Equations for local baseline emissions at the APG flare
1- Calculation of mass fraction of APG components

BE1		1	2	3	4	5	6	7	8=1*5/100	9=6*7	10=7*3/ $miCH_4$
	Index	*Vi*	*pi*	*Mi*	*µi*	*Ki*	*σc-i*	*Σi*	*k APG*	*σc_APG*	*σ CH4*
		Volume fraction, weighted average of monitored monthly data	Density of hydrocarbons and elements	Molecular mass of components	Molecular mass of icomponent in APG	Adiabatic index of icomponent of APG	mass content of carbon of icomponent in APG	Molar ratio	Adiabatic index of APG	Mass fraction of Carbon in APG	Hydrocarbons in CH4 equivalent
	Component	%	kg/m3	kg/mole	kg/mole		% mass	%		% mass	%
Unit	CH_4	77,50	0,716	16,043	12,433	1,31	74,87	0,516085	1,0153	38,6393	0,51609
	C_2H_6	2,87	1,342	30,07	0,863	1,21	79,98	0,035821	0,0347	2,8650	0,06714
	C_3H_8	5,81	1,969	44,097	2,562	1,13	81,71	0,106397	0,0657	8,6937	0,29245
	C_4H_{10}	6,51	2,595	58,124	3,784	1,1	82,66	0,157118	0,0716	12,9874	0,56924
	C_5H_{12}	2,34	3,221	72,151	1,688	1,08	83,24	0,070099	0,0253	5,8351	0,31526
	C_6H_{14}	1,28	3,842	86,066	1,102	1,07	83,73	0,045738	0,0137	3,8296	0,24537
	C_7H_{16}	0,58	4,468	100,08	0,580	1,06	84,01	0,024102	0,0061	2,0248	0,15035
	C_8H_{18}	0,14	5,10	114,23	0,160	1,05	84,21	0,006641	0,0015	0,5592	0,04728
	CO_2	0,51	1,977	44,011	0,224	1,3	27,29	0,009377	0,0066	0,2559	
	N_2	2,46	1,251	28,016	0,689	1,04		0,028622	0,0256		
	Total	100,00			24,08626				1,2660	75,6899	2,203182
		Density		1,07521							

2- Quantity of carbon atoms in molecular formula of APG

	1	2	3	4	5=(1*3/4)*2
	Mass fraction of Carbon in APG	Molecular mass of APG		Molecular mass of carbon	Quan. Of carbon atoms in molecular APG
BE2	*σ c_APG*	*µ APG*		*µ c*	*Kc*
Units	% mass	kg/mole	Scalar	kg/mole	carbon atoms
	75,6899	24,08626	0,01	12	1,519

3- CH_4 emission factor for APG flaring

BE3	1	2	3=1*2
	Ku/f (bf)	*σ CH_4*	*e CH4_baseline*
	Under firing coefficient	Total hydrocarbons in CH_4 equivalent	CH4 emission factor _ baseline
Units	Scalar	% mass	Kg CH4/kg APG
	0,035	2,203182	0,0771

4 - CO_2 emission factor for APG flaring

BE4	1	2	3	4	5	6	7	8=2/3	9=4/5	10=6/7	11=1*(8-9-10)
Units	Molecular mass of CO2	Qu of carbons in APG formula	Molecular mass of APG	CH4 emission factor _ baseline	Molecular mass of CH4	CO emission factor _ baseline (black firing)	Molecular mass of CO	C emission factor _ baseline	Molecular mass of CH4	Molecular mass of CO in APG	CO2 emission factor
	µ CO2	*Kc*	*µ APG*	*e CH4_baseline*	*µ CH_4*	*e CO_baseline*	*µ CO*	e C_baseline			*e CO2*
	kgCO2/mole	Carbon atoms	kg APG/mole	Kg CH4/kg APG	Kg CH4/kg mole	Kg CO/kg APG	kgCO/mole		Kg CH4/mole APG	Kg CO/mole APG	Kg CO2/kg APG
	44	1,519	24,086	0,0771	16	0,25	28	0,0631	0,0048	0,0089	2,1704

5 - Mass amount of APG flared

BE5	1	2	3=1*2
	Annual volumetric flow of APG to be flared	Density of APG	Mass amount of APG flared
	V APG	*ρ APG*	*M APG*
Units	ncm (1000)	kg/ncm	T
GPP	9230	1,07521	9924,2

6 - Total emissions from APG flare

BE6	1	2	3	4	5=1*2	6=1*3*4	7=5+6
	Mass amount of APG flared	CO2 emission factor_baseline	CH4 emission factor_baseline	CH4 global warming potential	CO2 emissions from complete burning	Total CH4 emissions in terms of tCO2e	Total CO2 emissions from APG flaring
	M APG	*e CO2_baseline*	*e CH4_baseline*	*GWP CH4*	*E_{CO2} complete baseline*	*E CH_4 baseline*	*E_{CO2e} flaring baseline*
Units	T	Kg CO2/kg APG	Kg CH4/kg APG	Scalar	tCO2e	tCO2	tCO2
GPP	9924,2	2,1704	0,0771	21	21539,3	16070,6	37609,9

The second major component of baseline emissions is the GHG to be released by grid power plants in course of generating power equal to the power amount to be generated by the GPP within the Project. Table 12 shows equation (*BE8)* that used to calculate baseline emissions from grid power plants.
That includes step up transformation from generation voltage, line losses and step down transformation to the delivery points. Grid plant input to the delivery system represents net output of the grid plants. Gross generation determines the actual fuel consumption. Current data shows that gross generation exceed net generation in the Tyumen grid by a factor of 1.053. That factor will be monitored each year.

The grid emission factor is developed in Annex 2 using "Tool to calculate the emission factor for an electricity system". The operating margin and build margin emission factors are very similar since the gas plants serving this region are all fired with gas or APG and operate at similar efficiencies. New plants in this area, if any, will almost certainly use natural gas. A simple average of the OM and BM has been used.

The Table 12 (A-B) combines local and grid power plants fuel consumption and emissions to calculate the total annual *ex-ante* estimate of baseline emissions.

Table 12: Baseline grid power plants emission equations electricity generation, and total baseline emission

(A) Electricity generation by GPP

BE7	1	2	3	4	5=4*3
	Electricity (net) generation	Transmission loss in high-voltage grid*	Displacement of gross grid generation	Margin emission factor	Total CO2 emissions_grid
	Elec_gen	*trans loss*	*Gross disp*	*EF CM*	*ECO2_grid*
Units	MWh	%	MWh	tCO2/MWh	tCO2
	31500	6	33511	0,522	17493

*Minimal level of losses,

(B) Gross grid baseline emissions

BE8	1	2	3=1+2
	Total CO2 emissions from APG flaring	Total CO2 emissions _grid	Total baseline emissions
	E CO2e flaring baseline	*ECO2_total*	*ECO2e_total_baseline*
Units	tCO2	tCO2	tCO2
	37610	17493	**55102**

D.1.2. Treatment of leakage in the monitoring plan:

No leakages were identified that correspond to net changes of emissions which occur outside the project boundary and are measurable and attributable to the Project activity. (Gas pipeline from oil field to pre-treatment block is about 1 km, and has doubled insulation). Emissions related to the supply of fuel for the emergency diesel unit and the emissions from installing the new equipment will not be significant. Much greater emissions could be associated with delivery of gas to grid power plants situated in region (Surgut), which does not occur in the Project that presumes local on-site power generation and consumption. Therefore, the exclusion of leakages from the Project will assure conservatism in the estimation of emission reductions within the Project.

D.1.2.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:

ID number	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

D.1.2.2. Description of formulae used to estimate leakage (for each gas, source etc.; emissions in units of CO_2 equivalent):

No formulae used to estimate leakage (please see Section D.1.3).

D.1.3. 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):

Ex ante estimates of the total annual emission reductions for the Project have been derived in equation *ER1* as a difference between the total baseline emissions estimated by equation *BE6* in Table 11 and *BE9* in Table 12 total Project emissions estimated by equation *PE6* in Table 10.

Table 13: Annual emission reductions

ER1	1 (from BE9)	2 (from PE6)	3=1-2
	Total baseline emissions	Total emissions project	Total emissions reduction
	ECO2e_total_baseline	*ECO2e_total_project*	*ER CO2e_total*
Units	tCO2	tCO2	tCO2e
	55102	27543	27560

D.1.4. 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:

A four level system for the monitoring of environmental impacts has been established at the GPP. This system allows monitoring, reporting and controlling of the maximum concentrations of the hazardous substances emissions such as CH_4, NO_x, and CO:
1. First, the gas contamination sensors that monitor CH_4 concentrations relative to maximum permissible emissions (MPE) limits are installed at the APG treatment plant and at condensate collection tanks.
2. Second, the generating units at the power hall (GPP) are equipped with the *LENOX* controlling system, which automatically monitors CH_4 concentrations in the engines.
3. Third, the mobile mechanized plant, *TESTO*, monitors concentration of the hazardous waste in the exhaust gases at any desired measuring point (engine, power hall, etc. in GPP). The emissions measurement may be taken in any required place. Once the data is measured, the shift operator inputs it in his log book.
4. Fourth, the shift operator is periodically on a beat monitoring the situation with gas emissions.

In case of exceeding the established MPE maximum limits, the signals from sensors will come in GPP's automated control system (ACS) that will adjust working parameters of the equipment to an optimized safe operation level. The shift operator inputs the measurements (in case of exceeding the maximum limits) in the log book. All shift log books will be numbered, tied together and archived for 5 years.

In frameworks of National Environmental Regulation of host party – maximum permitted emissions (MPE) determined according to GOST 17.2.3.02-78 (regulation standards of harmful substance's emissions for Industry). GOST's using during estimation of environmental impact in frames of project documentation, simultaneously with established by Ministry of Health USSR in 1978 maximum permitted concentrations (MPC).

D.2. Data to be monitored:

Data/Parameter	Gen
Data unit	GWh
Description	Electricity supply to consumers at Vostochno-Perevalnoye oil-field on voltage 10 kV, and electricity supplied for self consumption 0,4 kV.
Time of	Monthly

determination/monitoring	
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	31,5 GWh (2010)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Electric meters are installed at the 10 kV (0,4 kV) in-door switch gears, data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of the State Office for Metrology and Standardization
Any comment	-
Data/Parameter	EmGen
Data unit	MWh
Description	Generation on emergency diesel generator that will lead to additional emissions based on diesel combustion
Time of determination/monitoring	Monthly
Source of data (to be) used	Electric meters
Value of data applied (for ex ante calculations/determination)	0 MWh
Justification of the choice of data or description of the measurement methods and procedures to be applied	Electric meters installed at the 10 kV switch gears, data will be archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of the State Office for Metrology and Standardization
Any comment	In a case of emergency situation on GPP, diesel generator provides electricity for the most important needs.
Data/Parameter	Vi
Data unit	%
Description	Composition of recovered gas measured at point M1, after pretreatment, during the period *y*
Time of determination/monitoring	Once a month by GUP "IPTER"
Source of data (to be) used	Measurement providing by authorized company
Value of data applied (for ex ante calculations/determination)	Vi shown below Table 11.
Justification of the choice of data or description of the measurement methods and procedures to be applied	Authorized company on its chromatograph, at the junction point and at exit from gas pre-treatment block. Annual figures will be the APG volume weighted averages of twelve times a year figures.
QA/QC procedures (to be) applied	**QA**: measurements from the chromatograph are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the chromatograph by the regional representatives of the State Office for Metrology and Standardization
Any comment	M APG and density calculating on the base of available APG composition.
Data/Parameter	$V_{F,y}$
Data unit	Nm^3

Description	Volume of the total recovered gas measured at point M1, after pretreatment, during the period *y*
Time of determination/monitoring	Monthly
Source of data (to be) used	Flow-meters with corrector
Value of data applied (for ex ante calculations/determination)	9230000 nm3 (2010)
Justification of the choice of data or description of the measurement methods and procedures to be applied	Flow-metering equipment installed at the junction point and at the exit from gas pre-treatment block measures volumes of APG automatically, archived electronically and in monitoring workbook.
QA/QC procedures (to be) applied	**QA**: measurements from the flow meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of State Office for Metrology and Standardization
Any comment	-

D.3. 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.
1. VAPG	Medium (in accuracy of measurements 5%)	**QA**: measurements from the flow meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of State Office for Metrology and Standardization
2.V%	Low (Instrumental error 1%)	**QA**: measurements from the chromatograph are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the chromatograph by the regional representatives of the State Office for Metrology and Standardization
3. ElecDel 10 kV	Low (Instrumental error 0,2%)	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of the State Office for Metrology and Standardization
4. ElecDel 0,4 kV	Low (Instrumental error 0,2%)	**QA**: measurements from the electricity meters is screened on monitors at the operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration of the meters by the regional representatives of the State Office for Metrology and Standardization
5. Heatdel	Low (Instrumental error 1%)	**QA**: measurements from the flow-meter is screened on monitors at the GPP operator's desk; readings are taken by the trained staff according to the requirements of the technical specifications; **QC**: periodic calibration by the regional representatives of the State Office for Metrology and Standardization
6. EF_{CO2}_diesel _fuel	Low	**QA:** the CO_2 emissions factor of the diesel fuel is taken from the Appendix B of the simplified modalities and procedures for

		small CDM project activities (IPCC factor); **QC:** periodic (once a year) check of this data
7. Gross_ cons	Low	**QA**: the total electricity of oil field will be taken from an official corporate report. Data on equipment loading based on technical parameters from technical passport. **QC**: periodic (once a year) check of this data

D.4. Brief description of the operational and management structure that will be applied in implementing the monitoring plan:

The Project's operational and management structure will be totally in compliance with that of existing at the GPP. Majority of variables are monitored under normal day-to-day routine practice. Data on GPP performance indicators, including APG deliveries and electricity/heat supplied to RITEK and also self consumption. Based on that, the monitoring structure will be as follows:

At the GPP level, the shift operators will be responsible, on day-to-day basis for monitoring the variables indicated above in subchapter D.1.1.1. and D.1.1.2., including taking the readings from electricity meters, APG flow meters, chromatograph and the fuel tank contents and deliveries. The monitoring and reporting of most of these data (volume, capacity and electricity flows) has been already adopted under the routine operation regime of the GPP. Composition and density of APG, specifies two times a year (in winter and in summer), by authorized organization. Emission reductions will be automatically determined, as a Microsoft Excel program will make the necessary calculations with the use of formulas described in the subchapters D.1.1.1 and D.1.1.2. and the tables provided in the Monitoring Workbook. All this information will be documented and stored in paper and electronically with the operator. The necessary instruction with regard to monitoring of emission reductions will be provided to GPP operators.

Every month, the data used to calculate emission reductions received will be summed up and be reported to the GPP's chief manager, who will transfer them via the internet to the head office of RITEK in Moscow. The manager of RITEK responsible for the Project will provide general supervision of the technical performance of GPP including verification of data storage. To provide the verification of emission reductions generated by the Project, the archiving of data will be extended until 2014.

D.5. Name of person(s)/entity(ies) establishing the monitoring plan:

LLC «Mejdunarodnaya Gruppa «Sigma»

Moscow, Russian Federation
Tel. +7 (495) 7753232
Fax +7 (495) 7753232
e-mail: sigma@effort.ru

SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions and formulae used in the estimation:

Ex-ante Project emission estimates have been developed on a basis of actual data on APG available for 2007 added with necessary information on gas composition from April and June of 2008. GPP were launched in April 2009. Further on the GPP is supposed to operate on APG with similar composition and on the base of the projected annual growth of power output. Therefore, *ex-ante* estimates provided in this section are assumed to reflect the planned figures for each year of the Project implementation (although the actual figures will vary based on ex post data).

Ex-ante Project emission estimates have been developed using the 6 equations shown in table 10 (see Section D.1.1.2.). Table 14 provides the *ex-ante* illustrative calculation of annual Project emission from APG combustion excluding possible emissions from emergency diesel generator at 27,543 tCO_2e.

Table 14: Project emissions from APG combustion at the GPP

APG combustion in Project gas power plant (GPP)			
Emissions from GPP calculation			
M APG	Mass amount of APG flared	t	9924
σ c_APG	Carbon mass fraction in APG	% mass	75,69
μ CO2	Molecular mass of CO2	Kg CO2/mole	44
μ C	Molecular mass of carbon	Kg C/mole	12
ECO2_combustion project	GPP CO_2 emissions project	tCO_2	27543

The *ex-ante* estimates of emissions from the emergency diesel generator are estimated in Table 15.

Table 15: Project emissions from emergency generator

Emgen_fuel	Electricity by emergency diesel generator	MWh	0
Diesel fuel EF	Emissions factor for electricity by diesel generator	tCO2/MWh	0,2626
Emgn_CO2	Total emissions _ emergency diesel generator	tCO2	0

Total Project emissions from all sources are then summarized for all relevant years in Table 16. *Ex-ante* estimates for 2009 through 2012 are equal to the *ex-ante* illustrative estimates shown.

Table 16: Total project emissions by year

year	APG combustion engines (furnaces)	Carbon mass fraction in APG	Molecular mass of CO2	Molecular mass of C	Total emissions project
		σ c_APG	*μ CO2*	*μ C*	*ECO2e_total project*
	tAPG	% mass	kgCO2/mole	kgC/mole	tCO_2e
Ex-ante illustration	9924	75,6899	44	12	27543
2009	5765	75,6899	44	12	16000
2010	9924	75,6899	44	12	27543
2011	10806	75,6899	44	12	29989
2012	12350	75,6899	44	12	34275

E.2. Estimated leakage and formulae used in the estimation, if applicable:

Leakage has not been quantified as explained in D.1.3.

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

Since quantified leakage estimates have been excluded, the total Project emissions are estimated as 26,952 tCO_2e per year and 107,807 tCO_2e for the period 2009-2012 (see table 16).

E.4. Estimated baseline emissions and formulae used in the estimation:

The estimations of the baseline emissions apply the equations demonstrated in the table 11 and 12. These estimations and are based on the measurements of the APG characteristics, available data on the Serginskoye flare stack for 2007-2008 and data on grid (Tyumenenergo) power plants generation. Future characteristics of the Serginskoye APG are not expected to change significantly (although the actual figures will vary based on ex post data). Therefore, *ex-ante* estimates provided in this section are assumed to be reasonably representative for each year of Project implementation.

The baseline emissions include 2 main sources:

- Annual emissions at the oil-field booster pumping station due to flaring of the amount of APG equal to the annual APG consumption by Project GPP;
- Annual regional grid plant emissions corresponding with the electric power generation, transmission and distribution equal to the amount of power consumed by the Project Owner from the GPP.

Table 17: Local baseline emissions from flaring APG to be used within the Project

Step 1. Determining mass amount of APG flared, kg			Ex-ante illustration
Index	Parameter	Units	Value
V APG	Annual volumetric flow of APG to be flared	ncm(000)	9230
P APG	Density of APG	kg/ncm	1,07521
M APG	Mass amount of APG flared	T	9924
Step 2. Calculation of APG molecular mass			
Index	Parameter	Units	Value
μ APG	Molecular mass of APG	kg APG/mole	24,0863
Step 3. Determining phisical-chemical parameters			
Index	Parameter	Units	Value
K APG	Adiabatic index of APG	-	1,27
Σc_APG	Mass fraction of carbon in APG	%	75,69
Kc	Quan. Of carbon atoms in molecular APG	carbon atoms	1,519
Step 4. Non-black flaring test: Discharge jet flow > 0,2 Sound velocity in APG flared			
Index	Parameter	Units	Value
U flow	APG`s discharge jet flow velocity	m/s	6 max 40 min
U sound	Sound velocity in APG flared	m/s	349,3
	Result of the test	6-40 m/s < 69,874 m/s	black firing
Step 5. CH4 emissions due to incomplete burning			
Index	Parameter	Units	Value
k u/f	Underfiring coefficient	-	0,035

σ CH4	CH4 mass fraction	% mass	2,203182
e CH4_baseline	CH4 emission factor_baseline	kgCH4/kgAPG	0,0771
MAPG	APG flared per year	kgAPG	9924184
E CH4_baseline	Total CH4 emissions_baseline	tCH4	765
		tCO2e	16071
Step 6. Total CO2 emissions from APG flaring			
Index	Parameter	Units	Value
μ CO2	Molecular mass of CO2	kg CO2/mole	44
Kc	Quan. of carbon atoms in molecular APG	carbon atoms	1,519
μ APG	Molecular mass of APG	kg/mole	24,09
e CH4_baseline	CH4 emission factor baseline	kgCH4/kgAPG	0,0771
μ CH4	Molecular mass of CH4	Kg CH4/kg mole	16
e CO_baseline	CO emission factor_baseline	kgCO/kgAPG	0,25
μ CO	Molecular mass of CO	kgCO/mole	28
e CO2	CO2 emission factor_baseline	kgCO2/kgAPG	2,1704
M APG	APG flared per year	kgAPG	9924184
E CO2 complete baseline	CO2 emissions from complete burning	tCO2e	21539
ECO2e_flaring_baseline	Total CO2e emissions from APG flaring	tCO2e	37610

The using (NII “Atmosfera”) methodology has been applied in this analysis as detailed in section D.1.1.4. (see table 11). The most critical inputs to these calculations are the parameters defining the composition of the APG that is used in the GPP. Step 4 of the calculation of baseline emissions from APG flaring also provides the calculation that is used to determine that the Serginskoye flare is operating in black-firing mode.

The usual historic mode of operation of this flare which is more than 8 years old has been black-firing mode and RITEK has little, if any, incentive to reconstruct the flare or change its operation in any fundamental way. The Project sponsors do not have guaranteed access to the specific data that would be required to calculate this test at routine intervals in the future. However, it is believed that any change sufficient to move away from black-firing mode would necessarily involve substantial reconstruction of the flare that would be clearly visible. Thus, photo documentation that the flare has not been fundamentally rebuilt is proposed as the appropriate monitoring method to establish that the black-firing parameters are appropriate for use in future calculations. If significant observable reconstruction occurs, the Project sponsor will request the data needed to recalculate the black-firing test.

Local baseline annual average emissions from the APG flared are estimated to be 37610 tCO2e. In the baseline scenario, RITEK would continue to consume electricity from the grid power plants. The respective amount of electricity is supplied by the GPP and the emergency diesel generator in the Project scenario. The *ex-ante* estimates of the annual baseline Tyumenenergo grid power plants emissions related to this supply are equal to 17493 tCO_2e (see table 12A-B). Monthly and annual power deliveries to RITEK will be monitored due to confirmed metering devices on feeders. The average power plants emission factor based on “Tool to calculate the emission factor for an electricity system” (as developed in detail in Annex 2) is equal to 0.522 t of CO2/MWh, according to the data based on five year record of operating experience.

Local and substituted power plants baseline emissions taken together as shown in Table 18 to make the total annual *ex-ante* estimate of 55,102 tCO2e. The *ex-ante* estimates for years 2009 through 2012 are assumed to be identical to the illustrative case shown, thus the total baseline emissions for the period 2008-2012 are estimated at 215,683 tCO_2e.

Table 18: Total baseline emissions

Year	Total CO2e emissions from APG flaring	Total CO2 emissions_grid	Total baseline emissions
	ECO2e_flaring_baseline	*ECO2_total*	*E CO2e_total_baseline*
	tCO2e	tCO2e	tCO2e
ex-Ante Illustration	37610	17493	55102
2009	21849	10162	32011
2010	37610	17493	55102
2011	40951	19047	59999
2012	46803	21769	68571
Total for 2009-2012	147213	68471	215683

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

The *ex-ante* emission reduction estimate is shown in Table 19 below. *Ex*-ante estimates are the same for future years although the actual figures will vary based on *ex-post* data on the APG used, the composition and characteristics of that APG, and the electricity delivered from the GPP (and the emergency diesel generator). Estimated emission reductions are 26,969 tCO_2e per year and 107,876 tCO_2e for the period 2009-2012.

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

The estimations for the Project emissions are provided in the tables 14, 15 and 16 in the section E.1. and the estimations for the baseline emissions are provided in the tables 17,18. As shown in the table 19, for the period 2009-2012, the total project emissions reductions due to the Project are estimated *ex-ante* at 107,876 tCO_2e as a difference between the project emissions (107,807 tCO_2e) and baseline emissions (215,683 tCO_2e).

Table 19: Ex-ante emission reduction estimates

Year	Estimated project emissions (tonnes of CO2 equivalent)	Estimated leakage (tonnes of CO2 equivalent)	Estimated baseline emissions (tonnes of CO2 equivalent)	Estimated emissions reductions (tonnes of CO2 equivalent)
Example		0		
2009	16000	0	32011	16011
2010	27543	0	55102	27559
2011	29989	0	59999	30010
2012	34275	0	68571	34296
Total (tonnes of CO2 equivalent)	107807	0	215683	107876

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:

According to the Order of the State Committee of the Russian Federation for Environmental protection as of 15.05.2000 # 372 "On the approval of the regulations on the assessment of the impact of the planned economic and other activity on the environment of the Russian Federation" the project developers must include in the project documentation the clause on assessment of environmental impact.

On assignment with *RITEK*, a scientific research institute, *NIPIGasPererabotka*, has elaborated the environmental impact assessment (EIA) for the Project.

EIA consists of the following chapters:

- general part;
- physical-geographical characteristics of the Project site;
- characteristics of the Project GPP as a polluting source;
- water disposal and water usage;
- waste management;
- impact on atmospheric air;
- protection and sound management of land;
- scope of environmental protection works;

With regard to the impact to atmospheric air, the emissions of polluting substances during Project construction and operation periods are represented in the tables 20, 21 and 22.

Table 20: Polluting emissions during operation period

Location	Source	Quantity	Polluting emissions		
			Type	g/sec	tonnes/year
GPP	Gas engine flue pipe	2	Carbon oxide, CO	2,13013	33,840949
			Nitrogen dioxide, NO_2	2,17518	34,556650
			Saturated hydrocarbons C1-C5	0,30903	7,796532
			Soot	0,08057	1,279936
			Sulphur dioxide	1,148883	18,25207444
			Formaldehyde	0,022978	0,365047
			Benzpyrene	0,000000252	4,003474E-06
			Nitrogen Oxide, NO	0,351991	5,592011

Table 21: Polluting emissions from machinery during construction period (12 months)

Location	Source	Quantity	Polluting emissions		
			Type	g/sec	tonnes/year
Project site	Construction machinery	15	Carbon oxide, CO	0,1670	9,12774
			Nitrogen dioxide, NO_2	0,1718	8,8732
			Kerosene	0,0484	3,1951
			Soot	0,0356	2,2834
			Sulphur dioxide	0,0216	1,3776
			Nitrogen Oxide, NO	0,351991	6,9952

Table 22: Polluting emissions from welding during construction period

Location	Source	Quantity	Polluting emissions		
			Type	g/sec	tonnes/year
Project site	welding		Ferrous oxide	0,007722	0,03791
			Manganese	0,000605	0,00291
			Dust SiO_2	0,000556	0,00277
			Fluorides	0,000516	0,002447
			Carbon Oxide, CO	0,00738	0,03559
			Nitrogen Oxide, NO	0,001500	0,00742

As shown in the table 20, the estimated climate effect will be limited to emissions of saturated hydrocarbons (C_1-C_5) in the amount of 7.796532 tonnes a year (on a basis of a one GPP's gas engine) and 1,366568 tonnes a year

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:

The environmental impact assessment (EIA) documentation with regard to this Project has undergone public environmental examination. The KhMAO Environment Protection Office (Okt'abrsky) has issued a conclusion stating that the Serginskoye GPP, complies with the requirements of the environmental legislation, normative and technical design documentation.

SECTION G. Stakeholders' comments

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

This project has not been controversial since the site is within the leasehold area that RITEK has long used for oil development and the emissions from the GPP are less significant than those from the flare. No significant comments were received during the preparation of the EIA.

Annex 1

CONTACT INFORMATION ON PROJECT PARTICIPANTS

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Annex 2

BASELINE STUDY

1. The description of the Tyumen power system

Tyumen power system is a major power complex of Ural United Power System. It delivers power and heat energy to consumers of the Tyumen oblast, including two autonomous Okrugs: Yamalo-Nenetzky and Khanty-Mansijsky. The description of the Tyumen power system is based on the official data site of the Tyumen power dispatching office.
The Tyumen power system unites ten thermal power plants, with the total installed capacity of 11,389 MW, including the following biggest plants:

Table 23: The biggest power plants in Tyumen power system

	Powerplant	Installed capacity, MW

1	Surgut GRES 1	3,280
2	Surgut GRES 2	4,800
3	Urengoy GRES	24
4	Nizhnevartovsk GRES	1,600
5	Tyumen HPP – 1	472
6	Tyumen HPP – 2	755
7	Tobolsk HPP	452
	Total	11,383

As of 1 January 2006, Tyumen power system produced 74,541.4 GWh of electricity (see table 25). Total consumption of electricity in Tyumen Oblast represented 69,972 GWh (see Table 24).

Table 24: Consumption of electricity in Tyumen oblast

	Consumers	GWh	Share%
1	Power plant's own use and grid losses	8,43	12,0
2	Industrial users	47,14	67,4
3	Transport and communications	7,06	10,1
4	Construction	6,80	9,7
5	Agriculture	0,280	0,4
6	Households	0,262	0,4
	Total	69,972	100

The length of grid transmission lines of 110-500 kV is 35,318.00 km, including:

500 kV transmission lines - 5453 km;
220 kV transmission lines- 7540 km;
110 kV transmission lines 22325 km

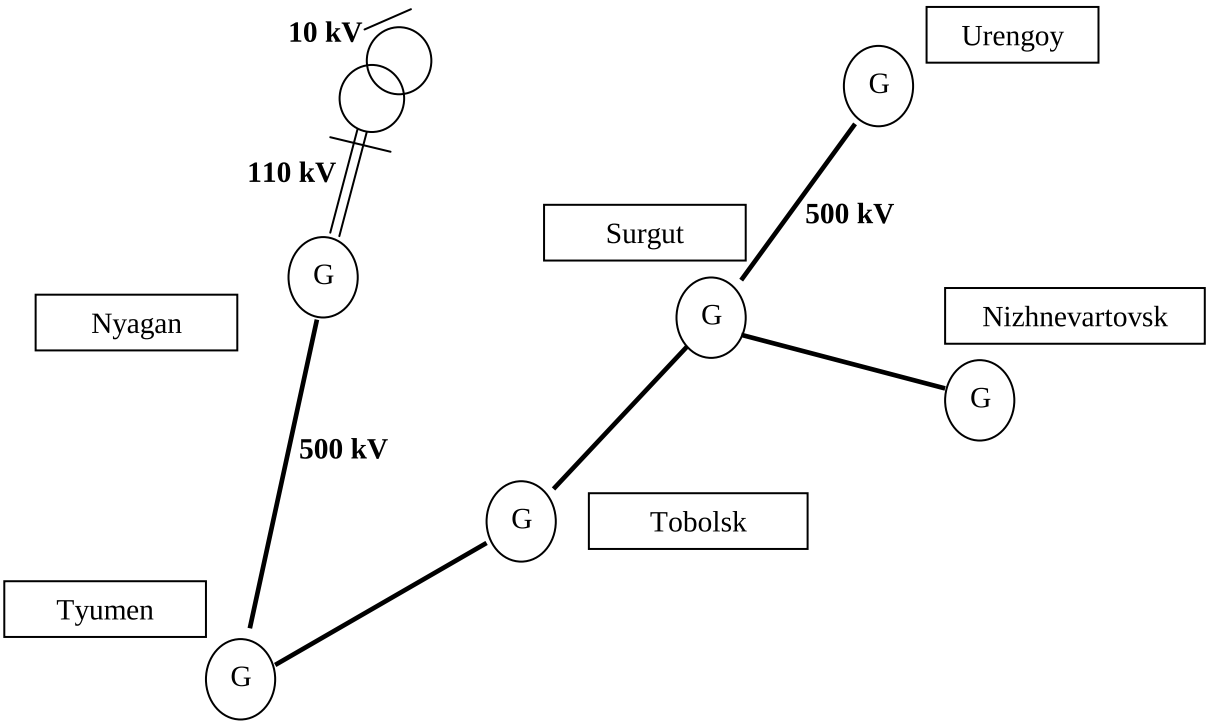
2. Calculation of gross generation/net generation ratio

Table 25: Gross generation/net generation ratio, own use and losses

	Item	Unit	Value
1	Electricity produced (gross generation)	GWh	74,54
2	Electricity delivered into grid	GWh	70,80
3	Own Use and Transmission Losses	GWh	8,42
4	Own Use (1) – (2)	GWh	3,74
5	Transmission Losses	GWh	4,68
6	Transmission Losses (5)/(2)	%	6,6
7	Gross generation/net generation, (1)/(2)		1,053

3. Delivery of the grid electricity to the Serginskoye oil field substation 10/110 kV and distribution among 10kV and less consumers

Prior the Project activity the electricity to the Serginskoye oil field 10 kV consumers was delivered from the grid of the Tyumen power system through the local 110/10 kV step down substation. Below is the sketch map presenting electricity delivery paths from the grid power plants to consumers at Serginskoye and other oil fields.



4. Delivery losses

During delivery of electricity through a grid transmission system that includes step up transformation, high voltage transmission system, step down transformation and medium and low voltage distribution lines, technical losses due to physical processes take place.
Since the reported delivery loss data for the Tyumen grid are not clear regarding the delivery voltages being referenced, more generic data was considered for Russian power systems. Table 26 shows losses of 6.0% from grid plants to 10 kV delivery points. Thus, the calculated values in the Project Monitoring Workbook have been limited to a conservative range of 5.0% to 6.0%.

Table 26: Loss percentage, %

Transmission system point	Loss percentage,%
Step up transformation (grid power plant – 500 kV substation)	1,0
500 kV transmission line	1,0
Step down transformation (500 kV line – 110 kV line)	1,0
500 kV transmission line	1,5
Step down transformation (110 kV – 10 kV)	1,5
Distribution lines (10 kV)	8
Total	**14**

Based on the data above, the sum of delivery losses in a regional system is 14%. But, due to the proximity (0.3-12,5 km) of local end consumers to the step down 110/10 kV substation at the Serginskoye oil field, the electricity losses in 10 kV voltage distribution lines are not taken into account.

Therefore, an extremely conservative estimate of 6% for the calculations of the electricity amount displaced by the Project has been used that excludes all distribution line losses.

5. Calculation of the baseline GHG emission grid factor for the Tyumen power system

The baseline emission factor (EF_y) for the grid-connected power plants is estimated according to the "Tool to calculate the emission factor for an electricity system" taken as a combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) factors. Calculation for this combined margin is based on the study and data on Tyumen power system provided by the Energy Scientific Research Institute named after G.M. Krzhizhanovskiy (OAO "ENIN") and the calculation was performed for 2004 for RAO "UES". In frameworks of preparing "Energy Strategy Development until 2015", According to ENIN, Tyumen power grid is assumed to be a largely separable entity.

Operating Margin emission factor ($EF_{OM,y}$)

Simple OM (a) method was used for calculation of Operating Margin emission factor ($EF_{OM,y}$) value. According to the "Tool to calculate the emission factor for an electricity system", the Simple OM method can only be used where low-cost/must run sources (which typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation) constitute less than 50% of total grid generation in average of the five most recent years. The Simple OM emission factor for Tyumen power grid is calculated *ex-ante* using the full generation weighted average for the most recent 3 years for which data were available at the time of PDD submission (from ENIN study).

The Simple OM emission factor is calculated as generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost and must-run plants:

$$EF_{OM,y} = \frac{\sum_{i,j} F_{i,j,y} * COEF_{i,j}}{\sum_j GEN_{j,y}}$$

Where

$F_{i,j,y}$ is amount of fuel i (in a mass of volume unit) consumed by relevant power sources *j* in year(s) *y*,

j refers to the power sources delivering electricity to the grid, not including low-operating cost and mustrun power plants, and including imports to the grid,

$COEF_{i,j}$ is CO_2 emission coefficient of fuel *i* (tCO_2/mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources *j* and the percent oxidation of the fuel in year(s) *y*,

$GEN_{j,y}$ is the electricity generated by source *j*.

The CO_2 emission coefficient $COEF_i$ is obtained as:

$COEF_i = NCV_i * EF_{CO2,i} * OXID_i$,

Where

NCV_i is the net calorific value (energy content) per mass or volume unit of a fuel *i*,

$OXID_i$ is the oxidation factor of the fuel (1996 Revised IPCC Guidelines for default values),

$EF_{CO2,i}$ is the CO_2 emission factor per unit of energy of the fuel *i*.

Where available, local values of NCV_i and $EF_{CO2,i}$ should be used.

The main assumptions with regard to the above-described formula in the case of Tyumen power grid are as follow:

- As shown in the table 27, the power generating plants of Tyumen grid are consuming natural gas and APG. Thus all regional power plants were considered as included generation.
- The Tyumen grid system is considered to have zero import. Due to the lack of information on imports and exports, this assumption was based on the fact that the electricity production by the Tyumen grid power plants exceeds consumption in this region.

• The local value of the CO_2 emission coefficient for natural gas consumed by the grid power plants was used. This value is estimated as 0.055 tCO_2/GJ (or 1.62 tCO_2 per ton of coal equivalent), based on the results of GHG emission inventory of RAO "Unified Electricity Systems".
• The local value of the CO_2 emission coefficient for associated petroleum gas (APG) of Western Siberian oil fields was used. This coefficient was calculated using the data on chemical composition of APG from ten oil fields (based on ENIN data).
• Because of absence of data on unit consumption of energy for generation of electricity at Urengoi GRES, this value was taken to be equal to the average for Tyumen power system.

Build Margin emission factor ($EF_{BM,y}$)

The Build Margin emission factor is calculated as the generation-weighted average emission factor (tCO_2/MWh) of a sample of power plants *m* as follows:

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

Where
$F_{m,y}$, $COEF_{i,m}$, $GEN_{m,y}$ are analogous to the variables described for the simple OM method above for plants *m*.
The Build Margin emission factor is calculated according to the option 1 of the Step 2 of the "Tool to calculate the emission factor for an electricity system" as $EF_{BM,y}$ *ex-ante* based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. The sample group *m* consists of five power plants that have been built most recently. This sample group comprises the annual generation of 41.42 MWh/y in 2004 (see table 31). The annual generation from these five power plants (calculated as generation in condensation circle) is larger that the power capacity additions that comprise 20% of the system generation (in MWh) and that have been built more recently.[35] The Tyumen system generation data is provided at the table 27 below.
During last 3 years some new projects of commissioning of new generating capacities (with modern technologies use) were announced. They were reconstruction and modernization of second block on Tyumen' HPP-1, commissioning of GPP in Nyagan (project belongs to TGK-10) with installed 2400 MW, and GPP in Tarko-Sale with designed capacity 1200 MW. But due to world crisis these plans were stopped. The most dramatic situation was with the second block of Tyumen' HPP-1 semi-constructed.
Thus, one may reasonably expect that GHG emission grid factors for the Tyumen power system (tCO_2/MWh) will remain roughly at today's level until 2012 (notwithstanding from the commissioning of second block on Tyumen' HPP-1, as the last one will occupy only 1% of total installed capacity) .

Baseline emission factor (EFy)
Baseline emission factor *EFy* is calculated as the weighted average of the Operating Margin emission factor $EF_{OM,y}$ and the Build Margin emission factor ($EF_{BM,y}$):

$$EF_y = w_{OM} * EF_{OM,y} + w_{BM} * EF_{BM,y}$$

where
w_{OM} and w_{BM} by default, are 50% (i.e. $w_{OM} = w_{BM} = 0.5$).

Input tables for the calculation of the baseline emission factor
Table 27: Main indicators of Tyumen Power system in 2004

	Power plant	Installed capacity	Distribution capacity	Comissioning date	Delivery	In cogeneration cycle	In condensation cycle	Fuel consumption	Fuel type
		MW	MW		GWh	GWh	GWh	TJ	

1	Surgut GRES 1	3280	3280	1983	23316	1153	22164	217962	APG
2	Surgut GRES 2 **	4800	4800	1988	30867	417	30450	273193	APG
3	Urengoy GRES	24	20,3	1992	165	41	120	2549	Gas nat.
4	Nizhnevartovsk GRES	1600	1600	2003	6692	123	6569	60065	Gas nat.
5	Tyumen HPP – 1*	472	472	1970	2339	1489	850	30384	Gas nat.
6	Tyumen HPP – 2	755	755	1990	4204	1511	2693	43041	Gas nat.
7	Tobolsk HPP	452	443	1986	2417	803	1614	38295	Gas nat.
		11389	11375,3		70000	5537	64463		

*First block of HPP was modernized and switched-on in the beginning of 2004 (January). www.regnum.ru/news/223849.html. Some later second block was switched-off for the next stage of modernization. So nowadays distribution capacity is about 400 MW.
** Due to a fire accident in the beginning of 2008 GRES was exploited (during the year) only at 40% of total installed capacity and the generation was substituted by another power-plants (mainly by Nizhnevartovsk GRES).

Table 28: Unit Consumption of Fuel by Tyumen Grid Power Plant

Power plant	**1996**		**1997**		**1998**		**1999**		**2000**	
	Share of elec. Prod by equip. group, %	**Unit cons MJ/kWh**	**Share of elec. Prod by equip. group, %**	**Unit cons MJ/kWh**	**Share of elec. Prod by equip. group, %**	**Unit cons MJ/kWh**	**Share of elec. Prod by equip. group, %**	**Unit cons MJ/kWh**	**Share of elec. Prod by equip. group, %**	**Unit cons MJ/kWh**
Surgut GRES 2	**100**	**9,24**	**100**	**9,21**	**100**	**9,15**	**100**	**9,09**	**100**	**9,07**
Nizhnevartovsk GRES	**100**	**9,38**	**100**	**9,31**	**100**	**9,26**	**100**	**9,10**	**100**	**8,81**
Tyumen HPP – 1	**100**	**9,08**	**100**	**9,03**	**100**	**8,72**	**100**	**8,51**	**100**	**8,79**
Tyumen HPP – 2	**78**	**7,87**	**81**	**7,90**	**81**	**8,03**	**76**	**8,15**	**80**	**8,26**
	22	**9,97**	**19**	**10,2**	**19**	**10,09**	**24**	**10,12**	**20**	**10,19**
Tobolsk HPP	**100**	**9,83**	**100**	**10,55**	**100**	**10,05**	**100**	**9,92**	**100**	**10,12**

Table 29: Calculated values of fuel unit consumption for electricity production at Tyumen Power System

Power plant	**Calculated value of fuel unit consumption for electricity production, MJ/kWh**									
	1996	1997	1998	1999	2000	Method of calculation	2001	2002	2003	2004
Surgut GRES 1	9,7	9,8	9,7	9,58	9,7	Averaging	9,65	9,65	9,65	9,65
Surgut GRES 2	9,24	9,21	9,15	9,09	9,07	Averaging	9,03	9,0	8,9	8,9
Nizhnevartovsk GRES	9,38	9,31	9,26	9,10	8,81	Averaging	8,7	8,5	8,6	8,6
Tyumen HPP – 1	9,08	9,03	8,72	8,51	8,79	Averaging	8,7	8,7	8,6	8,5
Tyumen HPP – 2	8,3	8,3	8,4	8,6	8,6	Averaging	8,7	8,8	8,9	9,0
Tobolsk HPP	9,83	10,55	10,05	9,92	10,12	Averaging	10,2	10,3	10,4	10,5
Mean	9,3	9,4	9,2	9,1	9,2		9,2	9,2	9,1	9,1

* To estimate the fuel unit consumption for electricity production from 2001 to 2004, the averaging method was applied to the available information for the period from 1996 to 2000. This method consists in calculating the simple average value of annual changes in the fuel unit consumption during the past period and applying this average value for the subsequent years. Decreasing of fuel consumption per unit (on few plants) doesn't mean significant modernization of exploiting equipment but mainly optimization of the generation cycle getting more flexible.

Table 30: CO_2 emission coefficient for associated petroleum gas (APG) of Western Siberian oil fields

Oil field	Composition of associated gas, vol.%							CO_2 emission coefficient, tCO_2/GJ *(COEFi)*
	CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	N_2	CO_2	
Aganskoye	0,806	0,06	0,067	0,04	0,012	0,012	0,003	0,059
Sovietskoye	0,736	0,058	0,099	0,066	0,025	0,014	0,003	0,059
Mamontovskoye	0,772	0,042	0,084	0,063	0,021	0,013	0,006	0,059
Tarasovskoye	0,779	0,049	0,082	0,046	0,013	0,017	0,013	0,059
Barsukovskoye	0,757	0,093	0,084	0,041	0,011	0,012	0,002	0,057
Purneftegazgeologia	0,915	0,035	0,018	0,013	0,005	0,012	0,004	0,058
Samotlorskoye-1	0,744	0,101	0,073	0,032	0,007	0,001	0,003	0,057
Samotlorskoye -2	0,902	0,03	0,033	0,017	0,005	0,012	0,001	0,058
Samotlorskoye -3	0,850	0,029	0,057	0,039	0,012	0,009	0,004	0,058
Average	0,827	0,03	0,065	0,048	0,016	0,012	0,003	0,058

Table 31: Calculation of Operating Margin (*$EF_{OM,y}$*), Build Margin (*$EF_{BM,y}$*) and Baseline emission factor (*EF_y*)

Power plant	Electricity generated by grid plant,	Unit Consumption of fuel	Unified fuel consumption	Efficiency	Fuel consumption by grid plant,	Emission coefficient for fuel,	Total CO2 emissions by plant,	Operating Margin Emission Factor,	Build Margin Emission Factor,	Combined Margin Emission Factor,
	GEN				*F*	*COEF*	*F*COEF*	*EFom*	*EFbm*	*EFcm*
	GWh	**MJ/kWh**	**gruf/kWh**	**%**	**TJ**	**tCO2/GJ**	**Tonnes CO2**	**tCO2/MWh**	**tCO2/MWh**	**tCO2/MWh**
Surgut GRES 1	22164	9,65	329	37	213777	0,058	12449,43	0,562		
Surgut GRES 2	30450	8,90	303	40,5	271056	0,058	15785,09	0,518	0,518	
Urengoy GRES	124	9,13	311	39,5	1132	0,055	62,59	0,505	0,505	
Nizhnevartovsk GRES	6569	8,28	282 / 303*	43,5	54397	0,055	3167,89	0,507	0,507	
Tyumen HPP – 1	850	8,52	290	42,2	7244	0,055	400,56	0,471		
Tyumen HPP – 2	2693	8,97	306	40,1	24152	0,055	1335,38	0,496	0,496	
Tobolsk HPP	1614	10,45	356	34,5	16870	0,055	932,79	0,578	0,578	
Tyumen Power Grid	64464				588474		34133,73	0,531	0,517	0,524

* Source – OGK-1 (2008) official site. www.ogk-1.ru

Annex 3

MAIN ELEMENTS OF THE METHODOLOGY OF CALCULATION OF EMISSIONS OF HAZARDOUS SUBSTANCES INTO THE ATMOSPHERE DUE TO THE FLARING OF THE ASSOCIATED PETROLEUM GAS AT FLARING STACKS

Data on flaring conditions and key characteristics of APG necessary for calculations of emissions of hazardous substances into the atmosphere due to the flaring of the associated petroleum gas at flaring stacks:

Indicator	Unit	Comments
V_{APG}	Nm3	Annual volumetric flow of APG to be flared
t	°C	Temperature of APG before flaring
D	m	Stack' pipe diameter
V_{APG}	% vol	Volumetric composition of APG
V_i	% vol	Volumetric concentration *i*-component in APG

ρ_{APG} ρ_i	Kg/m3	Density of APG and its components
m_i	Kg/mole	Molar mass of *i*-component in APG
k_i	Scalar	Adiabatic index of *i*-component in APG
σ_{C-i}	% mass	Mass content of carbon of *i*-components in APG

Step 1. Determining of mass amount of APG flared, kg

$$M_{APG} = V_{APG} * \rho_{APG}$$

Step 2. Calculation of APG molecular mass

$$\mu_{APG} = \Sigma\ 0.01*V_i * m_i;$$

Step 3. Determining physical-chemical characteristics of APG

3.1. Adiabatic index of APG (K_{APG}):

$$K_{APG} = \Sigma\ 0.01 * V_i * k_i;$$

3.2. Mass fraction of i-component in APG (σ_i):

$$\sigma_i = 0.01*Vi * \rho_i / \rho_{APG}$$

3.3. Mass fraction of carbon in APG (σ_C):

$$\sigma_{C\_APG} = \Sigma\ \sigma_i * \sigma_{C-i}$$

3.4. Quantity of carbon atoms in molecular formula of APG (Kc):

$$Kc = 0.01*(\sigma_{C\_APG}/\mu_c)*\mu_{APG}$$

μ_c - molecular mass of carbon equals to 12.

Step 4. Non-black firing test

This test determines combustion efficiency of the APG flaring. The formulae used:

4.1. The condition of non-black firing:

if $U_{flow} > 0,2\ U_{sound}$

then the soot does not discharges from the stack's pipe, the APG burning is complete.

if $U_{flow} < 0.2\ U_{sound}$,

the soot discharges that demonstrating incomplete burning of APG. In this case, under-firing coefficient equal to 0,035 must be taken into account in further calculations:

4.2. APG's discharge flow velocity, m/sec (U_{flow}):

$$U_{flow} = 4*W_v / (\pi *d^2)$$

W_v – APG volumetric flow, m^3/s;
d –Serginskoye oil field stacks diameter is equal to 0,2 m and 0,2 m;

4.3. Sound velocity in APG flared, m/sec (U_{sound}):

$$U_{sound}=91.5*(K*(T_{APG}+273)/\mu_{APG})^{0.5}$$

K_{APG} - adiabatic index of APG
$K_{APG} =\Sigma\ 0.01* V_i * k_i;$
Vi, - volumetric concentration i-component in APG, % vol;
ki – adiabatic index of i-component in APG;
T_{APG} – temperature of APG, °C;
μ_{APG} – molecular mass of APG, kg/mole.

Step 5. Determining CH_4 emissions due to incomplete burning

5.1. CH_4 emission factor, kg CH_4/kg APG (e_{CH4})

$$e_{CH4} = 0.01* \text{under-firing ratio} * \sigma_{CH4}$$

σ_{CH4} – CH_4 mass fraction, %.

5.2. CH_4 emissions, tonnes of CH_4 (E_{CH4})

$$E_{CH4} = 0.01 *e_{CH4} * M_{APG};$$

Step 6. Determining CO_2 emissions, taking into account the incomplete burning

6.1. CO_2 emission factor, kg CO_2/kg APG (e_{CO2})

$$e_{CO2} = \mu_{CO2} (k_C /\mu_{APG} - e_{CH4} / \mu_{CH4} - e_{CO} / \mu_{CO})$$

e_{CO} – CO emission factor, kg CO/kg APG; equals to 0,25[38]
μ_{CO2} – molecular mass of CO_2, equals to 44;
μ_{CH4} – molecular mass of CH_4, equals to 16;
μ_{CO} – molecular mass of CO, equals to 28

6.2. CO_2 emissions, taking into account the incomplete burning, tCO_2 (E_{CO2})

$$E_{CO2} = e_{CO2} * M_{APG}$$

Step 7. Determining total CO_2 equivalent emissions

$$E_{CO2e\_flaring} = E_{CO2} + E_{CH4} * GWP_{CH4}$$

GWP_{CH4} - Global Warming Potential, equals to 21 for methane